Application: A.20-11-XXX

Witness: Y. Freedman, A. Hastings, and J. Varela

Chapter: 1- Introduction and Policy

PREPARED DIRECT TESTIMONY OF

YURI FREEDMAN, AUSTIN HASTINGS AND JOSEPH C. VARELA

ON BEHALF OF SOUTHERN CALIFORNIA GAS COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, PACIFIC GAS AND ELECTRIC COMPANY, AND SOUTHWEST GAS CORPORATION

(POLICY)

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

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TABLE OF CONTENTS

Page

CHAPTER 1

PREPARED DIRECT TESTIMONY OF YURI FREEDMAN, AUSTIN HASTINGS AND JOSEPH C. VARELA

(Policy)

I. PURPOSE

Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southwest Gas Corporation (Southwest Gas) (collectively, the Joint Utilities) provide preliminary information and recommendations in the form of testimony to respond to the California Public Utilities Commission's (Commission) November 21, 2019 Assigned Commissioner's Ruling Opening Phase 4 (Phase 4 Ruling) of the Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions (Rulemaking).[1] The Phase 4 Ruling requires the Joint Utilities to "submit an Application with the following proposed additions or revisions to the Standard Renewable Gas Interconnection Tariff (SRGI Tariff):

a. A definition of renewable hydrogen for purposes of the Tariff;

b. A Preliminary Renewable Hydrogen Injection Standard;

c. Any modification to the hydrogen standard for biomethane; and

d. Any modifications to the interconnection protocols and agreements."

The Joint Utilities believe that development of a hydrogen injection standard is an important early step in progressing toward meeting the state's climate goals. To that end, the Joint Utilities are united in our efforts towards advancing real solutions in California's progress toward carbon neutrality. At this time, the Joint Utilities do not propose any additions or revisions to the SRGI Tariff that was adopted by the Commission in Decision (D.) 20-08-035 (Decision) on August 27, 2020; however, the Joint Utilities intend to propose future modifications to the SRGI Tariff and identify a hydrogen injection standard as critical research is conducted and additional information is gathered, to ensure the safety of the public and

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[1] Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of Rulemaking 13-02-008, R.13-02-008 (Nov. 21, 2019), https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M320/K307/320307147.PDF.

reliability of our systems. This approach was communicated to the public and members of the Commission's Energy Division during public workshops held pursuant to Paragraph 5 of the Phase 4 Ruling which requires the Joint Utilities to "hold at least two meetings of a technical hydrogen interconnection working group, open to all parties of the proceeding, to assist in developing the Application required by Paragraph 4 based on evaluation of available research and practices in other locations." The first technical hydrogen working group (working group) meeting was held on January 15, 2020, and an initial report was submitted to the Commission on February 19, 2020. The second working group meeting was held on June 16, 2020, and a subsequent report was filed August 14, 2020. Both working group reports are attached hereto as Attachment 1.

The purpose of this testimony is to (1) present a framework of what will be included and considered in a future hydrogen injection standard, (2) provide a definition of renewable hydrogen, (3) provide an overview of the Joint Utilities' current efforts in advancing the use of hydrogen within their respective systems, and (4) provide the rationale for why hydrogen can and should be an essential component of the future carbon neutral energy economy.

II. FRAMEWORK FOR A PRELIMINARY HYDROGEN INJECTION STANDARD

The Joint Utilities have been actively involved in studying and promoting hydrogen prior to the Phase 4 Ruling. This includes studying various hydrogen production pathways and actively promoting and engaging in efforts to investigate compatibility of hydrogen within the Joint Utilities' respective systems. Herein, the Joint Utilities elaborate on the current hydrogen trigger level for biomethane injected into the Joint Utilities' systems.

A. Current Biomethane Injection Standard

Currently, there is no maximum allowable hydrogen limit in the Joint Utilities' tariffs. Hydrogen is identified as a Pipeline Integrity Protective Constituent in the Joint Utilities' SRGI Tariffs with a trigger level of 0.1 vol%.[2] Exceeding the trigger level results in additional monitoring and measurement controls at the specific interconnector(s) that exceeds the threshold.[3] These controls may include increased frequency of the hydrogen testing from

[2] *See* PG&E Gas Rule 29, SoCalGas and SDG&E Gas Rule 45, and Southwest Gas Rule 22.
[3] *See* Decision Regarding the Biomethane Implementation Tasks in Assembly Bill 1900, D.14-01-034 (Jan. 16, 2014).

annually to quarterly, an impact study or installation of corrosion monitoring probes. Additionally, these controls are based on the specific interconnector's gas stream that is exceeding the threshold, rather than a system-wide deviation. As described in Chapter 4, each gas system is unique and therefore further research needs to be conducted in order for the Joint Utilities to safely blend higher amounts of hydrogen into their systems.

The Joint Utilities are committed to conducting the necessary work to safely introduce higher blend percentages into their respective systems; however, at this time, the Joint Utilities are not ready to propose a preliminary hydrogen injection standard or modifications to the hydrogen trigger level for biomethane, including modifications to the interconnection protocols and agreements.[4] Instead, as presented at the working group[5] meeting held on June 17, 2020, the Joint Utilities are requesting approval of a plan for developing a hydrogen injection standard with the proposed framework and milestones for next steps (see Section D, *infra*). As the Joint Utilities progress through the plan, fill the gaps of knowledge, and prepare the gas system for injection of hydrogen, proposed modifications to the SRGI Tariffs will be submitted to the CPUC for review and approval.

B. The Joint Utilities Prioritize Safety, System Integrity, Affordability, Reliability, and Carbon Neutrality

The Joint Utilities prioritize the following while working toward the introduction of hydrogen in the gas system: safety, system integrity, affordability, reliability, and carbon neutrality.

- **Safety:** Protecting the public, employees and contractors is the Joint Utilities' number one priority. As explained below, the Joint Utilities are following their American Petroleum Institute (API) 1173 Pipeline Safety Management Systems (PSMS) plans that provide for consistent and deliberate change management around the introduction of hydrogen.
- **System Integrity:** The Joint Utilities develop codes, standards, procedures and perform assessments of the gas pipeline system to mitigate integrity risk to the pipelines and keep the pipelines transporting gas safely. The Joint Utilities need to determine what

[4] Notably, the SRGI Tariff already provides a foundation for future changes to such protocols and agreements.
[5] *See* Attachment 1.

changes and updates need to be made to minimize risks to the gas system prior to injecting hydrogen into the system at various levels.

- **Affordability:** Expanding renewable energy in any form will be more expensive than relying solely on traditional energy sources. By utilizing existing infrastructure and by considering rate impacts in developing the hydrogen injection standard, the Joint Utilities demonstrate their commitment to providing scalable and affordable carbon neutral solutions.
- **Reliability:** As the use of intermittent renewable energy sources such as wind and solar increases, California must consider increasing challenges of maintaining reliability and resiliency. By creating a structured plan for safely increasing hydrogen injection into the gas system, the Joint Utilities will continue to deliver affordable and reliable energy to our customers and communities every single day, at the same time leveraging current investments in infrastructure, enhancing system reliability, and meeting customer expectations.
- **Carbon neutrality:** For California to achieve its carbon neutrality goals in less than three decades, hydrogen must have a significant role in the state's energy mix. The hydrogen injection standard is an important early step in progressing toward these goals. To that end, the Joint Utilities are united in our efforts towards advancing real solutions in California's progress toward carbon neutrality.

The Joint Utilities intend to utilize their respective API 1173 PSMS, which provide for a systematic approach to managing safety, including the policies and procedures for changes in how the Joint Utilities will incorporate hydrogen into their operations. API 1173 provides a framework for integrated and optimized asset, risk and operational management and provides structure and consistency around continuous improvement.

For hydrogen blending, the API 1173 Plan-Do-Check-Act model is realized in the Joint Utilities' research efforts described in Chapter 4, and the SoCalGas and SDG&E Hydrogen Blending Demonstration Program described in Chapter 3. Plan-Do-Check-Act is a continuous loop, and the Joint Utilities may choose to expand demonstration programs, expand risk modeling, and as noted above, will revise standards, policies, and procedures to safely blend hydrogen.

C. Future Hydrogen Injection Standards

1. Safety, system integrity, and reliability will guide future hydrogen injection standards.

The Joint Utilities propose to increase the hydrogen percentage blend over time as critical research is conducted and additional information is gathered from on-going analysis, research (as identified in the research matrix provided in the February 19, 2020 working group report provided in Attachment 1), and demonstration projects (see Chapter 3, Hydrogen Blending Demonstration Program). Updates and modifications to the SRGI Tariff will be required to include key elements for the interconnection and injection of hydrogen into the Joint Utilities' pipeline systems. At this time the Joint Utilities are not proposing modifications to the SRGI Tariff; however, work being done to understand the technical aspects of injecting and blending hydrogen into the gas system, as discussed in Chapter 4, will help define the modifications needed as we progress through the PSMS using the Plan-Do-Check-Act framework.

D. Proposed Schedule Progression and Future Approval of Hydrogen Blending Percentage

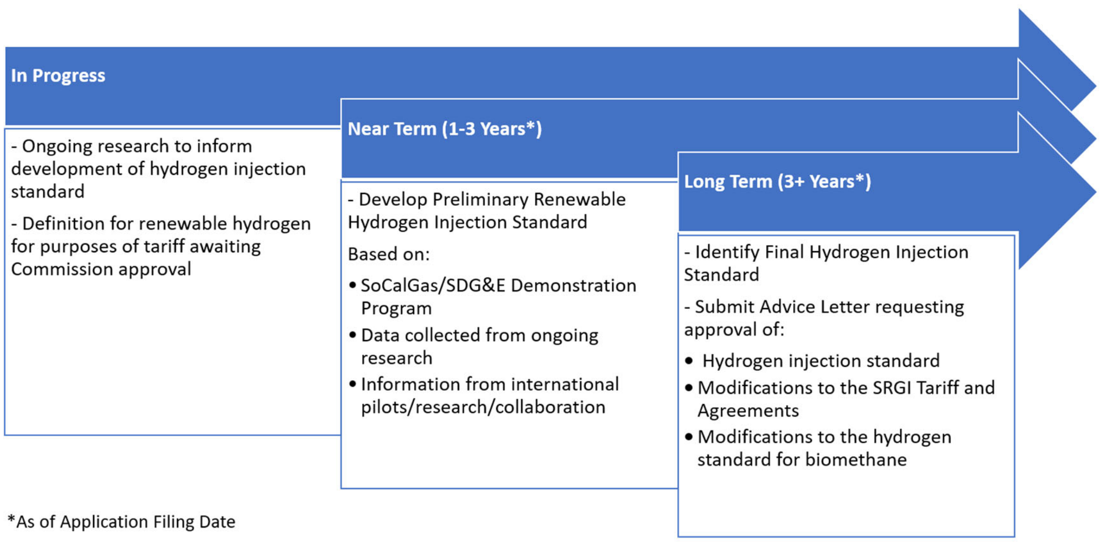
Foundational to the Joint Utilities' proposed framework is the successful and timely completion of research such that its findings and results can be safely integrated into each of the Joint Utilities' pipeline systems. As previously mentioned, the Joint Utilities intend to utilize this Application to lay the foundation for a hydrogen injection standard that prioritizes safety, system integrity, and reliability. The Joint Utilities believe that ongoing research will establish safe and innovative ways to re-purpose much, if not all, of our existing gas infrastructure for transport of a blend of Renewable Gas (RG) and natural gas. The demonstrations will be the primary vehicle for establishing the blending limit of similar systems such as comparable infrastructure components, materials, and customer equipment. Therefore, the Hydrogen Blending Demonstration Program proposed by SoCalGas and SDG&E in Chapter 3 will help guide our next steps towards a blending limit for similar plastic systems of all the Joint Utilities.

The Joint Utilities also propose to continue to hold an annual technical hydrogen working group open to the public and provide a follow up report to track progress on the demonstrations and research being conducted in support of achieving higher hydrogen percent blends. As more information becomes available through the research and demonstrations, the Joint Utilities will perform effectiveness reviews to determine when hydrogen blending can proceed forward.

The Hydrogen Injection Progression figure below (Figure 1) shows the path of ongoing research studies, demonstration projects (Chapter 3) and similar research (Chapter 4) and will validate current knowledge and test research results in operating conditions that reflect the diverse and complex natural gas infrastructure of each of the Utilities. It is possible that at the end of the scheduled studies, the result will lead to more questions with the need to conduct additional studies and testing to support the development of a hydrogen injection standard. The progression of work is dependent upon receiving approval for adequate funding mechanisms for the work to be completed. Chapter 4 contains broader technical details for the ongoing research.

Figure 1

Hydrogen Injection Progression



Although at this time the Joint Utilities are not seeking approval of a hydrogen injection standard, the Joint Utilities believe that future approval of a hydrogen injection standard should be approved via a Tier 3 Advice Letter with the appropriate technical information to support timely approval of the Utilities' request. A Tier 3 Advice Letter is appropriate as it is subject to Commission approval via adoption of a resolution during a voting meeting. This process involves a higher level of scrutiny and analysis, and the decision-making process is more transparent, as a resolution is subject to public comment. Therefore, the Joint Utilities request authorization from the Commission to submit a Tier 3 Advice Letter when the Joint Utilities have gathered enough supporting technical information to propose and defend a hydrogen injection standard.

III. RENEWABLE HYDROGEN

Herein, the Joint Utilities propose a definition for renewable hydrogen as required by the Phase 4 Ruling and describe the various production pathways to obtain renewable hydrogen.

A. Definition of Renewable Hydrogen

Renewable hydrogen means hydrogen derived from one of the following:

1) Electrolysis of water using renewable electricity. In this context, renewable electricity refers to electricity produced from sources which are eligible renewable energy resources as defined in California Public Utilities Code sections 399.11-399.36.[6]
2) Steam methane reforming (SMR), autothermal reforming (ATR), or methane pyrolysis of renewable gas (RG).
3) Thermochemical conversion of biomass, including the organic portion of municipal solid waste (MSW).

Although hydrogen produced by SMR, ATR, methane pyrolysis and thermochemical conversion of conventional methane with carbon capture and utilization or storage (CCUS)[7] is not included in the Joint Utilities' proposed definition of renewable hydrogen, CCUS can be employed to reduce greenhouse gas (GHG) emissions or to produce carbon negative hydrogen and should be included in any hydrogen injection standard approved by the Commission. A recent report by Lawrence Livermore National Laboratory[8] and a study by the Energy Futures Institute and Stanford[9] both strongly suggest that CCUS has a significant role in achieving California's carbon neutrality goals.

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[6] Adapted from 17 Cal. Code Regs. § 95481.

[7] Carbon capture, utilization, and storage refers to technologies that can reduce carbon dioxide (CO_2) emissions by capturing carbon emissions, transporting essentially pure carbon dioxide streams, and either storing it in underground reservoirs or using the carbon dioxide as a feedstock for commercial products including advanced materials.

[8] Sarah E. Baker et al., Lawrence Livermore National Laboratory, *Getting to Neutral: Options for Negative Carbon Emissions in California* (January 2020) at , *available at* https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.

[9] Webinar, Energy Futures Initiative and Stanford University, An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions (October 22, 2020) at S-1, *available at* https://sccs.stanford.edu/sites/g/files/sbiybj7741/f/efi-stanford-ca-ccs-full-rev1.vf-10.25.20.pdf.

The hydrogen resulting from any of these methods can be blended and injected into the natural gas system. Downstream, it could be separated out and used as fuel for fuel cell electric vehicles or remain as a blend and provided to end-use customers. In the future, it may be beneficial to consider 100% pure hydrogen pipelines to meet carbon neutrality targets as hydrogen demand increases.

B. Renewable Hydrogen Production Pathways

Below we elaborate further on each renewable hydrogen production pathway included in the Joint Utilities' definition.

1. Electrolysis

Water electrolysis uses electricity to split the water molecule into hydrogen and oxygen. This process takes place in an electrolyzer. Electrolyzers consist of an anode and cathode separated by a membrane, in an electrolyte solution. There are three main types of electrolyzers: (1) Polymer Electrolyte Membrane (PEM); (2) Alkaline; (3) Solid Oxide (SO).[10] Water electrolysis using renewable electricity allows for the storage of energy from the renewable electricity, that could otherwise be curtailed, in the form of hydrogen.

2. SMR, ATR, and Methane Pyrolysis

SMR involves methane (e.g. from natural gas or RG) reacting with high-temperature steam, 1292-1832ºF (700°C – 1,000°C) under 44 – 363 psi (3–25 bar) of pressure in the presence of a catalyst to produce hydrogen, carbon monoxide, and carbon dioxide.[11] Steam reforming is endothermic and requires heat to be supplied. In the "water-gas shift reaction," carbon monoxide and steam react over a catalyst to produce carbon dioxide and more hydrogen. Finally, in "pressure-swing adsorption," carbon dioxide and other impurities are removed from the gas stream, leaving marketable hydrogen. ATR combines SMR (endothermic) and partial oxidation (exothermic) reactions. Unlike SMR, ATR does not require external heat input because of the heat provided within the reaction vessel. The heat generated when methane is partially oxidized

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[10] Office of Energy Efficiency & Renewable Energy, Hydrogen Production: Electrolysis, *available at* https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.

[11] Office of Energy Efficiency & Renewable Energy, Hydrogen Production: Natural Gas Reforming, *available at* https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.

facilitates the endothermic SMR reaction.[12] Compared to SMR, ATR can be started and shut down more rapidly.[13] ATR also yields less NOx and net carbon dioxide emissions in comparison to SMR.[14] Methane pyrolysis involves the thermal decomposition of methane (e.g., from natural gas or RG) in the presence of a catalyst at temperatures ranging from 572 – 1832ºF (300ºC – 1000ºC), into separate solid carbon and gaseous hydrogen streams. The solid carbon can be used in many old and new industrial processes including as an advanced material feedstock for materials such as carbon fibers and carbon nanotubes.[15]

3. Thermochemical Conversion

Biomass gasification is a thermochemical process by which biomass is heated in the presence of oxygen to break it into its constituent molecules. Biomass pyrolysis is similar to biomass gasification, except the process occurs in the absence of oxygen. For biomass gasification, some oxygen is used for combustion/incineration within a certain part of the reactor. The process uses partial oxidation at high temperatures >1292ºF (>700ºC) with oxygen, air or steam.[16] Gasification produces an intermediate product gas called synthesis gas or syngas as its primary output consisting mostly of carbon monoxide and hydrogen with a small amount of methane and other constituents. In the "water-gas shift reaction" that follows, carbon monoxide and steam react over a catalyst to produce carbon dioxide and more hydrogen. A final step is to remove the carbon dioxide and other impurities from the gas stream, leaving marketable hydrogen.

[12] Cristina Antonini et al., Royal Society of Chemistry, Hydrogen production from natural gas and biomethane with carbon capture and storage – a techno-environmental analysis (March 11, 2020), *available at* https://pubs.rsc.org/en/content/articlehtml/2020/se/d0se00222d.
[13] Christos M. Kalamaras & Angelos M. Efstathiou, Power Options for the Eastern Mediterranean Region, Hydrogen Production Technologies: Current State and Future Developments (June 6, 2013), *available at* https://www.hindawi.com/journals/cpis/2013/690627/.
[14] Steven F. Rice & David P. Mann, Sandia National Laboratories, Autothermal Reforming of Natural Gas to Synthesis Gas (April 13, 2007), *available at* https://www.osti.gov/servlets/purl/902090-j09VTQ/.
[15] Geoffrey Ozin, Decarbonizing Natural Gas: Methane Fuel without Carbon Dioxide, Advanced Science News (March 20, 2018), *available at* https://www.advancedsciencenews.com/decarbonizing-natural-gas-methane-fuel-without-carbon-dioxide/.
[16] William Harris, How Gasification Works, HowStuffWorks (June 2, 2009), *available at* https://science.howstuffworks.com/environmental/green-tech/energy-production/gasification.htm.

IV. THE ROLE OF HYDROGEN IN A CARBON NEUTRAL FUTURE

A. Introduction

As a preliminary hydrogen injection standard is being developed, it is important to consider that hydrogen is an essential component of the energy economy of the future. In California and in other parts of the world, hydrogen will be integral to achieving energy decarbonization at scale. As indicated in Figure 2 below, hydrogen has the potential to provide emissions-free sustainable energy in a variety of end uses, such as fuel cell electric vehicles, stationary power and heat for buildings, backup power, industrial heat and feedstock, and distributed as well as central station generation.[17] Further, hydrogen is an attractive carbon neutral solution for hard to abate industries (e.g., shipping, aviation, heavy-duty long-haul transportation, iron and steel production, chemicals, and manufacturing processes that require high-temperature industrial heat such as aluminum, glass and cement).[18]

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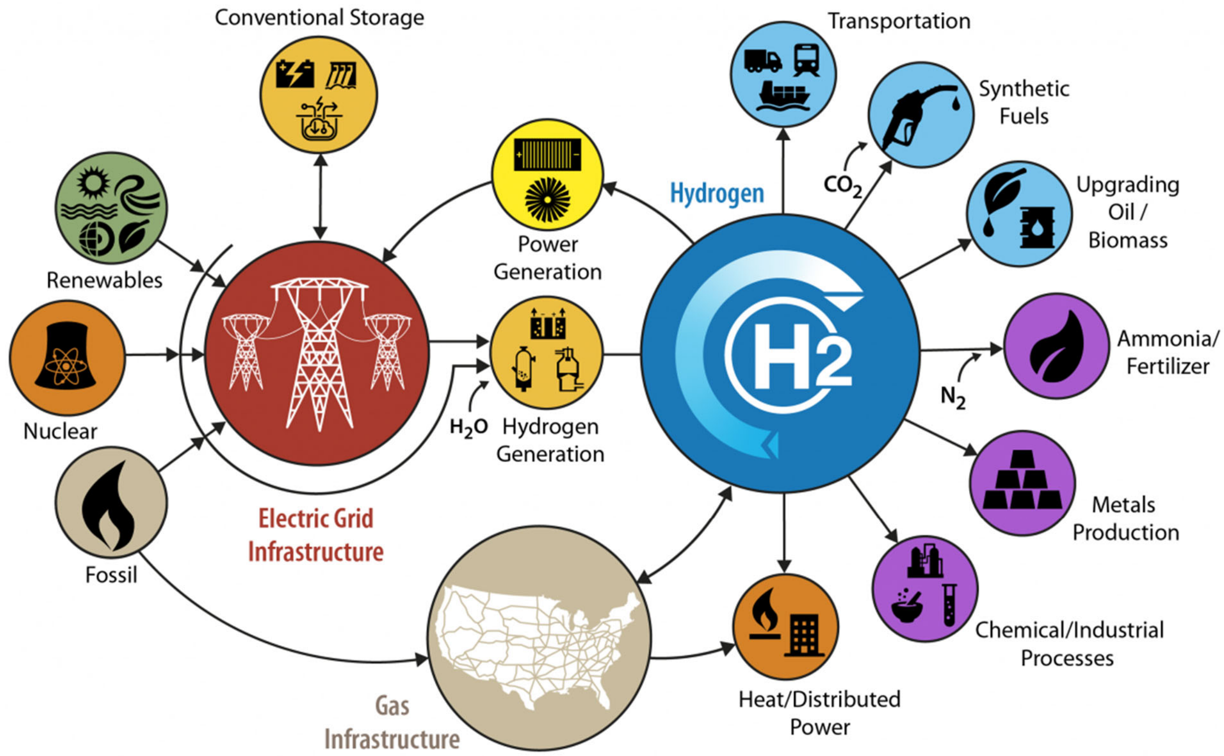
[17] M.W. Melaina et al., National Renewable Energy Laboratory, Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues (March 2013), *available at* https://www.nrel.gov/docs/fy13osti/51995.pdf.

[18] Kobad Bhavnagri, Bloomberg NEF, Hydrogen Economy Outlook (2020), *available at* https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf. The technical information/findings in the report have not been fully vetted by the Joint Utilities and are not meant to be representative of the Joint Utilities' current knowledge of how hydrogen impacts their respective systems.

Figure 2

Hydrogen Applications[19]



The flexibility of hydrogen as an energy carrier across multiple sectors makes it a unique carbon neutral energy solution enabling transportation, distribution and storage of clean energy. By decarbonizing multiple sectors of the economy, hydrogen is uniquely positioned to transform California's future energy system.

The Commission has acknowledged that "existing efforts and research status on hydrogen affirm that the issue is ripe for consideration"[20] and has directed the Commission's Energy Division to coordinate a third-party technical study to further assess the impacts of increased hydrogen concentration in California's gas storage and pipeline delivery system. The Commission has also indicated that any impacts to the safety of the gas systems or to customer end-uses must be clearly understood before a hydrogen injection standard could be implemented, in addition to the impacts and benefits on the environment and to customers. The Joint Utilities

[19] Office of Energy Efficiency & Renewable Energy, H2@Scale, *available at* https://www.energy.gov/eere/fuelcells/h2scale.
[20] November 21, 2019 Ruling at 7.

agree with this position and are undertaking steps to achieve this end.

B. Hydrogen Can Enable California's Climate Goals While Maintaining Energy Resiliency and Addressing Energy Generation Inefficiency

The Joint Utilities support California's climate and energy goals, including reducing emissions to 40% below 1990 levels by 2030 (SB 32)[21] and fulfilling the 100% Clean Energy Act of 2018 by 2045 (SB 100).[22] The Joint Utilities recognize the various challenges that will need to be addressed in order to meet these targets. To fully implement California's vision of a carbon neutral energy future and to provide energy resiliency, both clean electrons (through renewable electricity) and clean molecules (through RG, including hydrogen) will be required.[23]

According to Bloomberg New Energy Finance (BNEF), to achieve the Intergovernmental Panel for Climate Change's (IPCC)[24] global warming reduction target of 1.5-degrees (centigrade) by 2050, global energy consumption would need to decrease, and technological changes would need to occur (Report provided in Attachment 2). BNEF analysis suggests there is a role for both clean molecules and clean electrons by 2050 (as shown in Figure 3 below) and that the contribution of these two energy sources to global energy consumption under the IPCC 1.5-degree scenario is about equal (53% clean electrons and 47% clean molecules).[25] The 47% or 190 exajoules (EJ) of energy consumed in the form of molecule-based fuels would need to have a very low emissions intensity. Therefore, as a scalable energy carrier with a broad range of end uses, clean hydrogen is well positioned to play a prominent role in California's carbon neutral future.

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[21] Cal. SB-32, Chapter 249 (2016), *available at* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201520160SB32.

[22] Cal. SB-100, Chapter 312 (2018), *available at* https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.

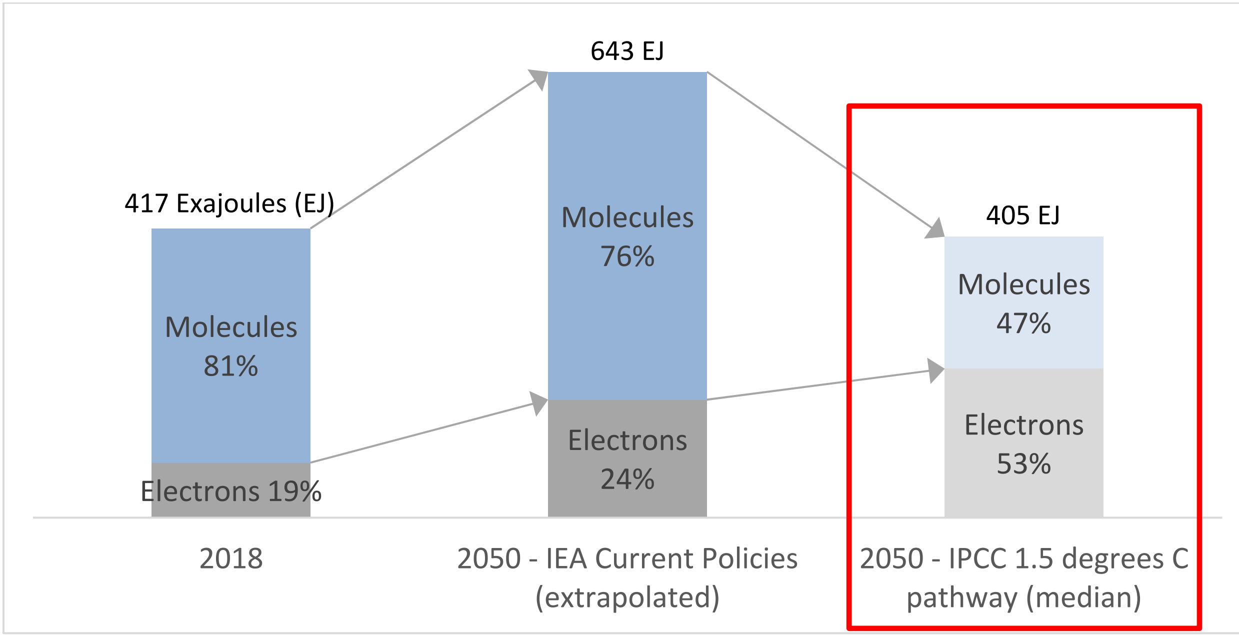
[23] Bhavnagri, *supra*. The technical information/findings in the report have not been fully vetted by the Joint Utilities and are not meant to be representative of the Joint Utilities' current knowledge of how hydrogen impacts their respective systems.).

[24] Valerie Masson-Delmotte et al. (eds.), Intergovernmental Panel for Climate Change, Global Warming of 1.5°C (2018), *available at* https://www.ipcc.ch/sr15/.

[25] Bhavnagri, *supra*. The technical information/findings in the report have not been fully vetted by the Joint Utilities and are not meant to be representative of the Joint Utilities' current knowledge of how hydrogen impacts their respective systems.

Figure 3

Projections for Global Final Energy Consumption in 2050 (source: BNEF)



In California, hydrogen can also address energy generation surplus and reliability concerns, as there are times when renewable energy cannot be consumed by the electric grid. To prevent overloading, excess renewable energy is either curtailed or given away to nearby states. Between 2018 and 2019 alone, the amount of curtailed energy from solar and wind more than doubled, according to the California Independent System Operator (CAISO).[26] In order to address this issue, consideration should be given to long-duration energy storage solutions. Battery storage alone, with its short discharge duration (4 to 6 hours), may not be able to meet this challenge. Therefore, hydrogen as a form of long-duration and large-scale energy storage could be a critical component to addressing renewable energy generation inefficiencies while California works toward achieving its clean energy goals. Figure 4 below shows capacity versus discharge duration for various types of energy storage solutions, including batteries and hydrogen storage.

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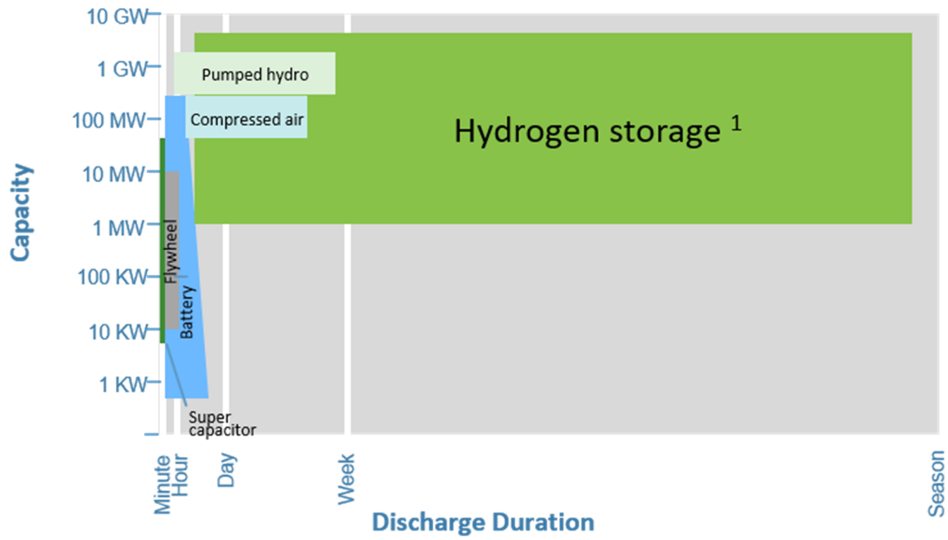
[26] Managing oversupply, California ISO, *available at* http://www.caiso.com/informed/Pages/ManagingOversupply.aspx.

Figure 4

Comparison of Energy Storage Alternatives



[1] As hydrogen or synthetic methane
Source: IEA Energy Technology Roadmap, Hydrogen and Fuel Cells

To continue to provide Californians with reliable and resilient energy, hydrogen for long-duration energy storage should be considered part of the state's mix of energy solutions. Moreover, gas infrastructure and storage are becoming increasingly important to resilience, a critical component of any energy supply strategy and one that is gaining momentum in the context of today's increased wildfire risk and other climate-driven natural disasters. Diversity in the state's energy portfolio is important for prudent risk management to support resilient energy infrastructure. California must leverage its existing energy infrastructure, technological expertise, and skilled workforce to maintain resilience and reliability while transitioning to a deeply decarbonized economy and mitigating the impacts of climate change.

C. Leveraging the Joint Utilities' Existing Gas Systems

In addition to other efforts, the blending of hydrogen into the existing gas systems will provide a significant boost towards achieving gas pipeline decarbonization in California. Furthermore, blending, where feasible, could be a lower cost option of transporting hydrogen than developing new hydrogen transmission and distribution infrastructure. With technological progress and sufficiently large, sustained, and localized demand, gas pipelines can be one of the most cost-effective long-term choices for hydrogen delivery. The advantage of hydrogen as a form of stored energy is that it can be transported, stored for long periods of time, and used as energy across a broad range of applications. Integration of hydrogen into the gas system will provide larger scale energy storage compared to battery storage, utilize existing infrastructure to allow for more locations for injection and dispensing hydrogen, as well as provide wider dispersion and access.

D. Hydrogen Is Being Used Around the World to Test Its Viability and Further Energy Goals, and California Can Learn from these Examples

In many nations, hydrogen has been increasingly seen as a driving force in the fight against climate change. Many utilities, energy companies, and nations are prioritizing the development of hydrogen infrastructure as an integral component of large scale decarbonization. A major step in the adoption of hydrogen in Europe was made in July 2020 when the European Commission released its ambitious hydrogen strategy. In particular, the strategy sets aggressive goals for production of electrolytic hydrogen in the European Union (EU): 6 gigawatts (GW) of electrolyzers by 2024 and 40 GW by 2030, plus additional 40 GW in neighboring countries to import hydrogen into the EU.[27] This strategy builds on significant progress toward adoption of hydrogen that was made across Europe over the last several years. Leeds, one of the largest cities in the United Kingdom (U.K.), launched the Leeds H21 City Gate hydrogen project in 2016,[28] targeting the conversion of the existing natural gas supply and distribution system to deliver hydrogen to consumers. Leeds H21 has examined the engineering, transition requirements, production, transportation, end use applications and related costs, while also assessing the initiative's impact on GHG emissions reduction.[29] As further described below, California can also learn from other hydrogen strategies, initiatives and investments being pursued throughout the world.

The Australian Government recently established a 300 million Australian dollar funding mechanism to support hydrogen-powered projects to "support the growth of a clean, innovative,

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[27] European Commission, Communication from the Commission to the European Parliament, the Council, the European Economic and Social Committee and the Committee of the Regions: a hydrogen strategy for a climate-neutral Europe, (Aug. 7, 2020), *available at* https://ec.europa.eu/energy/sites/ener/files/hydrogen_strategy.pdf.

[28] Northern Gas Networks, Watch our H21 Leeds City Gate film (July 12, 2016), *available at* https://www.northerngasnetworks.co.uk/2016/07/12/watch-our-h21-leeds-city-gate-film/.

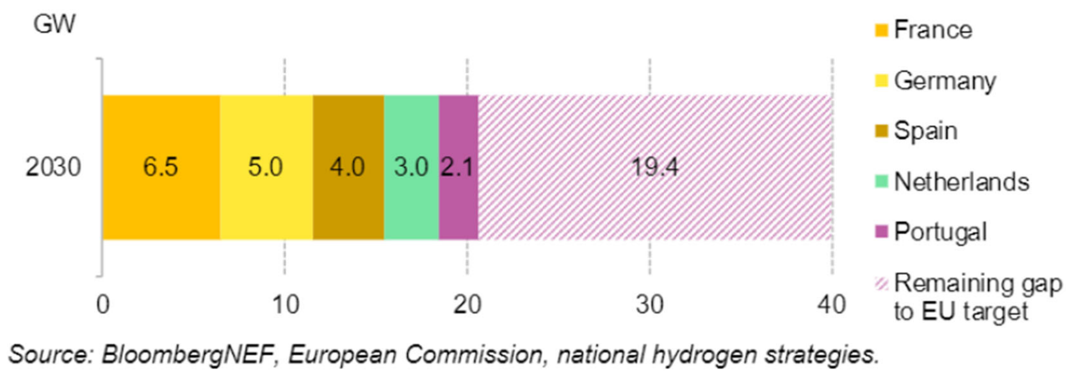
[29] H2FCSUPERGEN, Hydrogen in the North: the H21 Leeds City Gate report launces (July 15, 2016), *available at* http://www.h2fcsupergen.com/news/hydrogen-in-the-north-the-h21-leeds-city-gate-report-launches/.

safe and competitive Australian hydrogen industry,"[30,31] as part of their national strategy.

The European Commission,[32] as illustrated in Figure 5 below, has set a goal to build-out 40 GW of electrolyzers and produce 10 million metric tons of zero-carbon hydrogen within the EU by 2030.[33]

Figure 5

Electrolyzer deployment targets by the EU and member countries (source: BNEF)



Recently, Spain and Portugal announced draft hydrogen strategies that would help deliver ~6 GW to meet the EU goals. Together, they will include electrolyzer deployment targets of 4 GW and 2.1 GW respectively by 2030, which is equivalent to 15% of the EUs 40 GW goal. In addition, Portugal is considering hydrogen blending targets between 10% and 15% by volume by 2030, with a goal to ramp up to 50% by 2040 and 80% by 2050. Spain has set targets of up to 10% blending volume by 2030.[34]

Germany's National Hydrogen Strategy states that hydrogen is a multi-purpose energy carrier that can be used in fuel cells to power hydrogen-based mobility and serve as a basis for synthetic fuels, but also to store renewable energies.[35] To that end, Germany has allocated 9

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[30] CEFC, CEFC welcomes launch of new $300 million Advancing Hydrogen Fund (May 4, 2020), *available at* https://www.cefc.com.au/media/media-release/cefc-welcomes-launch-of-new-300-million-advancing-hydrogen-fund/.

[31] Australia's National Hydrogen Strategy, COAG Energy Council (2019), *available at* https://www.industry.gov.au/sites/default/files/2019-11/australias-national-hydrogen-strategy.pdf.

[32] *See* Bloomberg NEF, Europe's $500 Billion Plan Will Scale Up Green Hydrogen (July 13, 2020), https://www.bnef.com/insights/23661.

[33] *See* Bloomberg NEF, Spain and Portugal Approve Sunny Hydrogen Strategies (Oct. 13, 2020), *available at* https://www.bnef.com/insights/24463.

[34] *See id*.

[35] Federal Ministry for Economic Affairs and Energy, The National Hydrogen Strategy (June 2020), *available at* https://www.bmbf.de/files/bmwi_Nationale%20Wasserstoffstrategie_Eng_s01.pdf.

billion euros to hydrogen, including 2 billion euros for international partnerships in this sector. Germany is looking to develop up to 5 GW of hydrogen capacity by 2030, and an additional 5 GW by 2040.[36]

The French government's hydrogen strategy involves 7 billion euros in investments by 2030 with a target to build 6.5 GW of electrolysis for hydrogen production. In addition, the French government aims to create between 50,000 to 150,000 direct and indirect jobs over the next ten years.[37,38]

Netherlands aims to produce renewable hydrogen using renewable electricity generated by a 3 – 4 GW offshore wind farm in 2030, and 10 GW by 2040 as part of the objectives of the Dutch Climate Accord.[39]

Another example in the U.K. is the setup of two 20 million British Pounds Sterling (GBP) funds for innovation in low-carbon hydrogen supply and innovation in storage at scale, including Power-to-X[40]. The U.K. has been at the forefront of hydrogen blending, with testing of up to 20% hydrogen and has also announced decarbonizing industrial clusters supported by 170 million GBP of public investment from the Industrial Strategy Challenge Fund.[41]

Japan has also developed a strategic roadmap to implement a hydrogen strategy. The strategy includes new cost and deployment targets for hydrogen and fuel cells and utilizes hydrogen as an energy carrier in power generation. According to the International Energy Agency (IEA), the Development Bank of Japan has joined a consortium of companies to launch

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[36] Reuters, Germany earmarks $10 billion for hydrogen expansion (June 4, 2020), *available at* https://www.reuters.com/article/us-health-coronavirus-germany-stimulus/germany-earmarks-10-billion-for-hydrogen-expansion-idUSKBN23B10L?.

[37] Bernd Radowitz, France's $7bn hydrogen strategy could feature role for nuclear, Recharge (Sep. 9 2020), *available at* https://www.rechargenews.com/transition/frances-7bn-hydrogen-strategy-could-feature-role-for-nuclear/2-1-872014.

[38] Chris Randall, France presents national hydrogen strategy, Electrive (Sep. 14, 2020, 3:13 PM), *available at* https://www.electrive.com/2020/09/14/france-presents-national-hydrogen-strategy/.

[39] Renews.biz, Shell consortium eyes 10GW offshore wind-hydrogen giant (Feb. 27, 2020), *available at* https://renews.biz/58847/dutch-unveil-green-hydrogen-offshore-wind-mega-project/.

[40] Power-to-X (as defined by the European Commission) is the conversion of power from the electricity sector into another energy carrier which could include power to hydrogen gas, power to methane, power to liquids (hydrocarbons). Power-to-X can also refer to power-to-chemicals, power-to-ammonia and power-to-heat etc. *See* European Commission, METIS Studies, The role and potential of Power-to-X in 2050 (April 30, 2019), *available at* https://op.europa.eu/en/publication-detail/-/publication/1e6b9012-6bbc-11e9-9f05-01aa75ed71a1/language-en/format-PDF/source-96288622.

[41] IEA, The Future of Hydrogen (June 2019), *available at* https://www.iea.org/reports/the-future-of-hydrogen at 22.

Japan H2 Mobility[42] with a target to build 80 hydrogen refueling stations by 2021 under the guidance of the Japanese central government's Ministerial Council on Renewable Energy, Hydrogen and Related Issues.[43] Consistent with this direction, on October 13, 2020 JERA, a joint venture of major Japanese power companies and the world's largest liquified natural gas buyer, recently announced plans to reach carbon neutrality by 2050, with hydrogen as one of their major pathways to reaching this goal.[44]

Wood Mackenzie, based in the U.K., noted in their latest report on hydrogen, an estimated 15 GWs of global hydrogen projects that are currently in the pipeline. The pipeline project capacity has quadrupled from 3.2 GWs since 2019.[45] The report further states that twenty-two 100 MW+ green hydrogen projects have been announced, which in total include targets for 48 GW of electrolyzer deployments by 2030. The global interest and momentum towards transitioning to a hydrogen economy is accelerating due to hydrogen's versatility coupled with strong scaling potential and falling costs of renewable generation and hydrogen technologies, such as electrolyzers. According to the BNEF, the learning rates of Alkaline and PEM electrolyzers show 18 - 20% in potential cost reductions[46] considering the manufacturing scaling effect.

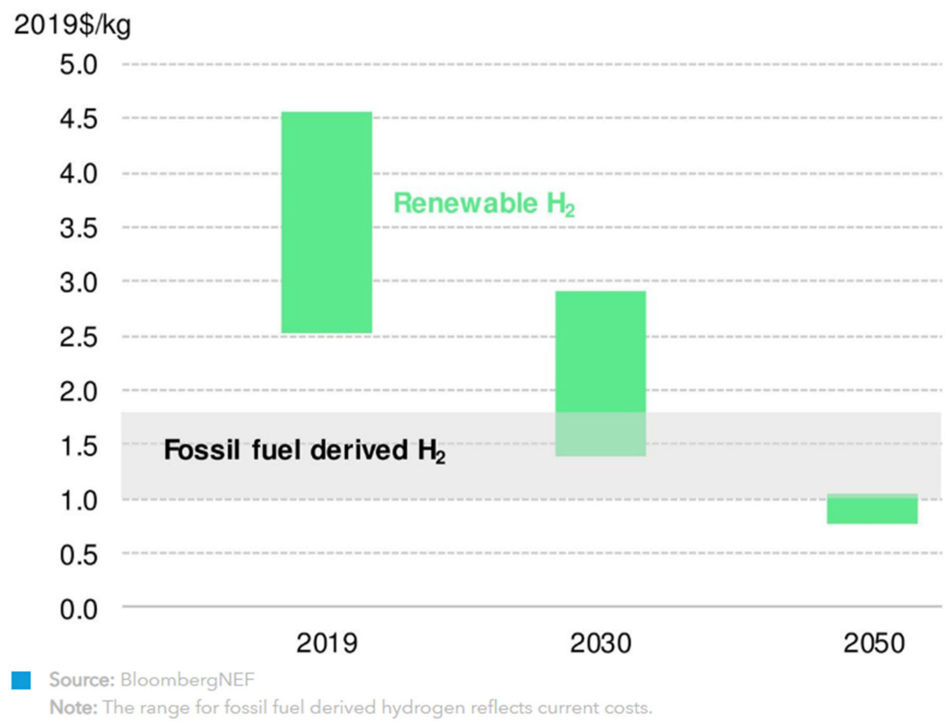
BNEF, in its analysis on the cost economics of hydrogen production, states that the rapidly declining costs of renewable energy globally can make it possible to achieve cost economic scaling of renewable hydrogen production. BNEF forecasts the production costs of renewable hydrogen (at large scale) will reduce from $2.5-6.8/kg (2019) to $1.4-2.9/kg (2030). As shown in Figure 6 below, the costs are expected to be just $0.8-1.0/kg by 2050, ensuring a

[42] Ministry of Economy, Trade and Industry, Eleven companies to collaborate in accelerating the development of hydrogen stations (March 5, 2018), *available at* https://www.meti.go.jp/english/press/2018/0305_001.html.
[43] The Future of Hydrogen, *supra* at 22.
[44] Eric Yep & Jia Hui Tan, Japan's largest power producer JERA plans net zero CO2 by 2050, S&P Global: Platts (Oct. 13, 2020), *available at* https://www.spglobal.com/platts/en/market-insights/latest-news/coal/101320-japans-largest-power-producer-jera-plans-net-zero-co2-by-2050.
[45] Wood Mackenzie, Hydrogen production costs to 2040: Is a tipping point on the horizon? (2020), *available at* https://www.woodmac.com/our-expertise/focus/transition/hydrogen-production-costs-to-2040-is-a-tipping-point-on-the-horizon/#:~:text=Hydrogen%20production%20costs%3A%20is%20a,of%20green%20with%20fossil%20generation.
[46] Learning rates show cost reduction trends with every doubling in manufactured volumes.

competitive and cost economic future for hydrogen.[47] From an energy equivalency perspective, the costs would reduce from $19-50/MMBTU (2019) to $10-21/MMBTU (2030). This would further decline to $6-7/MMBTU by 2050.[48]

Figure 6

Forecast levelized cost of renewable hydrogen production from large projects (Source: BNEF)[49]



The global push for hydrogen as an integral component of decarbonization is evolving not only through published national strategies, but also through development of demonstration projects across Europe and Asia. Additional information on hydrogen blending initiatives around the world is detailed in Chapter 3 under the International Hydrogen Blending Demonstrations section. SoCalGas and PG&E are actively collaborating with European companies in order to bring their experience to California and facilitate the adoption of hydrogen

[47] BNEF, Hydrogen: The Economics of Production From Renewables (2019), https://www.bnef.com/core/insights/21213?query=eyJxdWVyeSI6ImZ1dHVyZSBvZiBoeWRyb2dlbiIsInBhZ2UiOjIsImZpbHRlcnMiOnsiY29udGVudCI6WyJpbnNpZ2h0Il0sIm9yZGVyIjpbImRhdGUiXSwiZGF0ZXMiOls1XX19.
[48] Assuming energy equivalency conversion of 7.4 MMBTUs per kg of H2.
[49] Hydrogen: The Economics, *supra*.

into California's energy mix.

V. CONCLUSION

This concludes our prepared direct testimony.

VI. QUALIFICATIONS

Yuri Freedman

In my current role as Senior Director, Business Development, I manage the portfolio of growth initiatives and Research & Development activities for SoCalGas. Prior to this, I held the position of Director, Commercial Development for Sempra LNG and Midstream, and previously held the positions of Director, Infrastructure Investments for Sempra US Gas and Power, and Director, Corporate Mergers & Acquisitions for Sempra Energy.

Prior to joining Sempra Energy, I was a Managing Director on the energy team of Fortress Investment Group and a Vice President in General Electric's energy investment arm, GE Energy Financial Services. I began my career as a geologist working in Arctic regions of Western Siberia on the development and construction of oil and gas pipelines. I hold an MS in Engineering Geology from Moscow University (Russia), a PhD in Environmental Science and Energy Research from the Weizmann Institute of Science (Israel), and an MBA from the Yale School of Management.

I have not previously testified before the Commission.

Austin Hastings

Currently I hold the role of Director of Wholesale Marketing and Business Development for Pacific Gas and Electric Company. Among other responsibilities I am the PG&E Gas Operations lead for natural gas strategy. I have been with PG&E for over 23 years, all in the natural gas line of business. During this time, I have held numerous technical and leadership positions some of which include project management, pipeline engineering, liquified and compressed natural gas, gas standards, operator qualifications, cross bore and other construction technology and support departments. I hold a degree in Mechanical Engineering from CSU Fresno and am a registered professional engineer in the state of California.

Joseph C. Varela

I am a Director in the Energy Solutions Department for Southwest Gas Corporation. My business address is 3400 East Gas Road, Tucson, Arizona 85714. I have been employed with Southwest Gas for 30 years. In my current position, I am responsible for promoting the use of natural gas by educating the public, legislators, key decision makers and general industry on emerging natural gas technologies and renewable energy supplies. I hold a Bachelor of Science in Civil Engineering from The University of Arizona and a Master of Business Administration from the Eller College of Management at The University of Arizona. I hold board seats on Natural Gas Vehicles of America, Gas Technology Institute and the Renewable Natural Gas Coalition.

ATTACHMENT 1

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions.	R.13-02-008 (Filed February 13, 2013)

TECHNICAL HYDROGEN WORKING GROUP REPORT OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G), PACIFIC GAS AND ELECTRIC COMPANY (U 39 G), AND SOUTHWEST GAS CORPORATION (U 905 G)

JONATHAN D. PENDLETON Attorney for: PACIFIC GAS AND ELECTRIC COMPANY Law Department 77 Beale Street, B30A San Francisco, California 94105 Telephone: (415) 973-2916 Facsimile: (415) 973-5520 E-Mail: Jonathan.Pendleton@pge.com	DANA R. WALSH Attorney for: SOUTHWEST GAS CORPORATION 5241 Spring Mountain Road Las Vegas, Nevada 89150-0002 Telephone: (702) 876-7396 Facsimile: (702) 252-7283 E-Mail: Dana.Walsh@swgas.com
	JOHNNY Q. TRAN Attorney for: SOUTHERN CALIFORNIA GAS COMPANY SAN DIEGO GAS & ELECTRIC COMPANY 555 West Fifth Street, Suite 1400, GT14E7 Los Angeles, California 90013 Telephone: (213) 244-2981 Facsimile: (213) 629-9620 E-Mail: JQTran@socalgas.com

February 19, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions.	R.13-02-008 (Filed February 13, 2013)

TECHNICAL HYDROGEN WORKING GROUP REPORT OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G), PACIFIC GAS AND ELECTRIC COMPANY (U 39 G), AND SOUTHWEST GAS CORPORATION (U 905 G)

Pursuant to Ordering Paragraph 5 of Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of Rulemaking 13-02-008 (Scoping Memo), Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southwest Gas Corporation (Southwest Gas) (collectively, the Joint Utilities)[1] respectfully submit their Technical Hydrogen Working Group Report attached hereto as Attachment A.

Respectfully submitted,

By: *\/s/Johnny Q. Tran*
Johnny Q. Tran

Attorney for:
SOUTHERN CALIFORNIA GAS COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
555 West Fifth Street, Suite 1400, GT14E7
Los Angeles, California 90013
Telephone: (213) 244-2981
Facsimile: (213) 629-9620
E-Mail: JQTran@SoCalGas.com

February 19, 2020

[1] Pursuant to Rule 1.8(d), SoCalGas and SDG&E have been authorized to file this document on behalf of the Joint Utilities.

ATTACHMENT A

R.13-02-008, Phase 4:

Technical Hydrogen Interconnection Working Group Report

February 19, 2020

Prepared by:

Pacific Gas and Electric Company

San Diego Gas & Electric Company

Southern California Gas Company

Southwest Gas Corporation

Contents

List of Tables

List of Figures

1. Introduction

Pursuant to Ordering Paragraph (OP) 5 of the Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of Rulemaking (R.) 13-02-008 (Scoping Memo) issued on November 21, 2019, Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (Southwest Gas) (collectively, the Investor-Owned Utilities [IOUs]) submit this Technical Hydrogen Interconnection Working Group Report (Report) which is due to the California Public Utilities Commission (Commission) 90 days from the Scoping Memo.[1]

The first technical hydrogen interconnection working group (working group) meeting, as also directed in OP 5 of the Scoping Memo, was held on January 15, 2020 via webinar. This Report contains the following information which was presented during the working group meeting:

- General hydrogen knowledge
- Utility-specific hydrogen knowledge
- International hydrogen blending efforts
- IOU engineering work group
- IOU Hydrogen Research Action Plan
- Discussion of next steps

1.1. Working Group Meeting Summary

The working group meeting was open to all parties of the proceeding and was intended to assist in developing the preliminary hydrogen injection standard application (Application) due by November 21, 2020. The IOUs presented information on their hydrogen knowledge and R&D efforts. During the public discussion period, representatives from Common Ground Energy Corporation (a Canadian oil and gas company) and Green Hydrogen Coalition expressed their interest in hydrogen. Common Ground Energy Corporation mentioned the storage and transport of hydrogen as ammonia or toluene and the United Kingdom's HyDeploy hydrogen blending pilot project. Green Hydrogen Coalition asked how hydrogen will be integrated in other proceedings (i.e. SB 100, Integrated Resource Plan [IRP]) and the extent to which the Commission is working with the California Energy Commission (CEC). The Commission representative mentioned Assembly Bill (AB) 8 coordination efforts with the CEC and instructed that the IOUs may include in the Application a section on the larger role of hydrogen in other proceedings. A copy of the slide deck presented during the working group meeting is provided in Appendix A.

[1] Pursuant to OP 5 of the Scoping Memo, "The Joint Utilities shall hold additional technical working group meetings as needed and submit progress reports every 60 days thereafter."

2. General Hydrogen Knowledge

Hydrogen is widely seen as a pivotal component of the future clean energy economy. It has the potential to provide emissions-free sustainable energy in a variety of end uses, such as fuel cell electric vehicles, stationary power and heat for buildings, backup power, and distributed generation.[2] Hydrogen produced via electrolysis, where electricity is used to split water into hydrogen and oxygen, can result in zero greenhouse gas (GHG) emissions if produced using renewable energy. Power-to-gas (P2G) is the process in which this renewable hydrogen or electrolytic hydrogen can also be converted into renewable gas via methanation.

P2G provides a pathway to allow for power generation from intermittent renewable power sources such as wind and solar (thereby increasing the use of surplus renewable electricity) that would otherwise be curtailed, by storing it for later use in existing gas infrastructure, where it can be used for electric generation or other end-use applications of highest need. As California continues to meet its renewable portfolio standard requirements, it is faced with an increasingly urgent need to deploy utility-scale energy storage solutions to support intermittent renewable power generation. P2G should be evaluated for its potential to provide large-scale storage.

In addition, hydrogen can also be produced with natural gas or renewable natural gas (RNG) in a process called steam-methane reformation (SMR). Hydrogen produced via SMR is a valuable low-carbon fuel used today in various sectors (i.e. industrial, transportation) and can potentially be a solution to decarbonize the most difficult to abate sectors. RNG can also be reformed to create renewable hydrogen, which can be a negative carbon vehicle fuel with zero tailpipe emissions.[3] Today, 95% of the hydrogen produced in the United States is made by natural gas reforming in large central plants.[4]

Blending hydrogen into the existing natural gas pipeline network has been proposed by many associations as a means of increasing the output of renewable energy systems.[5] However, introduction of hydrogen at any specific blend concentration into a given system requires appropriate study, testing, and/or modifications to existing infrastructure, monitoring and maintenance practices.[6] Hydrogen presents critically important opportunities as a carbon-free fuel

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[2] Melaina, M.W., Antonia, O., and Penev, M. Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues (March 2013). Available at: https://www.nrel.gov/docs/fy13osti/51995.pdf.
[3] Depending on the pathway. RNG can have a negative Carbon Intensity. California Air Resources Control Board Low Carbon Fuel Standard Certified Pathways are available at: https://ww3.arb.ca.gov/fuels/lcfs/fuelpathways/pathwaytable_test3.htm
[4] U.S. Department of Energy. Office of Energy Efficiency & Renewable Energy. Hydrogen Production: Natural Gas Reforming. Available at: https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming.
[5] Hydrogen Europe. Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy (April 2019). Available at: https://hydrogeneurope.eu/sites/default/files/2019_Hydrogen%20Europe%20Vision%20on%20the%20role%20of%20Hydrogen%20and%20Gas%20Infrastructure.pdf.
[6] Ibid.

that can provide long-term energy storage and help the State meet Executive Order B-55-18 goals and Senate Bill (SB) 100 requirements.

3. Utility-Specific Knowledge

3.1. Southern California Gas Company (SoCalGas) and San Diego Gas & Electric Company (SDG&E)

In 2019, SoCalGas announced its vision to be the cleanest gas utility in North America and committed to a 5% RNG core throughput by 2022 and 20% RNG core throughput in the system by 2030. SoCalGas' commitment to develop RNG is part of a broader, integrated vision for the future of clean energy that keeps energy affordable, expands consumer choice, and develops long-term and seasonal renewable energy storage using existing infrastructure. SoCalGas is exploring how hydrogen can be part of the Company's vision, its relationship with the existing natural gas infrastructure, how it can help reduce reliance on fossil-based resources and be used in cross-sectoral applications in residential, commercial, industrial, and power generation applications. However, before SoCalGas determines the extent to which hydrogen injection and blending can occur in its system, there are topics that require continued research and testing to ensure safe and reliable operation of the utility system.

3.1.1. SoCalGas Hydrogen Research

SoCalGas' hydrogen research encompasses the entire scope of the value chain, from the backbone pipeline infrastructure to end user appliances and equipment. Research also includes studying the potential benefits of hydrogen generation and fueling to make positive contributions across various sectors, from transportation to power generation.

SoCalGas understands that research should not be done in silos and has established partnerships across the gas industry and academia to help understand the potential impacts of hydrogen injection and blending in the natural gas system. Some of the research topics studied with these partners include hydrogen embrittlement, P2G, underground storage, engines, operational safety, gas interchangeability, and system integrity. SoCalGas' partnerships and key studies are briefly described below and summarized in Table 1.

- The American Gas Association (AGA) and Canadian Gas Association (CGA) performed a literature review of hydrogen blending in the natural gas system. Topics reviewed include potential hydrogen impact on steel pipelines, plastic pipelines, underground storage operations, and system equipment.
- The Fuel Cell & Hydrogen Energy Association (FCHEA) worked together with a coalition of major oil & gas, power, automotive, fuel cell, and hydrogen companies to develop a Road Map to a US Hydrogen Economy. This comprehensive Road Map details how the U.S. can expand its global energy leadership, by scaling up activity in the rapidly emerging and evolving hydrogen economy, as policy makers and industry work together and take the

right steps. Analytical support was provided by McKinsey and scientific observations and technical input was provided by the Electric Power Research Institute (EPRI).

- Gas Technology Institute (GTI) performed a risk analysis to determine a hydrogen blending percentage that would not significantly increase overall risk. The analysis was completed for distribution and transmission pipelines (i.e. low, medium, high pressures) constructed using plastic and steel.
- GTI also completed a study to evaluate the material integrity and operational compatibility of a natural gas system with natural gas blended with 5 vol% hydrogen and to determine any actions needed to reduce risks and support hydrogen blending.
- The HYREADY project is a collaborative effort by several North American and European utilities to assess the impacts of introducing hydrogen into natural gas systems. It developed guidelines and decision trees to help determine if specific components of the system would be compatible with various percentages of hydrogen.
- University of California, Irvine (UC Irvine) constructed a P2G hydrogen blending pilot to evaluate the feasibility of generating hydrogen using an electrolyzer and blending the hydrogen into the university's natural gas network.
- DNV GL performed a gas interchangeability analysis to determine the minimum and maximum hydrogen content that can be added to natural gas within the SoCalGas service territory without increasing the risk of flame flashback.
- University of Southern California (USC) performed a literature review on several mechanisms of hydrogen embrittlement. Tensile and fracture tests on pipes and welds were also reviewed.
- USC also performed experiments to evaluate the impact of a hydrogen blend on storage formation materials. Permeability and porosity measurements were taken on samples before and after incubation in hydrogen-natural gas blends.
- University of Illinois at Urbana-Champaign performed a literature review and computer simulation of fatigue crack growth rates for line pipe steels. The analysis focused on long axial cracks on the pipe's inner surface and used SoCalGas historical pressure data. The gases compared were natural gas and pure hydrogen.
- Sandia National Laboratories investigated if hydrogen-natural gas blends can be used in existing on-board fuel tanks of natural gas vehicles. All four types of tanks were studied.
- Colorado State University performed a literature review and tests to determine the impact of using hydrogen-natural gas blends in spark-ignited natural gas engines. Engine performance and emissions compliance were recorded.
- The NYSEARCH RANGE™ model (Range of Acceptability for Natural Gas Equipment) utilizes the composition data of a proposed gas supply to generate graphical depictions of the performance characteristics of appliances in a service area, so that the range of acceptable gas supplies can be determined. The model incorporates the in-service appliance database from NYSEARCH's study on the impacts of varying gas compositions on the performance of installed residential appliances.

Partner	Scope
AGA/CGA	Blending of Hydrogen into Natural Gas Delivery Systems (2018)
FCHEA/McKinsey/EPRI	Development of a Comprehensive Road Map to a US Hydrogen Economy (2019)
GTI	Hydrogen Blending into the Natural Gas Network—A Risk Analysis (2010)
	Initial Assessment of the Effects of Hydrogen Blending in Natural Gas on Properties and Operational Safety (2015)
HYREADY	Engineering Guidelines—For the Preparation of Natural Gas Systems for Hydrogen/NG Mixtures (2018)
UC Irvine	Pilot project for power-to-gas with solar PV
DNV GL	Mathematical Demonstration of the Amount of Hydrogen That Can Be Added to Natural Gas (2017)
USC	Hydrogen Embrittlement Literature Review (2014)
	Permeability and Porosity Measurements of Gas Storage Rock Samples (2010)
University of Illinois at Urbana-Champaign	Evaluating Hydrogen Embrittlement of Pipeline Steels (2016)
Sandia National Laboratories	Hydrogen Effects on Materials for CNG/H2 Blends (2010)
Colorado State University	Impact of H2-NG Blending on Lambda Sensor NSCR Control and Lean Burn Emissions (2015)
NYSEARCH RANGE™	Interchangeability study for hydrogen-natural gas blends on SoCalGas customer equipment

Table 1: SoCalGas Hydrogen Research Partnerships and Key Studies

Note that available studies and guidelines on hydrogen blending in the natural gas system still recommend system-specific studies prior to beginning hydrogen blending because of the variability of utility systems.

3.2. Pacific Gas and Electric Company (PG&E)

PG&E's Gas Research and Development (R&D) and Innovation group developed the PG&E R&D RNG roadmap in 2018.[7] The RNG Roadmap encompasses the key segments covered in the RNG Value Chain and lays out PG&E's plan in the RNG and clean fuels space over the next 10 to 15 years. It also highlights the focus areas where PG&E sees opportunities and initiatives.

The last subject of the RNG roadmap is hydrogen. PG&E is exploring the potential of P2G to produce hydrogen. Storage of renewable energy becomes more important as renewable energy dominates our electricity portfolio. Hydrogen can also be blended and injected into the natural gas system as a means of storage and transportation. Once downstream, the hydrogen could be separated from the natural gas to be used as fuel for vehicles for transportation purposes or remain as a blend to be delivered to end use customers.

[7] PG&E Renewable Natural Gas Roadmap. Available at: www.pge.com/biomethane

The roadmap covers three focus areas for hydrogen: production of hydrogen (i.e. via P2G applications, SMR, etc.), hydrogen standards for blending and interconnection for transportation of hydrogen, and utilization of hydrogen by customers. At a high level, there is a need to develop a portfolio of hydrogen generation technologies; understand the safety impact of hydrogen blending in the natural gas system and on end use customer equipment; and develop hydrogen/natural gas extraction technologies for utilization of each fuel separately. Initial research is focused on obtaining scientific data from laboratory testing where there are knowledge gaps. However, we have had preliminary discussions with the California Energy Commission to start planning for the development of a real-world hydrogen pilot. This pilot will either demonstrate hydrogen injection on a small part of our low-pressure distribution system or involve designing a separate system for the test.

These are the different companies that PG&E has partnered with so far that are spearheading research: Brimstone Energy, CZERO, Gas Technology Institute (GTI), DNV GL (Netherlands), NYSEARCH, Opus12, Operations Technology Development (OTD) under GTI, Pipeline Research Council International (PRCI) and UC Irvine. The other California utilities are collaborating with PG&E on some of these as well.

One project under each focus area is highlighted below.

- Hydrogen Production: GTI is developing a compact hydrogen generator that takes methane and converts it into hydrogen and carbon dioxide. This compact hydrogen generator could be co-located at a power plant to utilize excess renewable electricity to create hydrogen, store it and then convert it back to electricity using a turbine when there is no solar or wind power available. The concentrated carbon dioxide byproduct could be sequestered or used to create other valuable products such as carbon nanotubes and entrained concrete.
- Hydrogen Transportation Via the Natural Gas System: A new ad hoc committee under Pipeline Research Council International was formed last year to focus on emerging fuels which includes hydrogen. In 2019, PG&E led the effort to put together a hydrogen roadmap focused on preparing existing natural gas infrastructure for the transportation of hydrogen at incremental blending limits starting with 1%. This year, PG&E will propose an evolving emerging fuels strategic research project to execute the roadmap starting with an exhaustive state of the art assessment focused on data from pilot projects.
- Hydrogen Utilization by Customers: NYSEARCH has partnered with Stanford University to look at long term viability of biological electrolysis using methanogenic microbes that take carbon dioxide (CO_2) captured from any CO_2 emitting source, combine it with hydrogen produced in situ to create additional methane that is completely interchangeable and can be injected into the natural gas system without further research or additional risk to system integrity.

3.3. Southwest Gas Corporation (Southwest Gas)

Southwest Gas proudly serves natural gas to more than 2 million customers in California, Arizona and Nevada, including approximately 200,000 customers in the state of California. Although Southwest Gas is new to the hydrogen-blending arena, it recognizes it has an important role to play in sustainability and is invested in the use of green technologies to reduce our GHG emissions. Southwest Gas' companywide goal is to achieve a 20% reduction in GHG emissions from fleet, facilities and other initiatives by the year 2025.

3.3.1. Southwest Gas Hydrogen Research

Southwest Gas is contributing to several hydrogen R&D studies to understand the viability of hydrogen injection into natural gas systems. The topics being evaluated include the effects of hydrogen embrittlement, as well as other effects of blending in natural gas systems.

Because hydrogen can have potential impacts on infrastructure and the end-user appliances, Southwest Gas is most concerned with maintaining a safe and reliable network while fulfilling its engagement to sustainability. To that end, for example, Southwest Gas is partnering with multiple utilities (including Dominion Energy, Duke Energy, National Grid, Nicor Gas, Northwest National, and Washington Gas) on the OTD 7.19.h project (OTD 7.19.h project), with the goal of establishing a strategic roadmap at the utility level to prioritize the steps required to utilize hydrogen as a safe energy source in a natural gas distribution system.

Southwest Gas will be hosting the kick-off workshop for the OTD 7.19.h project in April 2020 in Las Vegas, Nevada. All direct project sponsors and all OTD members will be invited to join the 1-day workshop with the goal of identifying the issues and technical challenges utilities face to incorporate hydrogen into their energy portfolio. The workshop is intended for member utility companies to identify knowledge gaps from their perspective.

Other hydrogen projects Southwest Gas is participating in are listed in Table 2 below.

Partner	Scope
Operations Technology Development (OTD)/GTI	7.19.h: Hydrogen Working Group
	6.14.b.2: Effects of Hydrogen Blending in Natural Gas on Material Properties and Operational Safety, Phase 2: Metallic Materials
Operations Technology Development (OTD)/ Sustaining Membership Program (SMP)	22378: Develop Hydrogen Embrittlement Agent for Steel Piping

Table 2: Southwest Gas Hydrogen Research Partnerships

4. International Hydrogen Blending Efforts

The IOUs are closely monitoring hydrogen blending projects happening around the world. The IOUs hope to learn the characteristics and experiences of these pilot projects that can be applied to the California utility system and determine any knowledge gaps that need to be addressed.

Most active and planned hydrogen blending pilot projects abroad are injecting hydrogen into natural gas distribution systems. Figure 1 displays active and planned hydrogen blending pilots with published hydrogen percentages as of December 2019. Italy's Snam is the only entity blending hydrogen into a transmission system. The IOUs are in the process of contacting the project owners to learn more about their pipeline system designs.

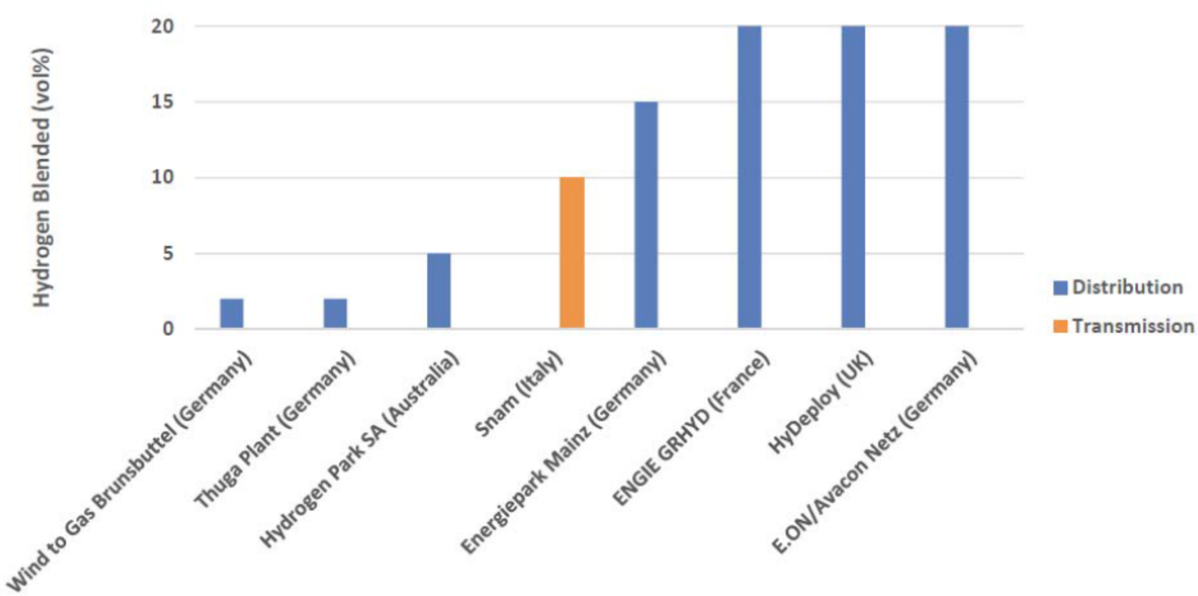

Figure 1: Hydrogen Blending Pilots Around the World

A brief description of these international hydrogen blending projects is provided below:

- The Wind to Gas Brunsbüttel project in Germany is injecting up to 2 vol% hydrogen into a natural gas distribution grid and supplying a hydrogen fueling station.[8]

[8] FuelCellsWorks. Wind2Gas Energy Inaugurates Electrolyzer in Brunsbüttel: More Green Hydrogen for Customers of Greenpeace Energy. Available at: https://fuelcellsworks.com/news/wind2gas-energy-inaugurates-electrolyzer-in-brunsbuttel-more-green-hydrogen-for-customers-of-greenpeace-energy/

- The Thüga plant project in Germany is injecting up to 2 vol% hydrogen into a natural gas distribution network.[9]
- The Hydrogen Park SA project in Australia plans to inject up to 5 vol% hydrogen into a natural gas distribution network that will feed 710 properties. The first hydrogen production and injection are expected in mid-2020.[10]
- Snam's pilot in Italy is injecting 10 vol% hydrogen into a natural gas transmission system that feeds two industrial customers (a water bottling plant and a pasta factory).[11]
- The Energiepark Mainz project in Germany is injecting up to 15 vol% hydrogen into a natural gas distribution network.[12]
- The ENGIE GRHYD project in France plans to inject up to 20 vol% hydrogen into a natural gas distribution network that will feed 100 households and a boiler for a health center.[13]
- The HyDeploy project in the United Kingdom is injecting up to 20 vol% into a private natural gas distribution network at the Keele University campus, feeding 101 homes and 30 faculty buildings.[14]
- E.ON/Avacon Netz's pilot in Germany plans to inject up to 20 vol% into a natural gas distribution network.[15]

More recent data points that have surfaced since January 2020 includes:

- Germany gas transmission operators are drafting a decarbonization strategy with a goal of transitioning 90 percent of their existing gas pipelines to all hydrogen.
- France's gas operators are recommending the country set higher targets for hydrogen blending from 6 percent to 10 percent by 2030 and 20 percent post-2030.

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[9] Thüga. Thüga-Gruppe: Bundesweit erste Einspeisung von Wasserstoff in Gasverteilnetz. Available at: https://www.thuega.de/pressemitteilungen/thuega-gruppe-bundesweit-erste-einspeisung-von-wasserstoff-in-gasverteilnetz/

[10] Australian Gas Networks. About the project. Available at: http://blendedgas.agn.com.au/about-the-project

[11] Snam. Snam: Hydrogen blend doubled to 10% in Contursi trial. Available at: https://www.snam.it/en/Media/news_events/2020/Snam_hydrogen_blend_doubled_in_Contursi_trial.html

[12] Energiepark Mainz. Technical Data. Available at: https://www.energiepark-mainz.de/en/technology/technical-data/

[13] ENGIE. Partners in the GRHYD project inaugurate France's first Power-to-Gas demonstrator. Available at: https://www.engie.com/en/journalists/press-releases/grhyd-inaugurate-frances-first-power-to-gas-demonstrator

[14] HyDeploy. About HyDeploy. Available at: https://hydeploy.co.uk/faq-category/about-hydeploy/

[15] E.ON. Hydrogen levels in German gas distribution system to be raised to 20 percent for the first time. Available at: https://www.eon.com/en/about-us/media/press-release/2019/hydrogen-levels-in-german-gas-distribution-system-to-be-raised-to-20-percent-for-the-first-time.html

5. Developing a Hydrogen Injection Standard

Currently, a uniform hydrogen injection or blending standard does not exist to define rules or requirements for allowable hydrogen concentrations in the natural gas system, injection or blending technology, uniform blend, pipeline systems material, measurement equipment, appliance and end use equipment compatibility, and the interconnection process, even where there are active pilot projects.[16] Thus, it leads the IOUs to set the groundwork for the actions needed to take place in order to create a hydrogen injection standard in California.

To start on the allowable hydrogen concentration, the IOUs have broken the California utility system into four common variable system elements. These system elements are:

- Long-term system integrity impacts;
- Industrial customers, natural gas vehicles, and system equipment;
- End use appliances (residential and commercial); and
- Regulatory rules and tariffs.

Utility systems have variability in pipeline and equipment characteristics and customer equipment profiles that need to be researched prior to injecting or blending hydrogen into the system. For these elements, there are published limits for hydrogen blending. Figure 2 displays some of the published limits in order of concentration by volume, from 0.03 to 30 vol%.

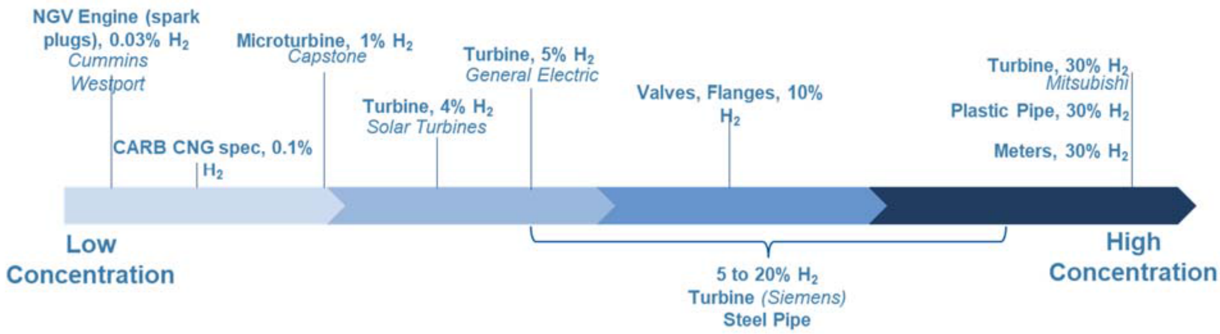

Figure 2: Current Knowledge of Hydrogen Limits

There are a wide range of limits across a utility system. It is important to note that the limits in Figure 2 were determined by external parties through laboratory environments or new installation and therefore not conclusive for the California utility system. Further studies distinctly profiled for the variability and dynamics of each IOU's natural gas system are warranted.

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[16] Hydrogen Europe. Hydrogen Europe Vision on the Role of Hydrogen and Gas Infrastructure on the Road Toward a Climate Neutral Economy – A Contribution to the Transition of the Gas Market. Available at: https://fsr.eui.eu/wp-content/uploads/2019_Hydrogen-Europe-Vision-on-the-role-of-Hydrogen-and-Gas-Infrastructure.pdf

6. IOU Engineering Work Group

The IOUs presented information on hydrogen and hydrogen blending at a Commission RNG Workshop on May 24, 2019. Shortly after this workshop, the IOUs formed an engineering work group, which meets monthly to brainstorm and discuss priority and key research topics. FortisBC, a Canadian electricity and natural gas utility, recently joined the work group, expanding the IOUs' collaborative efforts with an industry partner facing similar challenges.

6.1. Hydrogen Research Action Plan

The central component resulting from the formation of this work group is the Hydrogen Research Action Plan (see Appendix B). The purpose of this action plan is to help identify, prioritize, and track knowledge gaps for hydrogen blending. This plan is built upon four categories: system integrity, system and industrial equipment, residential and commercial end use equipment, and general. With regards to prioritization, the IOUs have indicated a timeline for conducting research and obtaining results. These timelines are categorized as in progress (completion dates are estimations), near-term (one to three years), and long-term (beyond three years).

Note that this action plan is a dynamic document and that priorities, timelines, and scopes may shift as the IOUs learn and understand more about hydrogen. The action plan contains the IOUs' current collective thoughts.

Some highlights of the Hydrogen Research Action Plan are:

- Hydrogen embrittlement and crack growth in steel pipelines at various hydrogen blend levels and pipe grades representative of the IOUs' utility systems
- Impacts on underground and aboveground storage infrastructure
- Feasibility of in-service welding while operating with hydrogen blends
- Impacts on leakage rates and leak detection equipment
- Effects on elastomers and rubbers
- Impact on cathodic protection on steels

7. Next Steps

While the Hydrogen Research Action Plan identifies items to be investigated, the IOUs are aware that one or more of the projects may or may not provide conclusive and/or favorable results. It is possible that additional research and/or the exploration of potential mitigative measures or technologies is necessary to begin hydrogen blending without compromising safety or system integrity.

Between now and when the IOUs submit the Application to the Commission (by November 21, 2020), the IOUs will host one or more all-party technical hydrogen interconnection working group meetings similar to the meeting held on January 15, 2020.

APPENDIX A

Technical Hydrogen Interconnection Working Group

PG&E, SDG&E, SoCalGas, Southwest Gas

January 15, 2020

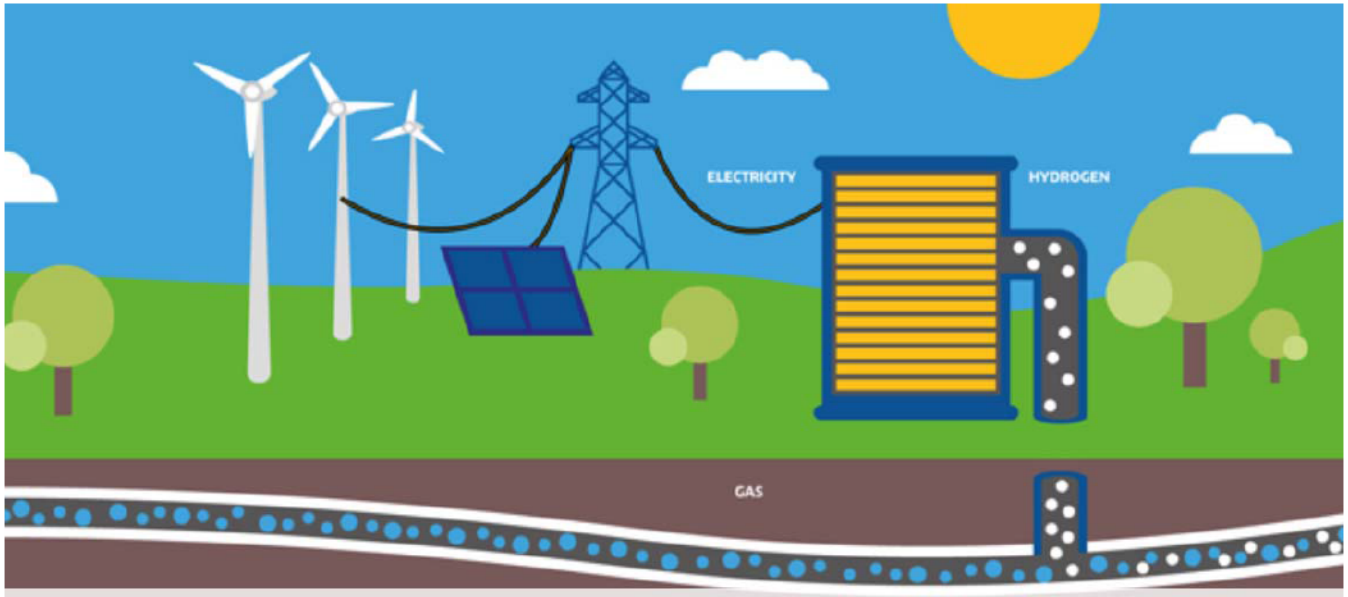
Introduction

- On November 21, 2019, Assigned Commissioner's Scoping Memo and Ruling opened Phase 4 of R.13-02-008
- Joint IOUs are starting to develop a Preliminary Hydrogen Injection Standard and related modifications to its tariffs and protocols
- Joint IOUs are inviting parties to join the Technical Hydrogen Interconnection Working Group (as described in Ruling Paragraph 5)

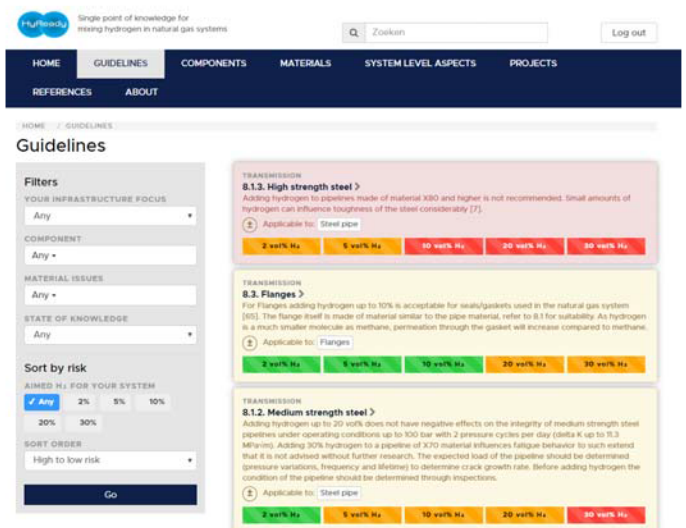
Utility-Specific Knowledge (PG&E)

PG&E R&D Roadmap: Hydrogen

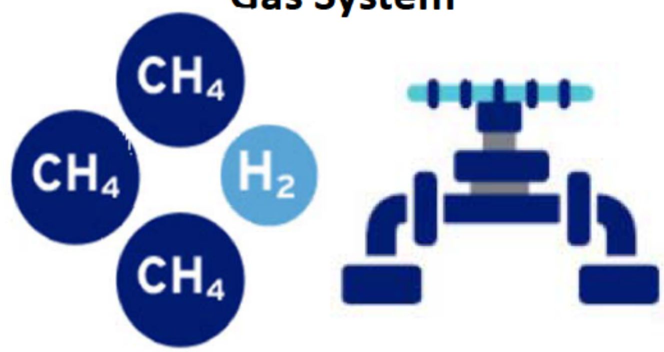
Power-to-Gas Applications for Hydrogen



Standards for Blending and Interconnection



Hydrogen Provided to Customers using Natural Gas System



PG&E R&D Hydrogen Partnerships

BRIMSTONE ENERGY

C|ZERO
Decarbonizing Natural Gas

gti

DNV·GL

NYSEARCH
Natural Gas RD&D

opus 12

OTD
Operations Technology Development

PRCI
Pipeline Research Council International
LEADING PIPELINE RESEARCH

THE UNIVERSITY OF CALIFORNIA • IRVINE •
LET THERE BE LIGHT

PG&E R&D Hydrogen Highlights

PRODUCTION		**Modular heat engine system to convert natural gas into hydrogen with carbon capture (2019)**
TRANSPORTATION		**Emerging fuels hydrogen roadmap (2019) and Strategic Research Project (2020)**
UTILIZATION		**Biological electrolysis of CO_2 and hydrogen into methane (2019)**

Utility-Specific Knowledge (SWG)

SOUTHWEST GAS CORPORATION

Partner	Scope	OTD Project number	Status
Operations Technology Development (OTD) & GTI	Hydrogen Working Group will include an initial workshop to memorialize challenges and goals, map out a strategic roadmap at the utility level, and prioritize next steps for developments of research projects/programs, position (white) papers, and other studies.	7.19.h: Hydrogen Working Group	Active Project – started in 2019
	Effects of Hydrogen Blending in Natural Gas on Material Properties and Operational Safety, Phase 2: Metallic Materials	6.14.b.2: Effects of Hydrogen Blending in Natural Gas on Material Properties and Operational Safety, Phase 2: Metallic Materials	Active Project – started in 2019
	Initial Assessment of the Effects of Hydrogen Blending in Natural Gas on Properties and Operational Safety	6.14.b: Initial Assessment of the Effects of Hydrogen Blending in Natural Gas on Properties and Operational Safety	Completed in 2015

Utility-Specific Knowledge (SoCalGas/SDG&E)

SoCalGas Vision

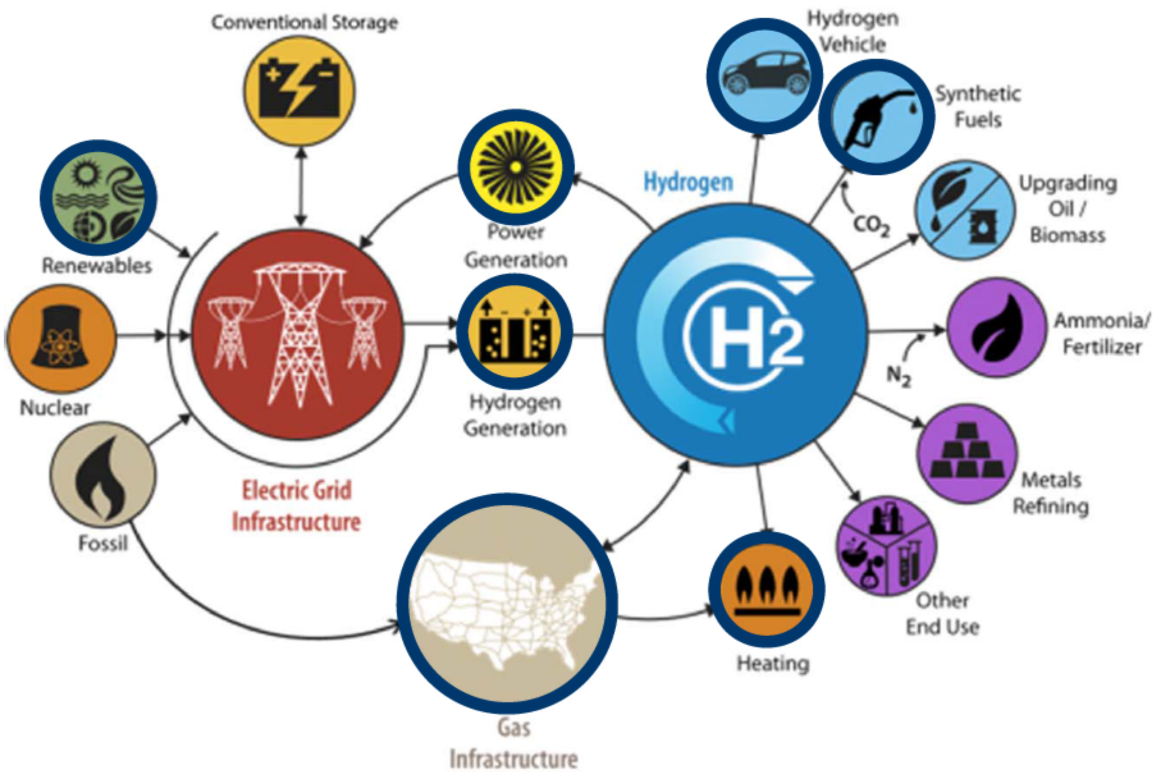
Be the cleanest gas utility in North America

» Balanced Energy approach to create a resilient, reliable, and affordable infrastructure for our energy future.

» Using green hydrogen technology, California can capture the excess wind and solar energy to be used when it is needed most. The excess wind and solar power can be converted into green hydrogen, which can be used alone, or mixed with traditional natural gas, or combined with excess carbon dioxide (CO_2) to be stored in the current natural gas pipeline infrastructure.

» Prior to introducing more hydrogen to SCG/SDG&E natural gas system, we are pursuing further studies distinctly profiled for the SCG/SDG&E gas system to understand impact of variability and dynamics.

SoCalGas Hydrogen Research Areas

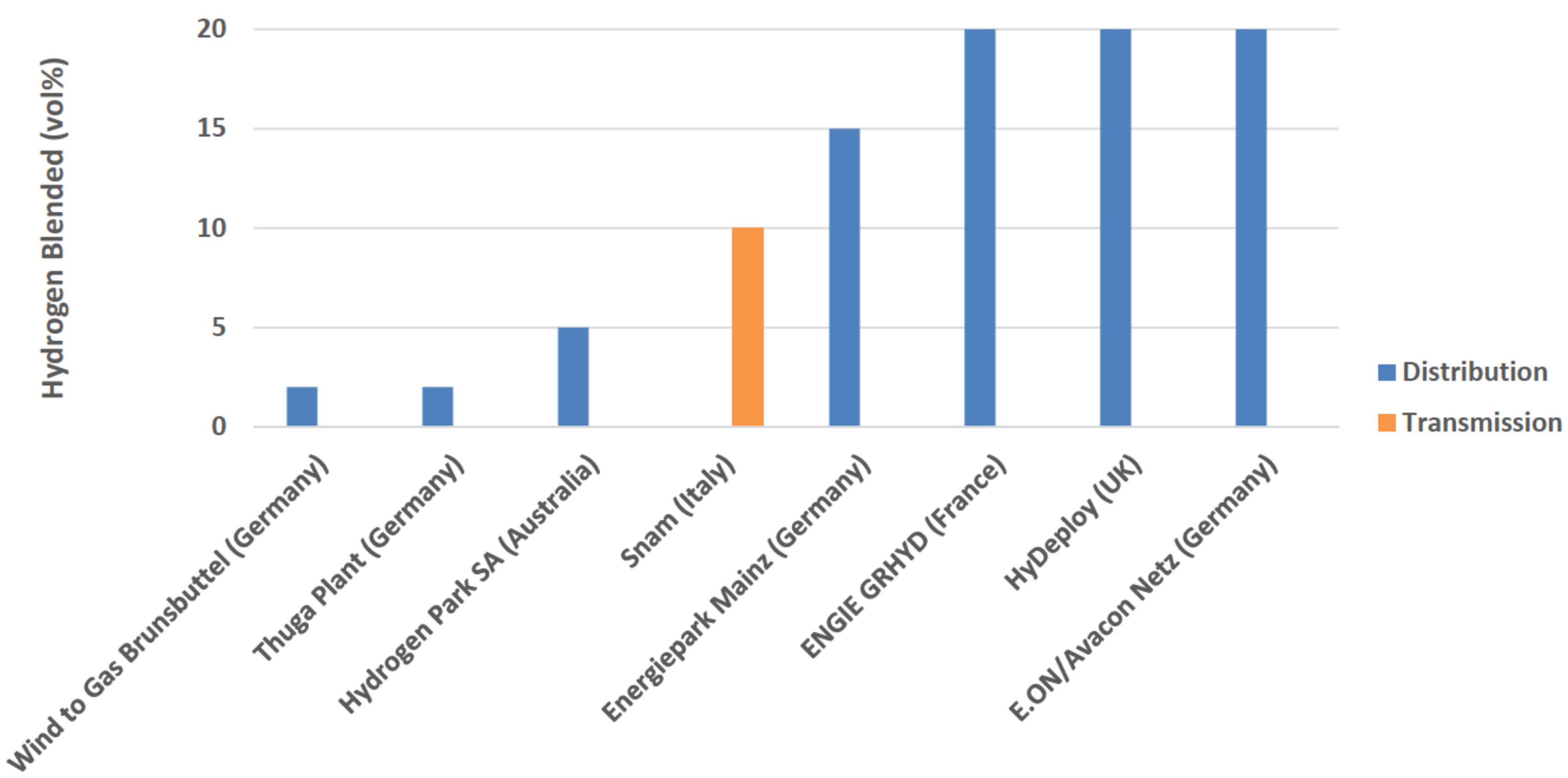


- Renewables
  - Biomass to hydrogen
- Hydrogen Generation
  - Electrolysis
  - Solar steam methane reforming
  - Methane pyrolysis
- Gas Infrastructure
  - Pipeline materials impact
  - Gas blending
- Hydrogen Vehicles
  - Fuel Cell electric vehicle development
  - Fueling station infrastructure
- Synthetic fuel
  - Co-electrolysis
  - Bio-methanogenesis
  - Electro-methanogenesis
- Heating
  - Hydrogen blending for residential and commercial space and water heating
- Power generation
  - Hydrogen blending for DG
  - Stationary fuel cells

Partnerships & Key Studies

Partner	Scope
AGA/CGA:	Blending of Hydrogen into Natural Gas Delivery Systems (2018)
Gas Technology Institute:	Hydrogen Blending into the Natural Gas Network – A Risk Analysis (2010)
	Initial Assessment of the Effects of Hydrogen Blending in Natural Gas on Properties and Operational Safety (2015)
HYREADY:	Engineering Guidelines – For the preparation of natural gas systems for hydrogen / NG mixtures (2018)
University of California, Irvine:	Pilot project for power-to-gas with solar PV
DNV-GL:	Mathematical demonstration of the amount of hydrogen that can be added to natural gas (2017)
University of Southern California:	Hydrogen Embrittlement Literature Review (2014)
	Permeability and Porosity Measurements of Gas Storage Rock Samples (2010)
University of Illinois at Urbana-Champaign:	Evaluating Hydrogen Embrittlement of Pipeline Steels (2016)
Sandia National Laboratories:	Hydrogen Effects on Materials for CNG / H2 Blends (2010)
Colorado State University:	Impact of H2-NG Blending on Lambda Sensor NSCR Control and Lean Burn Emissions (2015)
NYSEARCH RANGE™	Interchangeability study for hydrogen-natural gas blends on SoCalGas customer equipment.

Pilots Around the World



Hydrogen Injection Standard

- Currently, there is no standard defining rules for allowable hydrogen concentrations in the natural gas system, domestic or international
- Identify information needed in order to develop and finalize a hydrogen injection standard in California

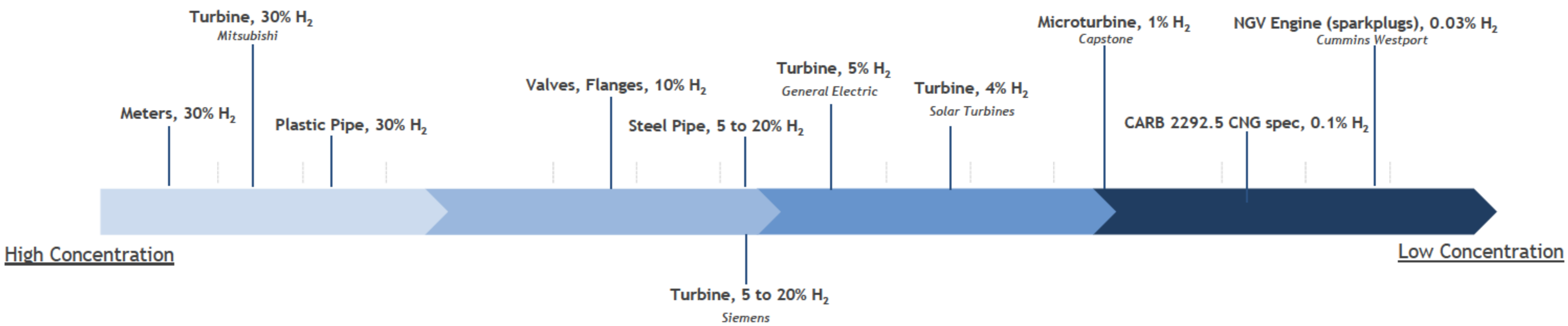
Common Variable System Elements

Issues that apply to most Utility Systems:

- Long-Term System Integrity Impacts
- Industrial Customers, NGVs, and System Equipment
- End-Use Appliances (Residential and Commercial)
- Regulatory Rules and Tariffs

Utility Systems have variability in pipeline and equipment characteristics and customer equipment profiles.

Current Knowledge of Limits*



* Limits are determined by external parties through lab environment or new installation and therefore not conclusive for California utility systems. Warrants further studies distinctly profiled for the variability and dynamics of each utilities' natural gas system.

Joint IOU Engineering Work Group

- Established after May 2019 CPUC RNG Workshop.
- Participants: PG&E, SDG&E, SoCalGas, Southwest Gas, (FortisBC)
- Meet once a month to share information, research, project ideas, etc.
- Drafted hydrogen research action plan to study key areas

Hydrogen Research Action Plan

- Identifies knowledge gaps where further research is needed
- 4 categories
  - System Integrity
  - System & Industrial Equipment
  - End User
  - General
- Focus areas include:
  - Hydrogen embrittlement
  - Underground and aboveground storage
  - In-service welding
  - Elastomers and rubbers
  - Leak detection/measurement equipment
- Timeline
  - Near-term: 1 to 3 years out
  - Long-term: Beyond 3 years
  - In progress: Completion dates are estimations

Moving Forward

- Projects listed in action plan may or may not yield conclusive/favorable results
  - Possibly require additional research and/or exploration of potential mitigative measures/technologies
- Initial status report
  - February 19, 2020
- Bimonthly progress reports
- Future meetings with the technical hydrogen interconnection working group
  - Open to all parties
- Preliminary hydrogen injection standard
  - November 21, 2020

Thank You For Your Time!

APPENDIX B

System Element	Research Topic	Objective/Goal	Status	Estimated Completion
System Integrity	Odorant	Determine if hydrogen will impact the effectiveness of odorant currently used for natural gas	In progress	2020
	Embrittlement/crack growth (transmission, distribution, storage)	Determine crack growth rates at various hydrogen blend levels (1%, 5%, 10%) with base metal, long seam, and girth weld testing for X70	In progress	Q2 2020
		Determine the effects of 5% hydrogen blending in natural gas on metallic materials	In progress	April 2021
		Determine crack growth rates at various hydrogen blend levels (1%, 5%, 10%) with base metal, long seam, and girth weld testing for X42 and X65	Near-term	TBD
		Determine crack growth rates at various hydrogen blend levels (1%, 5%, 10%) with base metal, long seam, and girth weld testing for vintage grade B and vintage X52	Near-term	TBD
		Identify mitigation measures for embrittlement and levels of effectiveness	Long-term	TBD
	Underground storage (reservoir)	Evaluate impact of hydrogen on underground storage reservoir characteristics and integrity	Near-term	TBD
	In-service welding	Study how hydrogen would impact the likelihood of hydrogen induced cracking during in-service welding	Near-term	TBD
	Valves, flanges, fittings, gaskets, sealants (elastomers, rubbers) used for transmission, distribution, underground/aboveground storage operations	Determine the impact on the integrity of rubbers and elastomers using hydrogen-natural gas blends	Near-term	TBD
		Determine the impact on leakage rates at transmission/storage pressures using hydrogen-natural gas blends	Long-term	TBD
	Permeation from plastic pipelines	Study change in flammability range when more hydrogen is added to natural gas (e.g. >20%)	Long-term	TBD
	Minimum ignition energy and hot tie-ins	Minimum ignition energy is reduced when hydrogen is added to natural gas; study how hydrogen would impact the feasibility of performing hot tie-ins	Long-term	TBD
	Cathodic protection (overprotection)	Study the possible embrittlement impact resulting from the combined effect of having hydrogen in the gas supply and hydrogen generated by improperly applied CP	Long-term	TBD
System and Industrial Equipment	Hydrogen blending injection skid	Develop and assess the economic feasibility of a certified low-carbon fuel standard pathway for hydrogen (generated via P2G) blended on the natural gas system; develop a blending system design	In progress	Q2 2020
	Engines/turbines	Demonstrate robustness of operation and extent of low emissions performance of an existing rotary engine based microCHP (combined heat and power) system when using various hydrogen-natural gas blends	In progress	Q4 2020
		Determine how injector/combustor configuration of a microturbine can be changed to remain in compliance with emission regulations when using various hydrogen-natural gas blends	In progress	Q4 2020
		Determine the maximum H2 levels that will not affect performance and/or remain in compliance with emission regulations	Long-term	TBD
		Current fuel specification for Solar turbines has a hydrogen limit of 4%. Collaborate with Solar to test turbine compatibility with hydrogen blends containing more than 4% hydrogen.	Long-term	TBD
	Equipment/measurement accuracy	Determine the maximum H2 levels that will not affect accuracy of meters and pressure regulators	Near-term	TBD
		Evaluate effectiveness of commercially available portable leak detection devices with hydrogen measurement capabilities, if equipment can handle diffusion of hydrogen; test compatibility of equipment currently used in company operations with hydrogen blends	Near-term	TBD
		Evaluate commercially available Btu analyzers compatible with hydrogen	Near-term	TBD
		Evaluate commercially available gas chromatographs with hydrogen measurement capabilities to see if they can be adopted for hydrogen blending operations	Near-term	TBD
	Compressors	Determine the impact on the operation and efficiency of compressors using hydrogen-natural gas blends	Long-term	TBD
	Hydrogen separation	Determine feasibility of installing hydrogen separation systems for gas equipment/facilities that cannot accept hydrogen	Long-term	TBD
	Ultrasonic meters	Assess the accuracy of ultrasonic meters when used for natural gas blended with hydrogen	Long-term	TBD
End User	Combustion/flame stability (e.g. flame flashback, flame lifting, flame yellow tipping)	Determine appliance characteristics based on gas supply composition data	In progress	2020
		Test common types of residential, commercial, industrial equipment using hydrogen blends	Near-term	TBD
	Emissions of residential, commercial, and industrial equipment (i.e. NOx, CO)	Determine the impact on emissions of residential, commercial, and industrial equipment when using hydrogen blends	Near-term	TBD
	NGV engine (CWI)	Study how replacing platinum spark plugs with iridium spark plugs can make CWI NGV engines more compatible with hydrogen blends; study potential impact of hydrogen on general engine performance	Near-term	TBD
	Feedstock customers	Interview customers with strict gas quality requirements and might not be able to accept hydrogen	Near-term	TBD
	Natural gas vehicle on-board fuel tanks	Determine the impact on integrity of NGV tanks made from high-strength steels (Types 1 and 2)	Long-term	TBD

General	Hydrogen blending working group	Facilitate working group to establish a comprehensive strategy for hydrogen blending. Develop a research/project roadmap that outlines the elements needed for successful implementation of hydrogen blending into natural gas pipelines (domestic members).	In progress	Ongoing
	Hydrogen roadmap	Identify conditions and develop tools and technologies to ensure the capability of injecting and transporting hydrogen and hydrogen-natural gas blends, including safe, reliable, and cost-effective operation of existing pipelines.	In progress	Ongoing
	Safety procedures	Determine the applicability of current natural gas safety procedures and safety zones for natural gas blended with hydrogen	Near-term	TBD
	In-line inspection tools and traps	Determine if hydrogen will impact the capabilities and performance of in-line inspection tools and traps	Long-term	TBD
	System capacity	Determine the impact on the pipeline system capacity when there will be a greater demand for gas due to the decreased energy content with hydrogen added to natural gas	Long-term	TBD
	CARB NGV fuel specification	Current CARB NGV fuel spec has a hydrogen limit of 0.1% hydrogen; justify modification of fuel specification	Long-term	TBD

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BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions.	R.13-02-008 (Filed February 13, 2013)

TECHNICAL HYDROGEN WORKING GROUP REPORT OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G), PACIFIC GAS AND ELECTRIC COMPANY (U 39 G), AND SOUTHWEST GAS CORPORATION (U 905 G)

JONATHAN D. PENDLETON Attorney for: PACIFIC GAS AND ELECTRIC COMPANY Law Department 77 Beale Street, B30A San Francisco, California 94105 Telephone: (415) 973-2916 Facsimile: (415) 973-5520 E-Mail: Jonathan.Pendleton@pge.com	DANA R. WALSH Attorney for: SOUTHWEST GAS CORPORATION 5241 Spring Mountain Road Las Vegas, Nevada 89150-0002 Telephone: (702) 876-7396 Facsimile: (702) 252-7283 E-Mail: Dana.Walsh@swgas.com
	ISMAEL BAUTISTA, JR. ELLIOTT S. HENRY Attorneys for: SOUTHERN CALIFORNIA GAS COMPANY SAN DIEGO GAS & ELECTRIC COMPANY 555 West Fifth Street, Suite 1400, GT14E7 Los Angeles, California 90013 Telephone: (213) 244-8540 Facsimile: (213) 629-9620 E-Mail: IBautista@socalgas.com EHenry@socalgas.com

August 14, 2020

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions.	R.13-02-008 (Filed February 13, 2013)

TECHNICAL HYDROGEN WORKING GROUP REPORT OF SOUTHERN CALIFORNIA GAS COMPANY (U 904 G), SAN DIEGO GAS & ELECTRIC COMPANY (U 902 G), PACIFIC GAS AND ELECTRIC COMPANY (U 39 G), AND SOUTHWEST GAS CORPORATION (U 905 G)

Pursuant to Ordering Paragraph 5 of Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of Rulemaking 13-02-008 (Scoping Memo), Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), Pacific Gas and Electric Company (PG&E), and Southwest Gas Corporation (Southwest Gas) (collectively, the Joint Utilities)[1] respectfully submit their second Technical Hydrogen Working Group Progress Report attached hereto as Attachment A.

Respectfully submitted,

By: *[/s/Ismael Bautista, Jr.]*
Ismael Bautista, Jr.

ISMAEL BAUTISTA, JR.
ELLIOTT S. HENRY

Attorneys for:
SOUTHERN CALIFORNIA GAS COMPANY
SAN DIEGO GAS & ELECTRIC COMPANY
555 West Fifth Street, Suite 1400, GT14E7
Los Angeles, California 90013
Telephone: (213) 244-8540
Facsimile: (213) 629-9620
E-Mail: IBautista@socalgas.com
EHenry@socalgas.com

August 14, 2020

[1] Pursuant to Rule 1.8(d), SoCalGas and SDG&E have been authorized to file this document on behalf of the Joint Utilities.

ATTACHMENT A

R.13-02-008, Phase 4:

Technical Hydrogen Interconnection Working Group Progress Report

August 14, 2020

Prepared by:

Pacific Gas and Electric Company

San Diego Gas & Electric Company

Southern California Gas Company

Southwest Gas Corporation

Contents

1. Introduction

Pursuant to Ordering Paragraph (OP) 5 of the Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of Rulemaking (R.) 13-02-008 (Ruling) issued on November 21, 2019, Pacific Gas and Electric Company (PG&E), Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E), and Southwest Gas Corporation (Southwest Gas) (collectively, the IOUs) submit this Technical Hydrogen Interconnection Working Group Progress Report (Report). The Ruling provides direction on the reporting requirement as follows:

> *The Joint Utilities shall hold at least two meetings of a technical hydrogen interconnection working group, open to all parties to the proceeding, to assist in developing the Application required by Paragraph 4 based on evaluation of available research and practices in other locations. The technical working group shall submit an initial report to the Commission 90 days from this Ruling. The Joint Utilities shall hold additional technical working group meetings as needed and submit progress reports every 60 days thereafter. The Joint Utilities shall collaborate with Energy Division to ensure that public workshops or webinars are hosted at appropriate times.*[1]

The first technical hydrogen working group (working group) was held on January 15, 2020, and an initial report per the Ruling was submitted to the Commission on February 19, 2020. The second working group meeting was held on June 17, 2020 via webinar. The IOUs aggregated all of the information in this Report, which contains the following information that was presented during the working group meeting:

- Working group meeting summary
- Joint IOU Technical Update
    - Research Action Plan Matrix Update
    - Preliminary Hydrogen Injection Standard Development
    - Hydrogen Blending Demonstration Proposal
- Presentations from Technical Guests
    - Shell
    - Solar Turbines
    - Fortis B.C.
- Next Steps

2. Working Group Meeting Summary

The second working group meeting was noticed to all parties in the Biomethane Order Instituting Rulemaking (R.13-02-008). The purpose of this second technical workshop was to provide a public forum for discussion on available research and industry knowledge to inform stakeholders on this proceeding and assist the gas utilities to develop a preliminary hydrogen injection standard. The IOUs presented an update on hydrogen research projects (part of the

[1] Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of Rulemaking (R.) 13-02-008, at 12 (Ordering Paragraph #5).

Hydrogen Research Action Plan Matrix), shared their respective approaches toward the preliminary hydrogen injection standard Application (Application) the IOUs are required to submit within 12 months of the Ruling,[2] and discussed proposing demonstration projects in the Application.

In order to better inform the proceeding, the IOUs collaborated with Shell, Solar Turbines, and Fortis B.C. (collectively, Guests) to present their hydrogen blending efforts. The Guests shared a similar vision that hydrogen can be an integral part of a viable solution in achieving a carbon neutral future, and that more research and demonstration projects are needed. Shell focused on its international efforts; Solar Turbines shared safety, integrity and reliability information regarding using hydrogen in its manufactured equipment; and Fortis B.C. shared upcoming demonstration efforts both at its campus and distribution system.

The IOUs and Guests emphasized that while hydrogen blending can be a critical component to meeting both their and the State's carbon-neutral future, it must be done with safety, system integrity, and reliability as the top priorities. The IOUs also stated that because more substantial research needs to be conducted to safely blend hydrogen into the gas systems, (1) the current 0.1% Biomethane Trigger Level will not be changed at this time, and (2) no blend percentage will be included in the preliminary hydrogen injection standard. The IOUs are committed to conducting the necessary work to safely introduce higher blend percentages into their respective systems, or portions thereof, as soon as it is feasible to do so safely. They are proposing to increase the percent blend over time for all, or portions of, their gas systems as more research is completed, more information is gathered from smaller-scale feasibility projects, and the IOU gas system training, standards, procedures, and assets (or portions thereof) are replaced / updated / modified accordingly.

During the public discussion period, representatives from University of California, Irvine (UCI) asked clarifying questions regarding why a blend percentage would not be proposed in the Application, and if there would be opportunities to do smaller scale demonstrations concurrently with research. In the joint Application, the IOUs will recommend research, assessment, and piloting plans with proposed timeframes to determine safety and operational considerations and the most attractive environments to safely introduce hydrogen into the existing gas pipeline system. Proper technical analysis with supporting ground truth assessments will be required evaluations. A question was also posed regarding the economics of Power-to-Gas (P2G) and the reduced roundtrip efficiency of hydrogen. UCI generally stated that forecasted costs of hydrogen are decreasing, and Solar Turbines clarified that the performance of a gas turbine itself does not change with the introduction of hydrogen. Rather, it is the compressors that have to run longer/harder to deliver an equivalent amount of energy. The IOUs mentioned that this effort is more focused on the technical details and it was noted that SoCalGas' and PG&E's research, development, and demonstration (RD&D) groups are closely following production technologies and the economics of hydrogen. Further, the IOUs and UCI noted that resiliency is a strong technical point for why hydrogen needs to be adopted. Even with lower roundtrip efficiency,

[2] Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of R. 13-02-008, at 12 (Ordering Paragraph #4).

hydrogen can be a less expensive solution for low-energy, high-power applications. UCI mentioned how hydrogen energy storage can be significantly cheaper for large amounts of energy even with low roundtrip efficiencies, and the gravimetric density or energy per mass of hydrogen makes hydrogen an attractive fuel source for use in heavy duty transportation and aviation, as batteries cannot meet these high-power demands.

3. Joint IOU Technical Update

3.1. Research Action Plan Matrix

In the first Working Group Meeting, the IOUs shared their Hydrogen Research Action Plan. The purpose of this action plan is to help identify, prioritize, and track knowledge gaps for hydrogen blending. As emphasized in the second working group on June 17, 2020, the Hydrogen Research Action Plan Matrix focuses on safety, system integrity, and reliability – the primary priorities for the IOUs in all efforts.

This research plan is built upon four categories: (1) system integrity, (2) system and industrial equipment, (3) residential and commercial end use equipment, and (4) general. With regard to prioritization, the IOUs have indicated a timeline for conducting research and obtaining results. These timelines are categorized by their planning horizon, as completion dates are estimates: near-term (one to three years), and long-term (beyond three years).

Note that this action plan is a dynamic document and that priorities, timelines, and scopes may shift as the IOUs learn and understand more about hydrogen blending. The action plan contains the IOUs' current collective thoughts.

On June 17, 2020, the IOUs shared updates of select projects tied to the Hydrogen Research Action Plan Matrix, summarized here:

3.2 Ongoing Research Collaborations

3.1.1. Pipeline Research Council International – Emerging Fuels Hydrogen Roadmap and State-Of-The-Art Study

In 2019, a new ad hoc committee under Pipeline Research Council International (PRCI) was formed to focus on emerging fuels, including hydrogen. Last year, PG&E led a team of other PRCI members to develop a hydrogen roadmap focused on preparing existing natural gas infrastructure for the transportation of hydrogen at incremental blending limits starting with 1%. In 2020, PG&E and SoCalGas are supporting a long term (2020-2045) PRCI emerging fuels strategic research program to execute the roadmap, starting with an exhaustive state-of-the-art assessment. The state-of-the-art study kicked off in April 2020 and is scheduled to be completed by August 2020. PRCI has completed Task 1, which is mapping of all RD&D projects and an external bibliography relevant to hydrogen blending in the natural gas system. The team identified approximately 90 RD&D projects and 250 references pertaining to hydrogen blending. As part of ongoing external outreach, Task 1 (Mapping), will remain open to allow for additional companies to participate and to capture anything that was missed during the initial mapping stage. In parallel, Task 2, state-of-the-art analysis, has started. This involves experts from each company reviewing the identified references and providing their expertise on the data (i.e., key results, discrepancies, gaps) to identify areas where there is sufficient information and areas where there are discrepancies or knowledge gaps. Results will be incorporated into 2021 PRCI research proposals and presented to the membership for a vote in Fall of 2020.

3.1.2. OPUS 12 – Chemical Electrolysis of Carbon Dioxide and Hydrogen into Methane

Opus 12 is developing an electrochemical process to convert carbon dioxide (CO_2) into chemicals and fuels. Using only CO_2, with water and electricity as inputs, electrochemical reduction of CO_2 could form the basis of an artificial carbon cycle that replaces a wide range of projects currently derived from fossil fuel resources, such as methane. PG&E and SoCalGas collaborated with Opus 12 to focus on increasing the production of methane from CO_2 by improving partial current density. The final report for this project was received on February 23, 2020. Opus 12 screened various novel catalysts produced in house or with partners, as well as commercial catalysts. In addition, the optimization of membrane electrode assemblies (MEA) manufacturing and testing conditions were evaluated to further boost methane production. Eight hours of stability at 50-60% faradaic efficiency at 300 milliampere per square centimeter (mA/cm^2) and a new internal record of twelve hours of stability at 200 mA/cm^2 was achieved. A scale-up of performance was also achieved from 25 (square centimeters (cm^2) to 100 cm^2 in this project, replicating a setpoint 3-hour stability at 50-60% faradaic efficiency at 300 mA/cm.^{2} Further work on assessing stability at 100 cm^2 will be performed in future phases.

3.1.3. NYSEARCH – Biological Electrolysis of CO_2 and Hydrogen into Methane

PG&E and SoCalGas partnered with multiple utilities and Stanford University on an NYSEARCH project to look at long-term viability of biological electrolysis using methanogen microbes that take captured CO_2 from any CO_2 emitting source and combine it with hydrogen produced in situ to create additional methane that is completely interchangeable and can be injected into the natural gas system. The final report for this project was issued on May 13, 2020.

The Phase I final report reviews the motivation and background for this research and the short-term benefit to utilities of investigating the potential of power-to-gas microbial operation. Microbial power-to-gas has been commercially realized by a company called Electroarchea, but Stanford presents an innovation to this microbial power-to-gas process by directly integrating the electrolysis process into the same microbial electrode reactor. Furthermore, the catalytically produced hydrogen (from the nickel-molybdenum cathode) is consumed almost instantaneously upon production, thus eliminating the need to transport hydrogen from the electrolysis process into a separate microbial reactor. This also contributes to an increase in overall energy efficiency of the microbial power-to-gas process compared with current state of the art processes. The results from Phase I show a reliable and repeatable integrated microbial power-to-gas system with very high and sustained Columbic efficiency throughout the operating timeline of the reactors. Stanford University also summarizes the biological findings to further understand how the cells are processing the hydrogen and carbon dioxide with the supply of electrons and the effects of its outside environment. The success of Phase I shows promise for this integrated microbial power-to-gas approach and NYSEARCH has initiated further Phase II work to test the inherent intermittency of renewable electric supply for microbial power-to-gas operations.

3.1.4. OTD and GTI – Hydrogen Working Group (Postponed due to COVID-19)

Southwest Gas is partnering with multiple utilities (including Dominion Energy, Duke Energy, National Grid, Nicor Gas, Northwest National, and Washington Gas) on the Operations Technology Department (OTD) 7.19.h project (OTD 7.19.h project), with the goal of establishing a strategic roadmap at the utility level to prioritize the steps required to utilize hydrogen as a safe energy source in a natural gas distribution system. Southwest Gas planned to host the kick-off workshop for the OTD 7.19.h project in April 2020 at its headquarters in Las Vegas, NV. This project was postponed due to COVID-19. The working group is starting to meet remotely to address focus areas and alignment with other industry efforts.

3.1.5. NYSEARCH – Supplemental Study: Blended H2 Gas Interchangeability for Local Distribution Company (LDC) Infrastructure Integrity

Southwest Gas and PG&E voted to approve funding along with 11 NYSEARCH member utilities. This project kick-off will start in the third quarter of 2020 with the intention of studying the effects of various levels of methane/hydrogen blends in materials used to distribute natural gas under realistic conditions to establish the level of response of these materials in the presence of hydrogen. The work will continue throughout 2020 and 2021.

3.1.6. DNV GL – In Service Welding onto Methane-Hydrogen Mixture Pipelines

SoCalGas joined a joint industry project led by DNV GL to investigate the effect of hydrogen blends on the ability to make safe in-service welds. The objective of this study is to determine if welding onto an in-service pipeline containing hydrogen and methane will lead to an increased risk of hydrogen cracking, and if so, develop mitigative measures. This project is estimated to be completed by end of 2021.

3.1.7. GTI – Hydrogen Blending Impacts on Residential & Commercial Combustion Equipment

SoCalGas is supporting a GTI-led project on hydrogen impacts on residential and commercial combustion equipment. This study will focus on emissions, efficiency, and performance of various common appliances in the residential and commercial sectors and will provide design guidance to manufacturers for lowering NO_x emissions. This project is estimated to be completed by end of 2020.

3.1.8. SoCalGas – Evaluation of Methane Detection Technologies with Hydrogen-Methane Blends, Evaluation of Gas Chromatographs Capable of Detecting Hydrogen

SoCalGas is evaluating leak detection equipment using various hydrogen blends to determine impacts to accuracy, performance, and lifespan. Leak detection equipment are critical tools for day-to-day operations. There are several types and technologies deployed that need to be evaluated with hydrogen blends. The types of technologies that will be evaluated include infrared (IR), thermal conductivity, flame ionization detector (FID), and catalytic reaction. This project is estimated to be completed by end of 2020.

SoCalGas also plans to evaluate two gas chromatographs capable of detecting and measuring hydrogen. Since CPUC-approved heating value measurement devices cannot analyze hydrogen in natural gas, SoCalGas has selected two gas chromatographs for evaluation. The devices that pass SoCalGas' evaluation will be submitted to the CPUC for approval.[3] This project is estimated to be completed by end of Q1 2021.

3.3 Preliminary Hydrogen Injection Standard

Hydrogen blended into natural gas is most compatible with newly installed, plastic infrastructure that is isolated from legacy materials. The natural gas network in California is interconnected, and consequently, the system is limited by its assets that have the lowest tolerance for blended hydrogen. Based on their work to date, the IOUs intend to propose in their Application a framework structure for what a hydrogen injection standard should look like. The IOUs intend the Application to serve as a plan to lay the foundation for an injection standard that prioritizes the three pillars: safety, system integrity, and reliability, and can be implemented to introduce hydrogen blending into the gas system in the future. This will include a structure of research milestones based on increasing blend percentages. The Application will also include a regulatory mechanism (i.e., Advice Letter-approval approach) to permit timely updates to the Hydrogen Blending Standard with focus on safety, system integrity, and reliability while advancing California's climate policy goals.

During the June 17, 2020 presentation, the IOUs discussed leveraging research completed on hydrogen blending internationally. The PRCI State of the Art Study discussed previously includes a critical technical evaluation of all available hydrogen research to catalogue boundary conditions for each project. This information will be used to determine the applicability and limitations of findings going forward. One of the largest differences between natural gas systems in Europe and California is that Europe is using relatively newer infrastructure (post-World War 2) with more hydrogen compatible materials, whereas California is looking to re-purpose steel and plastic piping networks that often include older piping and more variation in grades and welding techniques. Studies that focus on higher grade steels (generally known to be less tolerant of hydrogen) may not be applicable to lower grade steels (generally known to be more tolerant of hydrogen).

The IOUs believe that ongoing research will establish safe and innovative ways to re-purpose much, if not all, of our existing gas infrastructure for transport of hydrogen / methane blends. The results of ongoing / proposed research projects and pilots will provide the technical

[3] General Order 58-B requires devices measuring heating value of gaseous fuels for billing purposes be approved by Energy Division.

means to achieve this goal, build confidence in our approach, and maintain the safety and reliability of our systems.

3.4 Hydrogen Demonstration Proposal

In order to help inform an increased hydrogen injection blending standard, the IOUs propose to allow for demonstrations of hydrogen blending. The initial demonstrations will be led by SoCalGas. The IOUs' literature review and outreach show that current and planned international demonstrations range from 5% to 20% hydrogen blend in plastic pipeline (fed into Universities and residences); and 5% to 10% hydrogen blend in brand new steel pipeline connected to an industrial end user. The demonstrations/pilots will allow SoCalGas/SDG&E to collect data and inform other systems in California. They will also allow the ability to test new hydrogen injection equipment.

During the working group meeting, there was discussion of involving third parties in the demonstrations. The IOUs are not yet ready for pilots allowing third parties to interconnect their hydrogen to the IOUs' systems. More work is needed by the IOUs to vet the safety of injection and its impacts to system integrity and reliability. However, third parties are encouraged to continue to collaborate with the IOUs and work together to determine whether there are parts of the IOUs' systems where third party projects may be able to proceed before an increased hydrogen injection blending standard is proposed. The goal is for demonstrations to run concurrently with research efforts and help achieve milestones based on blend percentages.

4. <u>Technical Guests</u>

Shell, Solar Turbines and Fortis B.C. presented at the Technical working group held on June 17, 2020. These three companies are actively engaged in their own hydrogen efforts and share a similar vision that hydrogen is an international answer to a carbon neutral energy future, a similar goal of collaboration, and a similar understanding that more work is needed on hydrogen injection and blending.

4.1. Shell

Dr Wayne Leighty of Shell provided a high-level overview of Shell's hydrogen blending efforts and vision. Follow up questions may be directed to:

Wayne Leighty, MBA, PhD
Hydrogen Business Development Manager, North America
Shell New Energies
650 California Street, Suite 2250
San Francisco, CA 94108
832-680-9825

4.2. Solar Turbines

Dr. Rainer Kurtz spoke on behalf of Solar Turbines. Dr. Kurtz discussed[4] the impact of mixing hydrogen into natural gas, combustion in the gas turbine, safety, centrifugal gas compressors, emissions, and pipeline hydraulics. Dr. Kurtz stated that new Solar Lean Premix centrifugal gas compression units are compatible with up to 10% hydrogen / methane blends. It should be noted that few, if any, new Solar Lean Premix centrifugal gas compression units are currently installed / operating on IOU systems. Dr. Kurtz noted that older centrifugal gas compression systems, to include systems not manufactured by Solar, would have to be evaluated on a case-by-case basis to determine whether such systems could be upgraded for use of hydrogen / methane blends.

Relative to natural gas, hydrogen is lighter, carries less energy per unit volume, more energy per unit mass, has a higher heat capacity, and different viscosity. In terms of transport efficiency, centrifugal gas compressors will have to run faster and consume more power (i.e., burn more fuel gas) to maintain an equivalent energy throughput. Dr. Kurtz concluded that hydrogen blending can be achieved but Dr. Kurtz did not discuss the feasibility of compressing hydrogen / methane blends with reciprocating gas compression equipment.

4.3. Fortis B.C.

John Quinn, Senior Manager, spoke on behalf of Fortis B.C. Highlights of the Fortis B.C. presentation[5] included an overview of Fortis B.C., Hydrogen Research and Development, Appliance Performance Testing, and Pilot/Demonstration Efforts – University of British Columbia (UBC) Okanagan Campus H2 Lab, UBC Vancouver Campus H2 Hub, and a planned Hydrogen Deployment Demonstration Project. The appliance demonstration focused on models utilized in their service territory, testing increasingly higher blends of hydrogen. A subset of models experienced flashback at 10% hydrogen blend, resulting in a recommendation of a 5% blend limit at this time for the residential appliance population. The UBC Okanagan H2 Lab is planned as a laboratory to investigate hydrogen enriched natural gas from injection to combustion. The UBC Vancouver Hydrogen Hub will serve as a city scale integrated energy demonstration site and test bed for hydrogen injection. Lastly, Fortis B.C. is planning a Metro-Vancouver located demonstration project to inform necessary knowledge gaps to move from the requirement to survey, test, and trial all parts of the gas distribution network prior to hydrogen injection, to the ability to inject in an untested network. A key objective is to support development of standards allowing a third party to inject.

5. <u>Conclusion and Next Steps</u>

The IOUs are supportive of the concept of blending hydrogen into the natural gas pipelines and believe there will be viable options to do so. However, safety, reliability and system integrity concerns remain to be resolved and the IOUs are committed to resolving these concerns first. Per

[4] Natural Gas-Hydrogen Mixtures: Combustion and Compression, presented by Solar Turbines on June 17,2020.
[5] Renewable Gas Supply – Hydrogen, presented by Fortis B.C. on June 17, 2020.

the Ruling,[6] the IOUs plan to submit their joint Application to the Commission by November 23, 2020. As previously mentioned, the IOUs intend to propose a framework structure for what a hydrogen injection standard should look like and will utilize the Application to serve as a plan to lay the foundation for an injection standard. Verbal feedback from Energy Division staff during the second technical workshop included a request to identify milestones within the Application that will better inform timing for a Final Hydrogen Injection Standard. The Joint IOUs will provide recommendations within the Application on a plan for determining steps required to safely blend hydrogen into the gas system with proper technical backing based on completed research and ground truth assessments in controlled environments.

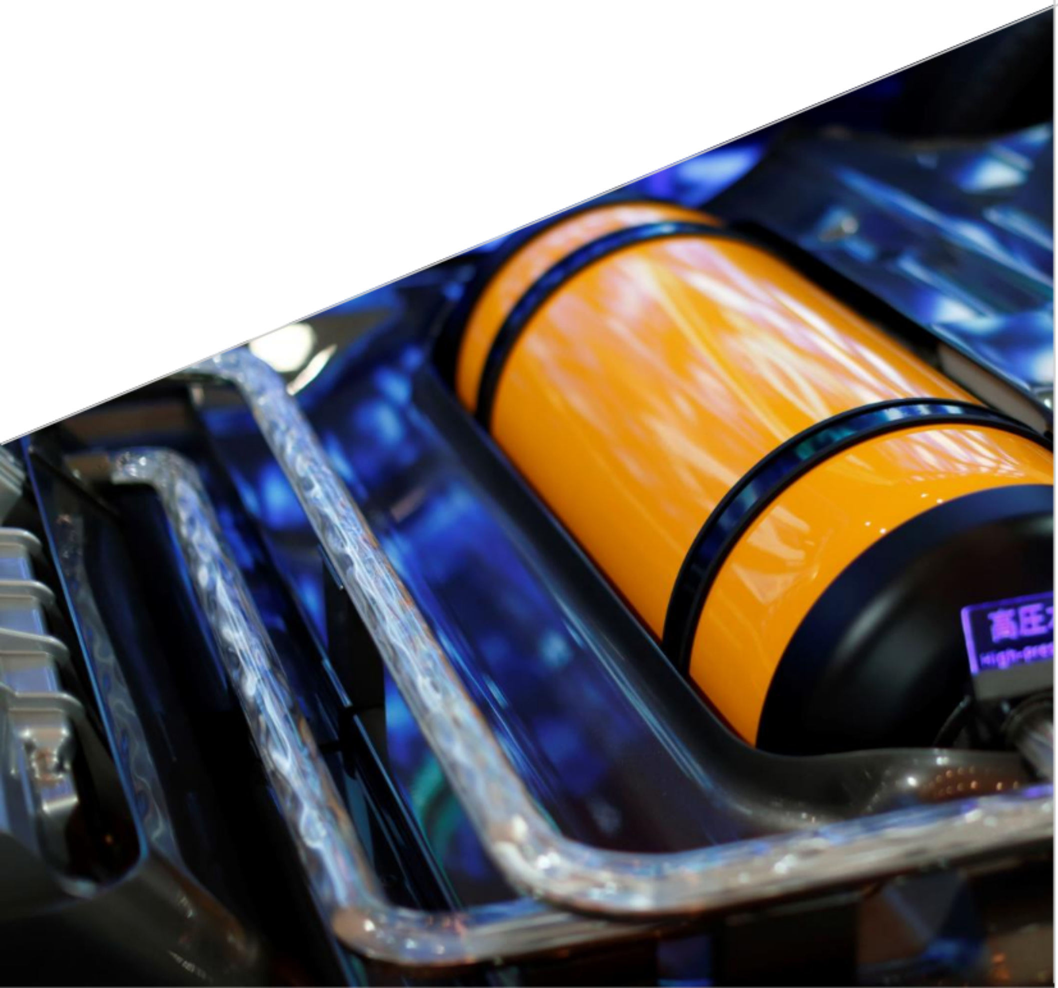
[6] Assigned Commissioner's Scoping Memo and Ruling Opening Phase 4 of R. 13-02-008, at 12 (Ordering Paragraph #4).

ATTACHMENT 2

Hydrogen Economy Outlook

Will Hydrogen Be the Molecule to Power a Clean Economy?

March 30, 2020



BloombergNEF

Contents

Table of figures

Table of tables

Section 1. Executive Summary

$6/MMBtu

Projected cost of producing renewable hydrogen in 2050

20%

Percentage of greenhouse gas emissions from fossil fuels and industry that can be eliminated by using hydrogen with a carbon price less than $100/tCO2

$11 trillion

Investment in supply infrastructure required for hydrogen to provide 24% of final energy in 2050

Hydrogen is a clean-burning molecule that could become a zero-carbon substitute for fossil fuels in hard-to-abate sectors of the economy. The cost of producing hydrogen from renewables is primed to fall, but demand needs to be created to drive down costs, and a wide range of delivery infrastructure needs to be built. That won't happen without new government targets and subsidies. This report is the final instalment of BNEF's *Hydrogen Special Project* and provides a global, independent analysis and outlook for a hydrogen economy. (See correction note at bottom of page 3.)

- **Meeting climate targets is likely to require a clean molecule**: renewable electricity can help reduce emissions in road transport, low-temperature industrial processes and in heating buildings. However, fossil fuels have a significant advantage in applications that require high energy density, industrial processes that rely on carbon as a reactant, or where demand is seasonal. To fully decarbonize the world economy, it's likely a clean molecule will be needed and hydrogen is well placed to play this role. It is versatile, reactive, storable, transportable, clean burning, and can be produced with low or zero emissions.
- **Renewable hydrogen is currently expensive, but costs are coming down**: in 2018, over 99% of hydrogen was made using fossil fuels, but hydrogen can also be produced cleanly using renewable electricity to split water in an electrolyzer. With the cost of wind and solar continuing to fall, the question is whether the cost for electrolyzers and renewable hydrogen can follow. While they are still expensive in Western markets, there are encouraging signs. The cost of alkaline electrolyzers made in North America and Europe fell 40% between 2014 and 2019, and Chinese made systems are already up to 80% cheaper than those made in the west. If electrolyzer manufacturing can scale up, and costs continue to fall, then our calculations suggest renewable hydrogen could be produced for $0.7 to $1.6/kg in most parts of the world before 2050. This is equivalent to gas priced at $6-12/MMBtu, making it competitive with current natural gas prices in Brazil, China, India, Germany and Scandinavia on an energy-equivalent basis, and cheaper than producing hydrogen from natural gas or coal with carbon capture and storage (CCS).
- **Transporting and storing hydrogen needs massive infrastructure investment**: hydrogen's low density makes it considerably harder to store than fossil fuels. If hydrogen were to replace natural gas in the global economy today, 3-4 times more storage infrastructure would need to be built, at a cost of $637 billion by 2050 to provide the same level of energy security. Its low density also makes hydrogen expensive to transport via road or ship. However, hydrogen flows nearly three times faster than methane through pipes, making this a cost-effective option for large-scale transport. But for hydrogen to become as ubiquitous as natural gas, a huge, coordinated program of infrastructure upgrades and construction would be needed, as hydrogen is often incompatible with existing pipes and systems.
- **A scaled-up industry could deliver hydrogen for a benchmark cost of $2/kg in 2030 and $1/kg in 2050 in many parts of the world:** hydrogen is likely to be most competitive in large-

scale local supply chains. Clusters of industrial customers could be supplied by dedicated pipeline networks containing a portfolio of wind- and solar-powered electrolyzers, and a large-scale geological storage facility to smooth and buffer supply. Our analysis suggests that a delivered cost of green hydrogen of around $2/kg ($15/MMBtu) in 2030 and $1/kg ($7.4/MMBtu) in 2050 in China, India and Western Europe is achievable. Costs could be 20-25% lower in countries with the best renewable and hydrogen storage resources, such as the U.S., Brazil, Australia, Scandinavia and the Middle East. However, cost would be up to 50-70% higher in places like Japan and Korea that have weaker renewable resources and unfavorable geology for storage.

- **But policy is critical**: reaching a delivered hydrogen cost of $1/kg will require massive scale-up in demand as well as cost declines in transport and storage technologies. And while hydrogen is a hot topic right now, there is little government policy currently in place to help this happen. Policy measures are generally focused on expensive road transport applications, and programs are poorly funded. The more promising use cases in industry are only funded with one-off grants for demonstration projects. For the industry to scale up, demand needs to be supported with comprehensive policy coordinated across government, and the roll-out of around $150 billion of cumulative subsidies to 2030.
- **…and so is carbon pricing:** even at $1/kg, carbon prices or equivalent measures that place a value on emission reductions are still likely to be needed for hydrogen to compete with cheap fossil fuels in hard-to-abate sectors. This is because hydrogen must be manufactured, whereas natural gas, coal and oil need only to be extracted, so it is likely always to be a more expensive form of energy. Hydrogen's lower energy density also makes it more expensive to handle. But if the required policy is in place, up to 34% of greenhouse gas emissions from fossil fuels and industry could be abated using hydrogen – 20% for less than $100/tCO2.
- **Hydrogen is a promising emissions reduction pathway for the hard-to-abate industry sectors**: the strongest use cases for hydrogen are the manufacturing processes that require the physical and chemical properties of molecule fuels in order to work. Hydrogen can enable a switch away from fossil fuels in many of these applications at surprisingly low carbon prices. For example, at $1/kg, a carbon price of $50/tCO2 would be enough to switch to renewable hydrogen in steel making, $60/tCO2 to use renewable hydrogen for heat in cement production, $78/tCO2 for ammonia synthesis, and $90/tCO2 for aluminum and glass manufacturing.
- **But its role in transport should be focused on trucks and ships**: hydrogen can play a valuable role decarbonizing long-haul, heavy-payload trucks. These could be cheaper to run using hydrogen fuel cells than diesel engines by 2031. But the bulk of the car, bus and light-truck market looks set to adopt battery electric drive trains, which are a cheaper solution than fuel cells. In our view, the fuel cell vehicle industry will also be the most expensive sector to scale up, requiring $105 billion in subsidies to 2030. For ships, green ammonia from hydrogen is a promising option, and could be competitive with heavy fuel oil with a carbon price of $145/tCO2 in 2050.
- **A hydrogen supply chain could deliver carbon-free dispatchable power:** with large-scale geological storage in place, hydrogen could be produced from renewable power that would otherwise be curtailed, stored and transported back to a generator at a cost of $8-14/MMBtu by 2050 in most locations. If gas turbines are hydrogen-ready, a carbon price of $32/tCO2 would be enough to drive fuel switching from natural gas to hydrogen. Producing hydrogen from excess renewable electricity would reduce waste and help to deliver a zero-emissions electricity system.

- **Hydrogen could meet up to 24% of the world's energy needs by 2050**: if supportive but piecemeal policy is in place, we estimate that 187 million metric tons (MMT) of hydrogen could be in use by 2050, enough to meet 7% of projected final energy needs in a scenario where global warming is limited to 1.5 degrees. If strong and comprehensive policy is in force, 696MMT of hydrogen could be used, enough to meet 24% of final energy in a 1.5 degree scenario. This would require over $11 trillion of investment in production, storage and transport infrastructure. Annual sales of hydrogen would be $700 billion, with billions more also spent on end use equipment. If all the unlikely-to-electrify sectors in the economy used hydrogen, demand could be as high as 1,370MMT by 2050.
- **Producing hydrogen at the scales required will, however, be challenging**: meeting 24% of energy demand with hydrogen in a 1.5 degree scenario will require massive amounts of additional renewable electricity generation. In this scenario, around 31,320TWh of electricity would be needed to power electrolyzers – more than is currently produced worldwide from all sources. Add to this the projected needs of the power sector – where renewables are also likely to expand massively if deep emission targets are to be met – and total renewable energy generation excluding hydro would need to top 60,000TWh, compared to under 3,000TWh today. China, much of Europe, Japan, Korea and South East Asia may not have enough suitable land to generate the renewable power required. As a result, trade in hydrogen would be necessary. Although more expensive, hydrogen production from fossil fuels with CCS may still need to play a significant role, particularly in countries like China and Germany that could be short on land for renewables but are well-endowed with gas and coal.
- **The signs of scale-up are not yet there, but investors should keep watch for seven signposts**: hydrogen has experienced a hype cycle before, and right now, there is still insufficient policy to support investment and to scale up a clean hydrogen industry. But with a growing number of countries getting serious about decarbonization, this could change. Investors should watch out for the following key events to help determine whether a hydrogen economy is emerging: 1) net-zero climate targets are legislated, 2) standards governing hydrogen use are harmonized and regulatory barriers removed, 3) targets with investment mechanisms are introduced, 4) stringent heavy transport emission standards are set, 5) mandates and markets for low-emission products are formed, 6) industrial decarbonization policies and incentives are put in place and 7) hydrogen-ready equipment becomes commonplace.
- On April 15, BNEF made a number of changes to this report. This version corrects a rounding error in the cost range of renewable hydrogen displayed on pages 1 and 18; minor errors on the cost of producing hydrogen from fossil fuels with CCS on pages 28, 33 to 37 and Figure 28, 34, 35 and 36; the cost range of renewable hydrogen displayed in Figures 22 to 25; the carbon price for power generation noted on page 64 to 65; adds a clarifying statement to the analysis on renewable resources on page 80 to 82 and updates Figure 59 to exclude some countries; and includes an Appendix on page 95 with supplementary information on how renewable resources are estimated.

Figure 1: The economics of a hydrogen economy

Scaling-up hydrogen

- Requires **$150 billion** of cumulative subsidies to 2030
- Which should drive the delivered cost of clean hydrogen down to **$15/MMBtu** in many parts of the world by 2030
- Delivered costs could fall further to **$7.4/MMBtu** by 2050
- Which would make clean hydrogen **competitive** with current natural gas prices in China, India, Brazil and Germany

Enables

- Making green steel with a **$50/tCO2** price on coking coal
- Clean dispatchable power with a **$32/tCO2** price on natural gas
- Green ammonia with a **$78/tCO2** price on natural gas
- Fuel cell powered trucks to compete by **2031-34** with diesel internal combustion engines

Abatement

- Of up to **one-third** of global emissions from fossil fuels and industry
- Reduction of up to 20% of global emissions for **under $100/tCO2** using hydrogen at $7.4MMBtu
- However the signs of scale-up are **not yet there** as policy support is insufficient
- Investors should keep watch for **seven signposts** to determine whether a hydrogen economy is emerging

Source: BloombergNEF. Note: Clean hydrogen refers to both renewable and low-carbon hydrogen (from fossil-fuels with CCS). Abatement cost with hydrogen at $1/kg (7.4/MMBtu). Currency is US dollars.

Section 2. Introduction

Hydrogen has once again become the subject of great enthusiasm in the energy sector. The growing imperative to reduce emissions beyond the electricity sector has reignited interest in its potential to be used as a low-carbon substitute for fossil fuels. Hydrogen is already used at scale in the chemicals industry and has many valuable physical and strategic properties. However, over 99% of hydrogen produced today is from fossil fuels, and research and development investment in the sector is below previous peaks. Visions of the wider use of hydrogen have failed to materialize three times before – will this time be different?

This outlook is the final instalment of BNEF's Hydrogen Special Project and draws together analysis and key findings from 12 studies published in 2019 and 2020.

Please see BNEF's **hydrogen theme page (web | terminal)** for access to the full suite of BloombergNEF research on hydrogen.

2.1. The need for a clean molecule

The 2015 Paris Agreement aims to hold the increase in global average temperatures to "well below" 2°C above pre-industrial levels, and pursue efforts to limit the increase to 1.5°C. Achieving this will require the reduction of global greenhouse gas emissions to net-zero by the second half of the century.[1]

Some parts of the economy cannot be electrified easily or economically

If this goal is to be met, zero- or low-carbon energy sources will need to replace the use of fossil fuels across much of the global economy. Low-cost electricity generation from renewables presents a viable decarbonization pathway for some sectors and could be expanded in road transport, heating and industry. However, some parts of the economy cannot be easily or economically electrified. These are known as the hard-to-abate sectors. Hard-to-abate sectors include aviation; shipping; long-distance and heavy-haul road transport; iron and steel production; chemicals; manufacturing processes that require high-temperature industrial heat such as cement, aluminum and glass; dispatchable electricity generation beyond a few days; and to some extent, the heating of buildings and water. Today, these sectors mostly rely on combustion of molecular fuels like coal, oil and gas. In addition, in some sectors like chemicals manufacturing, fossil fuels provide the raw materials that go into the finished product. In others, like iron and steel production, fossil fuels perform the chemical reactions necessary to produce the desired goods. The availability of a clean molecule would make transitioning these sectors easier, and in some cases will be a necessity if there is to be a low-carbon transition.

1 United Nations, *The Paris Agreement*, 2015

Hydrogen offers a potential solution

Hydrogen can do almost everything natural gas does

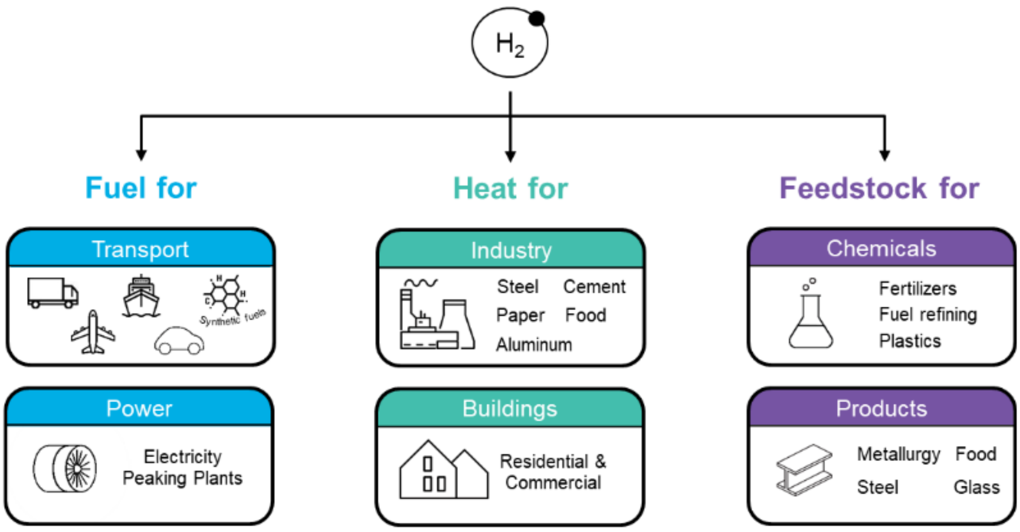
Interest in hydrogen is growing because it could be used to decarbonize many of these hard-to-abate sectors (Figure 2). Hydrogen is a molecule-based fuel that can be produced and consumed without releasing carbon dioxide or other greenhouse gas emissions.[2] It can be used as a fuel for peaking power generation, heavy trucking and for the light-duty vehicle applications that battery electric models may not serve well. Derivatives of hydrogen can be used as a fuel for aviation and shipping. Combusting it can provide both high-temperature heat for heavy industry, and space and water heating for buildings. And lastly it can be used as a feedstock to make chemicals and perform the chemical reactions that are necessary to manufacture many basic materials like steel, ammonia and methanol. In broad terms, hydrogen can do almost everything natural gas does in the current economy, and can displace many of the non-power sector uses for coal and oil.

Hydrogen is best used as a complement to electrification

In segments that electricity cannot serve, hydrogen offers the next-best solution

It is important to note that the best use of hydrogen is as a *complement* to electrification, and not a competitor. Electrification is likely to offer the cheapest route to decarbonize large portions of demand in many sectors of the economy, such as light-duty transport, space and water heating and many industrial and manufacturing processes. However, there are likely to be segments of demand in these sectors that electricity cannot economically serve (such as vehicles without easy access to charging infrastructure), where hydrogen offers the next-best solution.

Figure 2: The many uses of hydrogen



Source: BloombergNEF

Hydrogen has other important strategic benefits

Hydrogen can enable countries that are dependent on fuel imports to diversify their supplies

The use of hydrogen also has other benefits that make it valuable as a vector for decarbonization:

- *Energy security*: hydrogen can be made from renewable electricity at almost any location, enabling countries that are currently dependent on fossil fuel imports to diversify supply with domestic production. Hydrogen can also be generated in remote and off-grid locations, transported and shipped from energy-rich to energy-hungry regions and be stored in massive

2 Nitrogen oxides may be emitted if hydrogen is directly combusted, due to reaction with nitrogen in the air. These emissions can be avoided if hydrogen is converted to energy in a fuel cell. They can also be reduced through the use of scrubbers and via management of the combustion process.

quantities to act as a strategic reserve of power. Hydrogen can facilitate fuel-source diversity in a carbon-constrained economy, because it can be produced with minimal emissions from coal or gas using carbon capture and storage.

Hydrogen has many similarities and overlaps with existing fossil fuel industries…

- *Synergy with existing industries*: being a molecule-based energy carrier, the production, storage, transmission, handling and consumption of hydrogen has many similarities with existing fossil fuel industries. Manufacturing hydrogen equipment also overlaps with many existing chemical, manufacturing, engineering and technology sectors. This makes transitioning the skills, jobs, infrastructure, assets and business models of individuals, companies and countries easier and more attractive.

…this creates opportunities for incumbents to continue to prosper in a zero-carbon world

- *Positive transition opportunity*: hydrogen's synergy with the fossil fuels industry creates opportunities for incumbents to continue to prosper in a zero-carbon world. Many of the world's largest fossil-fuel companies and energy-exporting countries are considering or support the development of a hydrogen economy. This list includes Shell, BP, Saudi Aramco, Gazprom, Australia, Canada, Norway and the United States. Hydrogen could help recast the narrative on the fraught politics of climate change for many crucial actors, from threat to opportunity.
- *Viable and incremental transition pathway:* natural gas based infrastructure, such as pipelines, heaters, turbines and steel mills, has the potential for future conversion to hydrogen. This presents a second-life use for many large assets, avoiding the costs of full replacement, decommissioning of old assets and the pain of write-offs. It also offers existing industrial users of coal or oil an incremental approach to carbon emission reductions – first switch to gas-based systems and later convert these to hydrogen.
- *Sector coupling and renewable integration*: hydrogen can be used as a flexible store of renewable energy over long timescales, helping to solve one of the most challenging problems of a renewable power system. The massive amounts of wind and solar capacity required to produce hydrogen at the scales envisaged can also enhance power system reliability by acting as an additional swing supply source that can be diverted to the power grid when other generation is low., Electricity that might otherwise be curtailed can also be converted to hydrogen when renewable generation is high.

The idea of a hydrogen economy is not new

Hydrogen's properties as an energy carrier have been explored and utilized for over two centuries. The first internal combustion engines were fueled by hydrogen in the 1800s and the 'taming' of liquid hydrogen by NASA propelled humans to the moon in the 1960s.

Hydrogen has seen three previous waves of enthusiasm

Visions for a wider use of hydrogen in the energy industry have seen three previous waves of enthusiasm: in the 1970s during the oil crises, in the 1990s when concern about climate change gained momentum, and most recently in the early 2000s as emission reduction policy began to materialize and concerns about peak oil resurfaced.[3] Each of these waves focused on hydrogen as an alternative transport fuel but fizzled out as oil supply proved more plentiful than feared, aggressive climate policy failed to materialize, and the 'chicken-and-egg' challenge of establishing hydrogen-refueling infrastructure proved to be a higher barrier than the equivalent for recharging battery electric vehicles.

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3 International Energy Agency, *The Future of Hydrogen*, 2019.

Modern visions of a hydrogen economy

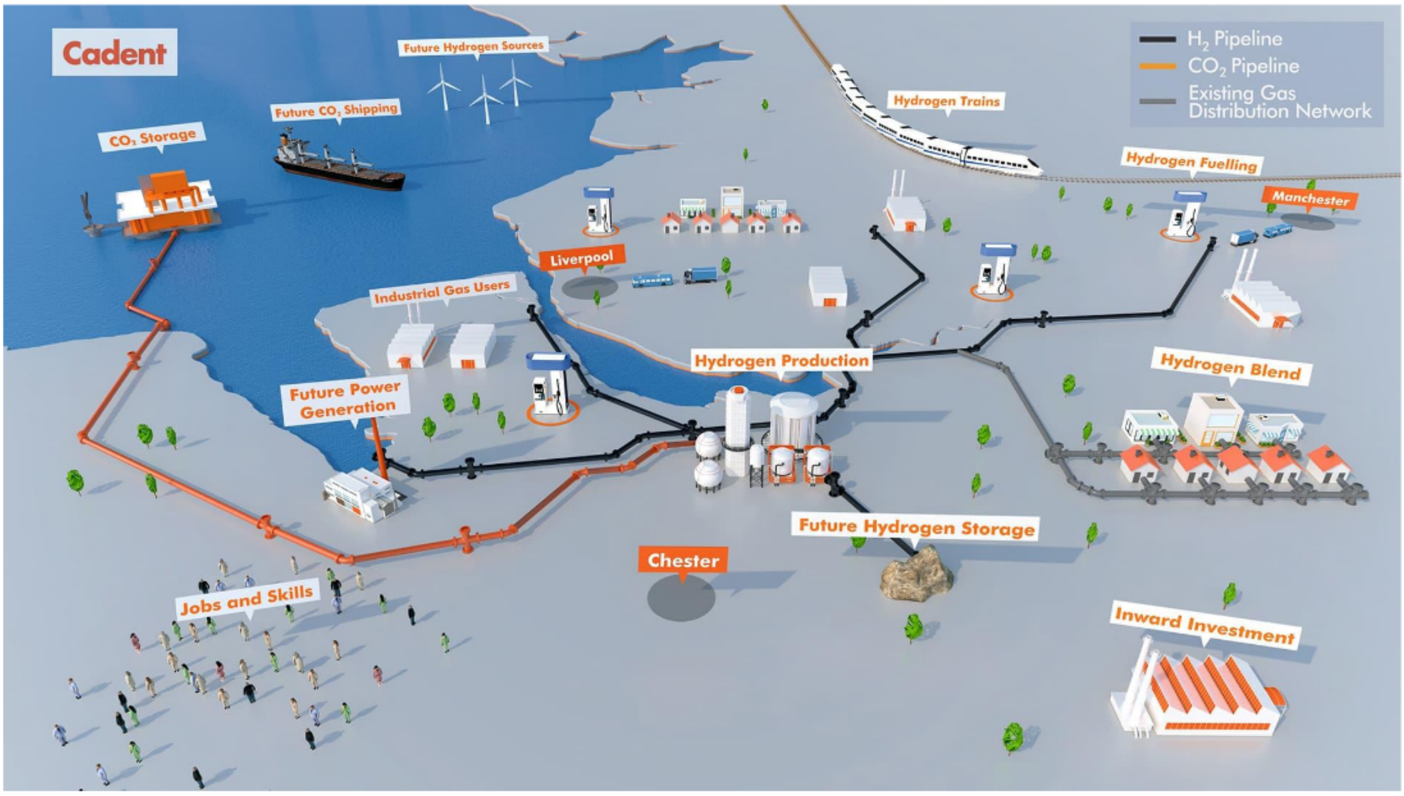
Hydrogen is now imagined as the new natural gas

Today's visions of a hydrogen economy propose use that is much wider than just transportation. It is now imagined essentially as the new natural gas. The Hydrogen Council – a lobby group formed in 2017 advocating the expanded use of hydrogen – outlines seven key roles for hydrogen in its vision for the gas meeting 18% of final energy demand in 2050.[4]

- *Enabling large-scale renewable energy integration and power generation*
- *Distributing energy across sectors and regions, allowing international energy trade and linking renewable-abundant regions with those requiring energy imports*
- *Acting as a buffer and strategic reserve of power to increase energy system resilience*
- *Decarbonizing transportation as a complement to battery electric vehicles (cars, trucks, buses, passenger ships, locomotives, and aviation via synthetic fuels)*
- *Decarbonizing industrial energy use, where electrification is not an efficient option*
- *Helping to decarbonize building heat and power, where gas networks are the primary source*
- *Providing clean feedstock for industries like chemicals and steel-making*

Proposed projects like the Hynet industrial cluster in Manchester, United Kingdom, envisage a similarly broad role (Figure 3). It would be produced at large scale, transported over land and sea, and used by a variety of sectors in the economy.

Figure 3: Example of a hydrogen industrial cluster – Hynet project in Manchester, UK



Source: Cadent/Hynet

[4] Hydrogen Council, Hydrogen Scaling Up, November 2017.

Can this time be different?

There is wide feeling that the current wave of enthusiasm for hydrogen may be the beginning of something more material. This is for four key reasons:

1. *Technology improvements*: rapid reductions in the cost of producing hydrogen from water using renewable energy and electrolyzers now make more realistic the prospect of producing emissions-free hydrogen economically.
2. *Serious decarbonization goals*: a growing number of countries, states and cities are setting legally binding targets for net-zero greenhouse gas emissions.[5] Initiatives like Climate Action 100, the Task Force on Climate-related Financial Disclosures and social movements like Climate Strikes and Extinction Rebellion are also increasing pressure on others to set emission goals consistent with climate science.
3. *Crucial zero-carbon role*: there is an increasingly prominent view that hydrogen will be necessary to achieve zero-carbon targets. This is because of its ability to decarbonize the hard-to-abate sectors, where there are often few other known options. Several major institutions have reached this conclusion, including the U.K. Committee on Climate Change,[6] the International Energy Agency (IEA),[3] and the Energy Transition Commission.[7]
4. *A broad coalition of proponents*: a number of major economies – notably Japan, Korea, China, the U.K., Germany, France and Australia – as well as a wide spectrum of companies in oil and gas, renewable energy, chemicals, electric utilities, automaking and engineering are advocating the expanded use of hydrogen in multiple sectors.[8]

There is an increasingly prominent view that hydrogen will be necessary to achieve zero-carbon targets

Ultimately, enthusiasm on its own will not be enough. The economics of using hydrogen will need to add up – or policy will have to be put in place to bridge the gap. Some researchers think there is likely to be a lead time of at least 10 years for the hydrogen industry to scale up, reduce costs and gain acceptance.[9] Analyses of carbon budgets suggests that decarbonization of the hard-to-abate sectors will need to start by 2030 for climate targets to be met.[7] Therefore, if hydrogen is to play a substantive role, development of the industry will need to start now.

2.2. The basics of hydrogen

Hydrogen is an energy carrier

Hydrogen is a carrier rather than a source of energy

Hydrogen is the simplest and most abundant element in the universe. However, on Earth, it is mostly non-existent in its free form, and energy must be used to liberate it from the molecules in

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5 Energy & Climate Intelligence Unit, Net Zero Tracker.

6 UK Committee on Climate Change, *Net Zero – The UK's contribution to stopping global warming*, May 2019.

7 Energy Transitions Commission, *Mission Possible: reaching net-zero carbon emissions from harder-to-abate sectors by mid-century*, November 2018.

8 For example see membership of the Hydrogen Council.

9 According to the IEA, at least ten years will be needed to expand the hydrogen industry to a point where governments, investors, equipment supplies and others have confidence in the sustainability of hydrogen markets.

which it naturally exists.[10] These include water, biomass, minerals and fossil fuels. For that reason, hydrogen is a *carrier* rather than a *source* of energy. The substance has several outstanding properties that make it an excellent carrier of energy.[11] It is light, non-toxic, reactive and emits no carbon pollution when combusted.

Light, but low volumetric density

Hydrogen is a very light gas, and contains the highest amount of energy per unit of weight (142MJ/kg) of any substance on earth, apart from nuclear fuels and anti-matter. It is three times lighter than gasoline for the same quantum of energy.

However, the volumetric density of hydrogen gas is very low at just 0.09kg/m^3 and this poses challenges, particularly for transporting and storing it. One cubic meter of space only fits 90 grams of hydrogen gas in normal conditions, eight times less than natural gas.[12] Put differently, if one kilogram of hydrogen were to be stored in normal conditions, eight times as much space would be needed than for one kilogram of natural gas.

Hydrogen can be compressed or turned into a liquid, but its boiling point is extremely low – it liquefies at -253ºC (90ºC colder than LNG, and only 20ºC above absolute zero).

How much energy is in a kilogram of hydrogen?

In this report, we express most costs in US dollars per kilogram ($/kg). One kilogram of hydrogen contains 0.142GJ of energy, equivalent to 39.4kWh at perfect conversion to electrical energy or 0.13MMBtu of natural gas (both values are at the high heating value (HHV) – see Appendix B). Table 1 gives an idea of what this means in practical terms. For example, 1kg of hydrogen gives 100km of range to a fuel cell electric vehicle (FCEV) like the Toyota Mirai.

A typical large-scale producer of hydrogen, such as a steam methane reformer serving an ammonia plant, will produce 500,000kg of hydrogen per day. In contrast, a typical electrolyzer today will produce only 22kg of hydrogen per day, although large plants of up to 8,380kg per day are now being offered by electrolyzer manufacturers.[13]

Reactive

Hydrogen's reactivity makes it useful in chemical processes, but also poses difficulties

Hydrogen also has important chemical qualities. It is highly reactive, which means it has a tendency to undergo chemical reactions with other materials. This makes it versatile and useful in chemical manufacturing processes. However, hydrogen's reactivity and tiny size also pose difficulties because it can escape through joints and seals in pipes, as well as diffuse into the molecular structure of some materials like steel, causing them to weaken and fail.

Safety matters

Hydrogen flames are invisible to the naked eye and propagate very quickly with a flame velocity eight-times faster than methane). Hydrogen gas has no natural odour, has an ignition range six-times wider than methane and a low ignition energy at one tenth that of methane. All these

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10 Naturally occurring reservoirs of hydrogen have recently been discovered, however, the extent of this resource is not known. For instance see: Prinzhofer, A. et. al., *Discovery of a large accumulation of natural hydrogen in Bourakebougou (Mali)*, International Journal of hydrogen Energy, October 2018.

11 Hydrogen Strategy Group, *Hydrogen for Australia's Future*, August 2019.

12 Normal conditions mean atmospheric pressure and a temperature of 0 degrees Celsius

13 Nel's A3880 product.

properties present safety challenges, and although hydrogen itself is non-toxic, it must be handled with care.

A range of options exist to help manage these issues, but safety will be vitally important in a future hydrogen economy. As these issues are being addressed in detail by policy-makers, we do not explore them further in this report.

Table 1: Quantities of hydrogen

Weight of hydrogen	Application
5kg	Toyota Mirai fuel cell vehicle (500km range)
22kg	Daily yield of a 50kW electrolyzer used to cool down thermal power generator
25kg	Toyota Sora fuel cell bus (~200km range)
200-500kg	Hydrogen refueling station capacity
3.3t	The energy equivalent of the world's largest battery (Hornsdale Power Reserve)
106t	The capacity of the space shuttle's external tank (liquid hydrogen)
392t	The energy equivalent of Japan's largest pumped hydro plant, Okutataragi
500t	Average daily requirement of a standard ammonia plant (2,250t-NH_3/d)
10,000t	The hydrogen storage working capacity of a large salt cavern
36,000,000t	US natural gas underground storage working capacity (energy content equivalent of 4.85 trillion cubic feet of natural gas)

Source: BloombergNEF, Toyota, NASA, EIA. t = metric ton

Table 2: Efficiency of hydrogen production technologies

Technology	Today	Future
Steam methane reforming	76%	76%
+ CCS	69%	69%
Coal gasification	60%	60%
+ CCS	58%	58%
Water electrolysis	64%	74%

Source: International Energy Agency. Note: efficiency is based on the lower heating value of hydrogen. CCS – carbon capture and storage

Hydrogen supply chains have high losses

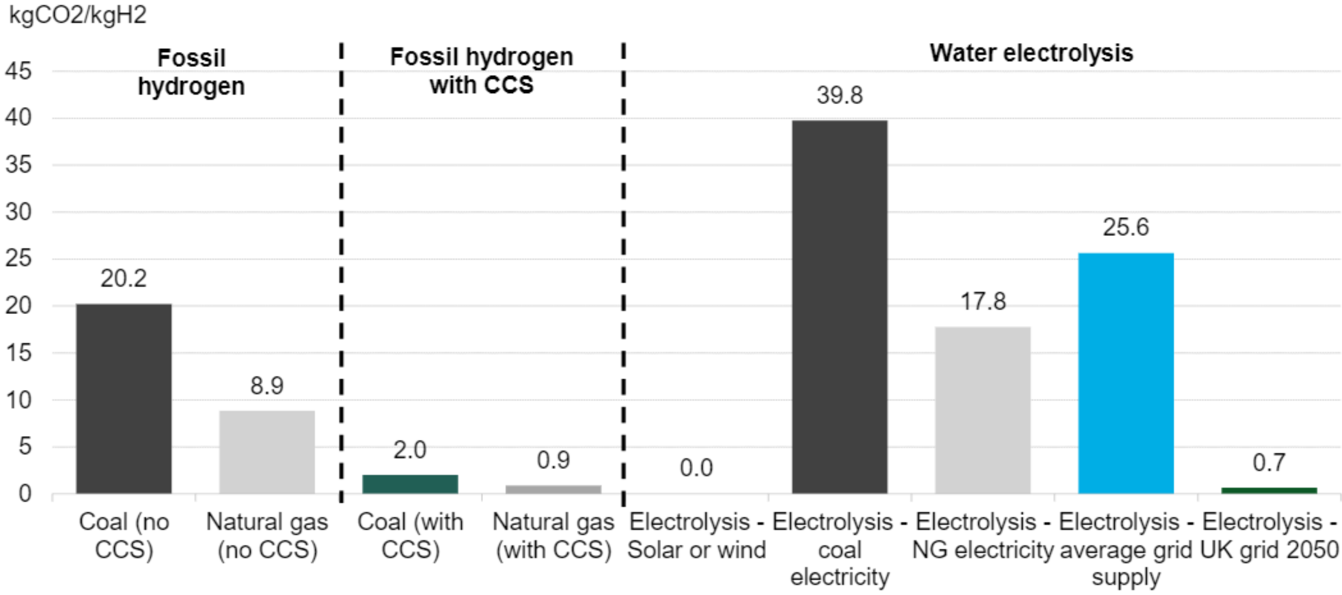
Producing one kilogram of hydrogen from natural gas via a process called steam methane reforming, from coal gasification, or from water using electrolysis, is only 60-76% efficient, and less if carbon capture and storage is required (Table 2). This means that 24-40% of the energy used to produce hydrogen is lost, usually in the form of heat. Further technical losses accrue when hydrogen is compressed or converted to other compounds for storage or transportation, as these require between 0.5% and 33% of the energy in the hydrogen, depending on technology used. If the final use of hydrogen is to produce electricity to power a car, then fuel cells again are only 40-60% efficient. This means that the round trip efficiency of using hydrogen for electricity is at best 45% and at worst 16%. For this reason, direct electrification is usually a more cost-effective means of decarbonization than hydrogen, where it's technologically possible.

Emissions

Although hydrogen produces no carbon emissions when burnt, if the hydrogen itself is produced using fossil fuels, or via fossil fuel derived electricity, then it can be highly polluting. Producing one kilogram of hydrogen from natural gas releases 8.9 kilograms of carbon dioxide (CO2), and 20.2 kilograms of CO2 is released if hydrogen is produced from coal. If electricity is generated using hydrogen manufactured from natural gas, the emissions intensity of generation would be 0.46kgCO2/kWh – some 35% higher than a state-of-the-art combined-cycle gas turbine burning natural gas, which emits 0.34kgCO2/kWh.

This means that, if the use of hydrogen is to reduce emissions, it must be produced with zero or low emissions. Adding CCS to fossil-derived hydrogen can reduce the carbon intensity of hydrogen production from fossil fuels by around 90% (Figure 4).[14] The residual emissions would require offsetting.

Figure 4: CO_2 intensity of hydrogen production



Source: International Energy Agency, BloombergNEF. Note: CO_2 intensities for hydrogen do not include CO_2 emissions linked to the transmission and distribution of hydrogen to the end users, e.g. from grid electricity used for hydrogen compression, or fugitive emissions from fossil-fuel extraction. CO_2 capture efficiency of CCS process assumed to be 90%. NG = natural gas.

Making hydrogen using grid power today is more polluting than producing it from coal

Water electrolysis powered by renewable electricity produces no emissions. But producing hydrogen via water electrolysis using electricity generated from fossil fuels is even more emissions-intensive than using a chemical reaction to produce hydrogen directly from coal or gas, due to the conversion losses of generating the electricity and then in the water electrolysis process (Figure 4). For example, producing one kilogram of hydrogen from an electrolyzer powered by the grid at today's average global emissions intensity would release 25.6 kilograms of carbon dioxide.

The emissions intensity of the electricity grid would need to fall below 0.02kgCO2/kWh in order for grid-connected water electrolysis to be less polluting than using natural gas with CCS. According to BloombergNEF's New Energy Outlook 2019, this is only foreseeable in a few select locations this side of 2050, without aggressive policy intervention. For instance, in the United Kingdom in 2050 our modelling has grid emissions intensity at 0.01kgCO2/kWh, which would result in hydrogen production with an emission intensity of 0.66kgCO2/kgH2 – a better outcome then producing hydrogen from natural gas with CCS. However, the global average emissions-intensity of generation is still expected to be 0.21kgCO2/kWh.

[14] CCS also increases the fuel consumption per kg of hydrogen produced. The auxiliary energy consumption for compressors, dryers and CO2 absorption plant typically requires 15-30% more energy. This is usually supplied by electricity, which could increase emissions from power generation, depending on grid intensity. Fugitive emissions from coal or gas extraction and delivery are also not included in the intensity figures below.

Types of hydrogen

Renewable hydrogen – hydrogen produced with zero carbon emissions from renewable energy sources like wind, solar or hydro, via water electrolysis. Renewable hydrogen can also be produced from biomass through a gasification process. Renewable hydrogen is often referred to as "green" hydrogen. Although the source is not defined as renewable, hydrogen can also be produced without carbon emissions from nuclear energy sources.

Low-carbon hydrogen – H2 produced from fossil-fuels with carbon capture and storage (CCS). This is sometimes referred to as "blue" hydrogen.

Clean hydrogen – H2 that is either renewable or low-carbon

Fossil hydrogen – H2 produced from fossil-fuels like coal, oil, natural gas or lignite with release of carbon dioxide and other waste gasses to the atmosphere. This is sometimes referred to as "brown", "black" or "grey" hydrogen.

2.3. The hydrogen industry today

The hydrogen production industry generated an estimated $130 billion of sales in 2018

The production of hydrogen is already a big business. Hydrogen is a commonly used industrial gas, and is central to the production of a host of everyday goods. Morgan Stanley estimates that the hydrogen production industry generated an estimated $130 billion of sales in 2018.[15]

Supply

The majority of hydrogen used today is produced in dedicated plants purpose-built to supply industrial customers with the gas. The International Energy Agency estimates that 117 million metric tons (MMT) of hydrogen was produced around the world in 2018. Of that, 69MMT or 59%, was produced by dedicated plants, and 48MMT or 41%, was produced as a byproduct of other processes (Figure 5).

The majority of dedicated hydrogen production comes from fossil fuels. Because hydrogen is consumed in massive quantities and is expensive to transport due to its low volumetric density, around 90% is produced in captive plants adjacent to the point of use. Byproduct hydrogen mostly comes from fossil fuel processes in the coke/iron, ethylene and oil refining industries, and is typically re-used as a feedstock or combusted to provide heat in the same plant where it is generated.

Demand

Hydrogen is predominantly used as a feedstock to produce ammonia and methanol, and to remove impurities from crude oil and reduce sulfur in the petroleum-refining process. Demand for hydrogen in these conventional applications has also been growing strongly, from under 30MMT in 1975 to over 100MMT in 2018 (both deliberate and by-product production).[16] If this historical growth rate were to continue, demand for dedicated production of hydrogen for conventional uses could nearly double to around 124MMT by 2050.[17] The key question – explored in detail in Section 6 – is how much demand could materialize for renewable and low-carbon hydrogen if a hydrogen economy were to come about?

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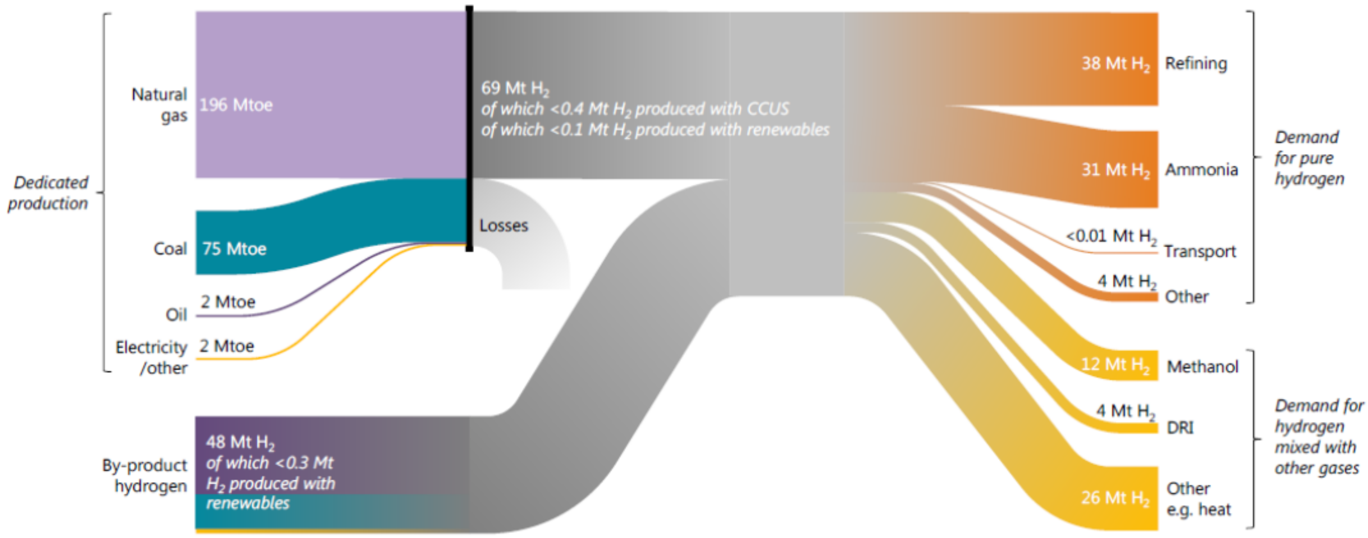
15 Morgan Stanley, *Global Hydrogen – A US $2.5trillion industry?*, 2018.

16 International Energy Agency, *The Future of Hydrogen*, 2019.

17 This would likely be an unsustainable emissions pathway, exceeding the Paris Agreement goals.

Figure 5: Supply and demand for hydrogen globally, 2018



Source: International Energy Agency. Notes: Other forms of pure hydrogen demand include the chemicals, metals, electronics and glass-making industries. Other forms of demand for hydrogen mixed with other gases (e.g. carbon monoxide) include the generation of heat from steel works arising gases and by-product gases from steam crackers. The shares of hydrogen production based on renewables are calculated using the share of renewable electricity in global electricity generation. The share of dedicated hydrogen produced with CCUS is estimated based on existing installations with permanent geological storage, assuming an 85% utilization rate. Several estimates are made of the shares of by-products and dedicated generation in various end-uses, while input energy for by-product production is assumed to be equal to energy content of hydrogen produced without further allocation.

Emissions

Making hydrogen produces 2.2% of global emissions

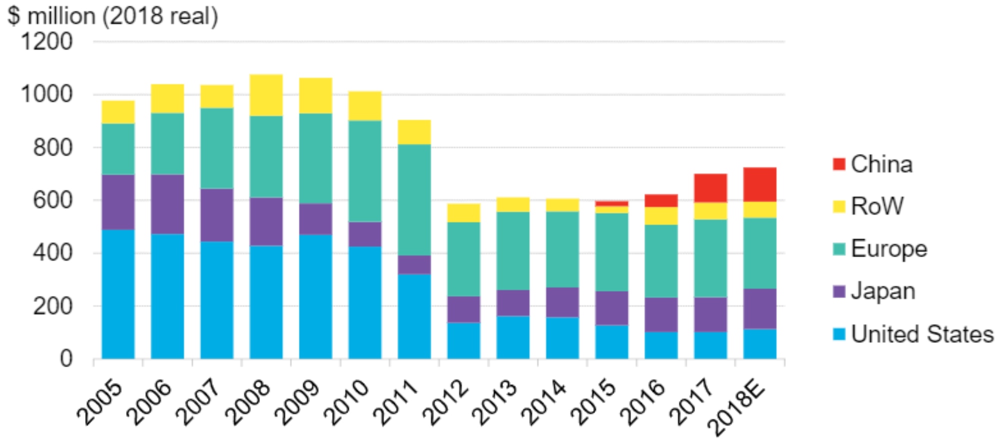
Hydrogen production today is a major source of emissions. The IEA estimates that hydrogen production globally releases 830MtCO_2 per year – equivalent to 2.2% of global energy-related emissions in 2018 – and consumes around 6% of natural gas and 2% of coal.

Investment

Data from the IEA also show that government spending on hydrogen energy research, development and demonstration (RD&D) has been rising 4.7% on average over the past four years, to an estimated $724 million in 2018 (Figure 6). China has seen the biggest increase in RD&D, from $19 million in 2015 to $129 million in 2018.

Overall, however, government spending on hydrogen is nearly one-third lower than its peak at around $1,100 million in 2008. This is mainly due to a drop in spending in the U.S. leaving Europe as the world's largest investor in hydrogen energy research.

Figure 6: Government research, development and deployment budgets for hydrogen and fuel cells



Source: International Energy Agency, RD&D Statistics (2018). Note: Government spending for Europe includes funding from the European Commission, but does not include sub-national funding, which can be significant in some countries.

Project pipeline

Only four planned projects are being developed by entities with resources to fund them

There is a pipeline of around 3GW of announced electrolysis projects that seek to demonstrate or use hydrogen in new applications. The majority of capacity comes from 21 projects that are over 10MW in size (Table 3). This is a significant increase on the typical scale of projects built in 2018, which was just 2-3MW. However, only two of these larger projects have achieved financial close. Ten projects (totaling 2,101MW) are currently at the planning stage but several appear to be speculative. We estimate that only four 10MW-plus projects currently under planning (totaling 206MW) are being developed by entities with the financial resources to fund them on their balance sheets. A further nine projects (totaling 875MW) are under feasibility study, mostly by large and financially strong entities.[18]

Table 3: Summary of announced electrolysis projects above 10MW

Project name	Capacity (MW)	Country	Developer	Start	Status	End-use	Technology
NEL - Nikola	1,000	U.S.	Nikola Motor Company	2020	Planning	Transport	Alkaline
H2V Product	500	France	H2V Industry	2021	Planning	Gas grid injection, Industry, transport	Alkaline
ECB Paraguay biofuel project	310	Paraguay	ECB Group, Paraguay government	2022	Planning	Renewable diesels, synthetic fuels	Alkaline
Rotterdam BP refinery	250	Netherlands	BP, the Port of Rotterdam Authority	2022	Feasibility study	Oil refining	Alkaline
GreenHydroChem Central German Chemical Triangle	140	Germany	Linde, Siemens, VNG and Fraunhofer IMWS	2024	Feasibility study	Industry, chemicals, oil refining, power storage	PEM

18 For further details on the project pipeline see: *Hydrogen: The Economics of Production From Renewables* (web | terminal)

Project name	Capacity (MW)	Country	Developer	Start	Status	End-use	Technology
Element One	100	Germany	TenneT, Gasunie Deutschland and Thyssengas	2022	Feasibility study	Gas grid injection, industry, transport	N/A
Hybridge	100	Germany	Amprion, OGE	2023	Planning	Power-to-gas, transport, industry, heating, power storage	N/A
Ijmuiden	100	Netherlands	Tata Steel, Nouryon	2023	Feasibility study	Chemicals, transport	Alkaline
Centurion	100	UK	TM Power, Inovyn, Storengy, Cadent and Element Energy	N/A	Feasibility study	Power-to-gas (gas grid injection), industry, transport	PEM
HyNetherlands - wind meets gas	100	Netherlands	Engie, Gasunie	2022	Feasibility study	Gas grid injection, industry	Alkaline
Engie - Yara Pilbara test	66	Australia	Engie	2021	Planning	Ammonia	Alkaline
Crystal Brook Energy Park, South Australia	50	Australia	Crystal Brook landowners, Neoen	N/A	Planning	Gas grid injection, power, transport, ammonia	N/A
HySynGas	50	Germany	Vattenfall, ARGE Netz, MAN Energy Solution	N/A	Feasibility study	Power, industry, synthetic gas for transport	PEM
Air Liquide Becancour	20	Canada	Air Liquide	2020	Planning	Industry, mobility	PEM
Fredericia, Denmark, Shell refinery	20	Denmark	Shell	2020	Feasibility study	Oil refining, power and energy storage, transport	Alkaline
Delfzijl project DSL-01 (60MW total planned)	20	Netherlands	SkyNRG, Nouryon and Gasunie	2022	Planning	Aviation fuel	Alkaline
Nordic Blue Crude	20	Norway	Nordic Blue Crude AS, Sunfire, Climeworks, EDL Anlagenbau	2020	Planning	Synthetic crude oil	SOEC
Port Lincoln project, Eyre Peninsula	15	Australia	Hydrogen Utility (H2U)	2021	Planning	Power to the grid, power storage, ammonia, chemicals	Alkaline
Lingen BP Uniper	15	Germany	BP, Uniper, Fraunhofer Institute for Systems and Innovation Research ISI	N/A	Feasibility study	Synthetic fuels, Power to gas, oil refinery	N/A
Refhyne	10	Germany	Shell	2020	Finance secured/under construction	Oil refining	PEM
FH2R Toshiba Tohoku Iwatani - Fukushima Power-to-gas Hydrogen Project	10	Japan	Japan's New Energy and Industrial Technology Development Organization, Toshiba Energy, Tohoku Electric Power and Iwatani Corporation	2020	Finance secured/under construction	Transport, power, industry	Alkaline

Source: BloombergNEF, International Energy Agency. Note: Technology refers to the type of electrolyzer technology employed, which is explained further in Section 3.1. PEM stands for proton exchange membrane, SOEC stands for solid oxide electrolyzer cell. Information was revised from IEA source data whenever updates were obtained by BloombergNEF.

2.4. Significant challenges

For a hydrogen economy to emerge, a number of significant obstacles need to be overcome. These are listed below and will be addressed in detail through subsequent chapters of this report.

- *Clean hydrogen is expensive to produce:* renewable and low-emissions hydrogen are currently more expensive to produce than fossil-hydrogen, and are much more expensive to use than fossil fuels. However, there is potential for the cost of producing renewable hydrogen to fall with greater scale. The potential for this to occur is explored in Section 3.
- *Hydrogen is difficult to store, transport and deliver*: hydrogen's very low density makes storage and most forms of transportation expensive and cumbersome in comparison to fossil fuels. Cost should come down with innovation and greater scale. The potential for this to occur is explored in Section 4 and Section 5.
- *Comprehensive policy and subsidies will be required to support demand*: because hydrogen must be manufactured from other energy sources and is more difficult to store, transport and handle, it is, and will likely remain, more expensive to use than cheap fossil fuels. For hydrogen to be competitive, subsidies, carbon pricing and other policy measures which recognize its emissions reduction benefits will need to be implemented, and this is explored in Section 6 and Section 8.
- *Producing hydrogen requires significant resources:* manufacturing renewable hydrogen at scale will require large amounts of electricity, land and water. This will add to the growing needs of the power sector, which will become even larger if emissions targets are to be met. This could be a material barrier for renewable hydrogen. This is examined in Section 7.
- *Hydrogen needs a high level of coordination*: the development of a hydrogen economy requires synchronized investments in production, transport, storage, delivery and usage infrastructure to overcome the chicken-and-egg dilemma of using a new fuel. A high level of coordination will likely be required between private and state actors, in multiple industries, at a local, national and international level. Standards governing hydrogen use will also need to be harmonized, regulatory barriers removed, and safety and social acceptance issues carefully managed. Governments will need to play a crucial role introducing long-term policy and whole-of-government strategies that can help coordinate these complex actions. The types of policy required are identified in Section 8.

Section 3. Production costs

For a hydrogen economy to develop, large volumes of hydrogen gas will need to be produced at low cost and with minimal emissions. Cheaper renewable energy and electrolyzers would make this possible. If the industry can scale up, our analysis suggests the cost of producing renewable hydrogen could fall from $2.53-4.57/kg in 2019 to $1.14-2.71/kg by 2030, and $0.73-1.64/kg by 2050. This would be cheaper than producing hydrogen from natural gas with CCS at $1.34-2.91/kg, and from coal with CCS at $2.51-3.3/kg, even if these costs fall in future. It would also make hydrogen competitive with the current wholesale price of natural gas in Brazil, China, India, Germany and Scandinavia on an energy-equivalent basis.

In this section, we explore the economics of hydrogen production. Section 3.1 summarizes our research on the cost of producing renewable hydrogen, and the potential that these costs have to fall with an increase in scale. Section 3.2 assesses the cost of producing low-carbon hydrogen from fossil fuels with carbon capture and storage. Section 3.3 compares the cost of producing hydrogen around the world from different sources, against the wholesale cost of fossil fuels.

3.1. Renewable hydrogen

This section summarizes our separately published research: ***Hydrogen: The Economics of Production From Renewables*** **(web | terminal)**

Water electrolysis powered by renewable electricity is likely to become the lowest-cost source of hydrogen production. Currently, the electrolysis industry plays a minor role in hydrogen production and is characterized by high costs and small scale. Only around 135MW of electrolyzers were shipped in 2018, and the levelized cost of hydrogen varies between $2.5 and $6.8/kg, depending on technology and geography. However, we think the global range of production costs from large-scale facilities could fall rapidly, driven by two factors – an ongoing decline in the cost of electrolyzers, and cheaper renewable electricity.

Electrolyzer costs

The cost of electrolyzers has been falling rapidly in recent years (Figure 7), and we believe there is significant potential for continued cost reductions with a modest scale-up in manufacturing.

There are two main technologies in commercial use today to electrolyze water – alkaline and proton exchange membrane (PEM) electrolyzers. Alkaline electrolyzers were commercialized in the 1920s and are a mature technology; PEM was first developed in the 1970s and is closely related to the fuel cell technology with the same name.

Electrolyzer manufacturing is currently a small industry. Of the 135MW shipped in 2018 – about 60% were made in China, predominantly to produce hydrogen for use in domestic industry, and 85% used alkaline technology.

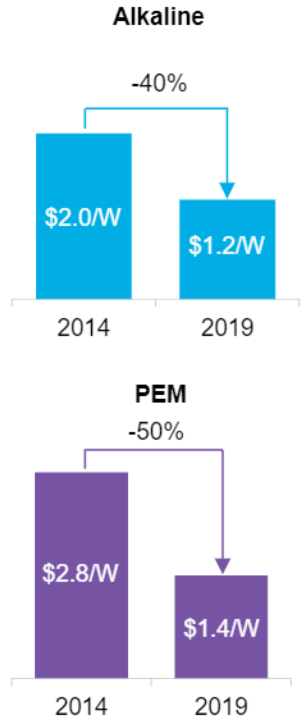
Alkaline electrolyzer costs

In 2019, alkaline electrolyzers made by European and North American manufacturers sold for around $1,200/kW. This appears to be many times more than the raw material costs of electrolyzers – which were estimated at around $100/kW in 2015[20] – and well above the fundamental costs of manufacturing. The explanation for this is that Western electrolyzer manufacturers have high soft costs and tend to focus more on new markets, such as fuel cell electric vehicles that have small, unpredictable order sizes and low annual production. As a result labor makes up a large fraction of overall cost, manufacturing facilities have low utilization rates, and manufacturers spend more on research, development and marketing of new products for emerging applications.[19]

In contrast, Chinese alkaline electrolyzer manufacturers tend to focus on existing industrial applications, with reported prices of around $200/kW in 2019, an impressive one fifth of those in the West. There appear to be two main reasons for this: cheaper raw materials and labor, and higher factory utilization rates that can be achieved because sales volumes are more predictable. Corporate spending on R&D and marketing is also likely to be much lower. Western manufacturers argue that Chinese product quality standards are lower. Whether that's true or not, the price difference suggests Western manufacturers could reconfigure their businesses to achieve much lower costs.

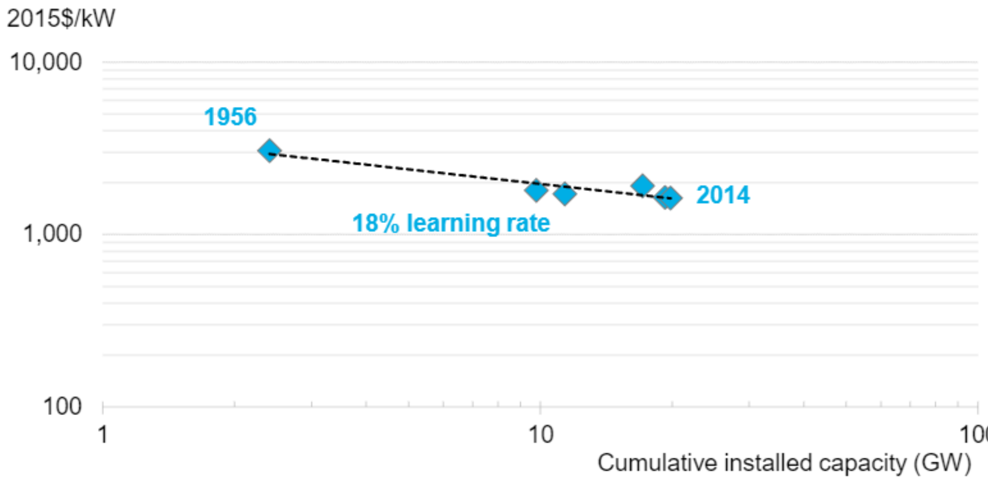
Studies by academic researchers suggest Western-made alkaline electrolyzers have a learning rate of 18% (Figure 8).[20] That means that, for every doubling in manufactured volume, the fundamental cost of manufacturing an electrolyzer falls by 18%.[21]

Figure 7: Benchmark system capex (Western-made electrolyzers)



Source: BloombergNEF

Figure 8: Learning rate of alkaline electrolyzers reported in academic literature



Source: O. Schmidt, A. Hawkes, A. Gambhir & I. Staffell, BloombergNEF

[19] This can be seen in the corporate cost structure of electrolyzer manufacturers. Company filings for instance show that labor costs at the largest Western electrolyzer manufacture Nel make up 47% of overall corporate costs. This compares to 17% at Jinko Solar, the world's largest PV module maker.

[20] O. Schmidt, A. Hawkes, A. Gambhir & I. Staffell, *The future cost of electrical energy storage based on experience rates*, Nature Energy volume 2, Article number: 17110 (2017).

[21] The authors note that there is a large error bound of +/-6% for this learning rate, due to the limited number and uncertainties in the data points available. The alkaline electrolyzer industry also contracted over the studied timeframe, which would generally lead to a slowdown in cost reductions, and underrepresent the learning rate.

However, the fact that current alkaline electrolyzer prices appear to be well above the fundamental costs of manufacturing, means this learning rate might be conservative and understate the potential for future cost reductions with increase in scale.

We think the cost of alkaline electrolyzers can fall much faster

Following extensive conversations with major manufacturers, we think the cost of alkaline electrolyzers could fall much faster than an 18% learning rate in the short term through a combination of five factors:

- *Higher automation levels and utilization rates*: currently, even the largest electrolyzer makers are running at annual capacities of several tens of megawatts, and have off-and-on operating patterns due to large variations in orders. With low and variable production volumes, many of the processing steps are currently performed by manual labor because the cost of automatic production lines cannot be justified. With more scale and more predictable orders, equipment suppliers will be able to build new facilities with high levels of automation.
- *Cheaper raw materials*: Larger buyers of any product have greater purchasing power, and are able to secure better deals from suppliers and also establish efficient supply chains. If a large amount of global manufacturing is concentrated in one country or among a small number of major manufacturers, then these savings can be more easily realized.
- *Larger electrolyzers and projects*: increasing the average size of a project also tends to reduce the cost per unit of capacity. This is true both at the manufacturing facility and at the project site. The typical scale for large electrolyzer systems built in 2018 was 2-3MW. The project pipeline suggests the market is moving to capacities of 10MW and eventually to above 100MW. Larger projects can lower system capex in three ways: they allow for the development of bigger electrolyzers with lower unit costs, the adoption of a modular system design (see subsequent discussion point) and they allow balance-of-plant costs to be spread over more units of production. We anticipate that this is likely to be the most important driver of cost reductions in the short term.
- *Modular construction*: in large electrolysis projects, modular construction techniques can be employed, cutting unit costs. Experience from the PV industry reveals that every time a project's size doubles, unit capex drops by 6.4% – due to two factors. Firstly, larger projects are able to purchase equipment at lower prices due to larger order sizes. Secondly, labor and construction costs per unit of installed capacity are reduced through higher productivity in repetitive tasks. These same factors should hold in the construction of large electrolyzers. Assuming the same 6.4% rate as PV implies that the unit capex of a 100MW electrolyzer system could be 20% lower than a 10MW system, and 36% cheaper than a 1MW system.

Alkaline electrolyzer cost projections

To project the cost of alkaline electrolyzers in the short term, we have developed a price-volume relationship based on our understanding of the cost reduction drivers described above, cost targets published by manufacturers, and known bid prices for larger systems.

Our estimates for future prices are split into a conservative and optimistic scenario for Chinese-manufactured electrolyzers (Table 4) and western-manufactured electrolyzers (Table 5).

- Our conservative scenario represents a world where electrolyzer deployment rises slowly in the near term due to limited policy support, and in the longer term a 'hydrogen economy' fails to develop.
- Our optimistic scenario represents a world where electrolyzer demand rises strongly in the near term driven by strong policy support, and a 'hydrogen economy' develops in the longer term, with demand for renewable hydrogen expanding substantially.

A. Conservative scenario

In this scenario, we assume that 2.9GW of electrolyzers are installed by 2030 – 1.4GW to serve traditional users of hydrogen, a figure that is in line with current trends, and an additional 1.5GW for low-carbon hydrogen projects, which amounts to half the current project pipeline. Low-carbon hydrogen projects tend to be bigger than traditional usage projects, and so will require the production of larger 5-10MW electrolyzer systems. We anticipate this should be enough to drive the cost of alkaline electrolyzers made in China down to $135/kW by 2030, or between the current bid price for 5MW units and the expected price of a 7.5MW unit (Table 4).

Table 4: Alkaline electrolysis system capex in China: forecast reasoning (large-scale projects)

Year	Optimistic	Conservative
2019	$200/kW: based on quotes from two major manufacturers and two project developers for projects of 3MW scale, deployed in general manufacturing industry applications, such as polysilicon production.	
2022	$150/kW: bid price for a 10MW project in China to be commissioned by 2022. We assume 2-3 projects of 10MW scale will be commissioned in China by 2022. Each 10MW project is composed of two 5MW units.	Costs fall as installations rise (consistent with the same price-volume relationship in the optimistic case). However, cost reductions are delayed due to the slower pace of scale-up: $181/kW for 2022 $163/kW for 2025 $135/kW for 2030 $98/kW for 2050
2025	$128/kW: 15% cost reduction from 2022, achieved by scale up to 7.5MW units to be used in larger projects of 30MW (7.5MW X 4) size (based on view of a major manufacturer).	
2030	$115/kW: additional 10% cost reduction from 2025, achieved by further scale up to 10MW units, used in projects of 100MW (10MW X 10) scale.	
2050	$80/kW: based on a 12% learning rate and cumulative installations rising from 20GW in 2018 to 2,846GW by 2050. This is consistent with the long-term view of a major Chinese manufacturer, which suggested costs could by 50% on 2019 levels at very large scales.	

Source: BloombergNEF Note: $ refers to 2019 USD. Note: assumes 90% of electrolyzer sales are for alkaline technology.

This modest amount of scale-up should similarly be enough to drive an incremental reduction in the cost of Western-made electrolyzers to 2025 (Table 5). However, by 2030, we believe that Western electrolyzer manufacturers will have to catch up rapidly with the costs and prices offered by their Chinese competitors or they will be outcompeted. At present, Western project developers are willing to pay a premium for European or American brands, but this is unlikely to continue indefinitely if local manufacturers fail to catch up to Chinese peers. A similar dynamic has unfolded in the global PV industry, as well as with many other products, although machines like wind turbines are an exception. Hence, by 2030 we assume that the price of Western-made electrolyzers converges to the level set by Chinese-made products (Table 5).

Table 5: Alkaline electrolysis system capex in countries other than China: forecast reasoning (large-scale projects)

Year	Optimistic	Conservative
2019	$1,200/kW: based on quotes from multiple manufacturers, project developers, and government research institutes.	
2022	$600/kW: based on optimistic forecast by multiple manufacturers and bid price from two project developers.	$1,100/kW: marginal capex reduction based on 20-30MW annual build.
2025	$400/kW: estimated from the $300-450/kW range of Nel's capex expectation for scaled-up production.	$1,000/kW: marginal capex reduction based on 30-40MW annual build.
2030	$115/kW: prices converge to Chinese levels due to competition and offshoring of production.	$135/kW: prices converge to Chinese levels due to competition and offshoring of production.
2050	$80/kW: prices in-line with Chinese levels.	$98/kW: prices in-line with Chinese levels.

Source: BloombergNEF. Note: $ refers to 2019 USD.

The price of alkaline electrolyzers falls to $98/kW by 2050 in the conservative scenario…

In the longer term, we use a learning rate approach to project system price reductions from 2030 to 2050. We assume that sales of electrolyzers continue to grow gradually. This is driven by increasing cost competitiveness for conventional users of hydrogen, who have a growing incentive to reduce carbon emissions. Overall, under this scenario, we assume that 365GW of electrolyzers supply 32MMT of hydrogen in 2050, which is 25% of estimated demand for hydrogen in existing use cases. Assuming that alkaline electrolyzers make up 90% total electrolyzer sales (see box below) and applying a 12% learning rate (the lower bound of the 18% +/-6% range) as identified in the academic literature, the price of alkaline electrolyzers falls to $98/kW by 2050.

Which electrolyzer technology will dominate in future?

The more established alkaline technology currently makes up 85% of annual electrolyzer sales, and this looks set to continue with the majority of projects in the pipeline electing to use alkaline technology (see Table 3 in Section 2.3). Our capex projections suggest that alkaline electrolyzer costs have the highest potential to fall in the near term, and are likely to become significantly cheaper than PEM by 2030. This is likely to entrench alkaline's position as the dominant water electrolysis technology, with PEM mainly being used for applications with significant space constraints, due to its smaller footprint.

It is often said that PEM electrolyzers work better alongside variable renewables due to their ability to ramp up and down rapidly. However, there is evidence in the academic literature that alkaline technology can also perform well under these conditions.[22] Any difference is unlikely to be significant enough to justify the price premium of PEM. In practice, the small footprint of PEM electrolyzers makes them a better option for space-restricted applications, and so are more likely to find a niche in small-scale, distributed deployments.

B. Optimistic scenario

…and $80/kW by 2050 in the optimistic scenario

In this scenario, cumulative electrolyzer installations rise to 2.9GW by 2025 and 27GW by 2030, driven by supportive subsidies and policies. This would require the regular sale of 10MW electrolyzer units, which should be enough to drive the cost of alkaline electrolysis systems made in China down to $115/kW by 2030 (Table 4). In this scenario, Western-based manufacturers evolve to more closely resemble Chinese players, and the cost of large-scale projects falls rapidly to $400/kW in 2025. This is within the target price of major manufacturers like Oslo-based Nel, which expects system capex to fall to $300-450/kW for large-scale production in automated facilities.[23] We assume the price of Western-manufactured electrolyzers converge with those made in China by 2030.

In the longer term, an aggressive expansion to 3,139GW of cumulative installed capacity, producing 275MMT of hydrogen, would see prices fall to $80/kW based on the same 12% learning rate as in the conservative scenario above (Figure 9).[24]

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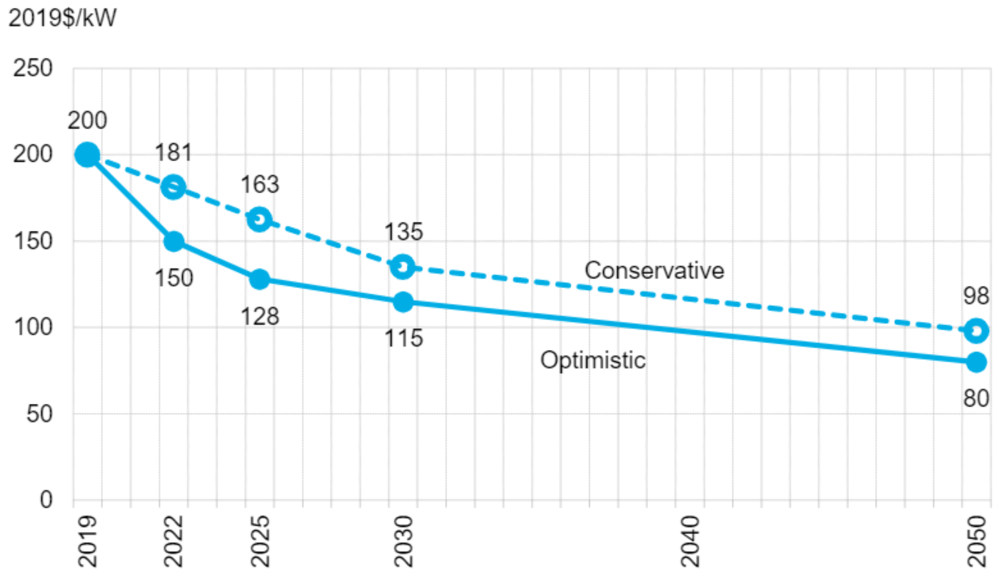
22 NREL's report published in September 2014: Novel Electrolyzer Applications: Providing More Than Just Hydrogen.

23 Nel, Q1 2019 earnings presentation, May 2019

24 We assume alkaline electrolyzers make up 90% of the total 3.139GW market for electrolyzers by 2050. Although $80/kW is below the raw material cost of alkaline electrolyzers made in 2015 (estimated at $100/kW) technological improvements and savings in the amount of material used should make these costs achievable.

Figure 9: System capex forecast of Chinese-made alkaline electrolysis projects (large-scale projects)



Source: BloombergNEF. Note: Assumes large-scale system sizes of 3MW in 2019, 10MW in 2022, 30MW in 2025, 100MW in 2030 and 400MW in 2050.

PEM electrolyzer cost projections

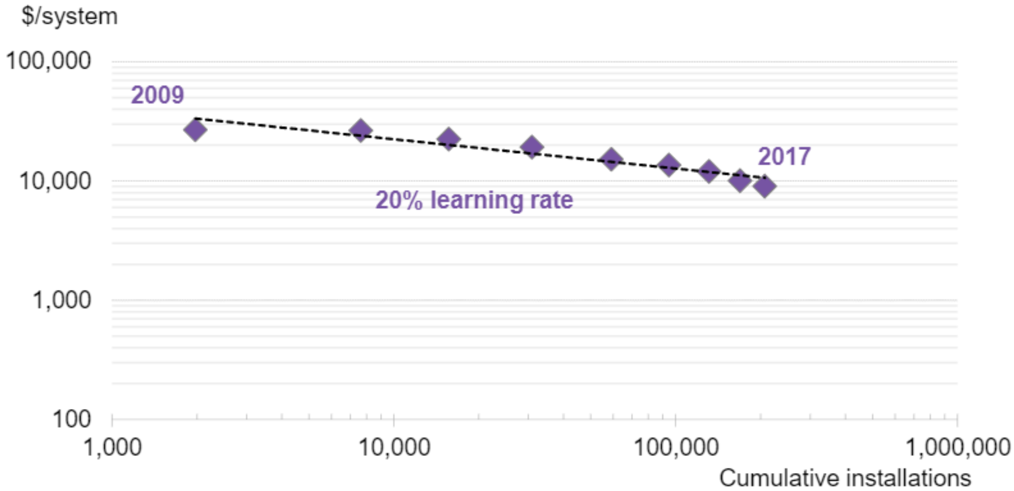
PEM electrolyzer system costs could also fall to $95-217/kW by 2050

The capex of less mature PEM electrolyzer technology is today around $1,400/kW. However, it too has potential to realize rapid cost reductions if demand grows. The closely related PEM fuel cell industry provides a valuable example of what could be expected. A learning rate of 14.4% has been calculated for fuel cell systems developed for automotive applications,[25] and a learning rate of 20% can be observed for stationary heat and power systems in Japan (Figure 10).[26]

25 James, D., 2019 DOE Hydrogen and Fuel Cells Program Review Presentation, May 2019

26 The Japanese Ene-Farm program is a limited dataset to calibrate a learning rate, and price data from this program has complications. Annual sales under the Ene-Farm program have stagnated in recent years, however, the price of fuel cells (excluding subsidies) has steadily fallen. Some of the cost reduction can likely be attributed to policy regime changes, which compressed the sales price and resulted in several manufacturers exiting the market. Nevertheless, we believe the learning rate is instructive of the potential for cost reductions.

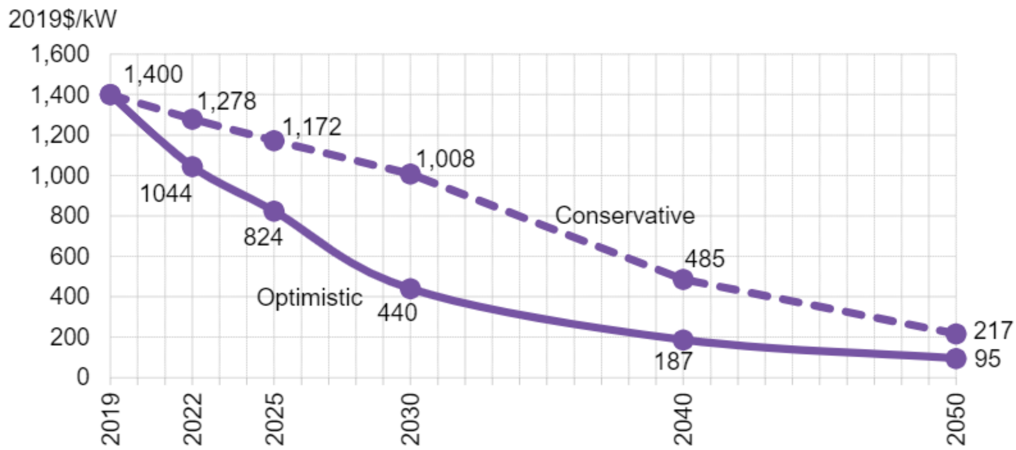
Figure 10: Installation volume and price of PEM fuel cell systems under Japan's Ene-Farm program



Source: Japan METI, BloombergNEF. Note: The power ratings of the systems are in the range of 700-1,000W.

Based on the 20% learning rate and an assumption that PEM technologies make up 10% of the total electrolyzer installation scenarios presented above, we estimate that the capex of 4MW-scale PEM electrolyzers could fall to $1,008/kW by 2030 and $217/kW by 2050 in the conservative scenario and $440/kW by 2030 and $95/kW by 2050 in the optimistic scenario (Figure 11).

Figure 11: System capex forecast of 4MW-scale PEM electrolysis projects (small-scale projects)

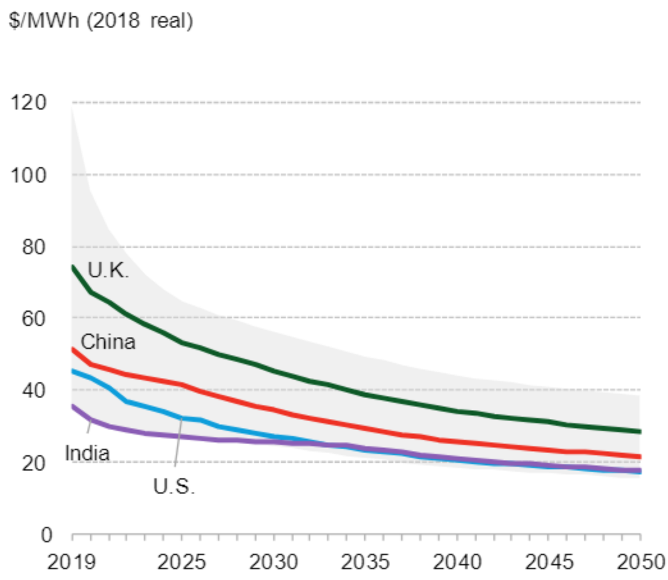


Source: BloombergNEF. Note: Assumes system size of 4MW in all years.

Renewable electricity costs

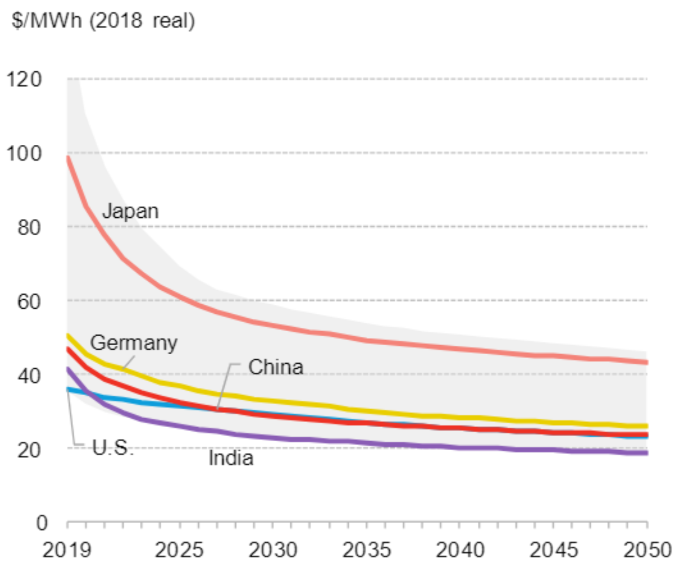
The cheapest power for an electrolyzer is likely to come from wind and PV generators, which are already the lowest-cost source of new bulk electricity supply in most major markets.[27] In our power technology analysis, the levelized cost of energy from high-quality wind and PV sites drops below $30/MWh (2018 dollars) by 2030, to around $20/MWh by 2050 in most major markets (Figure 12 and Figure 13).

Figure 12: Utility-scale PV LCOE, 2019-50



Source: BloombergNEF. Note: The grey range represents the global diversity of benchmark LCOEs. These figures exclude curtailment and subsidies.

Figure 13: Onshore wind LCOE, 2019-50



Source: BloombergNEF. Note: The grey range represents the global diversity of benchmark LCOEs. These figures exclude curtailment and subsidies.

We estimate that the cost of renewable power to an electrolyzer can be further reduced by exploiting two additional savings. Firstly, the development of a global hydrogen economy would massively increase the scale of renewables deployment (discussed in Section 7), resulting in even more aggressive cost declines for PV and wind from the additional learning. Secondly, costs can be trimmed and efficiencies gained through integrated system designs, where wind or PV plants are directly connected with the electrolyzer to eliminate grid connection fees and some power electronics. We estimate that these two factors together could reduce the cost of renewable electricity feeding into an electrolyzer by more than 20% by 2050.[28] Taking into account these savings, our calculations suggest that a directly connected PV or wind generator could provide electricity to a large-scale electrolyzer for just $24-28/MWh by 2030 and $15-17/MWh by 2050 in locations with good renewable energy resources.

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27 BloombergNEF, 2H 2019 LCOE Update (web | terminal)

28 For details see Section 5.5 of *Hydrogen: The Economics of Production From Renewables* (web | terminal)

Levelized cost of renewable hydrogen

Based on our estimates of the future cost of large-scale alkaline electrolyzers, increases in the efficiency of converting electricity to hydrogen, and savings from an optimized power supply design, we have used BNEFs country-level LCOE forecasts for wind and PV to estimate the potential cost of producing renewable hydrogen around the world.[29] The levelized cost of renewable hydrogen shows how much producers would need to be paid in order to achieve a target internal rate of return (IRR).[28]

The LCOH from large-scale facilities comes out as $1.1-2.7/kg in 2030 (Figure 14) and just $0.8-1.6/kg by 2050 (Figure 15). This assumes our optimistic projection for alkaline electrolyzer costs. If we use our conservative projection, the LCOH is 6% higher in 2030 and 18% higher in 2050.

Our calculations suggest renewable hydrogen will be cheapest to produce in countries with the lowest-cost renewable electricity. These include India, Brazil, Australia and Scandinavia, where H2 production costs come out below $1.40/kg in 2030 and $0.80/kg in 2050. The United States, China and Germany are projected to have costs between $1.40 and $1.60/kg in 2030 and $0.80 and $1.00/kg by 2050. Japan and Korea, where renewables are more expensive, are seen being the highest-cost places to produce renewable hydrogen, with costs above $2.40/kg in 2030 and $1.60/kg in 2050.

Figure 14: LCOH of hydrogen production from renewables - 2030

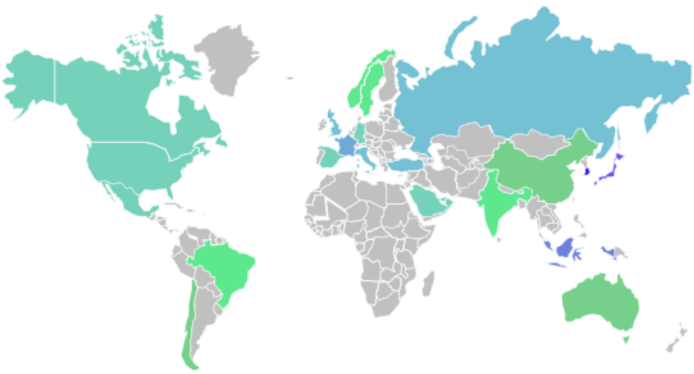
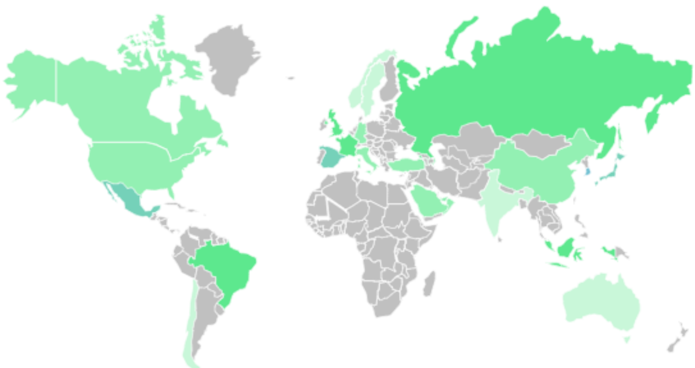


Figure 15: LCOH of hydrogen production from renewables - 2050



Legend (LCOH of hydrogen production ($/kg))

0.61 – 0.80	0.81 – 1.00	1.01 – 1.20	1.21 – 1.40	1.41 – 1.60	1.61 – 1.80	1.81 – 2.00	2.01 – 2.20	2.21 – 2.40	2.41 – 2.60	2.61 – 2.80

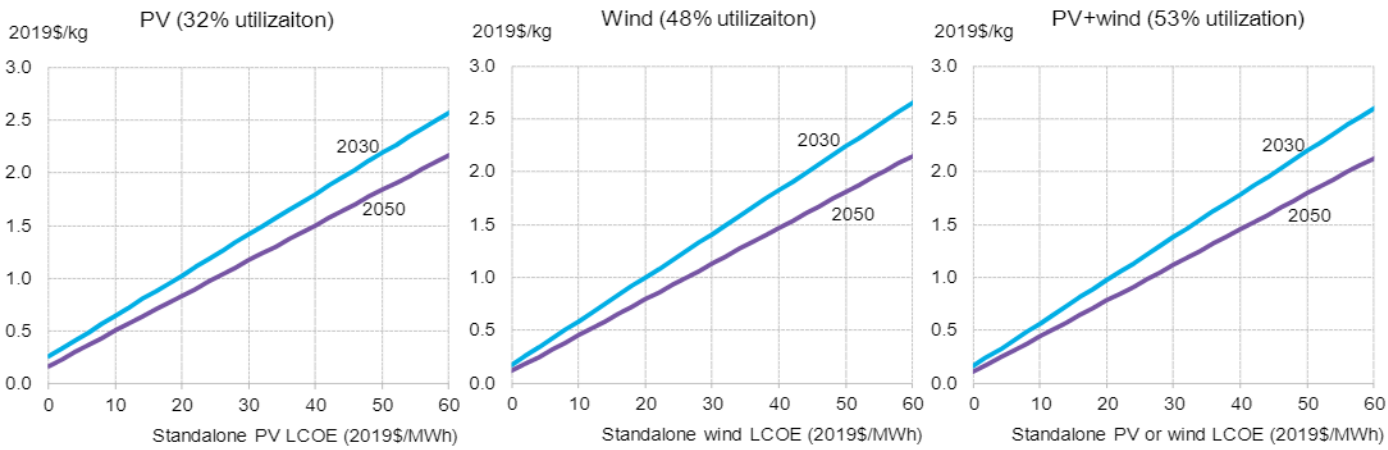
Source: BloombergNEF. Note: LCOH assuming our optimistic projection for alkaline electrolyzer costs. Costs would be 6% higher in 2030 and 18% higher in 2050 if the conservative projection for electrolyzer costs is used instead.

We find that the cost of producing hydrogen increases linearly with higher power costs (Figure 16). Furthermore the type of renewable technology has little impact, despite differences in the utilization rate, or run hours, of the connected electrolyzer. This is explained further below.

[29] We assume a modest increase in the efficiency of conversion of electricity to hydrogen for alkaline technology, from 53kWh/kgH2 in 2019 to 45kWh/kgH2 by 2050. This is consistent with the view of major manufactures and science agencies.

Overall, our LCOH figures are significantly lower than other published estimates, which tend to assume grid-supplied power is used. For instance, the IEA has renewable hydrogen costs of \$3.0/kg in 2030 and \$1.6-2.4/kg in its long-term projection.[30]

Figure 16: Sensitivity of LCOH to standalone PV and wind LCOE (large-scale alkaline electrolyzer), 2030 and 2050



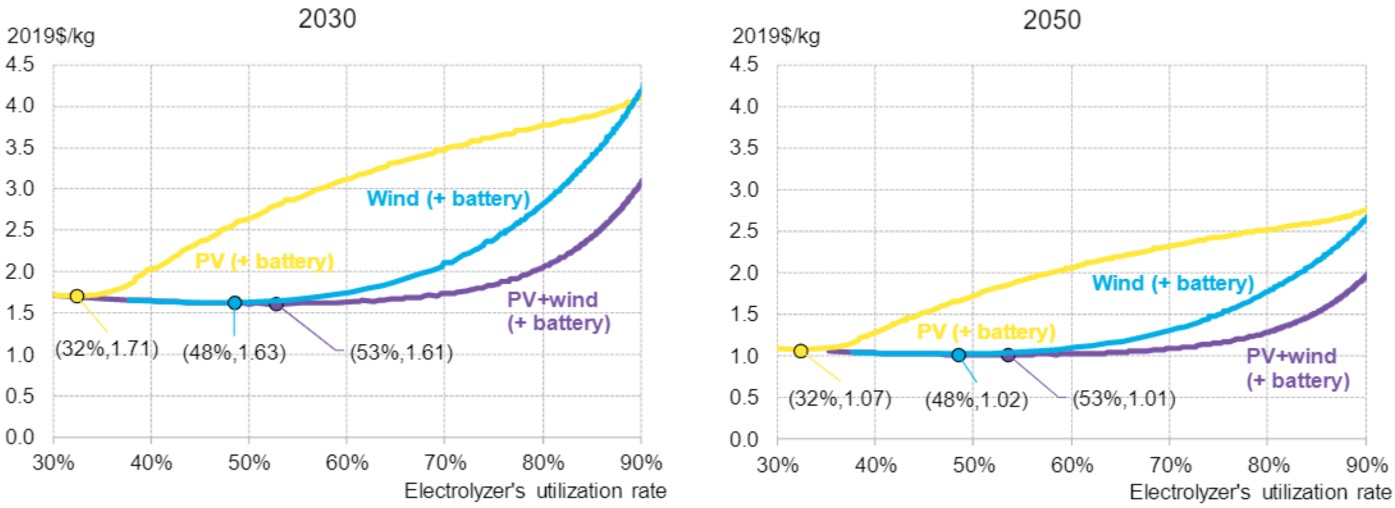
Source: BloombergNEF. Note: Based on the optimistic scenario electrolysis system capex of \$115/kW in 2030 and \$80/kW in 2050.

Maximizing run hours

While both alkaline and PEM electrolyzers are capable of working with a variable power supply, the typical disadvantage is that utilization rates will be low when powered by renewables, and this raises the levelized cost of hydrogen. This becomes less of a disadvantage as electrolyzer costs decline – because the capital cost of electrolyzers makes up a much smaller percentage of the levelized cost of producing hydrogen. Nevertheless, run hours can be maximized by coupling wind and PV generators where there is a negative correlation between their generation profiles. A renewable energy generator can also be oversized relative to the electrolyzer, which means more energy can be delivered in periods when the generator is below maximum output, increasing overall electrolyzer utilization. That does mean there would be some curtailment at times of maximum output but this has only a minor impact on system cost, particularly for systems powered by wind, or wind with PV (Figure 17). To achieve even high utilization rates, a battery can be added. These same strategies can be used to achieve higher run-hours and more stable supply for customers that require it, such as industrial processes (see Section 5.1).

30 International Energy Agency, *The Future of Hydrogen*, 2019.

Figure 17: LCOH forecast for large alkaline electrolysis systems running at different utilization rates



Source: BloombergNEF. Note: The electrolysis system size is assumed to be 100MW in 2030, and 400MW in 2050. Optimistic forecast for electrolyzer cost is adopted here. The dots indicate the power solutions corresponding to the lowest LCOH values.

3.2. Hydrogen from fossil-fuels with CCS

This section summarizes our separately published research: ***Hydrogen: The Economics of Production From Fossil Fuels*** (web | terminal)

The cost of producing hydrogen with CCS ranges from $1.3 to $3.3/kg

Low-carbon hydrogen can also be produced using fossil-fuels fitted with carbon capture and storage technology – so-called "blue hydrogen". Almost all studies on a future hydrogen economy nominate this as a major route of production, even though CCS technology has had a troubled history so far in the power sector.

In this section we estimate the cost of producing hydrogen from fossil fuels with CCS. Right now, this ranges from $1.34 to $3.34/kg, but could fall to $1.25 to 3.05/kg by 2050 if use of CCS technology become widespread. If this is so, it means the cost of blue hydrogen stays above our projected costs for renewable hydrogen in most locations in 2030 and all in 2050 (Table 10). However, the steady production profile of fossil fuel based hydrogen may justify its higher costs, at least in the short term.[31] Constraints on the supply of renewables in key regions (see Section 7.2) or the need to diversify for security of supply, may also create a role for hydrogen from fossil fuel with CCS.

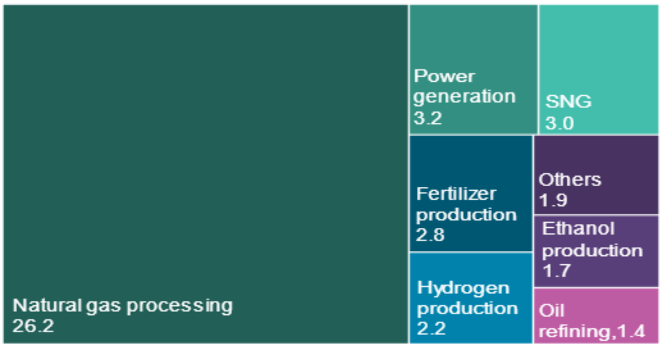
Technical viability and risks of carbon capture and storage

CCS is already operational on four hydrogen production facilities

In 2019, some 42.4MMT/year of CO_2 capture capacity was operating around the world (Figure 18). Some of this is already working on hydrogen production facilities. There are four large-scale hydrogen production facilities with CCS in operation in the United States and Canada, producing between 200 and 1,300 tons of H2 per day (Table 6), and a further two are under construction. Most have been built to use the captured CO2 for enhanced oil recovery.

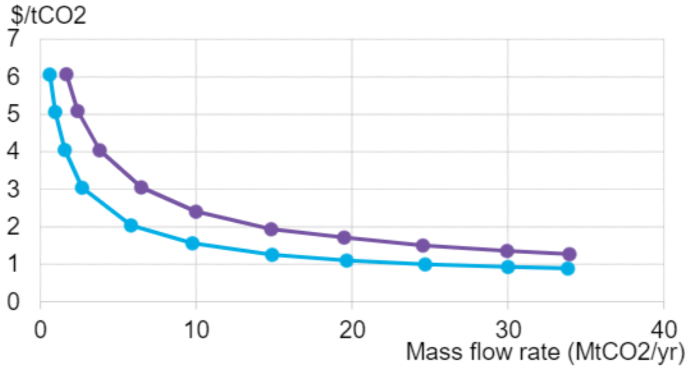
[31] In the longer term (to 2050) we expect the cost of firmed renewable hydrogen supply to undercut fossil fuels with CCS. This is discussed in Section 5.1.

Figure 18: Current global CO_2 capture capacity by source (MMT/year)



Source: BloombergNEF, Global CCS Institute

Figure 19: CO_2 transport cost estimates for onshore and offshore pipeline transport



Source: BloombergNEF, IPCC. Note: Transport distance assumed to be 250 kilometers.

Carbon capture and storage has a mixed track record to date. Many CCS projects in the power sector have faced financing, permitting, construction and business model challenges, which have inflated costs, caused delays and in many cases led to them to be abandoned.[32] For instance, the U.S. government spent $1.12 billion to fund nine CCS projects in 2010-2017, but six out of the nine projects were abandoned, mainly due to permitting or financing challenges.[33] CCS projects have also failed due to problems such as commercializing completely new gasification technologies, and failing to adhere to common project management practices.[34]

Table 6: Operational fossil fuel based hydrogen production plants with CCS

Project name	Location	Online since	H2 production capacity (tonne/day)	CO2 capture capacity (MMT/yr)	Technology	Owner	CO2 capture purpose	Capex ($ million)
Great Plains Synfuel Plant	North Dakota, U.S.	2000	1,300	3	Coal gasification	Dakota Gasification Company	Enhanced oil recovery	2,100*
Air Products - Valero Refinery	Texas, U.S.	2013	500	1	SMR	Air Products and Chemicals	Enhanced oil recovery	431
Coffeyville Gasification plant	Kansas, U.S.	2013	200	1	Petcoke gasification	CVR Energy, Chapparal Energy, Blue Source	Enhanced oil recovery	Not known
Quest CCS plant	Alberta, Canada	2015	900	1.2	SMR	Shell Canada	Emissions reduction	593**

*Source: BloombergNEF, Global CCS Institute. Note: SMR refers to steam methane reformation. *For the entire plant and not just CO_2 capture. ** At an exchange rate of 1USD=1.33CAD.*

32 For example see Global CCS Institute, ROAD Project – Close out report, July 2019 for information on the specific challenges faced by the *Rotterdam Opslag en Afvang Demonstratie project* which ultimately led to cancellation. SaskPower cancelled its plan to retrofit two old coal-fired power plant units with CCS. For details see: *CBC News*, *SaskPower abandons carbon capture at Boundary Dam 4 and 5*, July 2018

33 United States Government Accountability Office, *Advanced Fossil Energy: Information on DOE Provided Funding for Research and Development Projects Started from Fiscal Years 2010-17*, Septermber 2018.

34 For instance see: Hawkins, D. and Peridas, G., *Kemper County IGCC: Death Knell for Carbon Capture? NOT*, Natural Resources Defense Council, July 2017.

There are three steps in the CCS value chain – capture, transport and storage. CCS projects have tended to face most challenges in the first and third of these. Importantly, CO2 capture from the hydrogen production process is considered technically less complex than from other sources due to the high concentration of carbon dioxide in the waste stream. However, the challenges of geological storage remain.

CO2 capture

Capture costs of around $55-70/tCO2 have been demonstrated

Hydrogen production from the reforming of natural gas, or from gasification of coal, produces a highly concentrated waste CO2 stream that simplifies carbon capture. Chemical absorption using aqueous amine is a well-established technology that has been used commercially to separate CO2 and hydrocarbons in the natural gas production industry for decades. Capture costs of around $55-70/tCO2 have been demonstrated in operational hydrogen CCS projects. Estimates by third parties for capture costs for a spectrum of CCS applications tend to vary between $10 and $103 per metric ton (Table 7). Several other capture technologies like the use of polymeric membranes, direct air capture, chemical adsorption and biphasic solvents are being developed at pilot scale.[35]

Academics and industry research bodies believe that the commercialization of many of these new technologies could further simplify the carbon capture process and reduce the cost of CO_2 capture by around a third over the next decade, to around \$45/tCO_2.[36]

Table 7: CO_2 capture cost estimates of various research bodies

Organization	CO_2 capture cost estimate ($/tCO2)
Carbon Capture & Storage Association	$69-103 (in early 2020s)
IPCC	$33-57
Global CCS Institute	$45-60 (by 2025)
Grantham Institute – for steel industry	$10-115

Source: BloombergNEF, Carbon Capture & Storage Association, IPCC, Global CCS Institute, Grantham Institute

CO2 transport

Transport costs can add between $1 and $10/tCO2

The most common and economical method to transport large amounts of CO_2 is through pipelines. Transport costs can add between \$1 and \$10/tCO_2 depending on distance, mass flow rate of CO_2, terrain, and other project specific factors.

The unit cost of pipeline transport goes down with increasing capacity (Figure 19) and economies of scale can greatly reduce overall transport costs. But special land conditions, like dense population, protected areas such as environmental zones, wildlife conservation parks, national parks, and crossing major waterways, may significantly increase costs. For example, the cost of

35 For details on the status of various new and upcoming CO2 capture technologies see Bui, M. et al, *Carbon capture and storage (CCS): the way forward*, Royal Society of Chemistry, 2018.

36 For instance the CCS knowledge centre claims a possible reduction in CO_2 capture costs to \$45/tCO_2 due to application of learnings from the operation of Saskpower's Boundary Dam CCS project. For details see: International CCS Knowledge Centre, *The Shand CCS Feasibility Study report*, November 2018.

offshore pipelines for CO2 transport could be 40-70% more than for onshore pipes of the same size.[37]

Pipeline construction is a mature technology and the cost of CO2 transportation is not expected to fall substantially in the future. For offshore transport of CO2 over the seas, a cost-competitive transport option for longer distances might be the use of large tankers.

CO2 storage

Storage costs have ranged between $1 and $7/tCO2 for projects currently under operation

Every CCS project needs safe and permanent geological storage for captured CO2. Storage costs are less certain than capture and transport, and more site-specific. The major factors that determine the cost of storage are whether the reservoir is onshore or offshore; the reservoir depth; and the geological characteristics of the storage formation, such as permeability and thickness. The demonstrated costs of storage for existing projects range between $1 and $7/tCO2, similar to cost estimates by the IPCC (Table 8).

Table 8: Estimates of the CO_2 transport and storage costs

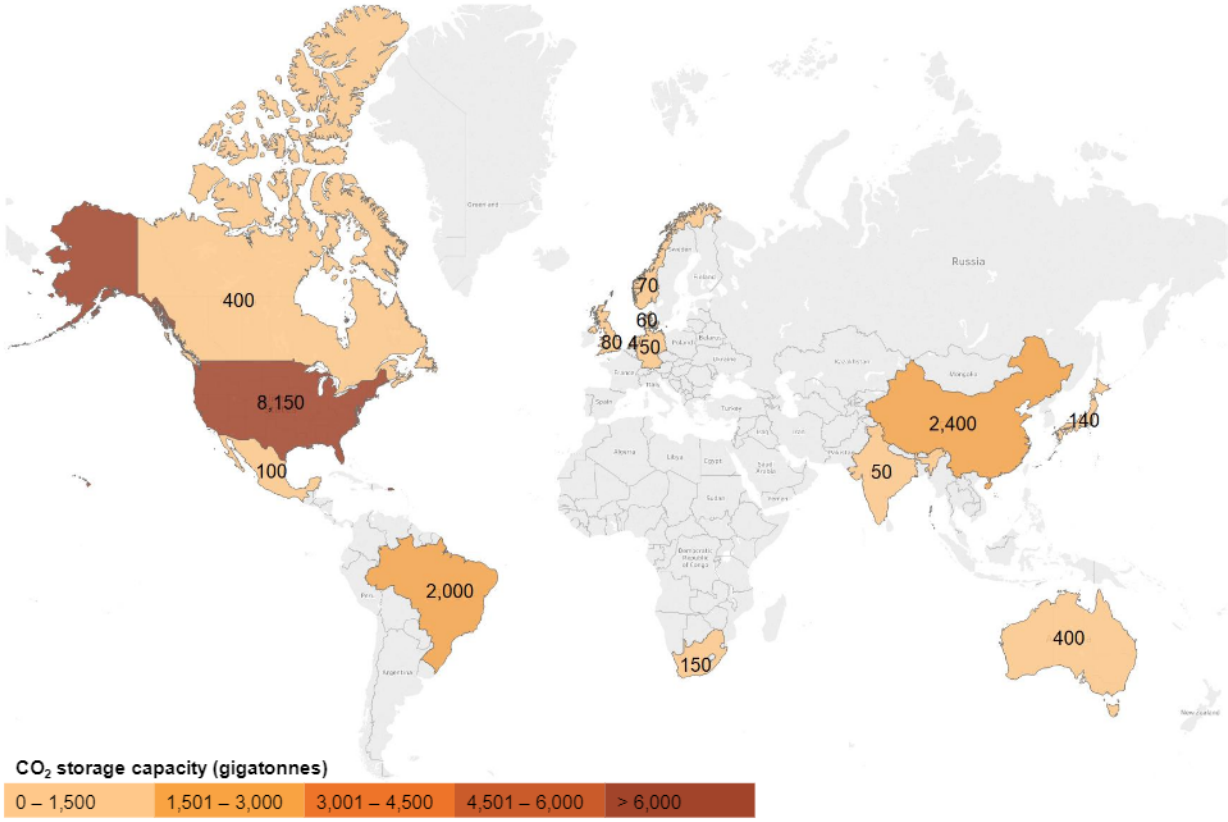
Type	Cost estimates ($/t$CO_2$ stored)
Onshore storage	0.5 – 8.0
Onshore storage + monitoring	0.6 – 8.3
Offshore storage (including pipeline transport)	6 – 31
Offshore storage (including ship transport)	12 – 16

Source: IPCC

There is ample geological storage capacity for captured carbon. According to the Global CCS Institute, total CO_2 storage potential is over 14,000 gigatonnes. This corresponds to thousands of years of storage at current global energy-related emissions levels of 30-40GtCO2 per year. However, these resources are not uniformly distributed (Figure 20).

37 See: Intergovernmental Panel on Climate Change, Special Report on Carbon Dioxide Capture and Storage, Cambridge University Press, 2005.

Figure 20: Global CO_2 storage resource potential



Source: BloombergNEF, Global CCS Institute

As an alternative to storage, captured CO2 can be utilized. However, unless it is permanently embodied in a product, atmospheric emissions will still result. A common use of captured carbon today is for enhanced oil recovery (EOR), and it could also be deployed for enhanced coal-bed methane recovery. These activities can provide (and to date, have provided) a business case to develop carbon capture technology, and the CO2 pumped underground to displace oil is generally regarded as permanently stored. However, as more fossil fuels are extracted in the process, we do not consider EOR to be carbon-neutral and do not consider it in detail in this report.

Leakage of CO_2 is considered probable by academics

Although the oil & gas industry has demonstrated successful CCS for decades, the development and operational risk of projects is still perceived to be very high. Leakage from reservoirs over the course of regular operations or due to natural disasters or accidents is considered to be probable by academics.[38] Leakage could adversely impact groundwater, air quality, and both human and

38 Blackford et al, *CO_2 leakage from geological storage facilities: environmental, societal and economic impacts, monitoring and research strategies*, Journal of Geological storage of carbon dioxide (CO2): Geoscience, technologies, environmental aspects and legal frameworks. November 2013.

animal health, but there is no firm consensus on the economic and environmental costs.[39] The public perception of CCS projects is also often poor, causing permitting and legal challenges.[40]

Emissions

Without CCS, the emissions from hydrogen production via steam methane reformation of natural gas are roughly half that of coal gasification without CCS (Figure 4 in Section 2.2). Using best available technology, CCS can reduce the carbon intensity of hydrogen production from fossil fuels by around 90%. As not all emissions can be captured, it is regarded as a low- but not zero-emissions technology. The residual emissions would require offsetting if net-zero targets are to be achieved. These could be substantial (see box below).

Adding CCS to fossil-derived hydrogen also increases the fuel consumption per kg of hydrogen produced. The auxiliary energy consumption for compressors, dryers and CO2 absorption plant typically requires 15-30% more energy. This is usually supplied by electricity, and this could increase emissions from power generation, depending on grid carbon intensity. Fugitive emissions from coal or gas extraction and delivery are not included in the intensity numbers in Figure 4.

Producing hydrogen entirely from coal with CCS could still release 2.80GtCO2 – equivalent to 8% of 2018 emissions

Residual emissions from CCS hydrogen

If a hydrogen economy develops, a large fraction of global energy needs would be met with hydrogen. In Section 6.3 we describe a *Strong Policy* scenario where some 696MMT of hydrogen is produced in 2050, supplying up to 24% of final energy. If this hydrogen was produced entirely from natural gas with CCS, 0.62Gt of CO2 would be released. This would be equivalent to around 1.7% of global emissions from fossil fuels and industry in 2018.[41] Emissions would be 1.41Gt, or 3.8% of 2018 levels, if coal with CCS was used instead. Offsetting 1.41Gt per year through reforestation would require over 4,686,400 square kilometers of forest to be regenerated – an area larger than India.[42]

Current production costs

Without carbon capture, we estimate that the cost of producing hydrogen from natural gas ranges from $0.71/kg to $2.29/kg, based on the $1.1-10.3/MMBtu spread of global natural gas prices today (Table 10). The cost or producing hydrogen from coal without CCS similarly ranges from $1.36/kg to $2.19/kg, based on a coal price range of $30-116/t today.

The added cost (and loss of efficiency) of CCS currently adds around $0.6/kg to the LCOH from a gas-based steam methane reformer, and $1.1/kg to coal gasification, and we assume costs remain at these levels for the next ten years to 2030.

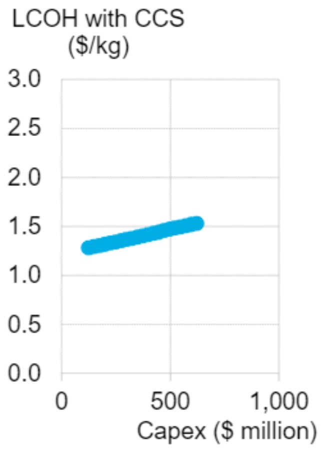
39 Deng, H. et al, *Leakage risks of geologic CO_2 storage and the impacts on the global energy system and climate change mitigation*, Journal of Climatic Change, September 2017..

40 Braun, C., *Not in My Backyard: CCS Sites and Public Perception of CCS*, Society for Risk Analysis, December 2017.

41 Global greenhouse gas emissions from fossil fuels and industry are estimated as 36.6MtCO2e in 2018. For details see Global Carbon Budget, Summary Highlights, Global Carbon Project, 2019.

42 Based on a forest sequestration rate of 3tCO2 per hectare per year, which is typical of boreal and temperate forests. See: Food and Agriculture Organisation of the United Nations, *State of the World's Forests*, 2001.

Figure 21: Sensitivity of the H_2 production LCOH to the CCS capex



Source: BloombergNEF

Hydrogen production costs are less sensitive to factors like the capital expenditure on the project than they are to fuel prices (Figure 21). A doubling of project capex would increase the cost of hydrogen produced by only 10%. The low sensitivity to capex is notable, as it lowers the risk that an overrun in the cost of a CCS hydrogen project will render a project uncompetitive.

Based on the assumptions outlined in Table 9 below, we estimate that the 2020-2030 cost of producing hydrogen from natural gas with CCS is between $1.34/kg and 2.91/kg, depending on the price of gas (Figure 22 and Table 10). For coal with CCS, costs range between $2.51/kg and 3.34/kg, depending on the coal price (Figure 23 and Table 10).[43,44] The combined cost for capture, transport and storage of CO2 is $57/t$CO_2$ for coal gasification with CCS and $71/t$CO_2$ for steam methane reforming with CCS.

Table 9: Cost assumptions for H_2 production using natural gas and coal with CCS, 2020-30

Element	Steam methane reformer with CCS	Coal gasification with CCS
Capex without CCS	$442 million	$1,298 million
Capex with CCS	$816 million	$1,729 million
Fixed O&M without CCS	$15.5 million/year	$38.9 million/year
Fixed O&M with CCS	$21.8 million/year	$51.9 million/year
Variable O&M	$1.1 million/year	$1.3 million/year
Cost of equity	10%	10%
Cost of debt	5%	5%
Debt % of total finance	70%	70%
Corporate tax rate	25%	25%
Inflation	2%	2%
Plant life	30 years	30 years
H_2 plant utilization	95%	85%
CO_2 capture efficiency	90%	90%

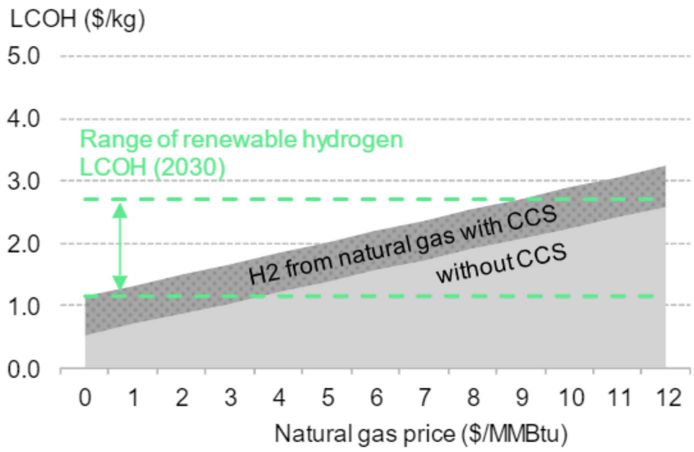
Source: Source: BloombergNEF, National Renewable Energy Laboratory, International Energy Agency. Note: Capex estimates for a 350,000 kgH2/day steam methane reformer facility and coal gasification facility. CCS plant capacity of 1MTPA for SMR and 2.3MTPA for coal considered.

Countries at the low end of the 2020-2030 production cost range are likely to be the U.S., Canada, Russia, and Saudi Arabia, where gas prices range between $1.1 and $3.1/MMBtu (Table 10). European countries like the U.K., Norway, Sweden and Netherlands with relatively expensive gas at $7-9/MMBtu will have higher costs. Hydrogen production costs from coal are also at the higher end of the range, even in countries with access to cheap coal (or lignite) at $30-40/t such as India, China, Germany and Australia. South Korea and Japan, which rely on imported coal and gas at $10-12/MMBtu and $100-120/t, are the most expensive places to manufacture hydrogen from fossil fuels with CCS.

43 These estimates do not include any carbon costs.

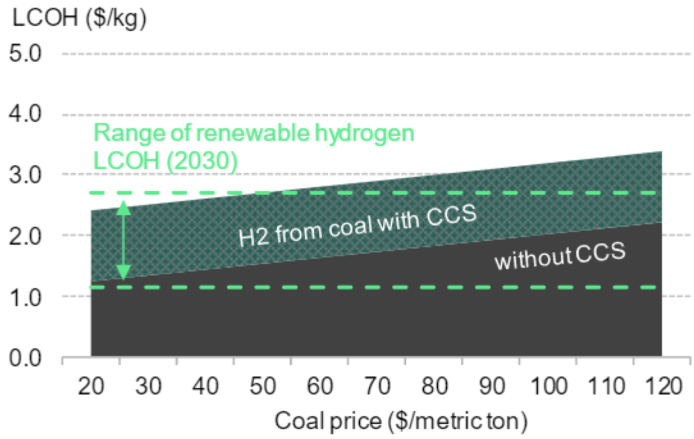
44 Our estimates are similar to costs reported by the IEA for CCUS. The IEA estimates that the LCOH of natural gas with CCUS in China is 1.5-2.4/kgH_2. See, International Energy Agency, *The Future of Hydrogen*, 2019.

Figure 22: LCOH from natural gas, 2020-2030



Source: BloombergNEF. Note: Does not include a carbon price.

Figure 23: LCOH from coal gasification, 2020-2030



Source: BloombergNEF. Note: Does not include a carbon price.

Potential future production costs

The IEA projects that the capex of a CCS system used on a steam methane reforming facility could fall by 52% in the "long term", which we interpret as the year 2050, assuming widespread use of CCS technology.[45] The low sensitivity to capex means this would only lower the cost of hydrogen production from natural gas with CCS by about $0.11/kg. This translates to a potential LCOH from natural gas with CCS between $1.25 and 2.82/kg in 2050, assuming the same $1.1-10.3/MMBtu spread in global natural gas prices (Table 10).

Assuming a similar rate of decline in capex for a CCS system on a coal gasification facility would lower the LCOH by about $0.29/kg. This translates to a potential hydrogen production cost from coal gasification with CCS between $2.22 and 3.05/kg in 2050, assuming the same $30-116/metric ton range of coal prices (Table 10).

Unique advantages of hydrogen production from fossil fuels with CCS

Hydrogen production with CCS offers a number of key advantages which may be particularly attractive in countries where fossil fuels are cheap, where there is good geological resources to store captured carbon, and where renewable resources are likely to be constrained. These could include China, India, Indonesia and Germany. Moreover, the fossil hydrogen with CCS path:

- Offers communities and businesses in existing fossil-fuel industries a viable pathway to transition to a clean economy.
- Provides a continuous supply of hydrogen, compared to that from renewables which generally produces a more intermittent stream of H_2 due to variability in the wind and solar resource.
- Increases the diversity of supply, boosting security and reliability and reducing the need for hydrogen storage compared to variable renewable production. This is particularly relevant for locations where the geology required for large-scale hydrogen storage is not available.

[45] The IEA does not provide an explicit definition for long-term in its estimates. For details see: International Energy Agency, *The Future of Hydrogen*, 2019.

Impact of carbon prices

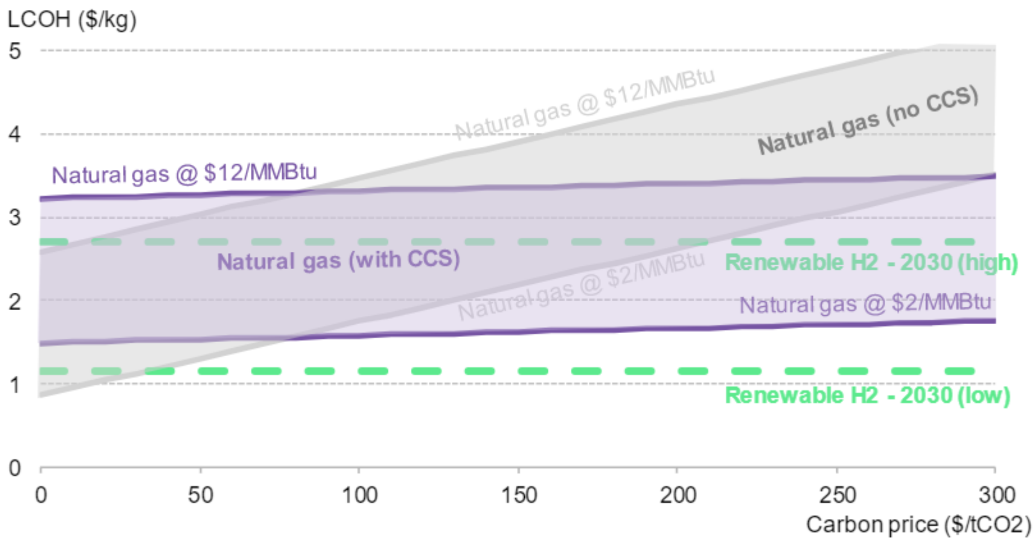
The production cost estimates above do not include taxes or pricing on any of the carbon emissions released. If applied, they would increase the cost of both fossil hydrogen, and low-carbon hydrogen from fossil fuels with CCS.

A carbon price of $71/tCO2 is needed to incentivize CCS on gas

A carbon price of $10/tCO2 increases the cost of producing hydrogen from natural gas without CCS by $0.09/kg and hydrogen from natural gas with CCS by $0.01/kg.[46] For coal-based hydrogen production, a carbon price of $10/tCO2 increases the cost of producing hydrogen without CCS by $0.20/kg, and with CCS by $0.02/kg. This reveals a number of important tipping points.

Figure 24 shows that a carbon price of $33/tCO2 would make it cheaper to produce renewable hydrogen at its low range cost in 2030 of $1.14/kg (see Section 3.1), than fossil hydrogen from $2/MMBtu natural gas without CCS. Similarly, a carbon price of $71/tCO2 would make it cheaper to produce low-carbon hydrogen from natural gas with CCS than fossil hydrogen without CCS.

Figure 24: Impact of carbon prices on the LCOH of hydrogen from natural gas

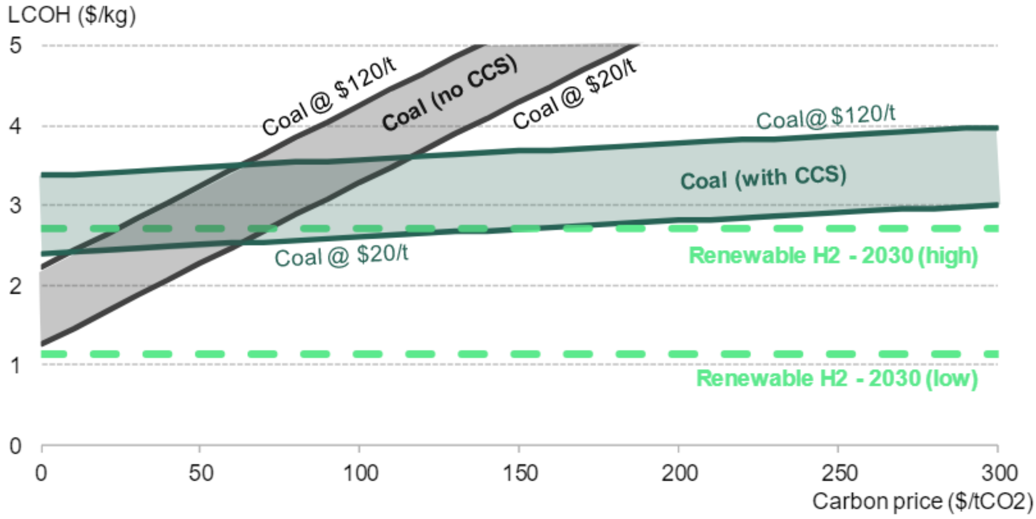


Source: BloombergNEF. Note: based on an emissions intensity of natural gas reforming of 8.85kgCO2/kgH2, and 0.89kgCO2/kgH2 when fitted with carbon capture and storage (CCS).

Figure 25 shows that no carbon price would be needed to make renewable hydrogen cheaper at its low range cost in 2030 (see Section 3.1), than fossil hydrogen from $20/t coal without CCS. Similarly, a carbon price of $57/tCO2 would make it cheaper to produce low-carbon hydrogen from coal with CCS than fossil hydrogen without CCS. By 2050, our modelling shows the low range cost of renewable hydrogen to be cheaper than all fossil-based options that use CCS even without a carbon price.

46 As discussed, this is because there are still some residual emissions with CCS technology.

Figure 25: Impact of carbon prices on the LCOH of hydrogen from coal



Source: BloombergNEF. Note: based on an emissions intensity of coal gasification of 20.21kgCO2/kgH2, and 2.02kgCO2/kgH2 when fitted with carbon capture and storage (CCS).

3.3. Conclusion

Table 10 provides a summary of our estimates for the projected cost of producing clean hydrogen in major countries:

- Renewable hydrogen costs are based on the levelized cost of electricity from the cheaper of wind or PV in each country, and assume our optimistic projections for alkaline electrolyzer costs.
- Low-carbon hydrogen with CCS costs are based on the natural gas and coal prices listed, which are our 2019 benchmarks for wholesale prices.

The bold font highlights the cheapest source of hydrogen in 2030 and 2050, and green shading denotes countries where renewable hydrogen is cheaper on an energy-equivalent basis than natural gas based on 2019 prices.

Table 10: Forecast renewable and low carbon hydrogen production costs, and fossil fuel prices by country

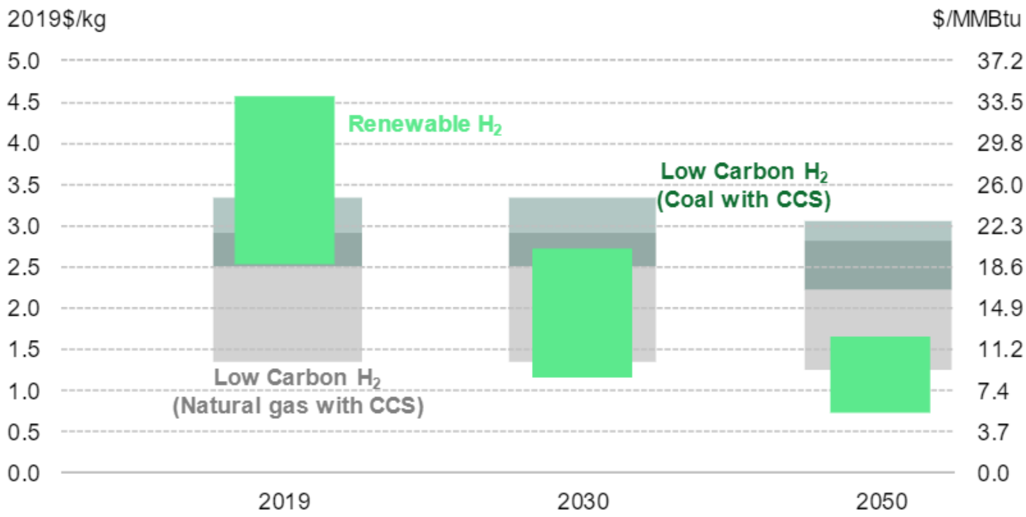
Country	Renewable hydrogen* ($/kg)		Low-carbon hydrogen - Natural gas with CCS ($/kg)		Low-carbon hydrogen - Coal with CCS ($/kg)		Natural gas price - $/kgH2 equivalent ($/MMBtu)	Coal/lignite# price - $kgH2 equivalent ($/t)
	2030	2050	2030	2050	2030	2050	2019	2019
U.S.	**1.41**	**0.84**	1.68	1.59	2.77	2.48	0.42 (3.1)	0.35 (57)
Canada	1.48	**0.98**	**1.34**	1.25	2.79	2.50	0.15 (1.1)	0.36 (59)
Brazil	**1.14**	**0.79**	2.36	2.27	2.92	2.63	0.96 (7.1)	0.45 (73)
China	**1.40**	**0.92**	2.55	2.46	2.51	2.22	1.11 (8.3)	0.38 (30)#
India	**1.17**	**0.76**	2.15	2.06	2.60	2.31	0.79 (5.9)	0.24 (40)
Japan	**2.46**	**1.60**	2.84	2.75	3.19	2.90	1.34 (9.9)	0.62 (100)
South Korea	**2.71**	**1.64**	2.91	2.82	3.34	3.05	1.39 (10.3)	0.72 (116)
Indonesia	2.09	**1.17**	**2.06**	1.97	2.84	2.55	0.72 (5.3)	0.39 (64)
Australia	**1.33**	**0.76**	1.92	1.83	2.51	2.22	0.61 (4.5)	0.38 (30)#
United Kingdom	**1.75**	**1.15**	2.46	2.37	3.00	2.71	1.04 (7.7)	0.50 (81)
Germany	**1.57**	**0.99**	2.63	2.54	2.60	2.31	1.17 (8.7)	0.50 (40)#
Russia	1.76	**1.15**	**1.41**	1.32	2.60	2.31	0.20 (1.5)	0.50 (40)#
Scandinavia	**1.17**	**0.73**	2.47	2.38	3.00	2.71	1.04 (7.8)	0.50 (81)
Saudi Arabia	1.50	**0.84**	**1.36**	1.27	2.92	2.63	0.17 (1.2)	0.45 (73)

*Source: BloombergNEF. Natural gas and coal prices based on data from the International Gas Union and International Energy Agency. Note: *for large-scale production from an integrated renewable power and electrolysis project, assuming our optimistic case alkaline electrolyzer cost projections. Coal is black coal, unless indicated with # for locations where lignite is likely to be cheaper. Natural gas and coal prices expressed in $/kgH2 on a high heating value energy equivalent basis, assuming 2,700kcal/kg lignite and 5,500kcal/kg for black coal. Green shading denotes locations where renewable hydrogen can become cheaper in 2050 on an energy equivalent basis than natural gas in 2019.* ***Bold*** *font highlights the least-cost source of hydrogen in 2030 and 2050.*

This analysis shows that the cost of producing renewable hydrogen across the world could drop from $2.53-4.57/kg in 2019 to $1.14-2.71/kg by 2030 and $0.73-1.64/kg by 2050, with the right scale-up. This would make it significantly cheaper than producing hydrogen from natural gas with CCS in 2050 at $1.25-2.82/kg, and from coal with CCS at $2.22-3.05/kg (Figure 26).

At these levels, it would also be competitive with the cost or producing fossil hydrogen without CCS, which ranges between $0.71/kg and $2.29kg, based on the $1.1-10.3/MMBtu spread of global natural gas prices today. By 2050, the projected cost of producing renewable hydrogen in Brazil, China, India, Germany and Scandinavia would even undercut the current wholesale cost of natural gas in those markets on an energy-equivalent basis (Table 10).

Figure 26: Forecast global range of levelized cost of hydrogen production from large projects



Source: BloombergNEF. Note: renewable hydrogen costs based on large projects with optimistic projections for capex. Natural gas prices range from $1.1-10.3/MMBtu, coal from $30-116/t.

Section 4. Storage and transport costs

If a hydrogen economy is to come about, a wide range of infrastructure would be needed to store and transport it. Hydrogen's low density makes it considerable harder to store than fossil fuels. We estimate that over 14,000 large salt caverns would need to be built at a cost of $637 billion for hydrogen to provide the same energy security as natural gas. Transport can be tricky too. Low densities make hydrogen expensive to transport via road or ship. However, hydrogen flows quickly through pipes, making this a more cost-effective option.

In this section we explore the economics of storing and transporting hydrogen. Section 4.1 provides a summary of the technologies and costs of storing hydrogen, and an estimate of the amount of storage infrastructure that would be required in a hypothetical hydrogen economy. Section 4.2 provides a summary of the costs of transporting hydrogen by pipelines, trucks and ships.

4.1. Storage

For more details on the economics and practicalities of storing hydrogen see: ***Hydrogen: The Economics of Storage*** (web | terminal)

For hydrogen to play a meaningful role as an energy carrier, plentiful and reliable storage will be required to ensure demand can always meet supply. Storing hydrogen in large quantities is not straightforward and will be one of the most significant challenges for a future hydrogen economy. It will proportionally also be one of the most costly elements – storing hydrogen will always be more expensive than storing natural gas because it takes up three to four times as much space as methane for the equivalent amount of energy, and it takes more energy to compress and liquefy.

Hydrogen storage technologies and techniques

Eight major technologies can be used to store hydrogen. Five are already commonly used today:

- Pressurized vessels – cylindrical tanks made of steel or composites
- Liquid hydrogen – tanks containing hydrogen cooled to a liquid
- Salt caverns – artificial cavities in underground salt formations
- Ammonia – a chemical containing nitrogen and three hydrogen molecules
- Metal hydrides – inter-metallic compounds that can absorb hydrogen

A further three are being actively explored for potential use:

- Depleted gas fields – underground reservoirs containing residual hydrocarbons that are not economically recoverable
- Rock caverns – artificial underground structures in rock
- Liquid organic hydrogen carriers – organic compounds that bind hydrogen

Each technology has different capabilities, applications, advantages and disadvantages. In Table 11 below, we compare the key characteristics of each technology. These are the volume of hydrogen it can store, the number of cycles it can perform, the current levelized cost of storing one kilogram of hydrogen (LCOS), the potential future LCOS if the technology is full developed, and important physical properties like pressure and density.

Table 11: Hydrogen storage options

	Gaseous state				Liquid state			Solid state
	Salt caverns	Depleted gas fields	Rock caverns	Pressurized containers	Liquid hydrogen	Ammonia	LOHCs	Metal hydrides
Main usage (volume and cycling)	Large volumes, months-weeks	Large volumes, seasonal	Medium volumes, months-weeks	Small volumes, daily	Small - medium volumes, days-weeks	Large volumes, months-weeks	Large volumes, months-weeks	Small volumes, days-weeks
Working capacity (t-H_2)	300-10,000t per cavern	300-100,000t per field	300-2,500t per cavern	5-1,100kg per container	0.2-200t per tank	1-10,000t per tank	0.18-4,500t per tank	0.1-20kg
Pressure (bar)	45-275	70-280	20-200	Up to 1,000	Ambient	Ambient	Ambient	~10
Benchmark LCOS ($/kg)[1]	$0.23	$1.90	$0.71	$0.19	$4.57	$2.83	$4.50	Not evaluated
Possible future LCOS[1]	$0.11	$1.07	$0.23	$0.17	$0.95	$0.87	$1.86	Not evaluated
Parasitic load (% H_2 HHV)[2]	1 - 2.5%	1 - 2.5%	1 - 2%	0.5 - 11%	25 - 33%	25 - 28%	29-33%	11 - 28%
Density (kg/m^3)[2]	4 - 20	4 - 20	4 - 20	3.5 - 50	70.8	107 - 121	47 - 57	40 - 140
Geographical availability	Limited	Limited	Limited	Not limited	Not limited	Not limited	Not limited	Not limited
Safety concerns[4]	Low	Low	Low	Medium	Medium	High	Medium	Medium

Source: BloombergNEF

[1] Benchmark LCOS at the highest reasonable cycling rate (see detailed research for details).

[2] Parasitic load and density rise with pressure for gaseous state storage. For liquid and solid state storage, they depend on plant size or specific LOHC/metal hydride used. Ammonia density is 107kg/m³ at 8.58bar and 20°C and 121 kg/m³ at 1bar and -33°C.

[4] Safety concerns are rated on a relative scale. Rating is subjective.

Each of the eight storage technologies uses pressurizing, liquefying or chemical compounding to increase the density of hydrogen to reduce the costs of storage.

- *Pressurizing* is currently the most common way to store hydrogen. It involves increasing the pressure of the gas so that more molecules fit into a particular volume. Pressures of up to 1,000bar (roughly 1,000 times atmospheric pressure) can be achieved, although a typical fuel cell electric vehicle stores hydrogen at 350-700bar (Table 12). Four hydrogen storage technologies use this method – salt caverns, rock caverns, depleted gas fields and pressurized tanks.
- *Liquefying* hydrogen entails cooling it to minus 253 degrees Celsius, which increases its density by about 800 times. It is similar in concept to liquefied natural gas, but the process requires significantly lower temperatures and so significantly more energy.

- *Chemical compounding or adsorption* involves combining hydrogen into molecules that exist in a denser state. The most common compound is ammonia, which when liquefied contains nearly twice as much hydrogen per cubic meter as liquefied hydrogen does. Two experimental technologies are metal hydrides, which store hydrogen in a solid state, and liquid organic hydrogen carriers (LOHCs) such as toluene, or methylcyclohexane, which bond hydrogen in more complex molecules. However, many of these chemical compounds are toxic, which creates safety concerns.

Increasing the density of hydrogen for storage or transport requires energy. Generally speaking, the greater the density of storage, the larger the energy requirements. Pressurizing hydrogen up to 1000bar requires 11% of the energy embodied in the hydrogen. This increases to 25-33% for chemical compounds or liquid hydrogen.

Table 12: Common hydrogen pressures

Hydrogen output	(bar)
Atmospheric	1.013
Alkaline electrolyzer	1-50
PEM electrolyzer	15-30
Steam methane reformer (SMR)	20-40
Transmission pipeline	100
Salt cavern	45-275
FCEV tank	700
High-end pressurized container	1,000

Source: BloombergNEF

Storage costs and most likely applications

To compare the cost of storage using different technologies, we calculate the levelized cost of storage (LCOS), which shows how much an operator would need to be paid in order to achieve a target internal rate of return for storing a kilogram of hydrogen.[47] The cost of storing hydrogen varies depending on the technology used and the volumes and duration of storage required (Table 11). A hydrogen economy will require both large-scale and small-scale storage, and utilize a variety of technologies for different applications.

- *Salt caverns* are the best option for storing large volumes of hydrogen for periods of several weeks or longer. They are relatively cheap, have low losses, keep the stored hydrogen pure, and are already in commercial use. There are six salt caverns around the world that are already used to store hydrogen, and thousands more store natural gas and other substances. However, storing hydrogen in them currently costs two to three times more than storing natural gas (Table 13). By our estimates, salt caverns can store hydrogen at $0.23/kg when cycled monthly, and this could fall to $0.11/kg in the future if U.S. Department of Energy capex targets are met. The problem is that salt caverns require specific geology so can't be built everywhere.
- *Rock caverns* are in principle the next best large-scale storage option. Our analysis suggests they have the potential to store hydrogen for around $0.71/kg, but this could be as low as $0.23/kg if abandoned tunnels or mines can be used. Rock caverns are generally smaller than salt caverns and the technology requires further development as none currently store hydrogen. Like salt caverns, they also require a specific geology.
- *Depleted fields* could be the third-best option for storing hydrogen, however, solutions need to be found to prevent methane contamination. Because of their massive size, they could be especially good at storing large volumes for long periods.
- *Liquid hydrogen, ammonia and LOHCs* are unlikely to be utilized purely for stationary storage purposes, but may be employed at the start or end of transport supply chains (discussed in Section 4.2 below).
- *Pressurized containers* are the most viable option for storing hydrogen in small quantities for short periods, with costs starting at $0.19/kg. Tanks are already widely used and are getting lighter and stronger, enabling them to store hydrogen at higher pressures and in larger quantities. They can be filled and emptied quickly, and are easily transported. With continual

Table 13: Cost of storing hydrogen versus natural gas, 2019

Tech-nology	H_2 ($/kg)	Natural gas ($/kg-$H_2$ equiv.)
Salt caverns	$0.23	$0.07-0.10
Depleted fields	$1.90	$0.47-0.49
Liquid state	$5.27	$0.37-0.48

*Source: BloombergNEF Note: *liquid state based on bi-weekly cycling*

47 For our detailed analysis on the costs and practicalities of storing hydrogen see: *Hydrogen: The Economics of Storage* (web | terminal)

improvements in technology, we project that costs could fall to $0.17/kg based on the targets of the U.S. Department of Energy and major manufacturers. Pressurized containers are likely to be used universally around the world for all applications requiring less than 1,000kg of storage.

Amount of storage required

A hydrogen economy will have to employ a combination of technologies to meet the full spectrum of needs – from large, centralized seasonal and strategic storage to fast-cycling, distributed storage for applications such as hydrogen vehicle-refueling stations.

Up to 20% of annual demand would need to be stored for energy security

If hydrogen is to be used across the economy, we estimate that at least one-tenth of annual demand (approximately 35 days) will need to be stored in each country (or region) if hydrogen comes from a steady low carbon source such as natural gas or coal with CCS.[48] If the hydrogen is produced from wind or solar, storage volumes of up to 20% of annual demand (approximately 70 days) will probably be required to balance the seasonal variability of renewable production.[49] This is consistent with the current storage volumes of natural gas, which vary from 5% to 31% of annual demand in major economies.

If global hydrogen demand amounts to 696MMT per year (this is the amount estimated in our *Strong Policies* scenario in Section 6.3), then approximately 140MMT of storage capacity would be required to hold 20% of annual demand. This is a very significant challenge. Storing 140MMT of hydrogen at high purity would require around 14,000 large salt caverns (of 10,000t capacity each) to be constructed at a total cost of around $637 billion.[50] To put that into context, right now there are 101 salt caverns that make up 6% of the world's natural gas underground storage capacity.

Geology matters

Japan would need to construct 924 rock caverns at a cost of $39 billion

The construction of large systems of salt caverns is only likely to be plausible in Europe, the U.S., central Canada, the Middle East, Central Asia, North Africa, Russia and the north west of Australia, where known salt deposits exist (Figure 27). Less geologically lucky countries like Japan, China, India, South East Asia, Sub-Saharan Africa and South America will have to rely on more expensive options and will face higher costs. It may also not be plausible for these regions to construct the amount of storage required. For example, in our *Strong Policies* scenario defined in Section 6.3, hydrogen demand in India would amount to 62MMT in 2050.[51] To store 20% of demand the country would need to construct 4,974 rock caverns at a cost of $208 billion.[52] Japan would need 924 rock caverns, at a cost of $39 billion.

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48 Based on the volume of hydrogen storage (as a share of annual demand) in the Spindletop salt cavern in Texas (8.2%) and the proposed H21 project in Leeds (12%). Global natural gas storage is equivalent to 11.7% of annual demand.

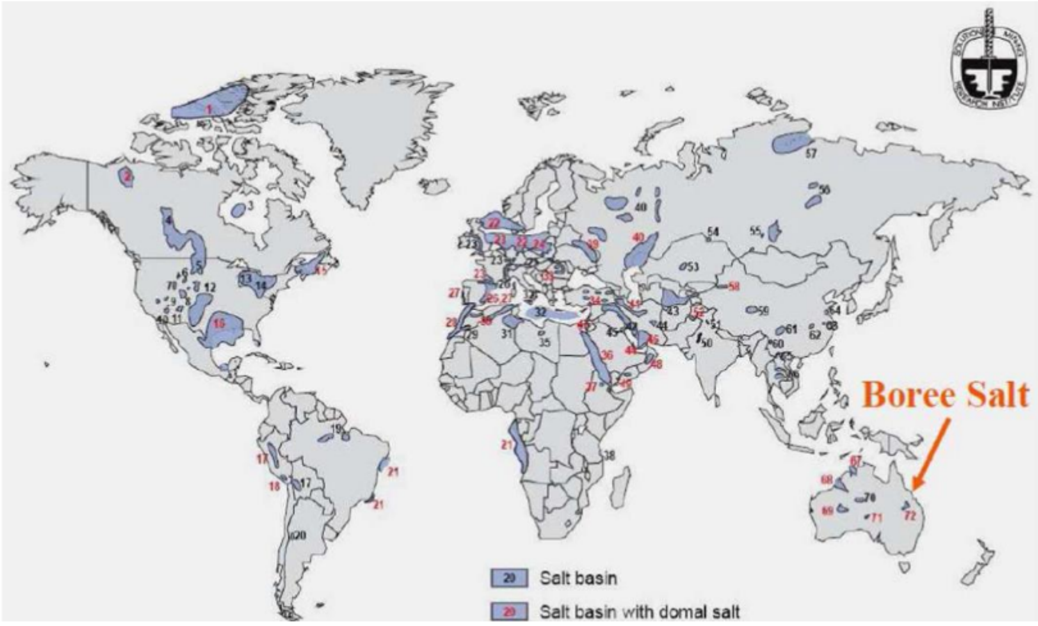
49 Based on our calculation of the storage capacity required to balance the variability of hydrogen supplied from a combination of wind and solar over a year in California (54 days) and Germany (73 days), in the unlikely scenario where deficits in renewable supply occur on consecutive days. The precise amount will vary depending on the characteristics of supply-side resources and demand profiles in each geography. For details see: *Hydrogen: The Economics of Storage* (web | terminal)

50 Based on a future best-case salt cavern capex of $4.55/kg-H2 stored.

51 Based on an assumption that India will consume 9% of global energy and Japan 2% in 2050.

52 Based on a future best case rock cavern capex of $16.69/kg-H2 stored.

Figure 27: Major world salt deposits



Source: Solution Mining Research Institute, published in Blanco and Faaij 2018, A review at the role of storage in energy systems with a focus on power to gas and long-term storage, Renewable and Sustainable Energy Reviews Journal

4.2. Transportation of hydrogen

For detailed information about the practicalities and costs of transporting hydrogen see:
Hydrogen: The Economics of Transport and Delivery (web | terminal)

If hydrogen is to become a widely used fuel, it is likely that significant volumes will need to be transported. Three main methods for moving hydrogen exist: pipes, trucks and ships. Which method works best depends on the volume and distance that hydrogen needs to be transported (Figure 28). Pipelines can be used to move hydrogen at relatively low cost, provided there is enough volume to justify the investment in infrastructure. However, hydrogen's low density makes carrying it in trucks and ships expensive, even if liquefaction, ammonia and LOHCs become cheaper. This suggests these methods are best avoided if possible.

Pipelines

Hydrogen can be transported under pressure in dedicated pipelines in a similar way to natural gas. Purpose-built pipelines will likely be needed for large-scale transmission as the materials used in existing high-pressure natural gas pipelines can be embrittled when hydrogen is introduced, even at low concentrations.[53] There are already around 4,542km of dedicated hydrogen pipelines in operation today. In contrast, blends of hydrogen can generally be tolerated by the pipes used in gas distribution networks, as these operate at lower pressures and often use different materials. This is discussed further in Section 7.7.

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[53] Because hydrogen is a tiny molecules and highly reactive it can diffuse into the molecular structure of materials like steel and react with carbon in the molecular structure, causing it to fail.

High-capacity pipelines are the cheapest way to move hydrogen

High-capacity pipelines are the cheapest option for overland hydrogen transport and costs can be similar to moving natural gas, if utilized frequently. This is because hydrogen is lighter than methane, so travels nearly three times faster through a pipe. As a result, pipeline capacity only needs to be 2-20% larger to carry the same amount of energy, helping to compensate for hydrogen's low volumetric energy density. The cost of the materials used for hydrogen pipes are also broadly comparable with gas pipes. These factors give pipelines a particular advantage over other modes of hydrogen transport. However, large scales and high utilization remain key.

Using data from the IEA and U.S. Department of Energy, we calculate that a 100km journey via a high-capacity pipeline moving more than 100 tons per day costs around $0.10/kg.[54] We estimate that this could fall to about $0.06/kg with better technology and wider adoption of large-scale hydrogen storage technologies. Even bigger pipelines – for instance for international trade – would have even lower costs. A much longer 1,000km journey via a very high-capacity onshore pipeline moving more than 5,000 tons per day could cost around $0.09/kg in future, also including the costs of compression and storage.[55]

Trucks

Trucks can be used for low-volume transport, but are costly

Trucks can also be used to carry trailers of compressed hydrogen gas (CGH2), liquid hydrogen (LH2), LOHCs or ammonia. Trucks carrying CGH2 and LH2 are already in common use, safely moving hydrogen around cities on a regular basis, but are expensive. We estimate that for low-volume delivery less than 300km, trucks with compressed hydrogen are the cheapest option today, with a 50km trip costing $0.81-1.19/kg.[56] These costs could fall to $0.64/kg for the same 50km journey as trailer capacity grows and cylinders get cheaper. For longer distances of 300-400km, converting or refrigerating the hydrogen into LOHC or LH2 is cheaper than compressed hydrogen, and should cost around $3.30/kg today and could drop to $1.10/kg in future for a 400km trip if these technologies develop. Trucking ammonia poses greater safety risks due to its toxicity, and should generally be avoided in urban areas, as accidents are often fatal.

Ships

Ships can be used for long-distance transport, but are very costly

Hydrogen can also be moved via ship as LH2, LOHC or ammonia in purpose built vessels. Shipping is a costly form of transport due to the need for expensive conversion and reconversion of hydrogen to either liquid or other chemical forms. Liquefying hydrogen requires about one-third of the energy contained in the hydrogen, but can be done using electricity at the exporting terminal, where energy should be cheap and abundant. Less energy is required to produce LOHCs and ammonia, but large amounts of energy are required to reconvert, or crack the chemicals back to hydrogen at the destination country, which is by definition energy-poor.

We calculate that the costs of shipping start at $3/kg for a 5,000km voyage using ammonia.[57] Costs could fall to $2/kg in future with greater scale and more efficient equipment, according to

54 This includes the cost of compression and storage of 20% of the gas in a salt cavern. Storage infrastructure must be used in the process of transporting hydrogen to ensure supply can meet demand, manage flow rates and maintain pressure. The cost of the 100km pipeline movement on its own is $0.06/kg. For detailed information on our calculations of the cost and practicalities of transporting hydrogen by pipelines see Section 5 of *Hydrogen: The Economics of Transport and Delivery* (web | terminal).

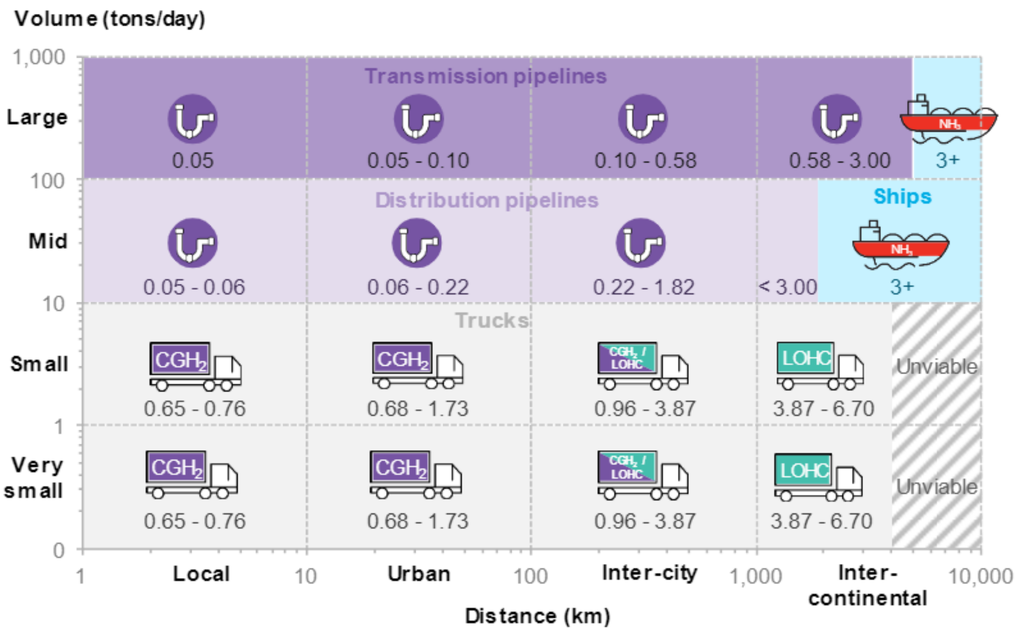
55 Based on the current cost of high pressure gas transportation (from Mokhatab, S. et al, *Handbook of Liquefied Natural Gas*, 2014), adjusted for the lower density of hydrogen.

56 See Section 6 of *Hydrogen: The Economics of Transport and Delivery* (web | terminal).

57 See Section 7 of *Hydrogen: The Economics of Transport and Delivery* (web | terminal).

our estimates. However,this is still expensive relative to the cost of producing renewable hydrogen. If production costs are to fall below $1/kg by 2050 (see Section 3.1), shipping could easily add 200-300% to the cost of the delivered gas.

Figure 28: H_2 transport costs based on distance and volume, $/kg, 2019



Legend: Compressed H2 Liquid H2 Ammonia Liquid Organic Hydrogen Carriers

Source: BloombergNEF. Note: figures include the cost of movement, compression and associated storage (20% assumed for pipelines in a salt cavern). Ammonia assumed unsuitable at small scale due to its toxicity. While LOHC is cheaper than LH_2 for long distance trucking, it is less likely to be used than the more commercially developed LH_2.

The whole chain matters

Although pipelines are the cheapest option on a distance-travelled basis, the optimal transport option in any particular application will depend on the technologies employed in the rest of the supply chain. How hydrogen is produced, stored and consumed – including at what scale, pressure and what technologies are used – could influence which transport option works best. For instance, the high pressure required at a vehicle refueling station could favor a supply chain that uses compressed gas. Or ammonia could be better as it can be combusted in a turbine.

Regulations, space, safety, commercial readiness and energy requirements all matter

Regulations and safety can also have a big impact. In Japan, trailers carrying CGH and LH2 are not permitted to pass through tunnels longer than 5km or under the sea. Trucking ammonia is cheaper than trucking LH_2 or LOHC. However, ammonia is a toxic gas, which raises social acceptance concerns and the possibility of a backlash by local residents against ammonia storage facilities in their neighborhood.

Energy requirements are also important. While LOHCs and ammonia are the cheapest ways of transporting H_2 for overseas journeys over 5,000kms, converting or cracking them back to hydrogen requires significant energy usage at the importing country, which may itself have high energy costs.

Section 5. Delivered costs

Considering the cost of production, storage and transportation, we estimate that a scaled-up renewable hydrogen industry could deliver fuel to large-scale users for a benchmark cost of $2/kg ($15/MMBtu) in 2030 and $1/kg ($7.4/MMBtu) in 2050. These delivered costs are likely to be achievable for clusters of large-scale industrial users in China, India and Western Europe. Costs would be 20-25% lower in regions with the best renewable and hydrogen storage resources, such as the U.S., Brazil, Australia, Scandinavia and the Middle East. However, costs would be up to 50-70% higher in Japan and Korea, which have weaker renewable resources and unfavorable geology. Supplying small-scale users and far-away locations costs more.

In this section, we provide estimates for the delivered cost of hydrogen that should be possible if the industry achieves scale-up and cost reductions in key locations around the world. Section 5.1 details costs to large-scale users, Section 5.2 costs to small-scale users and Section 5.3 the costs to countries dependent on international imports.

We expect that delivered costs will be influenced most strongly by two factors: scale and geographical location. The scale of hydrogen supplied determines the type of technology that can be employed to store and transport the fuel (for details see Section 4.1 and 4.2). This strongly impacts costs. Geographical location determines the availability and quality of renewable energy resources, which impact hydrogen production economics (for details see Section 3.1); the type of underground resources that are available for large-scale storage, which determines storage costs (for details see Section 4.1); and the cost of transporting hydrogen if imports are necessary.[58]

5.1. Large-scale users

The lowest costs can be achieved for industrial clusters

The most efficient and cost-effective way to deliver hydrogen is likely to be via large-scale, localized supply chains. An example of this would be a cluster of industrial facilities that consume hydrogen, located within a radius of 50-100 kilometers. A network of high-capacity transmission pipes would supply these users with clean hydrogen produced across a portfolio of wind and solar powered electrolyzers, with supply smoothed by the use of a large-scale geological storage facility like a salt or rock cavern.

This configuration offers the lowest costs because renewables-powered electrolysis, salt or rock caverns and high-capacity transmission pipes are the most economic forms of production, storage and transport. In addition, the use of a portfolio of renewable generators would help to provide a more continuous supply of hydrogen, minimizing the capacity of storage required for reliable supply, or the need for production from fossil fuels with CCS (see below).

58 Geographical location also influences the cost of fossil fuel resources, and therefore the economics of producing low carbon hydrogen using CCS (Section 3.2). However,as low carbon hydrogen is likely to be a more expensive option, this section focuses mostly on the delivered costs of renewable hydrogen.

Hydrogen could be delivered to large-scale users at a benchmark cost of around $2/kg in 2030 and $1/kg in 2050

In such a system, we calculate that hydrogen could be delivered to large-scale users at a benchmark cost of around $2/kg in 2030 and $1/kg in 2050 (Figure 29). For example, in China we estimate a possible delivered cost of $1.97/kg in 2030, based on the following:

- Production cost of $1.40/kg for renewable hydrogen produced using electricity from a wind farm with an LCOE of $28/MWh (Table 10).
- Transport cost of $0.03/kg for a 50km movement in a large-scale transmission pipeline (Figure 28).[59]
- Storage costs of $0.36/kg, making the conservative assumption that 50% of annual demand passes through a rock cavern.[60]

By 2050, we estimate that delivered costs in China could fall to $1.01/kg if decreases in the cost of production, transport and storage occur from industry scale-up. These costs are representative of other regions with average renewable energy resources, where rock caverns will need to be used for hydrogen storage – such as India and Western Europe.

Delivered costs could be as low as $1.48/kg in 2030 and $0.84/kg in 2050 in countries such as Australia, the U.S., and Brazil that can produce hydrogen from cheap renewable electricity and store it in salt caverns. Costs are likely to be highest, at around $2.85/kg in 2030 and $1.74/kg in 2050, in countries such as Japan and Korea with relatively expensive renewable energy that need to use rock cavern storage.

Figure 29: Estimated delivered hydrogen costs to large-scale industrial users, 2030

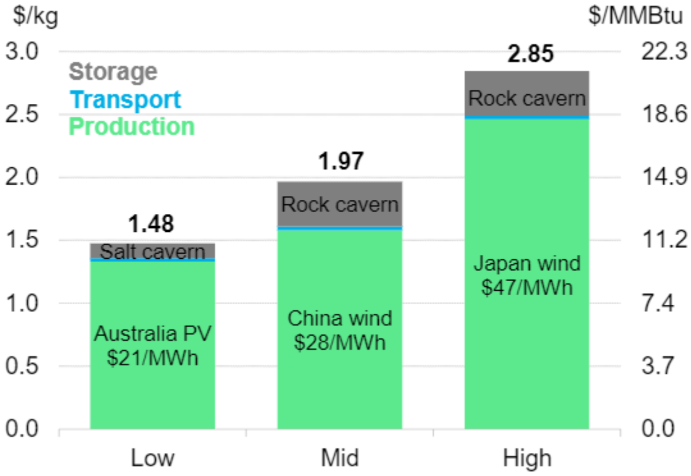
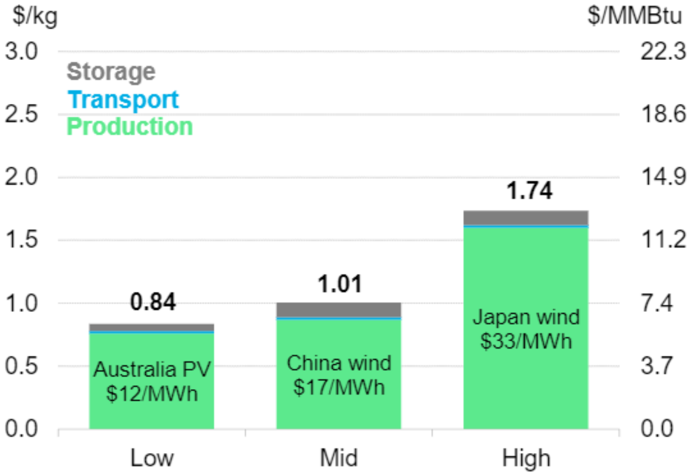


Figure 30: Estimated delivered hydrogen costs to large industrial users, 2050



Source: BloombergNEF. Note: Power costs depicted are the LCOE used for electrolysis, and are lower than the BNEF's standard LCOE projections in 2050 due to savings from integrated design of the electrolyzer and generator, and anticipated additional learning from increased renewable deployment for hydrogen production (see Section 3.1). Production costs are based on a large-scale alkaline electrolyzer with capex of $135/kW in 2030 and $98/kW in 2050. Storage costs assume 50% of total hydrogen demand passes through storage. Transport costs are for a 50km transmission pipeline movement. Compression and conversion costs are included in storage. Low estimate assumes a salt cavern, mid and high estimate a rock cavern for both 2030 and 2050.

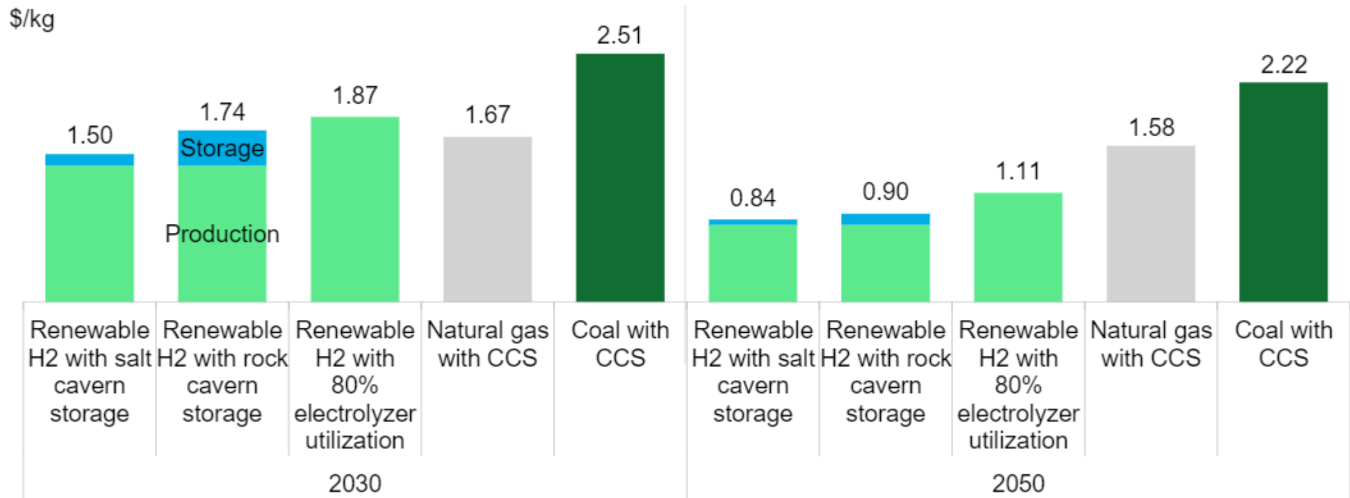
59 Note, costs depicted in Figure 28 include the cost of movement, compression and associated storage. $0.03/kg is the cost for movement only, as compression and storage are accounted for in the cost of rock cavern storage in the item below.

60 Our analysis indicates that around 70 days of storage (or 20% of annual demand) would likely be sufficient to balance the seasonal variability of renewable production. See Section 4.1 for details.

Can fossil fuels with CCS lower the cost of stable hydrogen supply?

Although low-carbon hydrogen production from fossil fuels with CCS could reduce or potentially eliminate the need for storage, we estimate that it is unlikely to result in lower delivered costs. Figure 31 below compares the costs of firmed hydrogen production from renewables versus hydrogen from fossil fuels with CCS. It shows that the cost of renewable hydrogen production firmed with storage is likely to be similar to the cost of low-carbon hydrogen from fossil fuels plus CCS by 2030, and to be lower by 2050. The supply of renewable hydrogen could also be firmed by oversizing the power supply relative to the size of the electrolyzer (for details see Section 3.1), and this is also likely to be cheaper than fossil fuels with CCS by 2050.

Figure 31: Cost of stable hydrogen supply in 2030 and 2050



Source: BloombergNEF Note: low-range production costs are depicted. Gas price of $3/MMBtu, coal of $30/t. Storage costs assume 50% of demand passes through a storage asset. Production from renewable H2 with 80% electrolyzer utilization is achieved by using a combination of wind and PV with a battery, oversized relative to the electrolyzer to achieve high run hours.

5.2. Small-scale users

Producing onsite using a grid electrolyzer is likely to be the simplest, but also the most costly option

The delivered cost of hydrogen to small-scale facilities, such as vehicle refuelling stations, is likely to be higher than for industrial clusters, as the same scale benefits cannot be achieved. There are four options for supplying small-scale users: the hydrogen can be produced onsite with an electrolyzer either powered by the grid or a small-scale PV system, or hydrogen can be delivered either by truck or pipe from a large-scale producer at an offsite location. The economics of these four options are summarized below: [61]

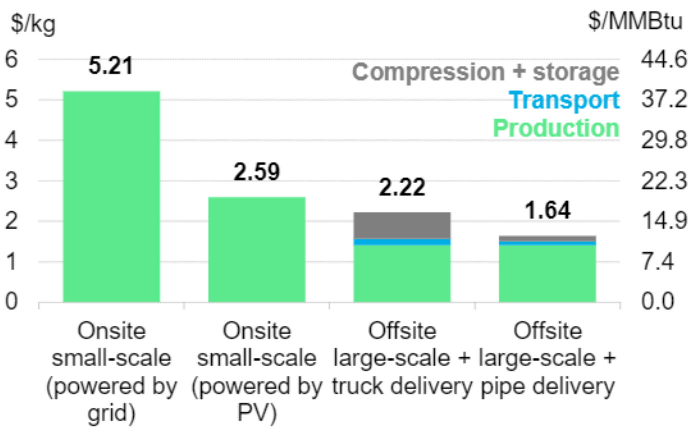
- *Onsite electrolyzer, powered by the grid*: Hydrogen produced onsite using an electrolyzer powered by the grid is likely to be the simplest, but also the most costly option. Using grid-supplied power is also likely to be highly polluting, unless a renewable energy supply can be guaranteed (see Figure 4 in Section 2.2). Assuming an electricity price of $100/MWh in 2030 (the average price for commercial users in the U.S. and China today) and a PEM electrolyzer capex of $440/kW (our optimistic projection for 2030 – see Section 3.1) yields a hydrogen

[61] For detailed information on the economics of small-scale hydrogen production see section 6.2 of *Hydrogen: The Economics of Production From Renewables* (web | terminal).

supply cost of $5.20/kg. By 2050, we assume electricity prices fall to $70/MWh and assume a PEM system capex of $95/kW, but this still gives a supply cost of $3.23/kg. These costs are in-line with the small-volume merchant price of fossil fuel derived hydrogen (without carbon capture) of $2-4/kg today.

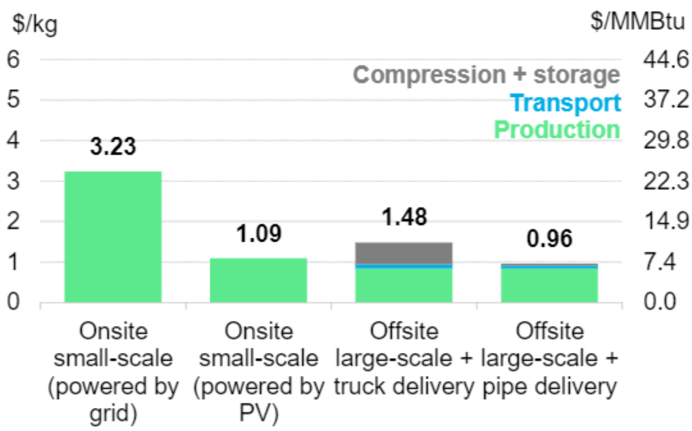
- *Onsite electrolyzer, powered by small-scale PV*: Hydrogen produced onsite using an electrolyzer powered by small-scale PV should be substantially cheaper ($2.59/kg in 2030, $1.09/kg in 2050) as the cost of power is less ($39/MWh in 2030, $26/MWh in 2050). The variability of supply would, however, need to be acceptable, and enough space available to host the PV panels.
- *Offsite large-scale production, delivered by truck*: Hydrogen delivered to a small-scale customer from an offsite large-scale producer is likely to be a cheaper option than onsite production in 2030, but not in 2050. For example, the projected levelized cost of producing hydrogen at a large-scale facility in the US is $1.41/kg in 2030 and $0.84/kg in 2050 (see Table 10 in Section 3.3). Compression, storage and transport of hydrogen in a truck driving 50km is projected to add $0.81/kg in 2030 and $0.62/kg in 2050,[62] leading to a delivered cost of $2.22/kg in 2030 and $1.48/kg in 2050.
- *Offsite large-scale production, delivered by pipe*: In theory, a dedicated pipe could also be used, but the user would need to have a large demand of 10-100t/day to justify the infrastructure. For context, a large refuelling station has a capacity of about 1t/day. Compression, associated storage and transport of hydrogen 50km via small pipes is projected to add $0.23/kg in 2030 and $0.12/kg in 2050,[62] leading to the lowest delivered cost of $1.61/kg in 2030 and $0.90/kg in 2050.

Figure 32: Estimated delivered hydrogen costs to small-scale users, 2030



Source: BloombergNEF. Note: Large-scale production based on alkaline electrolyzer with capex of $135/kW, powered by PV with an LCOE of $16.9/MWh. Small-scale production based on a PEM electrolyzer with capex of $440/kW, powered by distributed PV with an LCOE of $39/MWh or the grid with a power cost of $100/MWh. Transport costs are for a 50km movement in 2019, and storage.

Figure 33: Estimated delivered hydrogen costs to small-scale users, 2050



Source: BloombergNEF. Note: Large-scale production based on alkaline electrolyzer with capex of $98/kW, powered by PV with an LCOE of $16.9/MWh. Small-scale production based on a PEM electrolyzer with capex of $95/kW, powered by distributed PV with an LCOE of $26/MWh or the grid with a power cost of $70/MWh. Transport and storage costs are for a 50km movement in the future best base.

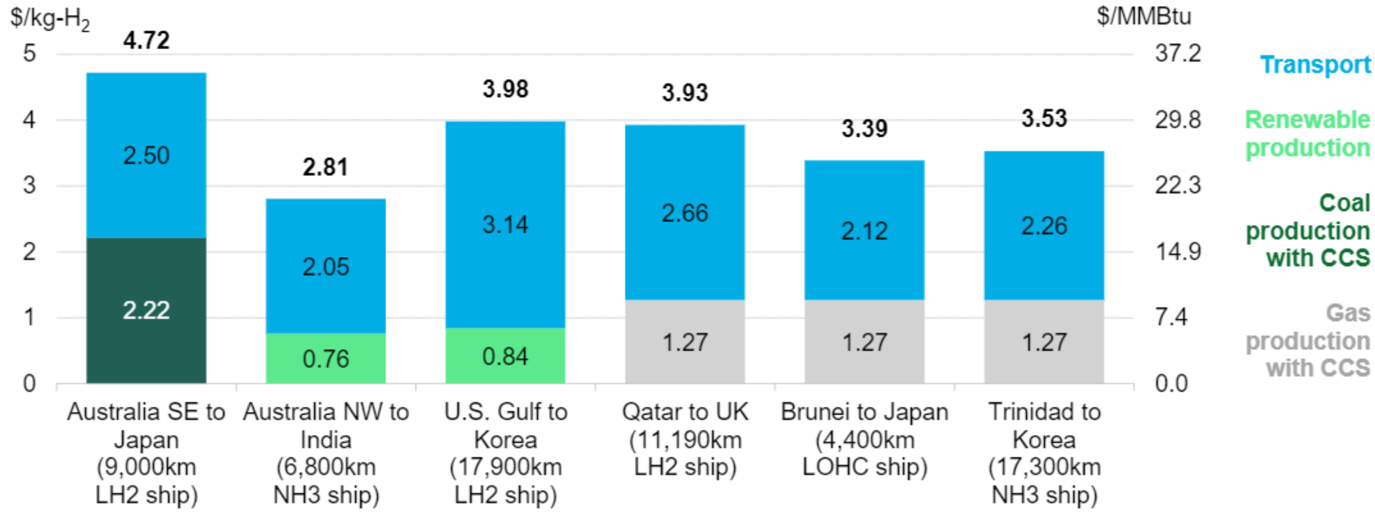
[62] See Section 6 of *Hydrogen: The Economics of Transport and Delivery* (web | terminal).

5.3. International import

The cost of transporting hydrogen across the seas is likely to remain high, even if costs come down in line with expectations. However, inter-continental transfers via high capacity pipelines could be attractive.

Using production cost estimates from Table 10 in Section 3.3 for potential hydrogen-exporting countries and estimates for the cost of shipping,[63] our calculations for the delivered cost of hydrogen imported via ship in 2050 come out between $2.81/kg and $4.72/kg, depending on the particular transport and production technologies, as well as shipping route (Figure 34). These costs are high, and well above the projected cost of producing hydrogen from renewable energy onshore in the destination countries instead.

Figure 34: Cost of production and long-distance hydrogen transport via ship, 2050



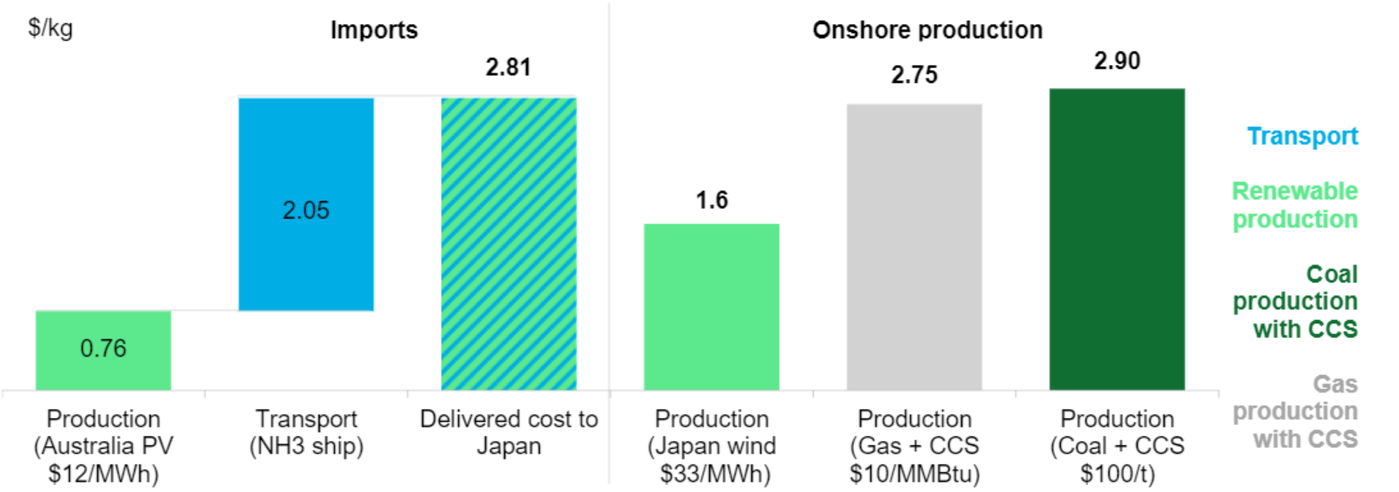
Source: BloombergNEF. Note: compression/conversion, reconversion to hydrogen and storage costs are included in transport. SE – South East, NW – North West, LH2 – liquid hydrogen, NH3 – ammonia, LOHC – liquid organic hydrogen carrier.

For example, the landed cost of renewable hydrogen produced in North West Australia and shipped to India (or Japan) comes out at $2.81/kg in 2050. However, by then, renewable hydrogen could be produced for $0.76/kg in India or $1.6/kg in Japan (Figure 35).

In general the cost difference between countries with low and high renewable hydrogen production costs is unlikely to be large enough to justify the added cost of a 5,000km transport voyage by ship ($3/kg today, $2/kg in future best case). Imports of renewable hydrogen could however, be competitive with the cost of producing H2 from fossil fuels with CCS in countries where gas and coal are expensive, such as Japan (Figure 35).

[63] See Section 7 of *Hydrogen: The Economics of Transport and Delivery* (web | terminal).

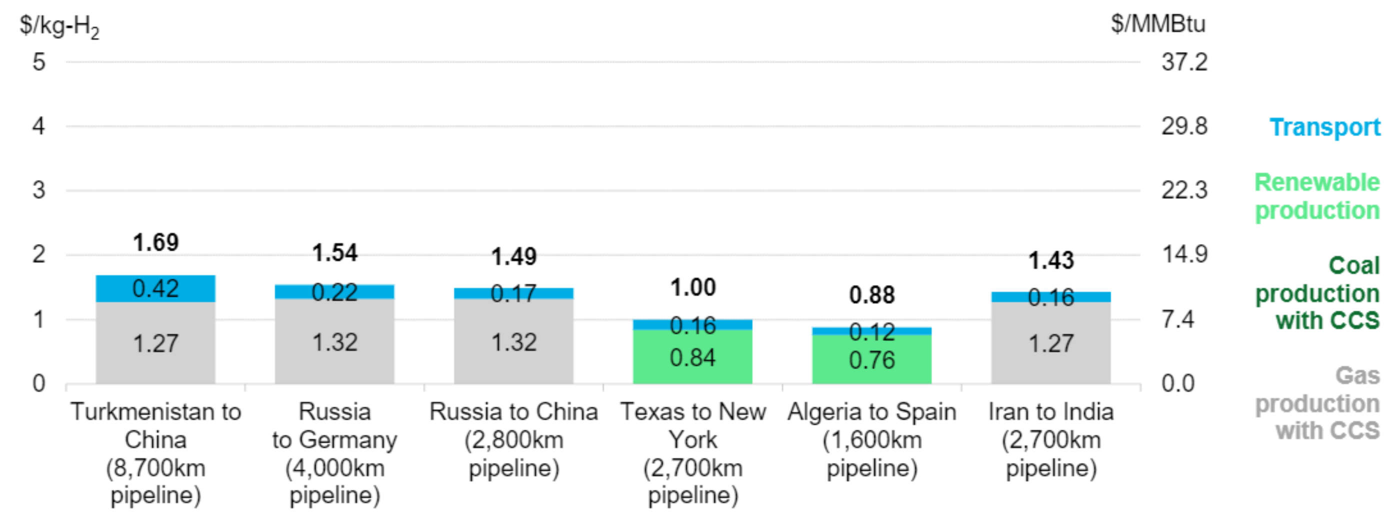
Figure 35: Landed cost of hydrogen in Japan: seaborne imports from Australia versus onshore production, 2050



Source: BloombergNEF. Note: Transport cost for a 6,800km voyage from North West Australia to Japan. Power costs depicted are the LCOE used for electrolysis, and are lower than the BNEF's standard LCOE projections in 2050 due to savings from integrated design of the electrolyzer and generator, and anticipated additional learning from increased renewable deployment for hydrogen production (see Section 3.1). Production costs are based on a large-scale alkaline electrolyzer with capex of $98/kW in 2050.

Pipelines are a lot cheaper. The delivered cost of hydrogen imported via pipeline in 2050 is likely to range between $0.88/kg and $1.69/kg, depending on route (Figure 36). This is because a 5,000km journey via a very high capacity (>5000 tons/day) onshore pipeline only costs $0.26/kg (including the costs of compression and storage). That's well within the variance in production costs between countries, suggesting that pipeline-based imports may be a common feature of a future hydrogen economy, helping countries to meet their clean energy needs at the lowest possible cost.

Figure 36: Cost of production and long-distance hydrogen transport via high-capacity pipeline, 2050



Source: BloombergNEF. Note: compression and storage costs included in transport. Assumes a 6,600t/day pipeline.

By contrast, seaborne imports of hydrogen are only likely to take place when a country cannot physically generate enough renewable hydrogen to meet its own needs domestically, and cannot obtain secure access via a pipeline. This may be the case in countries like Japan and South Korea, where we estimate there is not enough space to build renewable energy capacity to supply both the electrical system and the hydrogen industry (see Section 7 for details), and relations with nearby countries are poor.

Section 6. The economics of demand

Hydrogen will only gain use as a clean fuel if the economics work. At our estimated delivered prices of $2/kg in 2030 and $1/kg in 2050, we find that the economics of using hydrogen can come close, but subsidies or carbon prices will still be needed for it to compete against the cheapest fossil fuels in use today. Up to 20% of greenhouse gas emissions from fossil fuels and industry could be abated using hydrogen for a carbon price lower than $100/tCO2 in 2050. If the required policy is in place, we estimate that demand for hydrogen could be up to 696MMT by mid-century. That's enough to meet 24% of projected energy consumption if warming is limited to 1.5 degrees.

In the previous section, we showed that if scale-up occurs, renewable hydrogen could be delivered to large-scale users in most parts of the world for a benchmark cost at or below $2/kg, or $15/MMBtu, by 2030 and $1/kg, or $7.4/MMBtu, by 2050. In this section, we examine the economics of using hydrogen at these prices and estimate potential demand. Section 6.1 explains how hydrogen can be used, the carbon prices it requires and the volume of demand that could materialize if policy support is in place. Section 6.2 summarizes the abatement potential of using hydrogen in each sector. Section 6.3 presents two scenarios for long-term demand if policy support materializes.

6.1. Economics by sector

The technology exists today to use hydrogen in a wide variety of sectors. But whether it ultimately gains use will depend on its cost relative to the fuels it seeks to displace, the cost of retrofitting or replacing equipment to enable its use, the economics of other competing low- and zero-carbon pathways, and the amount of policy support the industry receives.

Hydrogen could be used in 11 hard-to-abate sectors. For each sector we summarize:

1. How hydrogen can be used as a substitute for fossil fuels
2. The price hydrogen needs to fall below to begin competing with the use of *expensive* fossil fuels
3. The carbon prices required for hydrogen to compete with the use of the *cheapest* fossil fuels at our estimated delivered prices of $2/kg in 2030 and $1/kg in 2050
4. The potential demand for hydrogen in 2050 in two policy scenarios (see box below)

Considering these four factors, and the availability of alternative decarbonization technologies, we provide a qualitative assessment of the potential role that hydrogen could play in decarbonizing each sector, as a low, medium or high rating.

Hydrogen policy scenarios to determine volume of demand

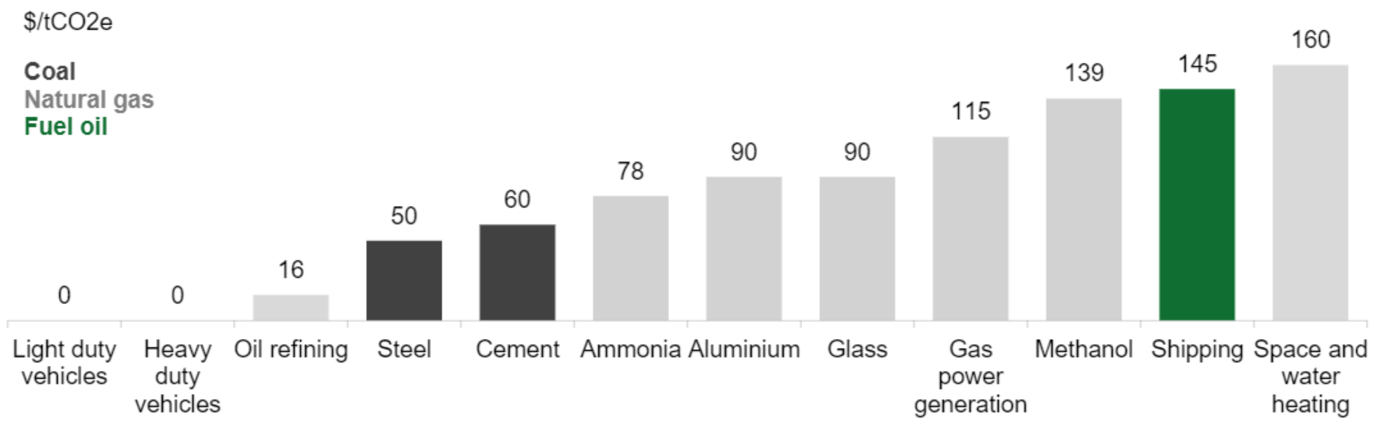
Because hydrogen must be manufactured from other energy sources and is more difficult to store, transport and handle, it is – and will likely remain – more expensive than cheap fossil fuels. For its use to be economically viable, subsidies or other policy measures that recognize the emissions reduction benefits will be required.

While it is not certain these policies will materialize, in the remainder of this section we examine two possible scenarios for policy support and scale-up, in order to estimate a potential range of demand:

- ***Weak Policy* scenario**: efforts to decarbonize the global economy and support the use of hydrogen are piecemeal but continue to progress. A suite of measures are used around the world to continue to drive investment in clean energy technologies – including vehicle emissions standards, tax credits, reverse auctions and upfront subsidies – but are not sufficient to limit warming to less than 2 degrees. Effective carbon prices (either through regulation or explicit pricing) tend toward $50/tCO2 in 2040-50, focused on regions with existing pricing schemes like Europe. This scenario is akin to a continuation of the current state of affairs.
- ***Strong Policy* scenario**: efforts to decarbonize the global economy and support the use of hydrogen are comprehensive. There are significant measures in place to drive investment in clean technologies and emission reductions – including stringent vehicle emission standards, massive public investment in enabling infrastructure, and progressive prohibitions on the use of fossil fuels.[64] Efforts notionally aim to limit warming to less than 2 degrees, but are not always rigorously calibrated to do so. Carbon prices – with complementary carbon border adjustments – are in place in most major economies and tend toward effective prices of $100/tCO2 in 2040-2050.

Overall, we find that carbon prices, or equivalent policies, will be required for hydrogen to be competitive with the cheapest fuels in use in each sector. In 2030, when hydrogen could be delivered to large-scale users for around $2/kg, a carbon price of $125-295/tCO2 would be needed to make hydrogen competitive. In 2050, when we assume large-scale delivered hydrogen prices fall to $1/kg, no carbon price would be needed for renewable hydrogen to be competitive in road transport if vehicle production has scaled up, but other sectors would still need a carbon price of $50-160/tCO2 to match the cheapest fossil fuels currently in use (Figure 37).

Figure 37: Carbon prices required for hydrogen to compete with the cheapest fossil fuel in each use case, 2050



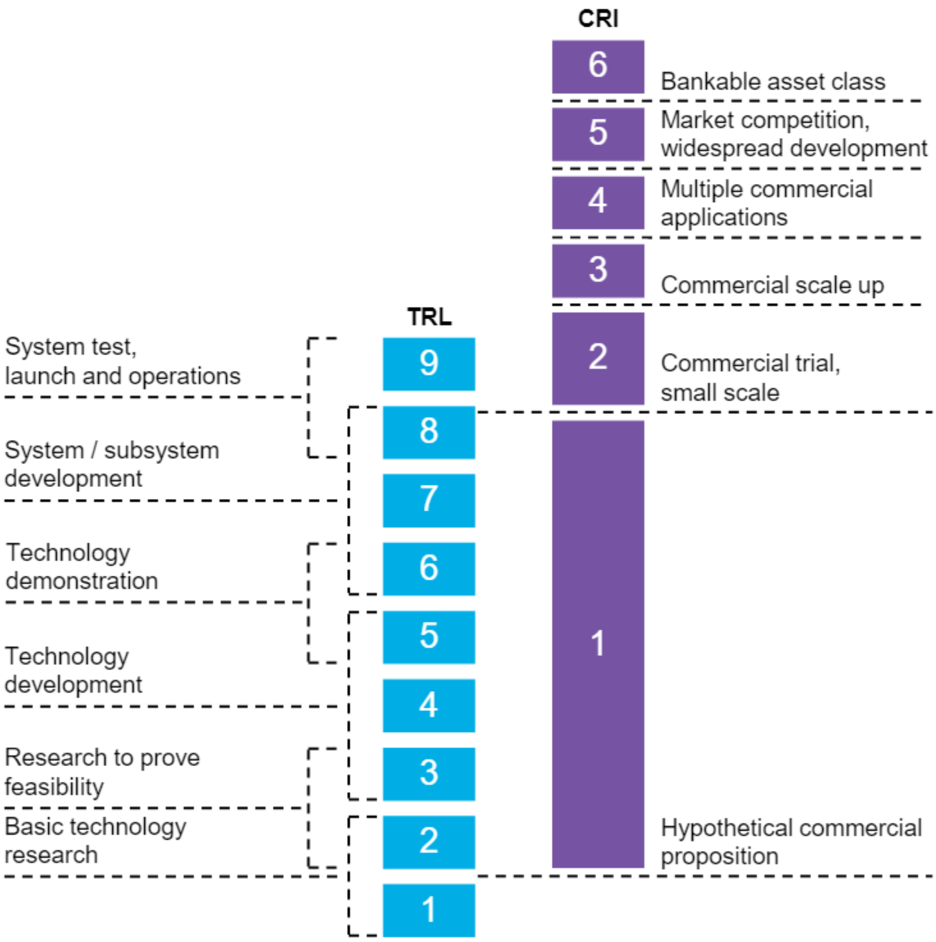
Source: BloombergNEF. Note: based on a hydrogen price of $1/kg and equipment costs that vary be sector. Fuel depicted refers to the dominant fuel in each industry.

64 Prohibitions on the use of fossil fuels are likely to be required to achieve net-zero emissions – in particularly oil – due the feedback loops in resource economics. If demand for fossil fuels declines, prices are likely to fall, making it harder for clean technologies to compete.

Technology Readiness Level

To compare the maturity of different technologies, this report uses the Technological Readiness Level (TRL) and Commercial Readiness Index (CRI), adopted from Australia's Commonwealth Scientific and Industrial Research Organisation (CSIRO).[65] Figure 46 gives definitions of individual technological and commercial readiness levels and illustrates how they relate to each other.

Figure 38: Technological readiness level and commercial readiness index



Source: CSIRO, BloombergNEF

[65] Bruce et al., *National Hydrogen Roadmap*, Commonwealth Scientific and Industrial Research Organisation, 2018.

Steel

Key points

- There is a high potential to use hydrogen in steel production.
- Renewable hydrogen becomes competitive with expensive gas-based process at $2.50/kg.
- A carbon price of $85/tCO_2$ in 2030, and $50/tCO_2$ in 2050 would be needed for hydrogen to compete with the cheapest coal-based steel production processes
- The steel sector could deliver 9-45MMT of demand for renewable hydrogen by 2050.

For our full assessment of using hydrogen in steel making, see ***Hydrogen: Making Fossil-Free Steel*** (web | terminal)

Steel production can be decarbonized almost completely, by using hydrogen

Steel is one of the world's most important materials. It can be found everywhere, from our dinner spoons to building beams. However, the production of steel is responsible for around 7% of global greenhouse gas emissions each year due to the role that fossil fuels, particularly coal, play in the manufacturing process. Hydrogen can displace almost totally the need for fossil fuels by acting as both the feedstock for the chemical reaction necessary to reduce iron ore to pig iron, and also by providing the high-temperature heat for the steel-making process.

Renewable hydrogen, or low-emissions hydrogen from fossil-fuels with CCS, can be a comprehensive substitute for natural gas in an existing manufacturing technology called a *direct reduction* furnace, which is currently used to make around 9% of primary steel worldwide. Seven pilot plants are currently being developed to demonstrate the use of *hydrogen direct reduction*, and have a TRL of 5-6. Three other projects are also investigating the potential to use a partial blend of hydrogen in coal-based blast furnaces. However, this technology is less mature at TRL 2-5, and cannot fully decarbonize the process.

Price

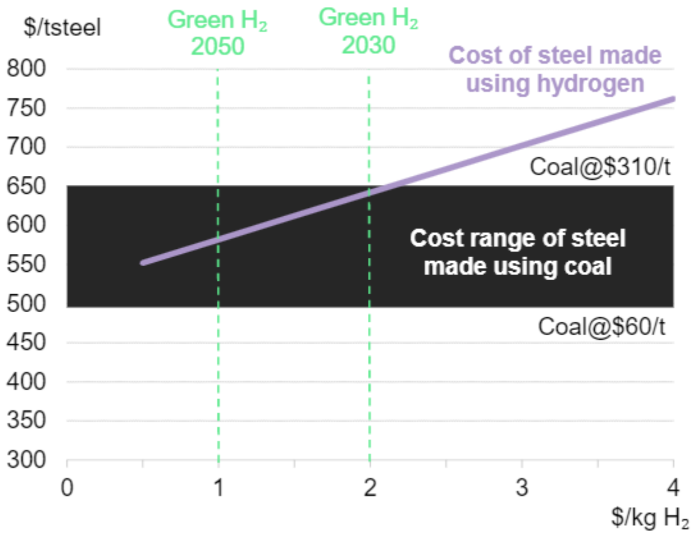
Our calculations suggest that the hydrogen-based steel making process would be competitive with high-cost coal-based and high-cost gas-based steel processes at our benchmark price of $2/kg in 2030. By 2050, the hydrogen-based process would be competitive with low-cost natural gas steel-making and mid-cost coal steel-making, if delivered hydrogen prices fall to $1/kg (Figure 39 and Figure 40).

A carbon price of $85/tCO2 would be required to make hydrogen competitive with the cheapest coal-based plants in 2030, and $50/tCO2 would be needed in 2050.

Volume

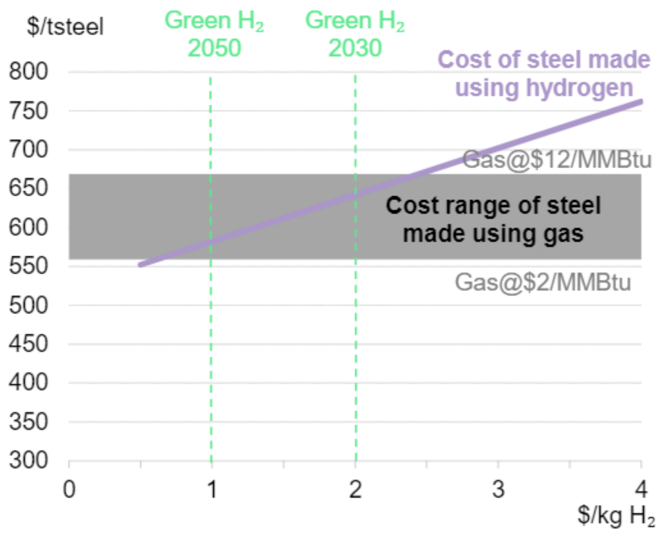
If carbon prices are in place, a portion of new steel plants built after 2030 could be based on hydrogen-ready technologies, which can initially run with natural gas, and eventually switch to hydrogen. Our range of future demand for renewable hydrogen in the steel sector in 2050 is 9-45MMT. In a *Weak Policy* scenario, approximately half of new-build steel plants after 2030 could use hydrogen (producing a total of 10% of all primary steel in 2050). In a *Strong Policy* scenario, we assume that 50% of all primary steel could be made using hydrogen by 2050.

Figure 39: Levelized cost of steel: hydrogen versus coal



Source: BloombergNEF

Figure 40: Levelized cost of steel: hydrogen versus natural gas



Source: BloombergNEF

Ammonia

Key points

- There is a high potential to use hydrogen in ammonia production.
- Renewable hydrogen becomes competitive with expensive gas-based process at $2.16/kg.
- A carbon price of $189/tCO2 in 2030 and $78/tCO2 in 2050 would be needed for renewable hydrogen to compete with the cheapest gas-based ammonia production processes.
- The ammonia sector could deliver 5-28MMT of demand for renewable hydrogen by 2050.

For our full assessment of using hydrogen in ammonia production see, ***Hydrogen: Making Green Ammonia and Fertilizers*** (web | terminal)

Hydrogen is already the key ingredient in the ammonia production process

Ammonia is one of the world's most important chemicals, as it is the foundational compound of fertilizers. Hydrogen is already the key ingredient to make ammonia, but the vast majority of H2 today is made from fossil fuels making the ammonia sector responsible for around 1% of global greenhouse gas emissions. Renewable hydrogen can easily be substituted and would remove virtually all carbon emissions from the ammonia production process. Six pilot plants are currently under development to demonstrate the technology, which has a TRL of 9.

Price

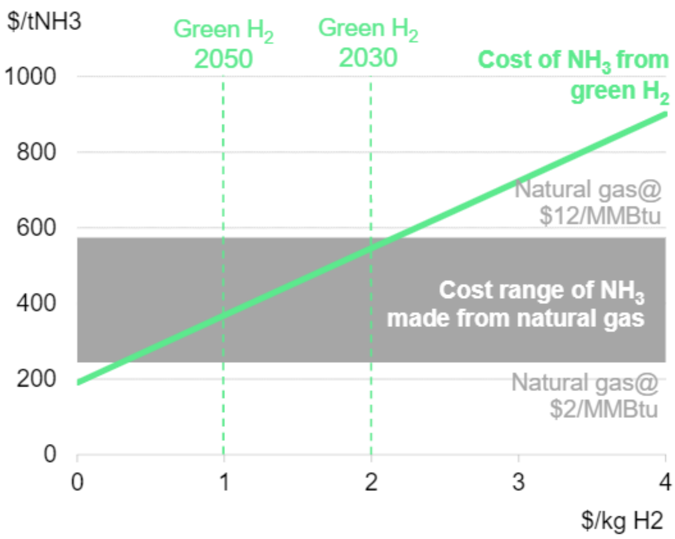
Once the delivered cost of renewable hydrogen falls below $2.16/kg, it becomes competitive with gas-based ammonia production at a gas prices around $12/MMBtu (Figure 41). However, ammonia production is dominated by countries with cheap feedstock. To compete with gas-based production at $2/MMBtu, green hydrogen prices would have to be as low as $0.30/kg.

At our benchmark renewable hydrogen cost of $1/kg in 2050, a carbon price of $78/tCO2 would make renewable hydrogen competitive with the cheapest gas-based ammonia production. A carbon price of just $24/tCO2 in 2050 would allow renewable hydrogen to undercut ammonia production from cheap coal.

Volume

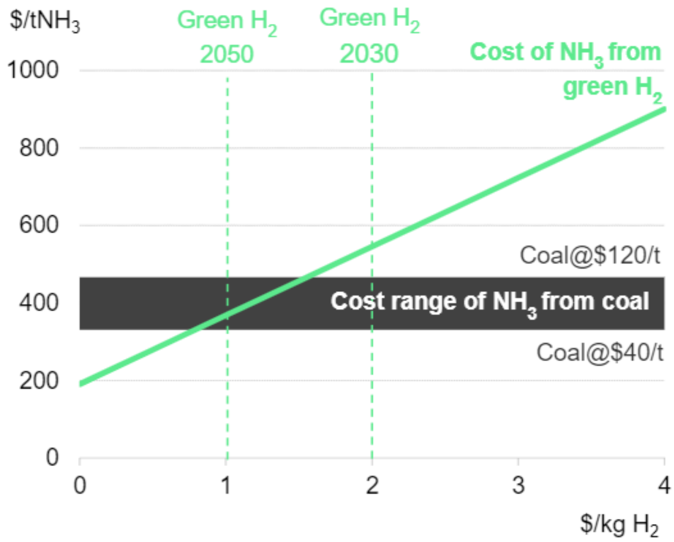
Overall we estimate that there is high potential to use renewable hydrogen to decarbonize the ammonia production process. Demand could range from 5 to 28MMT in 2050. In a *Weak Policy* scenario, we assume half of new ammonia plants built after 2030, to satisfy new demand and replace retiring capacity, use renewable hydrogen. In a *Strong Policy* scenario, we assume 50% of all ammonia production utilizes renewable hydrogen by 2050.

Figure 41: Levelized cost of ammonia: hydrogen versus natural gas



Source: BloombergNEF

Figure 42: Levelized cost of ammonia: hydrogen versus coal



Source: BloombergNEF

Oil refining

Key points

- There is low potential to use renewable hydrogen in refining
- Renewable hydrogen becomes competitive with expensive natural gas-based hydrogen production in refining at $2.59/kg.
- A carbon price of $129/tCO$_2$ in 2030, and $16/tCO$_2$ in 2050, would be needed for hydrogen to compete with the cheapest natural gas.
- Refining could deliver 2-6MMT of demand for renewable hydrogen by 2050.

Hydrogen is a key feedstock in oil refining. It is used to remove sulfur and other impurities, and manipulate hydrocarbon molecules into different forms (see box below). Demand for hydrogen in refining has grown as fuel quality standards have become more stringent, increasing the need for desulfurization of road fuels. At the same time, supply of heavier grades of crude oil, such as those from Canadian oil sands, have increased demand for hydrocracking.

Based on 2018 data, around 38MMT of hydrogen are used in refining. Around one third of this is produced within refineries, mainly by reforming processes that produce hydrogen as a by-product of combining short-chain hydrocarbon molecules. The remaining two-thirds, or around 25MMT, are produced from fossil fuels. This is either dedicated onsite production (17MMT) or purchased from an external supplier (8MMT).[66] From a technical perspective, renewable hydrogen can be easily substituted, and three pilot plants have recently been announced. CCS could also be fitted to existing reforming facilities, and has a TRL of 9, with four plants already operating.

Existing use of hydrogen in oil refining

Hydrogen is currently used in oil refining in the following ways:

- *Hydrodesulfurization* is the removal of sulfur and other impurities using a stream of hydrogen rich gas.
- *Hydroisomerisation* is the transformation of straight-chain alkanes into branch-chained alkanes required to increase the octane rating of gasoline.
- *Dearomatization* is the transformation of aromatics into cycloparaffins and alkanes.
- *Hydrocracking* splits long-chain hydrocarbons into shorter-chain hydrocarbons.

Price

Renewable hydrogen at $2.59/kg would be competitive with hydrogen derived from natural gas at $12/MMBtu for refining processes. However, refineries generally have access to cheap fossil fuels and renewable hydrogen would need to fall below $0.86/kg for it to become competitive with the cost of building a new gas-based hydrogen production process purchasing fuel at $2/MMBtu (see Figure 22 in Section 3.2). An onsite electrolyzer powered with cheap renewable power may be able to achieve these costs in some locations by 2050, but without storage, supply would be intermittent. At our benchmark delivered renewable hydrogen prices of $2/kg in 2030 and $1/kg in 2050, carbon prices of $129/tCO2 and $16/tCO2 respectively would be required to compete with the cost of gas-based hydrogen (see Figure 24 in Section 3.2).[67]

Volume

In the short term, we expect hydrogen demand in refining to continue to grow as fuel quality standards tighten and proliferate around the world.[68] This makes the sector a good candidate for pilot and demonstration projects using electrolyzers or CCS in the next few years where these new facilities can help meet incremental demand. However, beyond a five-year time horizon, the need for hydrogen in the oil refining industry is clouded by two factors. Firstly, supply of crude oil is expected to shift to lighter grades, which is likely to reduce the need for hydrogen for hydrocracking.[69] Secondly, we expect the growing uptake of electric vehicles and alternative drive-trains to reduce demand for road fuels, which could also reduce demand for hydrogen.[70] Although growth in other segments of oil demand is currently projected to increase and compensate for the fall in road fuels, refining these products typically requires less hydrogen.[71]

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66 International Energy Agency, *The Future of Hydrogen*, 2019.

67 For fossil hydrogen with CCS to be economic, a carbon price of $79/tCO2 would be required in 2030 and 2050.

68 Increasing fuel quality standards and sulfur content limits will require further refinery upgrades and use of hydrogen for desulfurization.

69 Light grades from the U.S. are expected to grow in excess of heavier grades, leading to a 'lightening of the crude slate'.

70 We expect demand for gasoline to peak in 2028 and road diesel in 2035. For details see: 2019 Road Fuel Outlook (web | terminal).

71 For details see: Questioning the Consensus on Oil Demand (web | terminal).

Additionally, if deep decarbonization is to occur, the overall demand for oil products should also fall.

In a *Weak Policy* scenario, we assume demand for oil products and hydrogen in refining stays flat, requiring 25MMT of dedicated hydrogen production in 2050. However, we assume that renewable hydrogen only supplies 2MMT of this demand, because existing onsite hydrogen production plants are sunk costs, and therefore difficult to displace economically. In a *Strong Policy* scenario, we assume that demand for oil products halves due to growth of fuel-cell and battery electric vehicles, and displacement of oil in the marine, buildings, industry, and power sector. This leads to a 50% drop in demand for dedicated hydrogen production to 12MMT by 2050. We have assumed that renewable hydrogen supplies 6MMT in this scenario, due to stronger incentives to reduce emissions.

Methanol

Key points

- There is a low potential to use renewable hydrogen in methanol production
- Renewable hydrogen becomes competitive with expensive gas-based process at $0.94/kg
- A carbon price of $226/tCO2 in 2030 and $139/tCO2 in 2050 would be required for renewable hydrogen to compete with cheapest gas in methanol production.
- The methanol sector could deliver 1.1-3.4MMT of renewable H_2 demand by 2050

For our full assessment of using hydrogen in methanol production see: ***Hydrogen: The Economics of Low-Carbon Methanol*** (web | terminal)

An external source of carbon dioxide is needed to make methanol, which makes the economics challenging

Methanol is a primary chemical that is used to make a variety of products, such as plastics, plywood, paints and textiles, and as an additive in transport fuels. However, methanol is responsible for 0.6% of global greenhouse gas emissions each year due to the widespread use of coal and gas in its production. Methanol could be made from renewable hydrogen instead, but the economics look challenging.

Today, methanol is predominantly made by rearranging the carbon, hydrogen and oxygen molecules contained in water and coal, or gas, in a chemical process. Instead, renewable hydrogen made from water electrolysis, and carbon dioxide captured from an external source, could be used to reduce or eliminate the CO2 emissions. There are currently two facilities producing methanol from renewable hydrogen, in the Netherlands and Iceland.

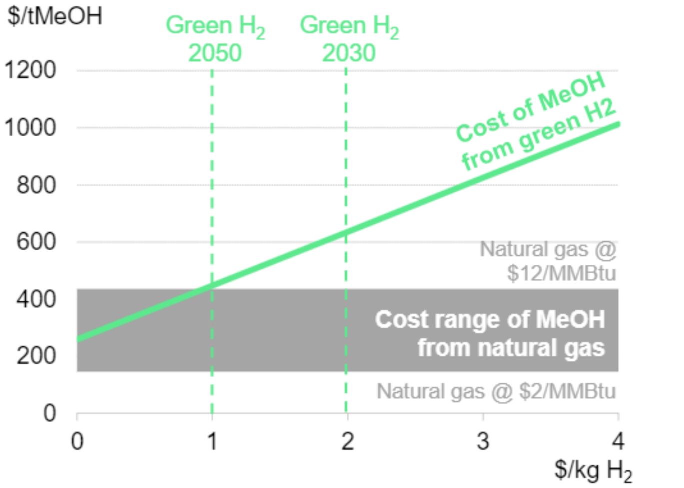
Price

Renewable hydrogen would need to fall below $0.94/kg for the process to be competitive with an expensive gas-based methanol production process using $12/MMBtu gas (Figure 43). However, most methanol is produced in countries with gas at $2/MMBtu or even less, or coal as cheap as $20/t, and this is difficult for renewable-based methanol to compete with. This is because the chemical reaction to make methanol from hydrogen and CO2 is less efficient, and carbon dioxide also needs to be procured from an external source – which entails costs.

If a carbon price is applied, the relative economics improve, but not enough. A carbon price does two things to methanol production economics – it makes fossil-based methanol production more expensive due to the emissions liability, and it could also lower the cost of procuring the required CO2 feedstock for the hydrogen-based methanol production process from a third party. If carbon taxes are high enough, a methanol producer may even be paid to absorb carbon from a third party.[72]

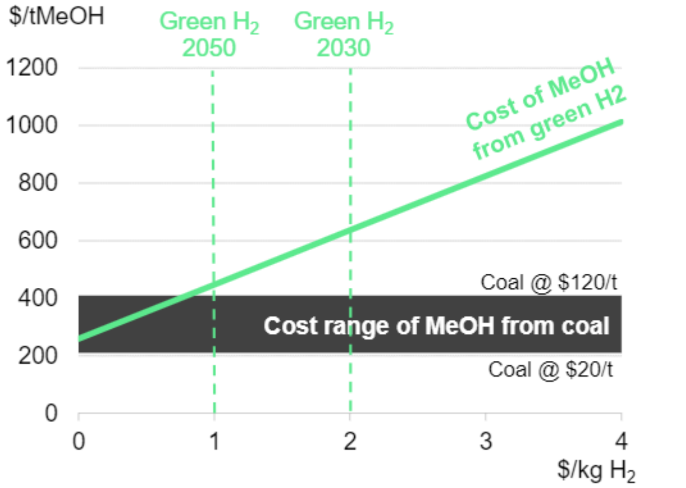
At our benchmark renewable hydrogen cost of $1/kg, a carbon price would need to be $226/tCO2 in 2030 and $139/tCO2 in 2050, for hydrogen-based methanol to compete with cheap natural gas-based production. A carbon price of $91/tCO2 in 2030 and $51/tCO2 in 2050 would be enough for hydrogen-based methanol to compete with cheap coal-based production, most of which is in China.

Figure 43: Levelized cost of methanol production: hydrogen versus natural gas



Source: BloombergNEF. Note: MeOH is methanol. Assumes CO2 feedstock cost of $95/t for methanol production from hydrogen. Feedstock intensity of 29MMBtu natural gas per ton of methanol.

Figure 44: Levelized cost of methanol production: hydrogen versus coal



Source: BloombergNEF. Note: MeOH is methanol. Assumes CO2 feedstock cost of $95/t for methanol production from hydrogen. Feedstock intensity of 1.99t of coal per ton of methanol.

Volume

Even with carbon emission restrictions in place, we think its unlikely many methanol plants based on renewable hydrogen will be built, due to the high operating costs. In a *Weak Policy* scenario we assume that 10% of new methanol plants built from 2030 could be based on renewable hydrogen. In a *Strong Policy* scenario, we assume 10% of all methanol production in 2050 is based on renewable hydrogen. For production to be much higher than this, a strong end-user pull for decarbonized plastics and other products derived from methanol would probably be required.

72 If a carbon price is in place a third-party emitting CO2 may pay a renewable methanol producer to absorb their waste carbon dioxide (or meet some of the costs of capture) to reduce their own emissions liability.

Cement, aluminum and glass

Key points

- There is medium potential to use renewable hydrogen for cement, aluminum and glass.
- Renewable hydrogen becomes competitive with expensive natural gas processes at $2/kg.
- A carbon price of $220/tCO2 in 2030, and $90/tCO2 in 2050, would be required for renewable hydrogen to compete with the cheapest fuels
- The cement, aluminum and glass sectors could deliver 20-41MMT of demand for renewable hydrogen by 2050.

For our full assessment of using hydrogen in cement, aluminum and glass production, see: ***Hydrogen: The Economics of Industrial Heat*** (web | terminal)

Hydrogen can be used as clean-burning alternative to combusting fossil fuels

High-temperature heat is a vital input to the manufacture of everyday products like cement, aluminum and glass. However, generating this heat produces about 15% of total global greenhouse gas emissions. Coal, oil and natural gas are the dominant fuels, but hydrogen has the potential to be used as an alternative fuel source and could be competitive with the cheapest fossil fuels in 2050 at a carbon price of $90/tCO2.

High-temperature heat is typically produced by combusting fossil fuels directly in kilns, furnaces and melters. Hydrogen can be used as clean-burning alternative either on its own, or blended with natural gas. However, since industrial facilities often have a unique design, the practicalities of fuel switching need to be assessed on a case-by-case basis.

Hydrogen could play a significant role by 2050 in the cement industry, where predominantly coal, oil and petcoke are used for heat. However, as fuel combustion only contributes 40% of the sector's emissions, other strategies such as clinker reduction and changing cement chemistries will also be required.

Electricity is already extensively used in the smelting step of primary aluminum production, and is the best technology to decarbonize heat in this process. However, alumina production, aluminum recycling and baking of electrodes for primary production rely on the combustion of natural gas and heavy fuel oil for high-temperature heat. Renewable hydrogen has medium potential to play a role in decarbonizing these processes.

Glass only uses a small fraction of industrial heat overall. However, the manufacturing process is very energy-intensive, as high temperatures are used to convert raw materials to molten glass. Hydrogen could technically replace fossil fuel use in the melting furnace and is likely to be economically competitive with some gas and oil (Figure 46).

Price

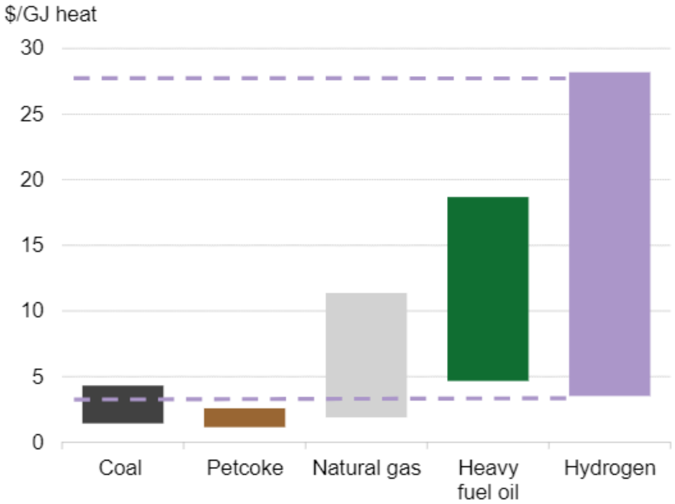
Hydrogen would be an expensive source of heat at our 2030 benchmark price of $2/kg, so is unlikely to play much of a role in decarbonizing high-temperature heat in the short to medium term (Figure 45). However, in the longer term if hydrogen prices fall to our benchmark of $1/kg in 2050, it would be a viable abatement option. At $1/kg, a carbon price of just $30/tCO2 would make hydrogen competitive with the cheapest fuel oil, $60/tCO2 would make it competitive with all coal and petcoke, and $90/tCO2 would make it competitive with the cheapest natural gas, based on today's prices.

Figure 45: Cost of heat, based on 100% energy conversion

Fuel	Unit	Energy content (GJ/unit)	Fuel cost ($/unit) Low	Fuel cost ($/unit) High	Heat cost ($/GJ) Low	Heat cost ($/GJ) High
Coal	tonne	27.8	$40	$120	$1.40	$4.30
Petcoke	tonne	34.8	$40	$90	$1.10	$2.60
Natural gas	MMBtu	1.055	$2	$12	$1.90	$11.40
Heavy fuel oil	tonne	42.8	$200	$800	$4.70	$18.70
Hydrogen	kg	0.142	$0.50	$4	$3.50	$28.20

Source: BloombergNEF. Note: Energy content is the gross calorific value.

Figure 46: Cost of fuel based on energy value



Source: BloombergNEF. Note: Energy content is the gross calorific value.

Volume

Overall, we estimate that 26-43% of high-temperature heat in the cement, aluminum and glass industries could be supplied by hydrogen in 2050. In a *Weak Policy* scenario, we assume hydrogen replaces 25% of fossil fuels used in cement and 10% of fossil fuels used in aluminum and glass. In a strong policies scenario, we assume hydrogen replaces 50% of fossil fuels in cement and 25% of fossil fuels used in aluminum and glass.

Power generation

Key points

- There is a high potential to use hydrogen in power generation.
- Renewable hydrogen becomes competitive with expensive gas-based open- and combined-cycle generation on a levelized-cost basis in countries like Japan at $1.2/kg
- A carbon price of $295/tCO2 in 2030 and $115/tCO2 in 2050 is required for hydrogen to compete with the cheapest natural gas on a total cost-of-energy basis.
- The power generation sector could deliver 6-219MMT of demand for hydrogen by 2050.

For our full assessment of using hydrogen in power generation, see: ***Hydrogen: The Economics of Power Generation*** (web | terminal)

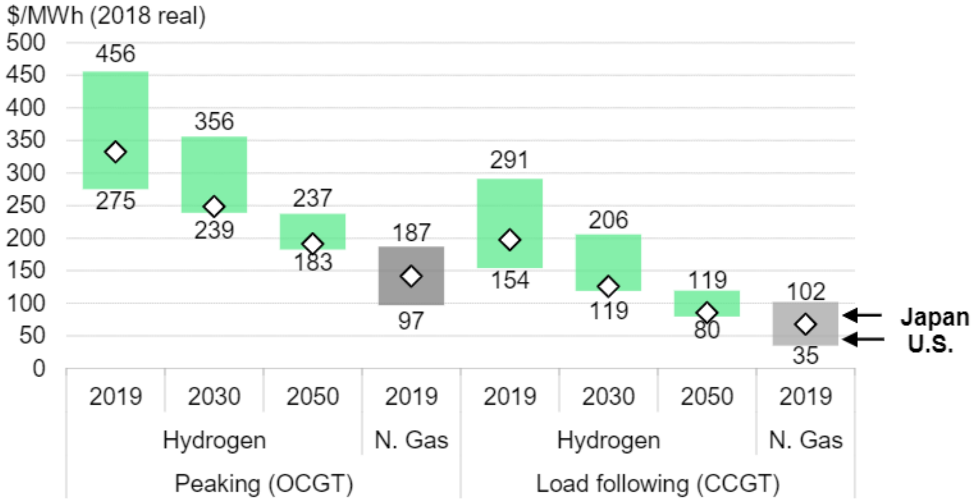
Hydrogen could be used to generate electricity and provide flexible and dispatchable power to complement wind and solar in the power system, potentially taking over the role currently played by natural gas. Hydrogen could be produced with excess renewable power, transported by pipeline, stored in a salt or rock cavern storage asset and then converted back to power through a fuel-cell or a combustion turbine, to meet electricity demand at times when the renewables output is low. Around 150 to 200 combustion turbines globally already operate with gases containing various proportions of hydrogen, mainly at chemical facilities where it is produced as a by-product.

Around 150 to 200 combustion turbines globally already operate with hydrogen

However, because hydrogen burns at very high temperatures, current combustion turbines running on pure hydrogen would emit high levels of NOx emissions (equivalent to old coal-fired power plants). To limit NOx emissions, diffusion combustors or scrubbers can be used, but add around 30% to the cost of a conventional gas turbines today. Pure hydrogen-burning turbines have a TRL of 5-6.

Along with turbines, fuel cells are a mature hydrogen power generation technology at TRL 9, with a relatively high efficiency (48-60% HHV). However, they are expensive, mainly because of the low number of units produced and the use of precious materials in electrodes. There are currently more than 1GW of stationary fuel cells installed, mainly in behind-the-meter applications running on hydrogen that is reformed inside the system from natural gas.

Figure 47: Potential LCOE of hydrogen-fuelled turbine power plants



Source: BloombergNEF Note: 'N. Gas' is natural gas. Natural gas LCOEs vary with fuel price: $2 (low) to $7 (mid) and $12/MMBtu (high) and do not include a carbon price.

By 2050, hydrogen power generation could compete with the cost of expensive natural gas power

Price

We estimate that stored renewable hydrogen could be supplied back to a generator at a cost of $1.7-3.3/kg by 2030 in most locations, achieving a levelized cost of electricity of $239-356/MWh for open-cycle peaking plants and $119-206/MWh for combined-cycle, load-following plants – that's about twice as expensive as similar natural gas power plants (Figure 47). By 2050, these hydrogen costs could fall to $1.1-1.9/kg, achieving an LCOE of $183-237/MWh for peaking and $80-119/MWh for load following, which would be low enough to compete with similar plant running on expensive natural gas at $12MMBtu.[73] However, a carbon price of about $181/tCO2 by 2030, and $55/tCO2 by 2050, will be required for hydrogen at $1.9/kg and $1.2/kg to compete with mid-cost natural gas at $6.5-7/MMBtu, which accounts for around 50% of global gas generation. At our benchmark hydrogen prices of $2/kg in 2030 and $1/kg in 2050, a carbon price of $295/tCO2 would be required in 2030, and $115/tCO2 in 2050, to compete with the cheapest natural gas at $2MMBtu, such as the gas extracting countries of the Middle-East. These carbon

[73] The delivered cost of renewable hydrogen is different to our default benchmarks of $2/kg in 2030 and $1/kg in 2050 in this section, as we make a conservative assumption that 100% of H2 should be stored for electricity generation (compared to 50% stored in the benchmark estimates). At the benchmark hydrogen price of $2/kg and $1/kg, a carbon price of $295/tCO2 and $115/tCO2 would be required to compete with the cheapest natural gas at $2MMBtu.

prices are on a new-build basis. If turbines are hydrogen-ready, then the carbon price required to fuel switch from $7/MMBtu gas to $1.2/kg hydrogen is only $32/tCO2.

Volume

If turbines are hydrogen-ready, then the carbon price required to fuel switch is only $32/tCO2

Overall, we estimate that there is high potential to use clean hydrogen to decarbonize dispatchable generation in the power sector. Demand could range from 6 to 219MMT by 2050.

In our *Weak Policy* scenario, we assume that utilities and developers in regions with mid-cost gas build new hydrogen generators when the prices justify, resulting in 25% of new build peaking plants and 50% of new load-following plants installed after 2045 using hydrogen.

In our *Strong Policy* scenario, we assume the majority of gas turbine peaking and load-following plants built after 2030 are hydrogen-ready, allowing 50% of the global gas fleet to switch to hydrogen by 2050, driven by carbon prices of around $100/t.

Building heat and gas network blending

Key points

- There is low to medium potential to use renewable hydrogen for building heat.
- The delivered cost of renewable hydrogen to small-scale users needs to fall to $1.30-4.00/kg to compete with gas boiler heating. This is unlikely before 2050 in most regions.
- A carbon price of $290/tCO_2$ in 2030 and $160/tCO_2$ in 2050 would be needed for renewable hydrogen to compete with the cheapest gas heating.
- Despite higher comparative costs, hydrogen use may be necessary to avoid costly upgrades to electricity networks if heat is to be decarbonized
- Building heat could deliver 21-53MMT of demand for renewable hydrogen by 2050

For our full assessment of using hydrogen for building heat, see: ***Hydrogen: The Economics of Space and Water Heating*** *(web | terminal)*

The economic viability of using hydrogen for building heat will come down to a city-by-city assessment

The heating of space and water in buildings is responsible for 6% of global greenhouse gas emissions due to the widespread use of gas, coal and oil. Renewable hydrogen could be blended and even fully substitute for natural gas to help decarbonize building heat, but significant challenges exist. The economic viability of using hydrogen for heat will depend on a city-by-city assessment of whether it will be cheaper to re-purpose the gas network, upgrade the electricity grid, or a combination of both, to provide clean heat.

Hydrogen can be blended into the existing natural gas network as an initial step to reduce the emissions of space and water heating. A blend of 5-20% by volume can be tolerated by most systems without the need for major infrastructure upgrades or end-use appliance retrofits or replacements. Blends were actually commonplace in the past, and the gas networks of Hawaii and Singapore currently still operate with 10% and 50% blends respectively. However, blending to 20% renewable hydrogen would reduce the carbon emissions associated with gas combustion by only 7%, due to the lower density of hydrogen compared to methane.[74] For deeper decarbonization, natural gas networks could be re-purposed to supply 100% hydrogen, but much

[74] Staffell, I., Scamman, D., Velazquez Abad, A., et al., 'The role of hydrogen and fuel cells in the global energy system', Energy & Environmental Science, 12(2), 463-491, 2019.

of the infrastructure would need to be modified or replaced.[75] Pipelines made of steel are generally not compatible due to the risk of hydrogen embrittlement, but distribution systems made with modern polyethylene pipes will face lower hurdles, as these are already fit for hydrogen distribution. End-use appliances would also need to be adjusted or switched. A study by Northern Gas Networks in the U.K. estimated that converting appliances would cost roughly $4,000-4,500 per household, which could more than double the total cost of a network upgrade.[76]

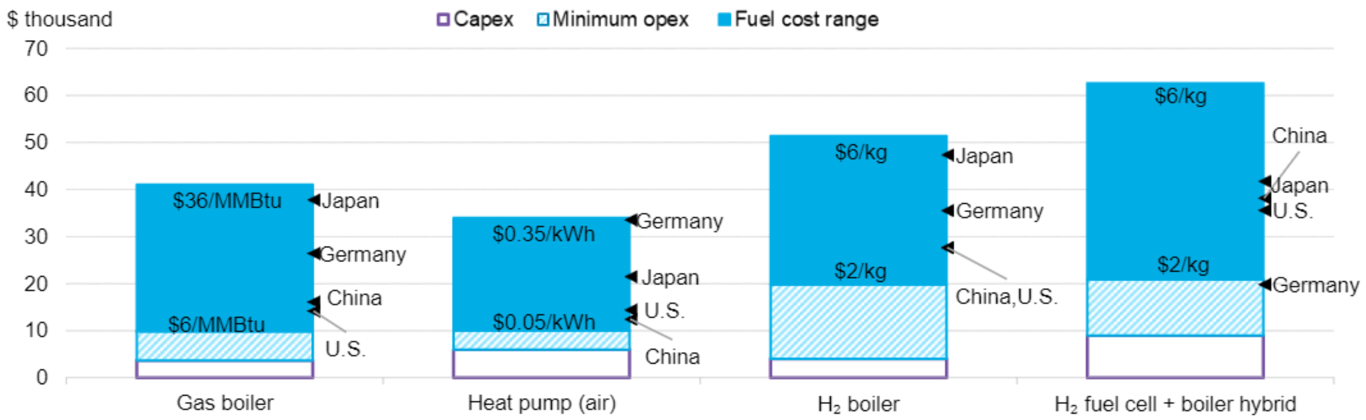
Price

To compete on cost with existing gas boiler heaters, the price of delivered hydrogen to residential customers would need to fall to between $1.30/kg and $4.00/kg, depending on location. This seems unlikely to occur by 2050 in most regions as delivery will probably add $1-4/kg on top of the cost of large-scale production at $1-2/kg.[77] Carbon prices could help bridge the gap, but would need to be very high, at around $290/tCO2 in 2030 and $160/tCO2 in 2050 in regions with very low retail natural gas prices like the U.S.

Volume

We think there is low to medium potential to use hydrogen for building heat. Demand could range from 21 to 53MMT by 2050. With current electricity and gas prices, the cheapest technology to decarbonize space heating will generally be an electric heat pump (Figure 48), provided the electricity supplied is clean and cheap. However, large-scale electrification of heat may put upward pressure on electricity prices, due to the cost of upgrading the grid to manage the extra load, as well as running more expensive peaker plants during the coldest weather. We therefore think hydrogen could be used in some locations to keep grid-upgrade costs down.

Figure 48: Lifetime costs based on future capital costs, expected fuel costs and moderate residential heating demand



Source: BloombergNEF. Note: Residential hydrogen price assumed is: $3/kg in China, $4/kg in Germany, $5.5/kg in Japan, $3/kg in the US. Lifetime cost for fuel cell includes savings from electricity production. Realized electricity value of $0.1/kWh is used, except for specified countries, where country's current benchmark retail electricity price is used. For air-sourced heat pumps, a COP of 3.5 is used for moderate heating demand.

75 For further details on the economics and practicalities of hydrogen blending into natural gas networks see Section 5.1 of *Hydrogen: The Economics of Transport and Delivery* (web | terminal).

76 Northern Gas Networks, H21 North of England feasibility study, 2018.

77 Delivery of gas to small residential customers through a comprehensive distribution network is likely to be more expensive than the estimates for large-scale delivery given in Section 6.3 due to low utilization rates and the longer distances involved

In our *Weak Policy* scenario, we assume that an average of 10% hydrogen by volume is blended into gas networks around the world, which is a low enough concentration to avoid the need to upgrade pipeline infrastructure and appliances. In our *Strong Policy* scenario we assume hydrogen plays a key role complementing electrification, and 25% of gas-based building heat globally is powered by hydrogen.

Road transport

Key points

- There is medium potential to use hydrogen to decarbonize road transport.
- A variety of fuel and capex subsidies are required to drive cost reductions. These are equivalent to carbon prices of $214/tCO2 on heavy-duty trucks, $138/tCO2 on busses powered by diesel, and $442/tCO2 on passenger vehicles powered by gasoline in 2030
- With subsidy-driven scale-up, long-haul, heavy-duty fuel cell trucks can become competitive with diesel in 2031-34 on a total cost of ownership basis. No subsidies would be required to compete with fossil fuels after this point.Road transport could deliver 117-265MMT of demand for hydrogen by 2050.

For our full assessment of using hydrogen in road transport, see: ***Hydrogen: Fuel Cell Vehicle Outlook*** (web | terminal)

For decades, hydrogen fuel cell electric vehicles (FCEVs) were considered the ultimate technology to reduce emissions from road transport. However, the explosive growth of battery electric vehicles since 2010 has cast significant doubt on the future market for FCEVs. And with a few exceptions such as Hyundai and Toyota, most auto manufacturers have significantly reduced their fuel cell vehicle programs.

Compared to battery electric vehicles, fuel cell vehicles have three significant disadvantages:

- The first disadvantage is there are no existing mass market applications for fuel cells, so to reduce costs by increasing scale, FCEV sales have to increase. In contrast, battery electric vehicle manufacturers have benefited from decades of lithium-ion batteries sales in consumer electronics.
- The second challenge is the lack of existing hydrogen refueling infrastructure, whereas battery electric vehicles can use the existing electricity grid.
- The third challenge is the price of hydrogen at the pump, which remains significantly more expensive than other transport fuels.

Despite all these challenges, we still expect fuel cell vehicle technology to play a role in the decarbonization of transport – particularly for moving heavy goods over long distances. Fuel cells have a higher power density than lithium-ion batteries and the range of a fuel cell vehicle can be increased by adding more hydrogen tanks while using the same fuel cell stack size. This means the marginal cost of increasing the range of a fuel cell drivetrain is cheaper than a battery electric drivetrain. Fuel cell vehicles can also be refueled faster than battery electric vehicles. All these advantages have garnered the attention of commercial vehicle manufacturers such as Cummins, and they are now exploring applications.

Fuel cells have a higher power density than lithium-ion batteries

Our analysis indicates that heavy-duty, long-haul commercial vehicles are the most economic application for fuel cells. It is notable that there are currently few supporting policies encouraging adoption of fuel cell drivetrains in this segment, with an exception being Switzerland's heavy vehicle road tax exemption. Instead most subsidies continue to be targeted at the passenger vehicle market, where FCEVs have struggled to compete with cheaper battery electric vehicles.

Price

The economics of fuel cells vehicles are highly scale- and path-dependent, so both price and volume vary in our two policy scenarios.

A subsidy of $17k per heavy-duty truck would be required to bridge the capital cost difference with diesel engines

In our *Weak Policy* scenario, subsidies for FCEVs remain limited to a few countries such as Japan and are focused mainly on passenger vehicles. As a result, there is slow uptake of fuel cell technology across all vehicle classes, the various national and regional deployment targets are not met, and the industry scales up slowly. The average cost of a fuel cell system for passenger vehicles (100kW stack) falls from $180/kW today, to $114/kW by 2030. Similarly, heavy-duty commercial vehicle stacks (300kW) fall to $119/kW by 2030. At the same time, hydrogen pump prices come down from the current average of $11.7/kg, to $7/kg. For hydrogen at $7/kg to be competitive with diesel at $4.2/gallon, an additional fuel subsidy or a carbon tax of $2.5/gallon of diesel would be required. In addition, average subsidies of $17k per heavy-duty truck, $23k per medium-duty truck, $51k per bus and $20k per passenger vehicle would still be required in 2030 to bridge the capital cost difference with the equivalent internal combustion engine models for each class. The combined fuel and capex subsidies required for FCEVs to be cost competitive in 2030 in this scenario are equivalent to carbon prices of $214/tCO2 on heavy-duty trucks, $138/tCO2 on busses powered by diesel at $4.2/gallon, and $442/tCO2 on passenger vehicle powered by gasoline at $2.95/gallon. Under this scenario, we estimate that cumulative fuel and capex subsidy expenditure between 2019 and 2030 would be $24 billion, almost evenly split between subsidies for vehicles and hydrogen fuel. With this pattern of cost reduction, fuel cell drivetrains for heavy-duty long-haul trucks become competitive with diesel trucks on a total cost-of-ownership basis by 2034. For other segments, fuel cell drivetrains become competitive with internal combustion engines by the mid-2040s. Once they are competitive, no further fuel or capex subsidies would be required to compete with fossil fuels. However, fuel cell vehicles do not beat battery electric vehicle drivetrains on cost, although their longer range and shorter refueling time will appeal to some consumers.

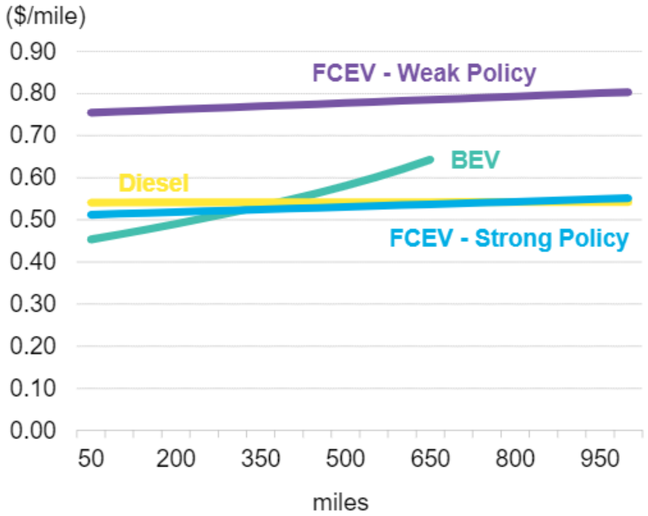
In the *Strong Policy* scenario, countries advocating fuel cell vehicle technology, such as Germany, Japan and Korea, increase and redesign their subsidy programs for the 2020-2030 period, with more support for the commercial vehicle segment. As a result, there is faster uptake of fuel cell technology across all vehicle classes, and current national and regional deployment targets are met. The average cost of a fuel cell system for passenger vehicles falls to $63/kW, and for heavy-duty commercial vehicles to $94/kW, by 2030. Hydrogen pump prices decline to $4/kg. At this price no fuel subsidies or carbon taxes would be needed for hydrogen to compete with average diesel prices, but subsidies would still be needed to make up for the higher upfront cost of fuel cell vehicle models. The combined fuel and capex subsidies required for FCEVs to be cost competitive in 2030 in this scenario are equivalent to carbon prices of $8/tCO2 on heavy-duty trucks, $31/tCO2 on busses powered by diesel at $4.2/gallon, and $94/tCO2 on passenger vehicles powered by gasoline at $2.95/gallon. Cumulative subsidy expenditure between 2019 and 2030 would be $105 billion, with 57% of subsidies for vehicles. In this scenario, fuel cell drivetrains for heavy-duty long-haul trucks become competitive with diesel trucks on a total cost-of-ownership basis by 2031 (Figure 49). For other segments, fuel cell drivetrains become competitive with internal combustion engines by the mid-2030s, but they still do not beat battery electric vehicle drivetrains on cost (Figure 50).

Volume

In our *Weak Policy* scenario, there are only 480,000 FCEV vehicles (across all classes) on the road in 2030. In 2050, fuel cell vehicles account for 2.5% of the light-duty vehicle fleet (passenger vehicles as well as light commercial vehicles), 2.5% of the medium-duty commercial vehicle fleet, 8% of the bus fleet and 25% of the heavy-duty commercial vehicle fleet (primarily long-haul class 8 trucks). In total, 117MMT of hydrogen is needed in 2050 to meet demand from road transport in this scenario, 91% of this for heavy-duty trucks.

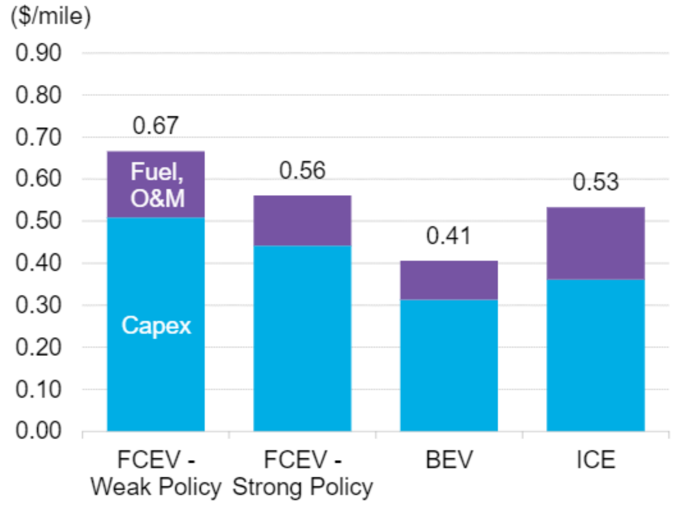
In our *Strong Policy* scenario, 3.7 million FCEV vehicles (across all classes) are on the road in 2030. In 2050, we assume fuel cell vehicles serve the portion of the road transport fleet which battery electric vehicles may not suit due to range or payload requirements. We assume this to be 10% of the light-duty vehicle fleet (adopted by consumers having long-range requirements), 25% of the medium-duty commercial vehicle fleet, 24% of the bus fleet and 50% of the heavy-duty commercial vehicle fleet. In total, 265MMT of hydrogen is needed in 2050 to meet demand from road transport in this scenario, 80% of this for heavy-duty trucks.

Figure 49: Total cost of ownership of heavy-duty trucks in the U.S. by range, 2030



Source: BloombergNEF

Figure 50: Total cost of ownership of SUVs in the U.S., 2030



Source: BloombergNEF

Shipping

Key points

- There is medium potential to use hydrogen-derived green ammonia (NH3) in shipping.
- Hydrogen will not be able to compete with fossil fuels in shipping without a carbon price.
- A carbon price of $227/tCO_2$ in 2030 and $145/tCO_2$ in 2050 would be required for hydrogen to compete with the cheapest fuel oil.
- Shipping could deliver 6-36MMT of demand for hydrogen by 2050.

For our full assessment of using hydrogen in shipping see, ***Hydrogen: The Economics of Powering Ships*** *(web | terminal)*

Ammonia ship engines appear to be the most promising option

Hydrogen can also be used as a fuel to power maritime transport vessels. There are three main technologies for the propulsion system – fuel cells, hydrogen engines, or ammonia engines.

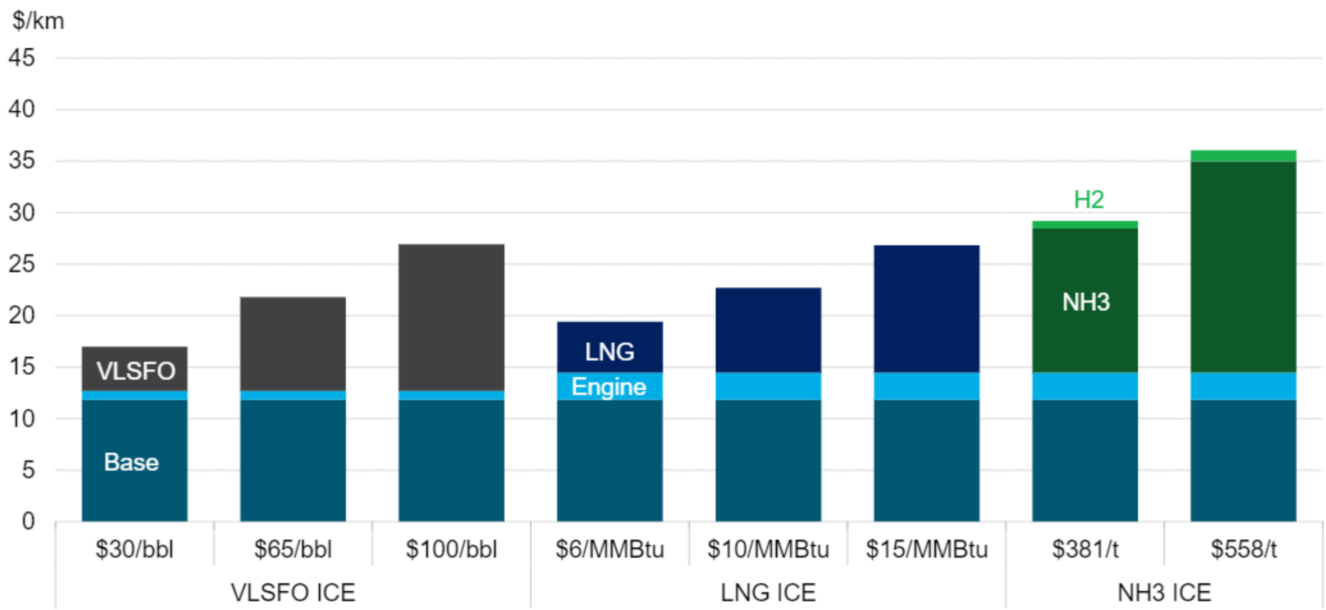
The use of green ammonia derived from renewable hydrogen appears to be the most promising option because it takes up less space than hydrogen, and freight ship economics are highly sensitive to volume requirements. It is also likely to be able to piggyback on existing storage and handling infrastructure for liquefied natural gas, which is increasingly being used as an alternative to heavy fuel oil.

Ammonia can be used at up to 95% concentrations to power an internal combustion engine.[78] The combustion of green ammonia produces no carbon emissions, although a selective catalytic reduction (SCR) unit is needed to reduce NOx emissions. However, the technology is still at an early stage, with a TRL of 3.

Price

At our benchmark hydrogen price of $2/kg in 2030, and $1/kg in 2050, we estimate that renewable ammonia could be supplied to a ship for $558/t and $381/t, including distribution and port storage costs. A carbon price of $108/tCO2 in 2030, and $27/tCO2 in 2050, would be needed for a bulk carrier powered by a green ammonia internal combustion engine (ICE) to be cost-competitive with the most expensive very low sulfur fuel oil (VLSFO) ICE bulk carrier with a fuel price of $100/bbl, on a total cost of ownership basis (Figure 51). A carbon price of $227/tCO2 in 2030 and $145/tCO2 in 2050, would be required for green ammonia to be cost-competitive with the cheapest VLSFO at $30bbl.[79]

Figure 51: The total costs of ownership (TCO) of a bulk carrier with various drivetrains and into-ship fuel costs



[78] Hydrogen or another hydrocarbon needs to be blended with ammonia due to its high auto-ignition temperature and narrow flammability limits which make combustion of the pure compound difficult.

[79] Assuming the current cost of both ammonia and VLSFO engines and vessels.

Source: BloombergNEF, IMO[80], thinkstep[81], IEA[82]. Note: VLSFO – very low sulfur fuel oil, LNG – liquefied natural gas, NH3 – ammonia, ICE – internal combustion engine. Vessel output assumed at 12MW. VLSFO stands for 0.5% sulfur fuel oil, which we will use as a representative of oil bunker fuels. NH3 ICE assumes the theoretical minimum CO_2 exhaust emission achievable. Total cost of ownership includes delivery, storage and other costs. A small amount of hydrogen is included in the NH3 vessel TCO because it is required a fuel additive to enable combustion in an engine. Ammonia prices of $381/t and $558/t reflect the green hydrogen prices of $2/kgH2 (expected by 2030) and $1/kgH2 (expected by 2050), as well as approximated distribution and port storage costs. TCO analysis does not take into account cargo revenue loss. Assumes current cost and efficiency of VLSFO, LNG and NH3 engines and vessels.

Volume

Overall we think there is medium potential to use renewable hydrogen to decarbonize shipping. Demand could range between 6 and 36MMT in 2050.

In our *Weak Policy* scenario, we assume that the 2050 emissions target by the International Maritime Organization (IMO) – to reduce absolute carbon dioxide emissions from international shipping by 50% from the 2008 levels – is ratified and results in the use of renewable ammonia for 10% of bunker fuel demand.[83] In our *Strong Policy* scenario we assume that a target is set for absolute maritime carbon dioxide emissions to reach net-zero by 2070. This would likely drive a large proportion of the ship fleet to adopt ammonia engines, resulting in around 58% of bunker fuel demand being met by renewable ammonia in 2050, with the remainder still fueled by oil.

6.2. Abatement potential

The bottom-up, sector-by-sector analysis presented in the previous sections shows that at a delivered price of $1/kg in 2050, hydrogen could enable emission reductions across many of the hard-to-abate sectors at surprisingly low costs. Figure 52 below shows the 2018 greenhouse gas emissions of all the sectors hydrogen could be used for, and the carbon price that would be required for hydrogen at $1/kg to compete with the cheapest fossil fuel in each use case.

In 2018, emissions from all sectors where hydrogen could be used amounted to 12.3GtCO2,[84] or 34% of global greenhouse gas emissions from fossil fuels and industry.[85] This analysis suggests that up to 7.4Gt or 20% of emissions in 2018 could be decarbonized with the use of hydrogen for a carbon price of less than $100/tCO2.

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80 IMO LNG Study (2016)

81 Thinkstep (2019), Life Cycle GHG Emission Study on the Use of LNG as Marine Fuel

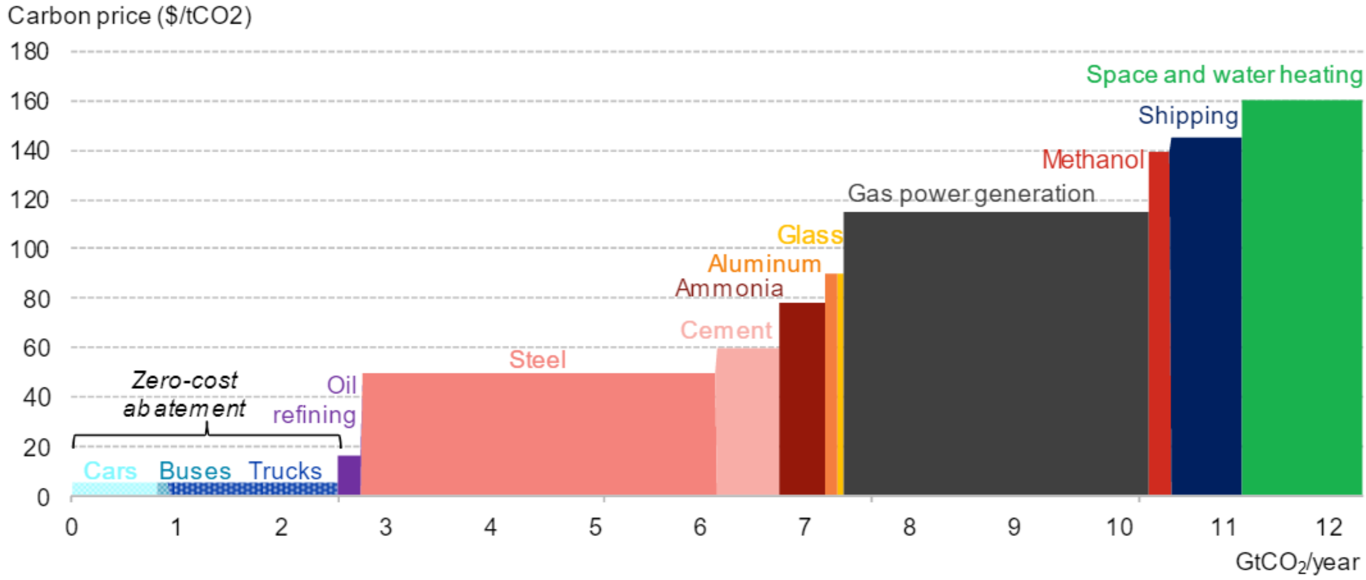
82 IEA Future of Hydrogen (2019)

83 Given the projected growth of ship bunker fuel demand, the use of LNG and efficiency measures alone will not be able to meet the IMO 2050 target. For details see: *Hydrogen: The Economics of Powering Ships* (web | terminal)

84 Only the portion of emission which hydrogen can viably abate are included for each sector: Aluminum emissions for alumina production and aluminum recycling only; cement emissions for process heat only; oil refining emissions from hydrogen production only; road transport and heating demand emissions are for the segment that is unlikely to be met by electrification only, assumed to be 50% of space and water heating, 25% of light-duty vehicles, 50% of medium-duty trucks, 30% of busses and 75% of heavy-duty trucks.

85 Global greenhouse gas emissions from fossil fuels and industry are estimated as 36.6MtCO2e in 2018. For details see Global Carbon Budget, Summary Highlights, Global Carbon Project, 2019.

Figure 52: Marginal abatement cost curve from using $1/kg hydrogen for emission reductions, by sector in 2050



Source: BloobmergNEF. Note: sectoral emissions based on 2018 figures, abatement costs for renewable hydrogen delivered at $1/kg to large users, $4/kg *to road vehicles. Aluminum emissions for alumina production and aluminum recycling only. Cement emissions for process heat only. Refinery emissions from hydrogen production only. Road transport and heating demand emissions are for the segment that is unlikely to be met by electrification only, assumed to be 50% of space and water heating, 25% of light-duty vehicles, 50% of medium-duty trucks, 30% of buses and 75% of heavy-duty trucks.*

6.3. Scenarios for long-term demand

Adding together the sector-by-sector estimates in the previous sections, we project that potential demand for hydrogen in the year 2050 could range between 187MMT in the *Weak Policy* scenario and 696MMT in the *Strong Policy* scenario. Table 14 and Figure 53 summarize the estimates by application for each policy scenario. The theoretical maximum demand for clean hydrogen if the entire sector was to switch to a hydrogen-based process is also given.

Weak Policy scenario

In the *Weak Policy* scenario, hydrogen would play a minor role in meeting the energy needs of the hard-to-abate sectors. We estimate that demand for zero- and low-carbon hydrogen could rise to 187MMT by 2050. Hydrogen would supply 27EJ of energy in the global economy, enough to meet 4% of projected final energy needs in 2050 with current policies,[86] or 7% in a 1.5 degree scenario.[87] Annual sales of hydrogen would be $187 billion in 2019 dollars (based on a $1/kg delivered price), with tens of billions more also spent on equipment and infrastructure.

[86] Final energy consumption with current policies is assumed to be 643EJ in 2050. This is based on an extrapolation of final energy demand from 2030 to 2040 in the International Energy Agency's, World Energy Outlook, 2019, Current Policies Scenario.

[87] Final energy consumption in a 1.5°C scenario is assumed to be 405EJ in 2050. This is based on the median value for all pathways limiting global warming below 1.5°C, or 1.5°C with limited overshoot, in the Intergovernmental Panel on Climate Change's, Special Report: Global Warming of 1.5°C, 2018.

Strong Policy scenario

In the strong policy scenario, hydrogen would play a major role in meeting the energy needs of the hard-to-abate sectors. We estimate that demand for zero- and low-carbon hydrogen could rise to 696MMT by 2050. Hydrogen would supply 99EJ of energy in the global economy, enough to meet 15% of projected final energy needs in 2050 with current policies,[86] or 24% in a 1.5 degree scenario.[87] Annual sales of hydrogen would be worth $696 billion in 2019 dollars (based on a $1/kg delivered price), with hundreds of billions more also spent on equipment and infrastructure.

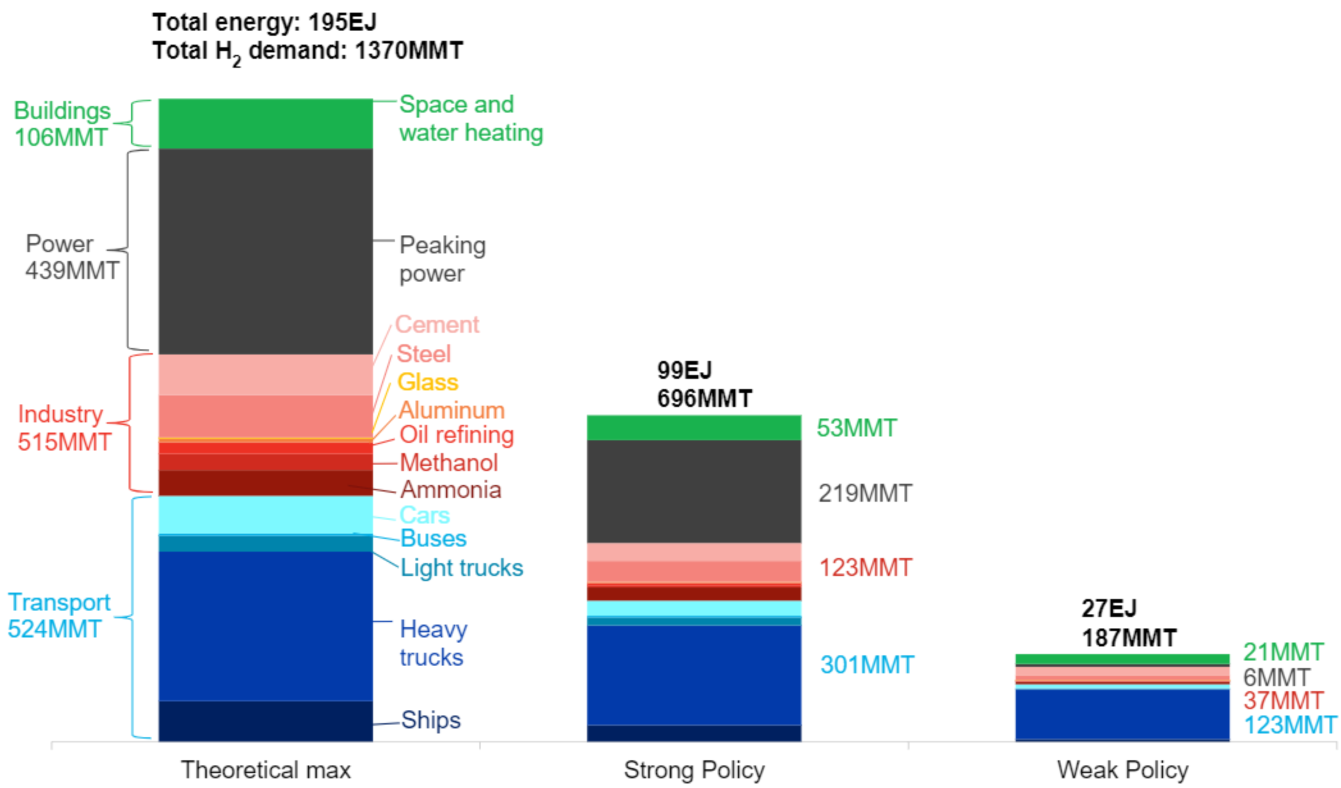
Table 14: Potential demand for clean hydrogen in different policy scenarios, 2050

Sector	Application	Max theoretical demand (MMT)	*Weak Policy*		*Strong Policy*	
			MMT	Reasoning	MMT	Reasoning
Buildings	Space and water heating	106	21	All gas networks globally injected with 10% hydrogen	53	Large electrification costs lead to 25% of gas-based building heat switching to hydrogen
Power	Peaking power	439	6	25% of peaking and 50% of load following plants built after 2045	219	50% of gas peaking and load following generation
Industry	Cement	87	19	Replace 25% of coal & petcoke	38	Replace 50% of coal & petcoke
	Steel	90	9	50% of steel plants built after 2030 use hydrogen	45	50% of all steel production
	Glass	2	0	Replace 10% of all fossil fuels	1	Replace 25% of all fossil fuels
	Aluminum	8	1	Replace 10% of all fossil fuels	2	Replace 25% of all fossil fuels
	Oil refining	25	2	8% of dedicated H_2 production	6	50% of dedicated H_2 production
	Methanol	34	1	10% of plants built from 2030	3	10% of all production
	Ammonia	55	5	50% of new plants from 2030	28	50% of all production
Transport	Cars	80	8	2.5% of passenger vehicle fleet	32	10% of passenger vehicle fleet
	Buses	5	1	8% of bus fleet	4	24% of bus fleet
	Light trucks	34	2	2.5% of medium-duty trucks	17	25% of medium-duty trucks
	Heavy trucks	319	106	25% heavy-duty trucks	212	50% heavy-duty trucks
	Ships	87	6	10% of bunker fuels green ammonia	36	58% of bunker fuels green ammonia
Total hydrogen demand		**1,370MMT**	**187MMT**		**696MMT**	
Total final energy served		**195EJ**	**27EJ**		**99EJ**	
Total (hydrogen % of final energy demand)*		**30-48%**	**4-7%**		**15-24%**	

*Source: BloombergNEF. Note: Aluminum demand is for alumina production and aluminum recycling only. Cement demand is for process heat only. Refinery demand is for hydrogen use only. Road transport and heating demand that is unlikely to be met by electrification only, assumed to be 50% of space and water heating, 25% of light-duty vehicles, 50% of medium-duty trucks, 30% of buses and 75% of heavy-duty trucks. *Low estimate of hydrogen percent of final energy demand based on assumption of 643EJ final energy demand in 2050 (extrapolation of IEA Current Policies Scenario); high estimate based on assumption of 405EJ in 2050 (average of 1.5°C compatible pathways analysed by the IPCC).*

It should be noted that neither of these scenarios represents a quantitative assessment of the amount of hydrogen use needed to achieve net-zero global emissions by 2050 (in order to limit warming to 1.5 degrees). If a majority of nations enforce emission caps to achieve net-zero by 2050, demand for hydrogen could be higher than either of these scenarios. The exact proportion would depend on the role that other decarbonization pathways also play, including direct electrification, biofuels, CCS, a circular economy, modal shifts and demand destruction. We estimate that if hydrogen is used to meet all of the unlikely-to-electrify energy demand in each sector, demand would total 1,370MMT – equivalent to 195EJ or 30% of projected final energy needs in 2050 with current policies and sectoral growth trends.[86,88] Alternatively, if policy measures to meet emission targets and promote the use of hydrogen do not materialize, then demand is unlikely to increase outside of current uses.

Figure 53: Potential demand for hydrogen in different scenarios, 2050



Source: BloombergNEF. Note: Aluminum demand is for alumina production and aluminum recycling only. Cement demand is for process heat only. Oil refining demand is for hydrogen use only. Road transport and heating demand that is unlikely to be met by electrification only: assumed to be 50% of space and water heating, 25% of light-duty vehicles, 50% of medium-duty trucks, 30% of buses and 75% of heavy-duty trucks.

88 In the road transport and space and water heating sectors we only consider the portion of demand that is unlikely to be met by electrification in this total. This is assumed to be 50% of space and water heating, 25% of light-duty vehicles, 50% of medium-duty vehicles, 30% of busses and 75% of heavy-duty vehicles.

Section 7. Electricity, land and water

If a hydrogen economy develops, massive amounts of electricity, land and water will be required to manufacture hydrogen. Producing 696MMT of renewable hydrogen would require 31,320TWh of electricity, which is more power than the world currently generates. Add this to projected electricity demand in a 1.5 degree scenario, and total renewable energy generation excluding hydro would need to top 60,000TWh, compared to under 3,000TWh today. China, Japan, Korea and parts of Europe and South East Asia are unlikely to have enough available land to generate the renewable power required. Imports of clean energy will likely be needed, which hydrogen can facilitate. Production from fossil fuels with CCS could also play a significant role.

In Section 6 above we estimated that if supportive policy materializes, demand for clean hydrogen could reach 696MMT in the year 2050, enough to supply 24% of final energy needs in a 1.5 degree scenario. In this section, we examine the physical constraints that may exist to producing hydrogen at this scale. Section 7.1 considers the amount of wind and PV capacity that would be needed to produce hydrogen entirely from renewables, and also supply enough electricity to meet a broader 1.5 degree climate goal. Section 7.2 estimates the amount of land that would be needed to produce this amount of energy, and whether sufficient wind and solar resources exist to do so. Section 7.3 estimates the amount of water that would be consumed for hydrogen production.

7.1. Electricity demand

Producing clean hydrogen will require large amounts of renewable electricity. But demand for renewable electricity is likely to grow for other uses too, particularly if climate goals are to be met. To consider whether enough power can be generated on the whole, we consider both sources of electricity demand below.

Electricity demand for hydrogen production

We estimate that producing the 696MMT of hydrogen per year entirely from water electrolysis would require 31,320TWh of electricity.[89] This is more than total global electricity generation in 2019, which we estimate to be around 26,653TWh.[90] To generate that amount of electricity entirely from renewables would require something like 6.0TW of wind and 6.3TW of PV capacity, together powering 8.3TW of electrolyzers.[91] This is nearly 10 times the current combined installed capacity of wind and PV, which stood at 1.3TW at the end of 2019.

[89] This figure is calculated assuming electrolyzer efficiency of 45kWh/kgH2

[90] For details see: BloombergNEF, *New Energy Outlook 2019* (web | terminal)

[91] This assumes an average electrolyzer utilization rate of 43%, with 30% of production from wind electricity, 40% from PV, and 30% from hybrid sites of wind + PV.

Electricity demand for broader decarbonization

Achieving emissions reductions in line with a 1.5 degree climate pathway will also require a massive increase in electrification and renewable energy deployment. To quantify this, we consider scenarios from the International Energy Agency and Intergovernmental Panel on Climate Change, which offer insight into the scale and shape of a decarbonized energy system (see box below).

The four changes needed to decarbonize the energy system

According to the IEA's World Energy Outlook, in 2018 the global economy consumed a total of 417EJ of energy.[92] Electricity made up around 19%, or 22,271TWh, with wind and PV providing just 8.3% of total electricity. The remaining 81%, or 337EJ, of final energy was consumed in the form of molecule-based fuels like coal, oil, gas and biomass, or provided directly as heat.

An extrapolation of the IEA's Current Policies Scenario to 2050 suggests that if the world continues along its present path, without any additional changes in policy, the global economy is on track to consume around 643EJ of energy by mid-century as population and economies expand.[93] This is a 54% increase from 2018. The Current Policies Scenario offers a sobering perspective on the future energy sector, with electricity expanding to just 25%, or 44,739TWh, leaving molecule-based energy to provide the remaining 75%. Without a zero-carbon alternative for molecular fuels, this scenario would see fossil fuel use increase considerably – and a catastrophic rise in global greenhouse gas emissions.

To change course, four significant changes are needed. The pathways analyzed by the Intergovernmental Panel on Climate Change offer a perspective of what it might take to achieve an emissions trajectory that limits global temperature rise to 1.5°C above pre-industrial levels.[94] First, it suggests the energy efficiency of the global economy would need to improve radically to restrict final consumption to around 405EJ, while still providing energy services to billions more people. Second, it asserts that electricity would need to be generated almost entirely from zero- or low-carbon sources. Third, it argues the proportion of final energy consumption met by electricity would need to increase to around 53%, or 216EJ, via massive electrification. This is equivalent to 59,883TWh of generation. And fourth, it suggests the remaining 47%, or 190EJ, of energy consumed in the form of molecule-based fuels would need to have very low emissions intensity. This is effectively the potential market for a clean molecule like hydrogen, for bioenergy and for continued use of fossil fuels with CCS. The IEA and IPCC scenarios are shown in Figure 54.

The IPCC analysis suggests that electricity demand will need to rise to 59,883TWh in 2050 through massive electrification to limit warming to 1.5°C. The majority of this electricity will also need to be produced from zero-carbon sources. Assuming that half of this generation comes from variable renewables – 30% wind and 20% PV – we estimate that 5TW of wind and 8TW of PV

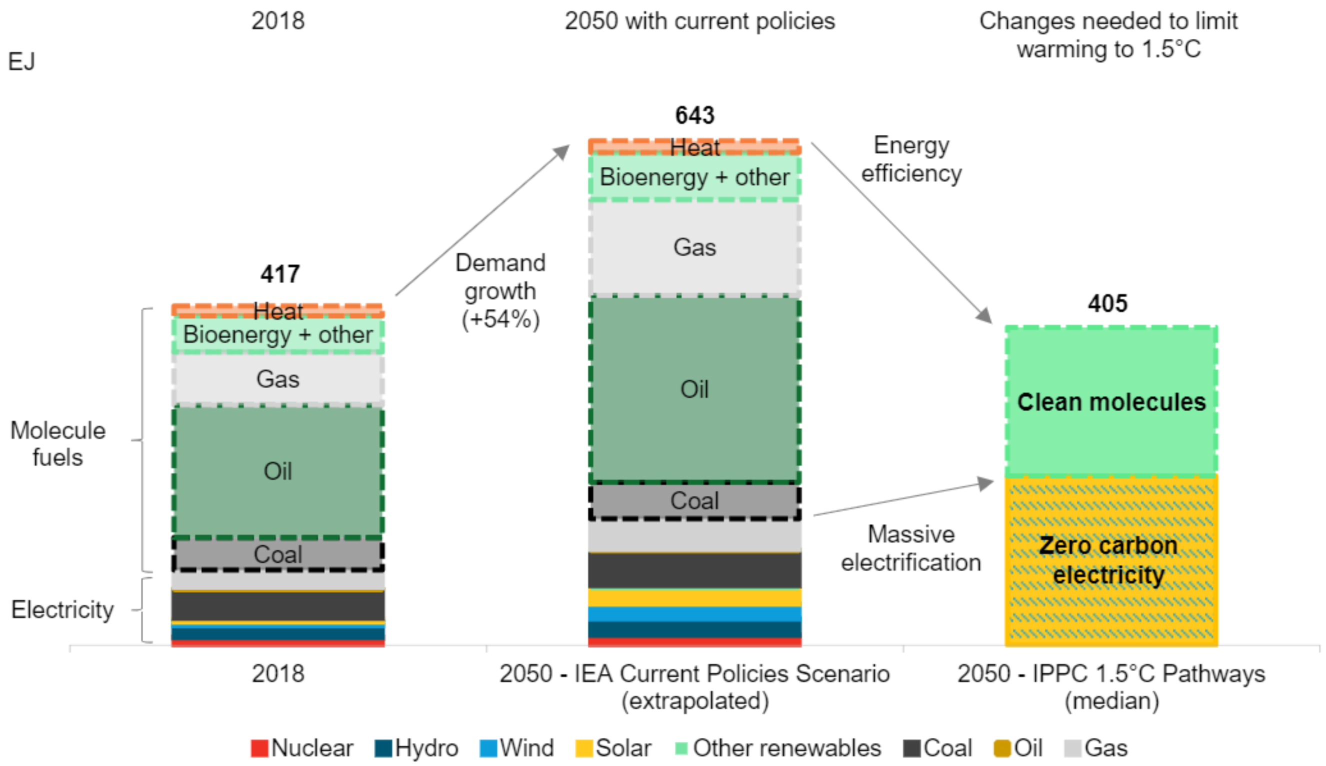
[92] This figure is total final energy consumption. International Energy Agency, *World Energy Outlook*, 2019

[93] The World Energy Outlook 2019 only produces a forecast up to 2040. We have extrapolated the increase between 2030 and 2040 in the IEA's Current Policies Scenario to approximate final energy consumption in 2050.

[94] Intergovernmental Panel on Climate Change, *Special Report: Global Warming of 1.5°C*, 2018. Note: Final energy consumption of 405EJ and the share met by electricity of 53% are the median value for all pathways limiting global warming below 1.5°C, or 1.5°C with limited overshoot.

capacity might be required worldwide for the electricity grid in 2050.[95, 96, 97] When imbalances exist between supply and demand, excess electricity could be diverted to produce hydrogen (see box below).

Figure 54: Projections for global final energy consumption in 2050 with current policies, and the changes required to limit warming to 1.5°C



Source: BloombergNEF, IEA, IPCC. Note: The IEA's Current Policies Scenario is extrapolated using data form 2030 and 2040 to approximate final energy consumption in 2050. The 1.5°C compatible pathway is the median value for the 53 pathways analysed by the IPCC limiting global warming below 1.5°C, or 1.5°C with limited overshoot.

Total electricity demand

In total, 61,261TWh of wind and solar generation might be required to produce both 100% of hydrogen and 50% of electricity for the grid in a 1.5 degree scenario in 2050. Splitting that figure by technology would mean around 11TW of wind and 14TW of PV capacity.

95 This assumption is consistent with the results of the 2 degrees scenario in BloombergNEF's New Energy Outlook 2019. In this, wind roughly provides 30% and PV 20% of global electricity, and curtailment averages 15% across the world.

96 The remaining 50% of generation for the electricity grid would need to be provided by other low-carbon sources, such as hydro, nuclear, biomass, fossil-fuels with CCS or by power generated from hydrogen.

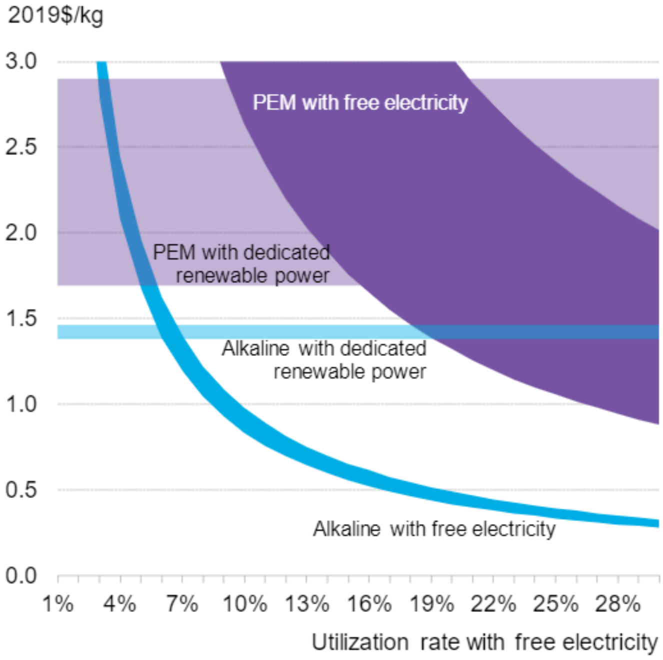
97 Wind and PV capacity in these figures is based on an average global capacity factor of 42% for wind and 16% for PV. Curtailment is not factored in, as we assume the hydrogen production sector absorbs imbalances in the power system. Wind and PV generation from the power system is diverted to hydrogen production at times of surplus (preventing curtailment); and at times of deficit, extra electricity is made available to the grid by reducing hydrogen production (removing the need for overbuild in the power system).

How much hydrogen could be produced from curtailment?

Our New Energy Outlook 2019 modelling for *2 degrees* suggests that if 50% of global electricity demand is met by wind and PV, around 15% of all generation would be curtailed due to mismatches in renewable supply and power demand.[98] Applying this to the median value for electricity demand in the 1.5 degree compliant pathways analyzed by the IPCC suggests that curtailment could amount to 10,715TWh in 2050. This could potentially produce 238MMT of hydrogen – or enough to supply around 34% of hydrogen demand in our *Strong Policies* scenario. In reality, it is unlikely that *all* curtailed power could be converted to hydrogen, as viability will vary on a project-by-project basis, depending on the electrolyzer utilization achievable at each site, and whether a physical route to market exists.

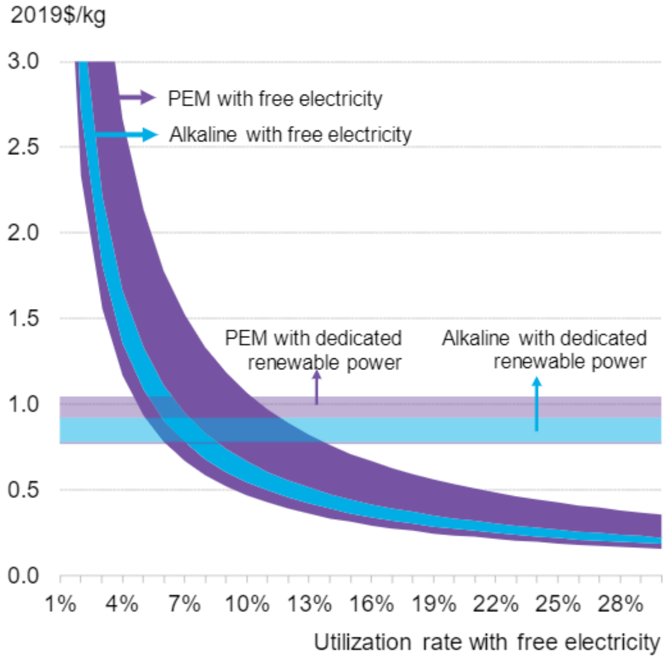
But assuming there is zero-cost electricity, the economics of powering an electrolyzer with otherwise curtailed electricity could be very attractive. This is particularly true if the electrolyzer is located at, or close to, the power asset and can avoid grid fees. By 2030, the capex of an electrolyzer should become low enough that a utilization rate of 6-7% is enough to make production from curtailed electricity on-par with the cost of a dedicated large-scale producer (Figure 55). If a utilization rate of 15% can be achieved with zero-cost electricity, the cost of hydrogen from an alkaline electrolyzer could be just $0.6/kg in 2030 and $0.4/kg in 2050 (Figure 56).

Figure 55: Levelized cost of hydrogen – electrolyzer powered by zero-cost electricity, 2030



Source: BloombergNEF. Note: Large electrolysis systems are assumed here with 100MW scale.

Figure 56: Levelized cost of hydrogen – electrolyzer powered by zero-cost electricity, 2050



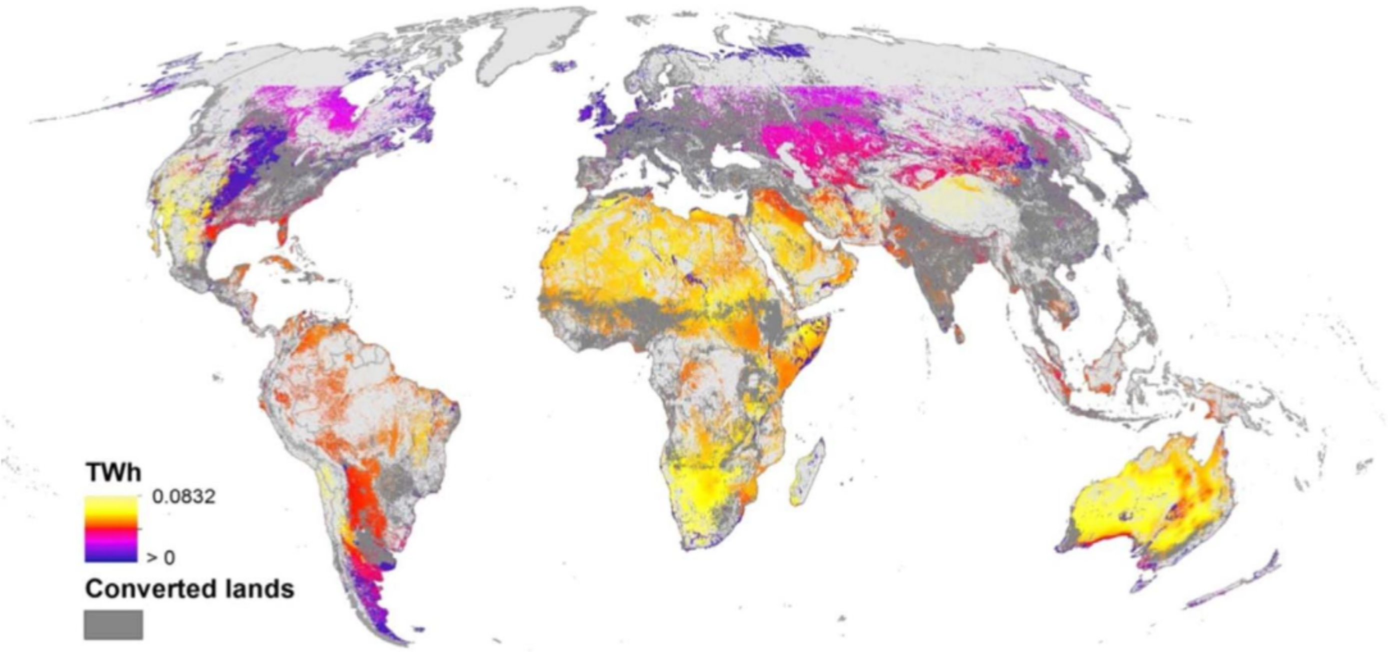
Source: BloombergNEF. Note: Large electrolysis systems are assumed here with 400MW scale.

98 Curtailment occurs when there is an excess of renewable generation relative to demand, or when grid constraints prevent a renewable asset from supplying power to the market.

7.2. Land and resource constraints

Some observers may question if there is enough land and renewable energy resource to generate this amount of power, because renewables requires much more space than extracting and processing fossil fuels.[99] A 2018 academic study by Baruch-Mordo et al. conservatively estimates that the total technical potential to generate electricity from solar (utility-scale, rooftop and solar thermal), onshore wind and hydro on all converted lands[100] combined equates to 185,827TWh, or 669EJ (see Appendix B).[101,102] This is 65% more than median final energy consumption (of all energy) according to the IPCC 1.5 degree pathways. Figure 57 shows the authors' modelling of the converted land area with technical potential for wind and solar electricity generation.

Figure 57: Converted land overlaid by maximal wind and solar technical potential



Source: Baruch-Mordo et al, 2018. Note: converted lands are terrestrial landscapes or freshwater systems already impacted by human activities.

If there is technically enough wind and solar potential to meet over 100% of total final energy in 2050, then we can conclude there is enough to produce both electricity and hydrogen in the scenario described above. However, local land or renewable constraints might still prevent countries from meeting their requirements using domestic resources alone.

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99 A study by Zalk, J. & Behrens, P., found that solar and wind power needs around 40-50 times more space than coal and 90-100 times more space than gas.

100 Converted lands are defined as terrestrial landscapes or freshwater systems already impacted by human activities (e.g. human settlements, agriculture lands, roads, and dams). The potential of offshore wind was not considered in this research.

101 Baruch-Mordo, S. et al, *From Paris to practice: Sustainable implementation of renewable energy goals*, Environmental Research Letters, December 2018.

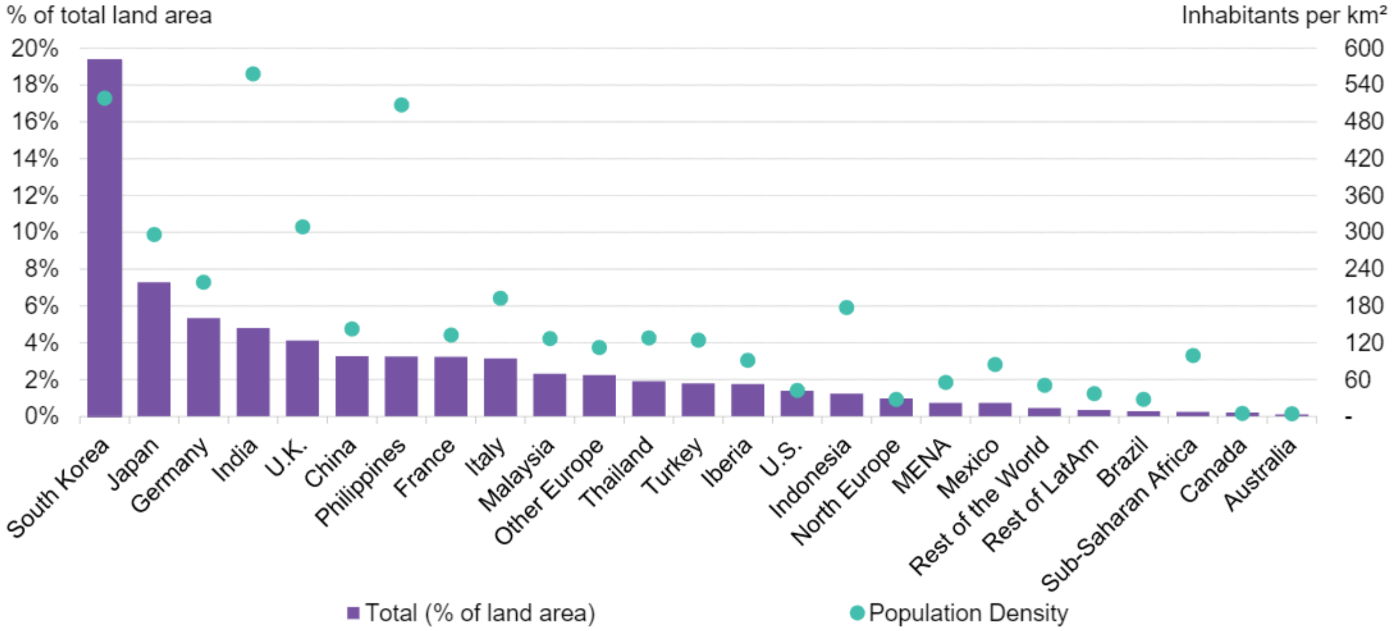
102 The methodology used by Baruch-Mordo to estimate potential renewable generation is conservative, and may underrepresent the amount of wind and PV generation achievable in some locations. We have excluded countries where the estimate for potential generation is below current levels.

The land requirement itself is significant. Assuming an area of 22km² per GW for utility-scale PV and 76km² per GW for onshore wind, 11TW of wind and 14TW of PV capacity would take up around 1,150,580 square kilometres. This is an area larger than Colombia, the 26th largest country in the world.[103]

Land requirements by country

To assess which countries could be self-sufficient in renewable energy for electricity generation and hydrogen production in a future decarbonized economy, we have estimated the fraction of landmass needed for wind and PV, by country, to meet indicative demand.[104] This calculation suggests South Korea would need to dedicate the largest fraction of its landmass to wind and PV, at 19%. For Japan that number is 7%. Others needing to commit large fractions of total landmass to renewables are Germany and India 5%, the U.K. 4%, and China 3%. However, others such as Australia, Canada, Sub-Saharan Africa and Latin America would need less than 1% of their landmass. These estimates and current population density by country are summarized in Figure 58.

Figure 58: Indicative estimate of the percentage of land occupied by renewables in a 1.5 degree scenario



Source: BloombergNEF. World Bank, Baruch-Mordo. Note: Estimate for the amount of land required to accommodate 11TW of wind and 14TW of utility PV capacity globally, geographically distributed in proportion to projected electricity demand by country in 2050. We have assumed a 22km²/GW for utility-scale PV and 76km²/GW for onshore wind. Land requirements for onshore wind includes only the foundation of the turbine as the area between turbines can be used as farm land or pasture.

[103] Land requirements for onshore wind only include the foundation of the turbine as the area between turbines can be used as farm land or pasture. Offshore wind is not considered in this analysis, but could play a significant role reducing the land area required.

[104] Indicative future hydrogen and electricity demand based on a simplistic assumption that these are proportional to electricity demand in 2050 from the *New Energy Outlook 2019*; that each country produces 100% of hydrogen and 50% of electricity from wind and PV in 2050. In reality, hydrogen demand, and the amount of hydrogen and electricity demand met by wind and PV is likely to vary by country.

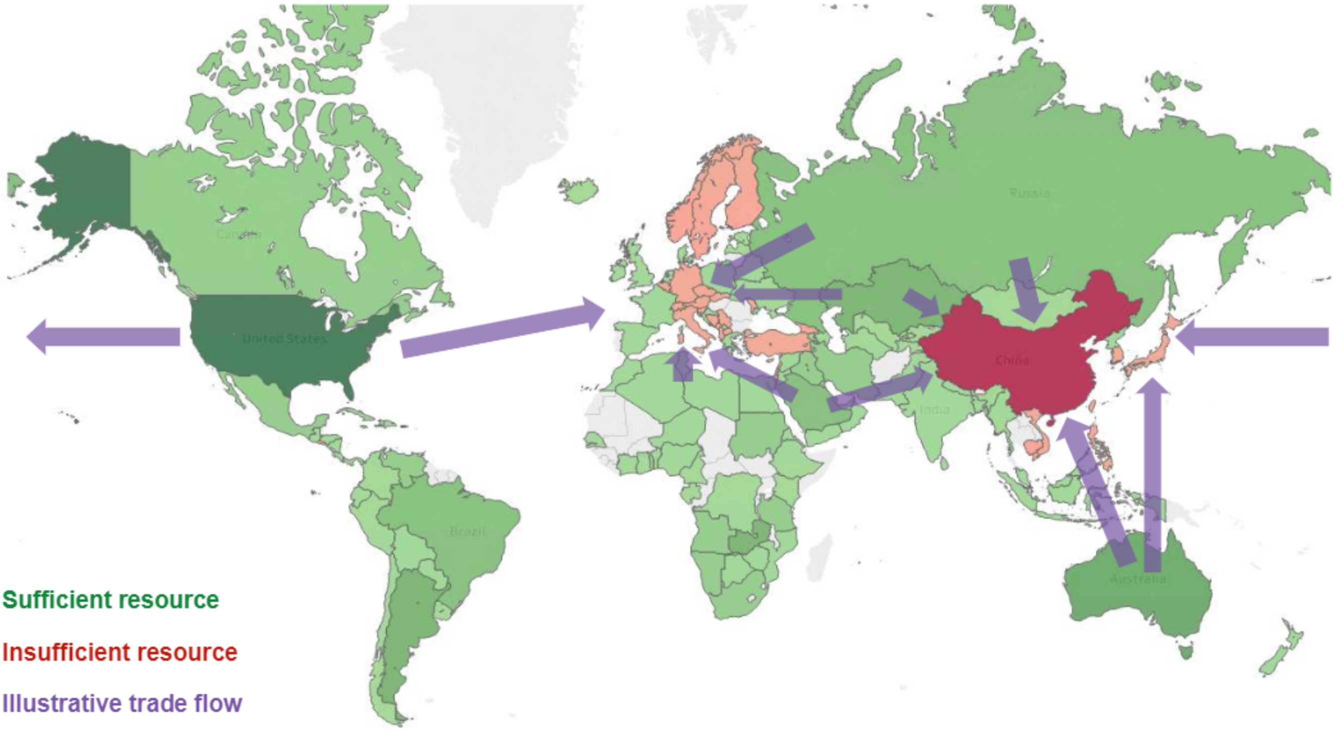
Overall, most countries would only need to dedicate a few percent of their total landmass to wind and PV in a 1.5 degree scenario where 50% of electricity and 100% of hydrogen is produced from these sources. However, even at today's levels, community resistance to renewable energy projects is already occurring in some countries. This suggests that other, likely more expensive, zero-carbon alternatives to wind and PV may ultimately be required. Options could include offshore wind, nuclear or the use of CCS with carbon offsets for electricity or hydrogen production. Energy imports via hydrogen or high-voltage transmission lines are also an option.

Resource constraints by country

39 countries do not have enough renewable energy resource to meet their 2050 power needs

However, when we consider estimates for available renewable energy resources on converted lands (which is the land already impacted by human activities) rather than total landmass, the situation looks less optimistic. Using the same energy demand as above, but comparing against the conservative estimate of technical potential to generate renewable electricity by Baruch-Mordo, we find that 33 countries may be unable to generate 50% of electricity and 100% of hydrogen from wind and PV in 2050 (Figure 33). This includes China, Japan, Germany and South Korea – four of the top 10 greenhouse gas emitters in 2017.[105]

Figure 59: Indicative estimate of the ability for major countries to generate 50% of electricity and 100% of hydrogen from wind and PV in a 1.5 degree scenario, 2050



*Source: BloombergNEF, Baruch-Mordo et. al, 2019. Note: **Green** = Country has sufficient estimated solar and wind resources to generate 50% of electricity and 100% of hydrogen by 2050. **Red** = Country has insufficient estimated solar and wind resources to generate 50% of electricity and 100% of hydrogen by 2050. **Purple** = illustrative hydrogen or electricity trade flows to deliver renewable energy from locations of surplus to deficit. The methodology used to estimate the potential for renewable generation is conservative, and may underrepresent the amount of generation achievable in specific locations. In some countries the estimate for potential generation is below current levels. These countries have not given a sufficiency rating.*

[105] Integrated Carbon Observation System, Global Carbon Budget, 2018.

Most European and South-East Asian countries would need to impinge on non-converted lands such as forests and other protected areas of natural value. Other options would include greater energy efficiency improvements, improved cross-border interconnectivity of electricity networks, or importing low-carbon energy carriers like hydrogen. In contrast, many countries could have a surplus of generation potential, and therefore have the capacity to export renewable electricity. Countries with the largest export potential according to our calculations are the United States, Australia, Kazakhstan, Zambia, Argentina and Saudi Arabia.

Taking into account proximity, North-African countries and Russia can be identified as potential exporters to the European market, while Australia, Kazakhstan and Russia could potentially help supply China, Japan, South Korea and other countries in South East Asia. Some of these energy flows are similar to the established trade routes for fossil fuel exports today. However, unless hydrogen can be supplied via a pipeline, imports are likely to be expensive (see Section 5.3).

Hydrogen from fossil-fuels with CCS is likely to play an important role

Many of the potentially renewable resource-constrained countries – such as China and Germany – are, however, endowed with ample and low-cost coal resources as well as suitable geological formations to store carbon (for details see Figure 20 in Section 3.2). The cost of producing hydrogen from coal with CCS in these countries is likely to be low ($2.22-2.31/kg) and cheaper than ship-borne imports, for instance from Australia ($2.81/kg). This suggests that production of hydrogen from fossil-fuels with CCS could play an important role in these regions.

7.3. Water constraints

Another important consideration for hydrogen production is water. Producing hydrogen through water electrolysis or fossil fuel reforming requires large amounts of water. Electrolyzers also require high-purity water in order to limit side reactions caused by salts.[106] It is therefore often thought that the water consumption of electrolysis may put additional pressure on water supply in many countries. In our assessment however, this is unlikely to be a key constraint.

Global water demand could exceed supply by 40% in 2030

The availability of fresh water is already a growing challenge in a number of countries, and this looks set to worsen.[107] By 2025, some 1.8 billion people are likely to be living in countries or regions with absolute water scarcity, and two-thirds of the world's population could be living under water-stressed conditions. Currently 2.1 billion people lack access to safe drinking water. If current consumption patterns of water continue, global water demand could exceed total supply by 40% in 2030.

The standard water consumption of hydrogen production for electrolysis[108] is 10L/kg of hydrogen. Production from natural gas via steam methane reforming consumes about 4.5-7L/kg of hydrogen, and coal gasification 9L/kg. Producing 696MMT of hydrogen in 2050, entirely from water electrolysis, would require 7bcm of water.

106 Bruce et al., National Hydrogen Roadmap, CSIRO, 2018. Resistance is generally used as the measure of water purity for industrial use. Higher purity corresponds to fewer conductive particles and higher resistance. Electrolyzers require a resistance greater than 1MΩ*cm.

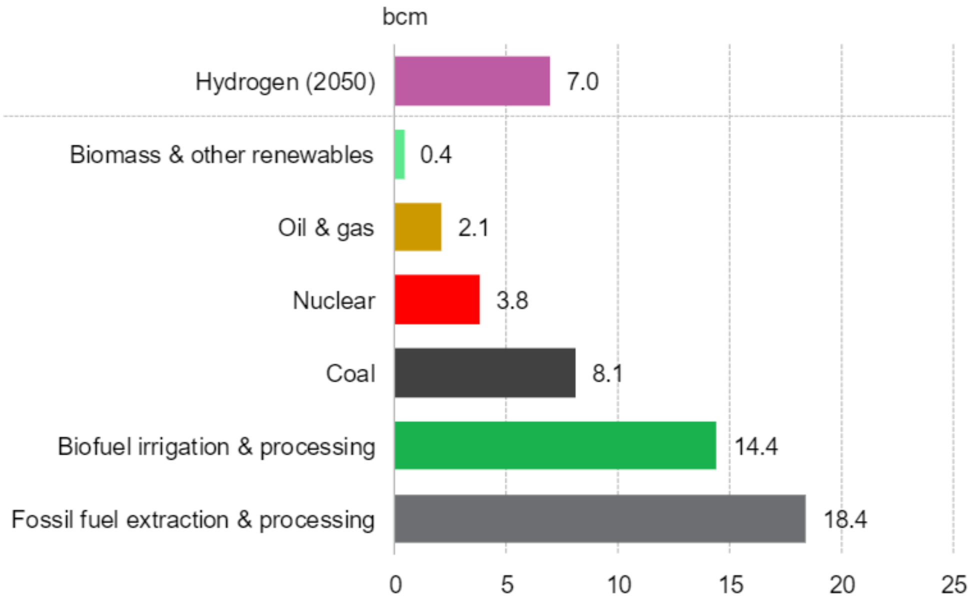
107 United Nations, Water Scarcity Factsheet, 2018. Note: Water stress starts when the water available in a country drops below 4,600L/day per person. When the 2,700L/day per person threshold is crossed, water scarcity is experienced. Absolute water scarcity is when less than 1,400L/day per person is available.

108 See Nel's product datasheet: 0.9L/Nm^3.

Hydrogen production would consume less water than coal generators do today

However, it should be noted that the energy sector today is already a massive consumer of water. According to the IEA, around 10% of global water withdrawals and 3% of consumption is used to produce energy. [109,110] By these numbers, hydrogen production in 2050 would account for 13% of water consumption in the energy sector at today's levels. This is relatively small compared with extraction and processing of fossil fuels at 34% and irrigation and processing of biofuel crops at 27% (Figure 60). As the energy sector amounts to roughly 3% of water consumption worldwide, and hydrogen accounts for 13% of water consumed in the energy sector, water for hydrogen production would only equal 0.4% of today's global water consumption.

Figure 60: Estimated global water consumption for hydrogen production in 2050 compared with global water consumption in the energy sector in 2016



Source: BloombergNEF, IEA. Note: The estimate of water consumption for hydrogen is calculated based on demand of 696MMT in our Strong Policy scenario, with 100% of production from water electrolysis. Water consumption for other sectors is based upon 2016 data from the IEA. Other renewables include wind, PV, geothermal and solar thermal, and excludes hydropower. Fossil fuel and biofuel numbers represent water consumption during primary energy production. All other numbers (except hydrogen) represent water consumption during power generation.

Despite the fact that population growth and global warming might further constrain fresh water supply, availability of water looks unlikely to be a critical constraint for the production for hydrogen – except in countries where water scarcity is or will be a reality in the near future.

The availability of high-purity water is also unlikely to be a critical constraint, as water can be purified at relatively low costs. In regions where fresh water is available, such as Europe and the U.S., a purifier is usually integrated in the electrolysis system. Potable water in the U.S. averages $0.4/ton and is of sufficient quality for electrolysis systems containing a water purifier. Where water supply is less pure, an external water purifier is generally used, and is commonplace today

109 International Energy Agency, World Energy Outlook, 2018.

110 Water withdrawal is the volume of water removed from a certain source and is always greater than or equal to water consumption. Water consumption is the volume of water withdrawn but not returned to the source.

in China. The cost of externally purified water is around $4/ton in China. At these prices, water makes up only $0.004 of the cost of producing a kg of hydrogen in the U.S. and $0.04 in China.

Desalination can be used, and adds only minor cost

Where fresh water is scarce, sea or brackish water can be used via desalination. Desalination through reverse osmosis would add around $0.7-2.5 per cubic meter to the cost of water and require additional electricity consumption of 3-4kWh per cubic meter. This would have only a minor impact on the total cost of electrolysis, adding $0.01-0.02/kg of hydrogen.[111] Assuming about half of water required for global hydrogen production is desalinated would require between 10 and 14TWh of additional power generation in 2050.

[111] IEA, The Future of Hydrogen, 2019.

Section 8. Outlook

The previous section shows that at full scale, the economics of using clean hydrogen can get surprisingly close to fossil fuels. But will this scale-up occur? Falling costs of production from renewables alone will not be enough to drive expansion in hydrogen use. For the industry to thrive, demand needs to be supported with comprehensive policy, and that is not yet in place. We estimate that around $150 billion of cumulative subsidies are required to 2030, followed by carbon prices and other policy measures strong enough to drive deep decarbonization and over $11 trillion of investment in supply infrastructure. If this occurs, hydrogen could play a substantial role by 2050. Without it, hydrogen could be a hype cycle again. To help determine whether a hydrogen economy will happen this time around, we present seven signposts of scale-up.

In this section, we examine the outlook for the development of a hydrogen economy. Section 8.1 summarizes the current policy environment and provides an estimate of the amount of subsidy and policy support required to achieve scale. Section 8.2 provides a list of signposts to observe to determine if scale-up is occurring.

8.1. Subsidies and policy support required

The analysis in Section 6 illustrates that if hydrogen can be delivered to large users for $1/kg in 2050, the economics of its usage could get surprisingly close to cost competitiveness with fossil fuels. However, to achieve these delivered costs, the industry needs to scale up. The use of clean hydrogen is expensive and uncommon today, and although there is appetite from private corporations to invest in hydrogen, policies and subsidies will be required to support investment.

Current subsidies and policies

Policy measures are generally focused on road transport

Right now there is little government policy in place to increase the use of clean hydrogen. Measures are generally focused on road transport applications, and although targets are relatively common, they have little funding associated with them.

Since 2014, several countries and public-private partnerships have published hydrogen roadmaps with detailed fuel-cell electric vehicle (FCEV) deployment targets adding up to over 3.7 million vehicles on the road by 2030. These include major markets such as China, Europe, Japan, Korea and California. However, the government money to support those targets has not been so forthcoming, and by our numbers, subsidies offered to date are enough for just 480,000 vehicles.[112]

Beyond transport, targets for hydrogen usage are not common and funding often comes as grants for demonstration projects. Grant funding provides essential one-off support for individual projects, but does not provide a framework or signal for long-term investment and scale-up.

[112] For details see: *Hydrogen: Fuel Cell Vehicle Outlook* (web | terminal)

Table 15 provides a summary of the notable hydrogen funding commitments and subsidies in place around the world.

The governments of Australia, Austria, Belgium, the Netherlands, New Zealand, Norway, France, Japan and Korea have, or are in the process of developing, national hydrogen strategies. However, to date, no comprehensive targets with investment mechanisms such as traded certificate schemes or green product purchasing mandates are in place to drive private investment in clean hydrogen projects.

Despite this, there is growing appetite from energy, transport and industrial companies to invest in hydrogen. According to the Hydrogen Council, its members have planned investments of over 10 billion euros ($11.1 billion) for commercializing hydrogen.[113] Experience suggests, however, that government co-funding will be essential for these projects to materialize.

Table 15: Summary of notable hydrogen funding commitments and subsidies

Country	Funding commitment
U.S.	• FCV subsidy of up to $7,000 per vehicle available in California
China	• FCV subsidy of up to CNY 300,000 ($43,000) for light-duty and CNY 500,000 ($72,000) for heavy-duty vehicles
India	• INR 60 million ($850,000) support for research proposals on hydrogen and fuel cells
Japan	• JPY 80.7 billion ($736 million) in funding in fiscal year 2020 allocated to hydrogen society initiatives (including FCV subsidies) • FCV subsidy of up to JPY 2 million ($18,350) per vehicle
South Korea	• FCV subsidy of up to KRW 35 million ($30,000) per vehicle
Australia	• AUD 370 million ($255 million) allocated to support hydrogen projects by the Australian Renewable Energy Agency and Clean Energy Finance Corporation
United Kingdom	• GBP 40 million ($52 million) in funds for innovation in low-carbon hydrogen supply and storage at scale • GBP 170 million ($220 million) Industrial Strategy Challenge Fund (not exclusively hydrogen) • FCV subsidy of up to GBP 3,500 ($4,500) per vehicle
Germany	• EUR 1,400 million ($1,550 million) over 10 years for the National Innovation Programme for Hydrogen and Fuel Cell Technologies • FCV subsidy of up to EUR 6,000 per vehicle
France	• EUR 100 million ($111 million) under the Hydrogen Deployment Plan
Belgium	• EUR 50 million ($56 million) regional investment plan for power-to-gas

Source: BloombergNEF, International Energy Agency

Required subsidies, policies and investment

The amount of investment and subsidy that is required to scale up hydrogen has not been calculated by any official body. The Hydrogen Council estimates that $280 billion of total investment is required to 2030,[114] with $70 billion in subsidies.[115] However, this subsidy value represents the cost gap between hydrogen technologies and the cheapest *low-carbon* alternative, not the cheapest fossil fuels.

[113] Hydrogen Council, *How hydrogen empowers the energy transition*, January 2017.

[114] Hydrogen Council, Hydrogen Scaling Up, November 2017.

[115] Hydrogen Council, *Path to hydrogen competitiveness – A cost perspective*, January 2020.

We calculate that $150 billion of subsidies will be needed to 2030

We anticipate that a similar amount of total investment will be required to 2030, but we calculate that $150 billion of cumulative subsidies will be needed to 2030 to bridge the cost gap between hydrogen and the cheapest *fossil fuels*. After 2030, carbon prices and other policy measures that are strong enough to drive deployment of hydrogen technologies and build $11 trillion of supply infrastructure will be required.

We have developed a three-phase timeline to consider the scale-up and emergence of a hydrogen economy (Table 16):

- In the first phase, the number and size of clean hydrogen demonstration projects would need to expand steadily to build experience and demonstrate delivered costs of $2/kg by 2030.
- In the second phase, clean hydrogen industrial clusters would need to be built from 2030 to 2040, to facilitate large-scale use and achieve delivered costs below $2 and closer to $1/kg.
- In the third phase from 2040 to 2050, comprehensive clean hydrogen supply networks would need to be established, allowing widespread use at a delivered cost of $1/kg to large users.

Policy measures will be essential in all three phases, and would need to focus on two critical elements: incentivizing the use of hydrogen, and coordinating the construction of the delivery infrastructure to supply it. The cost of producing renewable hydrogen looks likely to fall if demand increases. The milestones, policies and amount of subsidy required to achieve each of these phases is discussed in further detail below.

Table 16: The three phases of scale-up required for development of a hydrogen economy

Phase 1 – Large demonstration projects	Phase 2 – Hydrogen industrial clusters	Phase 3 – Comprehensive hydrogen networks
2020-30	**2030-40**	**2040-50**
The number and scale of demonstration projects steadily increases, building experience and driving down the costs of electrolyzers and FCEVs.	A number of hydrogen industrial clusters are built, driving significant scale and cost reductions, particularly in transport and storage infrastructure.	Comprehensive hydrogen supply networks become commonplace, with integrated transmission, distribution and storage, carrying 70-100% hydrogen.
Key milestones: • Renewable hydrogen delivered to large users for $2/kg • Electrolyzer sales surpass 1GW per year; cumulative 27GW by 2030 • FCEV sales surpass 100,000/year • Large-scale steel, ammonia and methanol plants using clean hydrogen are commissioned • Hydrogen blending surpasses 5% by volume in a major gas market	Key milestones: • Renewable hydrogen delivered to large users for $1-2/kg • Clusters supplying over 1,000tH_2/day are built supplying customers via pipeline networks + geological storage • Electrolyzer sales surpass 10GW/year • FCEV sales surpass 1,000,000/year, H_2 trucks reach cost parity with diesel • Several hydrogen CCS projects	Key milestones: • Renewable hydrogen delivered to large users for $1/kg • Gas networks are converted to hydrogen • Peaking power and industrial facilities are routinely powered by hydrogen • Electrolyzer sales surpass 100GW/year • FCEV sales surpass 10,000,000/year • Hydrogen exports surpass 10MMT/year
Will require: • Significant ramp-up in R&D&D funding • Direct capital subsidies • Gas network blending mandates • Introduction and reform of regulations and standards	Will require: • Carbon pricing • Industrial decarbonization policy • Green product mandates (e.g. steel, cement, fertilizers) • Gas network blending mandates • Stringent heavy transport emissions standards	Will require: • Carbon pricing • Carbon border adjustments • Zero-carbon regulations and standards (e.g. appliances) • Models for hydrogen transport and storage infrastructure investment (e.g. regulatory allowances for utilities)

Source: BloombergNEF

Phase 1: Large demonstration projects

For the hydrogen industry to achieve the first phase of scale-up, the number and average size of demonstration projects would need to increase steadily to build experience and drive down the costs of hydrogen technologies like electrolyzers, transport and storage systems, and end-use equipment. The key milestone in this phase is to achieve a delivered renewable hydrogen cost of $2/kg to large users by 2030. Demonstrating the use of clean hydrogen in large projects such as steel, ammonia and methanol plants, or blending into the natural gas grid, would also be important to build experience in the large-scale transportation and storage of hydrogen.

Demand for renewable hydrogen would need to scale up to around 2.7MMT a year

Based on the electrolyzer cost reduction pathways discussed in Section 3.1, we calculate that demand for renewable hydrogen would need to scale up to around 2.7MMT a year to reduce production costs enough to reach a delivered price of $2/kg. This level of demand would support the construction of 27GW of electrolyzers – enough to place the alkaline electrolyzer manufacturing industry on our "optimistic path" of cost reductions.[116]

To create 2.7MMT of demand by 2030, tens of full-scale hydrogen usage projects – or hundreds of partial use projects – would need to be supported by policies or subsidies. Table 17 shows the amount of hydrogen that would be consumed by a full-scale industrial facility, power generator, various types of FCVs and by blending 5% hydrogen (by volume) into a natural gas network the size of the United Kingdom. It also shows our estimates for the amount of subsidy required to cover the cost premium of using hydrogen at $2/kg compared to the cheapest fossil fuel in each application, expressed as an annual cash payment or as a carbon price.

Scaling up the use of hydrogen could be achieved by supporting projects in one or many of these sectors. To create 2.7MMT of demand by 2030, we estimate that the lowest-cost option would be to support the equivalent of 24 full-scale projects in the ammonia, methanol and refining sectors, as these require the least subsidy per unit of hydrogen consumed. In total, $4 billion of annual subsidy payments would be required by 2030 for least-cost scale-up.

However, to build broader experience, it would be better to demonstrate the use of hydrogen across a wider variety of sectors. Another way to create 2.7MMT of demand would be the equivalent of three full-scale projects in each of the industrial, power and buildings sectors listed in Table 17, including a blend of 5% hydrogen (by volume) into a natural gas network the size of the United Kingdom. This would require around $4.5 billion of annual subsidies by 2030. Alternatively, a larger number of demonstration projects that make partial use of hydrogen – for instance in 10-50% of their production – could also achieve the required scale.

The fuel cell vehicle industry will be the most expensive sector to scale up in the short-term

The fuel cell vehicle industry will be the most expensive sector to scale-up in the short-term. We estimate that $10.5 billion per year in subsidies would be required to put the sector on a path of rapid cost reduction.[117] This would be enough to support the deployment of 3.7 million fuel cell vehicles by 2030, subsidize fuel and build refueling infrastructure. Fueling these vehicles would require an additional 2.27MMT of hydrogen to be produced. However, as hydrogen supply to

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116 Electrolyzer costs also fall significantly in our conservative cost reduction scenario (outlined in Section 3.1). In this, 2.9GW of electrolyzers are installed by 2030. However,in this scenario overall demand and use of renewable hydrogen is unlikely to be sufficient to support the development of hydrogen transportation and storage infrastructure, meaning that delivered costs of hydrogen via infrastructure would not be demonstrated. The level of experience built in industry would also be relatively low, both in terms of applications and geography. For example, full-scale plant conversions would not be demonstrated.

117 For details see: *Hydrogen: Fuel Cell Vehicle Outlook* (web | terminal)

refueling stations is most often derived from fossil fuels due to sensitivity on costs, we assume this does not create demand for renewable hydrogen from electrolyzers before 2030.

Table 17: Hydrogen consumption and subsidy required for a full-scale facility

Sector	Application	Typical nameplate capacity of a full-scale facility / vehicle miles travelled	Hydrogen consumption of a full-scale facility (metric tons H_2/year)	Subsidy required to support use of H2 at $2/kg$^{\Omega}$	Carbon price required for H2 to compete with cheapest fossil fuel in 2030 ($/tCO2)	Carbon price required for H2 to compete with cheapest fossil fuel in 2050@ ($/tCO2)
Industry	Cement	1Mt-clinker/year	27,000	$38m/year	135	60
	Steel	2Mt-steel/year	119,880	$306m/year	85	50
	Glass	250,000t-glass/year	10,750	$16m/year	220	90
	Aluminum (alumina production)	3,000t-alumuna/day	31,865	$45m/year	220	90
	Aluminum (recycling)	200t-Al/day	2,037	$3m/year	220	90
	Refining	100,000bbl-crude/day	19,769	$23m/year	129	16
	Methanol	5,000t-CH_3OH/day	229,950	$330m/year	226	139
	Ammonia	2,250t-NH_3/day	155,216	$248m/year	189	78
Power	Peaking power	700MW	175,375#	$338m/year	295	115
Transport	Cars	10,000miles/year	0.17	$20k/vehicle^	442	0
	Buses	35,000miles/year	4.1	$51k/vehicle^	138	0
	Light trucks	30,000miles/year	1.1	$23k/vehicle^	n/a	0
	Heavy trucks	68,000miles/year	7.2	$17k/vehicle^	214	0
	Ships	100,000miles/year	781	$3m/year	227	145
Buildings	Gas network blending	3,000PJ/year*	351,707 for a 5% blend by volume	$2,300m/year	290	160

Source: BloombergNEF. Note: Estimated subsidy and carbon price is the payment required to cover the cost premium of using hydrogen compared to the cheapest fossil fuel in each sector, including additional capital expenditure. $^{\Omega}$ The hydrogen price for large-scale users. For FCVs, pump prices are *$4/kg in 2030-50.* @ *Assuming hydrogen price for large-scale users of $1/kg in 2050.* ** Annual natural gas consumption for the UK.* # *Assuming a combined cycle plant with 55% capacity factor. ^ Capex subsidy based on FCEV costs in the Weak Policy scenario. Subsidies for refuelling infrastructure are not included in per-vehicle subsidy figure, but are included in the total subsidy for transport discussed above. Carbon prices for FCEVs include both upfront and fuel subsidies, which fall to zero before 2050 as cost parity is achieved.*

In total, we estimate that around $15 billion per year of subsidy or $150 billion over the next 10 years, would be required for the first phase of scale-up to a hydrogen economy. This is a relatively small amount compared with other energy subsidies. The IEA estimates that global fossil fuel consumption subsidies totaled $424 billion in 2018, and have hovered around $400 billion per year since 2010.[118]

[118] International Energy Agency, Fossil fuel consumption subsidies bounced back strongly in 2018, June 2019.

Support for the hydrogen industry is likely to be easy to deliver through existing mechanisms like upfront capital subsidies and grants. New approaches such as gas blending mandates may be required, as well as the removal of regulations that limit, prohibit or impede the use of hydrogen and the introduction of standards to govern its safe use.

Phase 2: Hydrogen industrial clusters

The second phase of scale-up would involve the construction of large-scale hydrogen supply networks to clusters of industrial facilities. This would drive greater scale and further reduce the cost of producing, transporting and storing hydrogen. In our view, industrial clusters are the most cost-effective way to expand the use of hydrogen (see Section 6). Clusters would likely be constructed where decarbonization policy and incentives are strongest.

The key milestone in the second phase are clusters that supply over 1,000tH2/day to customers, via pipeline systems with geological storage, at a delivered cost between $1 and $2/kg. This is likely to require electrolyzer sales of over 10GW/year. The construction of several hydrogen CCS projects is also desirable to demonstrate viability and build experience for geographical regions with poorer renewable energy resources. For the FCEV industry to scale up too, key milestones are more than 1,000,000 vehicle sales a year, and for FCEV heavy-duty trucks to reach cost parity with equivalent diesel models.

Building industrial clusters is likely to require a suite of supportive measures. These could include carbon pricing; specific industrial decarbonization policies such as tax concessions to help pay for converting infrastructure to hydrogen; and green product mandates that require a percentage of products like steel to be sourced from near-zero emission producers. For FCEV truck sales to increase materially, policy measures such as stringent heavy transport emissions standards would need to be introduced. Increasing the volume of clean hydrogen production more broadly could also be achieved by the use of blending mandates into the gas network.

Our estimate for the amount of subsidy required to achieve scale-up in this phase is expressed in terms of carbon prices. In 2030, the effective carbon prices required to support projects competing against the cheapest fossil fuels in use today range from $85 to 295/tCO2, excluding road transport applications. If those price levels are difficult to achieve, then a combination of subsidies and regulations could be used instead.[119]

Phase 3: Comprehensive hydrogen networks

The third phase of scale-up is to establish comprehensive hydrogen supply networks, with integrated transmission, distribution and storage infrastructure, carrying 70-100% hydrogen. In this phase, the use of hydrogen as a fuel would become commonplace.

Key milestones in the third phase are to achieve a delivered renewable hydrogen cost of $1/kg to large users by 2050, and the widespread conversion of existing natural gas networks to hydrogen. Peaking power and industrial facilities would be routinely powered by hydrogen, and production volumes would be large enough to support electrolyzer sales of over 100GW per year. For the FCV industry, the key milestone would be sales of more than 10,000,000 per year. International export supply chains would also have emerged, surpassing 10MMT/year of trade.

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[119] Currently, only around 17% of global emissions are covered by a carbon pricing policy, and carbon prices are well below the levels needed to drive reductions in industrial sectors. In addition, manufacturing industries are generally exempt or receive substantial free-allowances from carbon pricing regimes (such as the EU ETS). This reduces the incentive for industries to decarbonize.

Achieving this third phase of scale-up would need carbon prices to be complemented with carbon border adjustments,[120] as well as zero-carbon regulations and standards that limit the use of fossil fuels in end-use appliances. Financial models to support investment in hydrogen transport and storage infrastructure – for example regulatory allowances – would also be required.

The carbon prices in this phase should fall to zero for road transport options and to between $16 and $160/tCO2 for other sectors (Figure 45). As many emission-intensive industries are subject to international trade pressures, it is likely that carbon pricing schemes will need to be supplemented by carbon border adjustments to penalize imported goods produced from fossil fuels.

In total, we estimate that over $11 trillion of investment (in 2019 dollars) by 2050 would be required to build the supply infrastructure necessary for all three phases of scale-up to a hydrogen economy. Hydrogen production and storage infrastructure alone would cost over $10.5 trillion. Assuming 100% of production from renewables, approximately $9.1 trillion would be required to build 6.0TW of wind and 6.3TW of PV capacity, and $809 billion for 8.3TW of electrolyzers. An additional $637 billion would be required to build over 14,000 large salt caverns.[121] Hundreds of billions more would also be needed to build and retrofit hydrogen transport infrastructure.

8.2. Seven signposts of scale-up toward a hydrogen economy

Despite growing interest in hydrogen, it is not yet clear whether a hydrogen economy will develop. The technology has experienced a hype cycle before, but a growing number of countries, states and cities are setting legally binding targets for net-zero greenhouse gas emissions.[122] Therefore, this time could be different. To help track progress, we have identified seven signposts in policy, regulation and market development that we believe are critical for scale-up and emergence of a hydrogen economy (Table 15):

1) Net-zero climate targets are legislated

2) Standards governing hydrogen use are harmonized and regulatory barriers removed.

3) Targets with investment mechanisms are introduced.

4) Stringent heavy transport emission standards are set,

5) Mandates and markets for low-emission products are formed

6) Industrial decarbonization policies and incentives are put in place.

7) Hydrogen-ready equipment becomes commonplace.

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[120] Carbon border adjustments – or equivalent measures – will likely be necessary to ensure goods made using hydrogen are competitive with imports made using cheaper fossil fuels.

[121] This is a conservative estimate for the production and storage infrastructure required to supply 696MMT of hydrogen (estimated demand in our *Strong Policies* scenario) entirely from renewable sources, with storage entirely in salt caverns. If a share of production is met by fossil fuels with CCS, and a proportion of storage occurs in rock caverns, total investment will be higher. Assumes average wind capex from 2030-50 of $1.09m/MW, large-scale PV capex of $0.41m/MW, alkaline electrolyzer capex of $97.5/kW and salt cavern capex of $4.55/kg-H2 stored. Capacity requirements are discussed in Section 7.1.

[122] Energy & Climate Intelligence Unit, Net Zero Tracker.

Table 18: Seven signposts of scale-up toward a hydrogen economy

Event	Effect	Examples
1) Net-zero climate targets are legislated	Makes it clear that the hard-to-abate sectors will need to decarbonize	• Countries or states set legally binding targets for zero emissions by a defined date • Countries that have legislated targets include the United Kingdom, France, Sweden, Norway and New Zealand. Dozens more are under consideration • Sub-national jurisdictions can also set targets, for instance California, Victoria, New York City • Companies may also set targets, but these are not legally enforceable
2) Standards governing hydrogen use are harmonized and regulatory barriers removed	Clears or minimizes obstructions to hydrogen projects	• Removal of regulations that limit, prohibit or impede the use of hydrogen. Common examples are restrictions on use of liquid hydrogen by civilians, hydrogen concentration in gas networks, carriage of hydrogen through tunnels etc • Consistent technical standards are set on hydrogen pipeline pressures, compatible materials, refuelling nozzles for vehicles, end-use appliances etc • Introduction of guarantee-of-origin schemes to define and certify that hydrogen is renewable or low carbon, particularly for voluntary buyers
3) Targets with investment mechanisms are introduced	Provides a revenue stream for producers, increases competition, builds capacity and experience, and gives equipment manufacturers confidence to invest in plant	• Open-access schemes that provide revenue for independent project developers to produce low or zero-emissions hydrogen, e.g. tradeable certificate schemes and feed-in tariffs or premiums for hydrogen supplied into gas networks • Hydrogen blending mandates introduced for gas network operators/retailers • Reverse auctions for hydrogen supply
4) Stringent heavy transport emissions standards are set	Provides an incentive for manufactures to produce, and users to buy, fuel cell trucks and ammonia-powered ships	• Tailpipe emission standards or fuel efficiency standards for buses and trucks are significantly tightened • International Maritime Organization's 2050 emissions target is ratified
5) Mandates and markets for low-emission products are formed	Provides an incentive for manufacturers to produce low-emission goods (e.g. steel, cement, fertilizers, plastics) that will often require the use of hydrogen	• Governments or large corporates set embodied emission standards or green purchasing mandates for inputs to buildings, infrastructure and products • Targets/regulations are introduced requiring existing hydrogen users (e.g. ammonia producers, refineries) to procure percentages of low-carbon or renewable hydrogen • Voluntary markets and labelling standards for green products are introduced, e.g. green fertilizers, zero-embodied-emission cars • Markets, trading hubs, exchanges and price benchmarks are established for trade in hydrogen
6) Industrial decarbonization policies and incentives are put in place	Helps to coordinate infrastructure investment and scale efficient use of hydrogen. Provides incentives for hydrogen use	• National industrial strategies include grants/funding/tax exemptions for conversion to hydrogen • Utilities directed or given revenue allowances to build hydrogen infrastructure • Exemptions and free allocation of carbon credits for heavy industry in emission-trading schemes are removed • Carbon border adjustments/tariffs are introduced • Specific targets for hydrogen use in industry are introduced
7) Hydrogen-ready equipment becomes commonplace	Enables and reduces the cost of fuel switching to hydrogen	• New pipeline infrastructure uses hydrogen-tolerant materials like polyethylene • New gas turbine models are capable of operating on hydrogen • New marine internal combustion engines are capable of operating on ammonia • End-use appliances such as boilers are designed to operate on hydrogen • New steel-plants show preference for Direct Reduction furnaces

Source: BloombergNEF

Appendices

Appendix A. Technical information

Unit conversion

Table 19: Unit conversion of hydrogen

	Unit	kg	GJ (HHV)	GJ (LHV)	kWh (HHV)	kWh (LHV)	MMBtu (HHV)	Gal of gasoline equiv. (HHV)	Nm^3	Sm^3
1	kg	1	0.14	0.12	39.4	33.3	0.13	1.08	11.12	11.74
1	GJ (HHV)	7.04	1	0.85	277.78	234.74	0.95	7.58	78.32	82.64
1	GJ (LHV)	8.33	1.18	1	328.70	277.78	1.12	8.97	92.68	97.8
1	kWh (HHV)	0.025	0.0036	0.003	1	0.85	0.003	0.027	0.28	0.3
1	kWh (LHV)	0.03	0.0043	0.0036	1.18	1	0.004	0.032	0.33	0.35
1	MMBtu (HHV)	7.44	1.06	0.89	293.07	247.67	1	8.01	82.63	87.19
1	Gal gasoline equiv. (HHV)	0.93	0.13	0.11	36.60	30.93	0.125	1	10.33	10.90
1	Normal cubic meter (Nm^3)	0.09	0.013	0.011	3.55	3	0.012	0.097	1	1.06
1	Standard cubic meter (Sm^3)	0.085	0.012	0.01	3.36	2.84	0.011	0.092	0.95	1

Source: BloombergNEF
Sm^3: one m^3 of hydrogen at 15°C and 1 atmospheric pressure (1.013 bar)
Nm^3: one m^3 of hydrogen at 0°C and 1 atmospheric pressure (1.013 bar)
Gal of gasoline equiv.: gallon of gasoline equivalent

Heating values (HHV and LHV)

The heating value of hydrogen is the amount of heat released during combustion. Because heat is a form of energy, we measure heating value in joules. Two types of heating value exist – high (HHV) and low (LHV). HHV shows the total (gross) energy contained in the fuel, while LHV represents the net value of energy in the substance. The difference between HHV and LHV is the latent heat of vaporization, or energy used up vaporizing water during combustion. For example, the energy content in 1kg of hydrogen is 0.14GJ (39.4kWh) HHV, and 0.12GJ (33.3kWh) LHV.

In this report, all energy values are in HHV terms unless noted otherwise.

Appendix B. Estimation of technical potential for renewable electricity generation

Our analysis employs data from a 2018 study by Baruch-Mordo et al. that estimates the total technical potential to generate electricity from solar (utility-scale, rooftop and solar thermal), onshore wind and hydro on all converted lands.[123]

Converted lands are defined in the study as "land already impacted by human activities", and therefore specifically excludes "natural lands" which have not been impacted by human activity (for example, areas of wilderness and national parks). In total, the study identified 83% of total terrestrial land as being "converted".

The study then utilized geospatial analysis with the following methodology to calculate the technical potential for renewable energy generation on converted lands:

Wind

To be suitable for wind generation, converted land must meet the following conditions:

- Not be urbanized
- Have an annual averaged wind speed above 7m/s at 80m elevation
- Have a slope less than 30%
- Have an elevation < 2,000m
- Be at last 14.9km^2 in size

The technical potential for wind generation is then calculated based on an assumed power density of 2MW/km^2 and a predicted capacity factor at each location, using data on wind speeds.

Utility scale PV

To be suitable for large-scale PV generation, converted land must meet the following conditions:

- Not be urbanized
- Have a slope less than 5%
- Have agricultural land area < 20%

The technical potential for large-scale PV generation is then calculated based on an assumed power density of 26MW/km^2 and a predicted capacity factor at each location, derived using solar irradiation data.

Rooftop PV

To be suitable for rooftop PV generation, converted land must be urbanized.

The technical potential for small-scale PV generation is then calculated based on the amount of rooftop in a given urban area, an assumption that 14.5% of roof area is usable for PV (due to roof design and shading), a further discount for a "packing factor" which accounts for the spacing required to avoid shading (dependent on latitude) and a predicted capacity factor at each location.

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123 Baruch-Mordo, S. et al, *From Paris to practice: Sustainable implementation of renewable energy goals*, Environmental Research Letters, December 2018.

About us

Contact details

Client enquiries:

- Bloomberg Terminal: press <Help> key twice
- Email: support.bnef@bloomberg.net

Kobad Bhavnagri	Head of Special Projects	kbhavnagri@bloomberg.nef
Seb Henbest	Chief Economist	shenbest@bloomberg.net
Ali Izadi-Najafabadi	Head of Intelligent Mobility	aizadinajafa@bloomberg.net
Xiaoting Wang	Specialist, Solar	xwang263@bloomberg.net
Martin Tengler	Associate, Japan	mtengler@bloomberg.net
Jef Callens	Associate, Energy Economics	jcallens1@bloomberg.net
Atin Jain	Associate, India	ajain405@bloomberg.net
Tifenn Brandily	Associate, Energy Economics	tbrandily@bloomberg.net
Wayne Tan	Analyst, Oil Demand	mtan336@bloomberg.net

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