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RENEWABLE THERMAL COLLABORATIVE

Assessment of green hydrogen for industrial heat

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April 2023

Foreword

The industrial sector is the largest source of US emissions after electricity and transportation, accounting for approximately 24% of the total emissions in the United States.[1] Over half of the industrial emissions come from fossil fuel combustion to generate process heat. Decarbonizing industrial process heat, and overcoming the many technological, market, and policy barriers that prevent companies from using renewably powered heat, is essential for meeting a 1.5°C climate goal.

More and more governments and companies are committed to climate actions across the global economy. They are examining and implementing various decarbonization tools with governments offering new policy incentives, and investment in R&D and renewable energy generation accelerating across renewable thermal energy solutions.

Among these solutions, hydrogen[2] has a critical and unique role to play in decarbonizing industrial process heat. The industrial sector often needs high heat for production. Green hydrogen, made from electrolysis powered by renewable energy, is a strong candidate for decarbonizing high-heat industrial processes, such as manufacturing steel, chemicals, and cement. According to the ***Renewable Thermal Vision Report*** published by the Renewable Thermal Collaborative, blue and green hydrogen can supply approximately 13% of the industrial process heat by 2050.[3]

Beyond industrial process heat, green hydrogen can also cheaply store energy to balance intermittent and variable electricity production from wind and solar. Hydrogen fuel cells are already used to power cars, buses, trains, and other vehicles, and will be an important feedstock for future aviation fuels. Hydrogen is also an essential feedstock in many chemical reactions.

Reflecting its importance, green hydrogen is gaining momentum globally and in the United States. It was named a specific priority for 2023 at the 27th United Nations (UN) Conference of the Parties (COP27),[4] where leaders discussed the importance of mobilizing capital to develop and scale green hydrogen projects, the role of policy as an instrument to drive down costs, and the need for standards and a certification system to enable trade.

Interest in green hydrogen is growing among the many companies setting ambitious science-based climate targets. More than a fifth of the world's 2000 largest companies have made net zero commitments by 2050.[5] According to the Science Based Targets initiative (SBTi), 1,524 companies globally and 202 companies in the United States have committed to net-zero targets, of which 391 global and 63 US companies have an SBTi-approved target.[6] To reach these goals, companies need rapid development of infrastructure and deployment of low-carbon technologies such as green hydrogen.

In the United States, recent federal legislation, including the Infrastructure Investment and Jobs Act (IIJA; also known as the Bipartisan Infrastructure Law [BIL])[7] and the Inflation Reduction Act (IRA),[8] has put meaningful policy and billions of dollars of funding behind the push for clean hydrogen, including investment in research, development, and demonstration (RD&D) and tax credits directly incentivizing clean hydrogen investment and production. The Department of Energy (DOE) recently announced its National Clean Hydrogen Strategy and Roadmap, a vital plan to build industry alignment and a path forward for the clean hydrogen economy.[9]

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1 EPA, https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions "Sources of greenhouse gas emissions," last updated August 5, 2022. Accessed January 2023

2 For the purposes of this paper where hydrogen is referenced it refers to pink, blue, turquoise and green hydrogen unless noted otherwise.

3 RTC, https://www.renewablethermal.org/vision/ Renewable thermal vision, 2022. Accessed January 2023.

4 © Argus Media group 2022. https://www.argusmedia.com/en/news/2390368-cop-27-breakthrough-agenda-set-hydrogen-priorities "COP 27: Breakthrough Agenda set hydrogen priorities," November 11, 2022. Accessed January 2023.

5 UN Climate Champions. https://racetozero.unfccc.int/21-of-major-companies-commit-to-net-zero/" 21% of major companies commit to net zero, March 23, 2021. Accessed March, 2023.

6 Science Based Targets, https://sciencebasedtargets.org/companies-taking-action SBTi target dashboard. Accessed January 2023.

7 White House, https://www.whitehouse.gov/build/ Delivering results from President Biden's Bipartisan Infrastructure Law." Accessed January 2023.

8 White House, https://www.whitehouse.gov/ostp/news-updates/2022/09/20/launching-a-transformative-decade-of-climate-action/ "Launching a Transformative Decade of Climate Action." Accessed March 2023.

This report sets out to explore the role that hydrogen can play in decarbonizing industrial heat. While there are many other potential uses of hydrogen within the energy transition-as set out above-and other levers to drive lower-carbon industrial processes, we explore those in this report only in passing to provide further context.

Within this report, we have focused our attention on green hydrogen, meaning electrolytic hydrogen produced from renewable generation. We recognize that there are other low-carbon types of hydrogen, including blue, pink, and turquoise, which can also have applications in industry. Additionally, we are intentionally not including grey, brown, or black hydrogen in our analysis due to their high emissions profiles.

Deloitte[10] and the World Wildlife Fund (WWF), together with the Renewable Thermal Collaborative[11] (a global coalition for companies, institutions, and governments committed to scaling up renewable heating and cooling at their facilities.) prepared this paper. The primary goal is to better understand the potential for and barriers to the development and use of green hydrogen for industrial heat applications and to identify stakeholder priorities for enabling green hydrogen to play an appropriate role in industrial decarbonization for large energy users.

The report evaluates the following questions:

- What is the technical and economic potential for scaling the use of green hydrogen for industrial process heat in a cost-effective, environmentally friendly, and socially responsible way?
- What are the major technological, financial, policy, and other barriers in the nascent hydrogen market in the United States?
- What are the potential pathways for scaling green hydrogen for industrial heat use in the United States?

This report provides insights and considerations for large corporate energy buyers and other key market and policy stakeholders to scale green hydrogen for industrial heat applications. Based on this analysis, energy buyers interested in scaling green hydrogen for industrial heat applications may want to consider the following three key takeaways:

- The IRA aims to dramatically lower green hydrogen production costs. However, infrastructure and cost barriers persist in other parts of the hydrogen value chain. Transportation, storage, and retrofitting investments required on the end-use side still pose challenges to scaling the demand for green hydrogen. Overcoming these challenges will likely require additional policy support.
- Green hydrogen will be a key component of the decarbonization strategy for chemicals, cement, and iron and steel. Therefore, energy buyers in these subsectors will be early adopters and should begin to take advantage of current policies, such as the IRA and regional hubs, as part of a broader plan to decarbonize.
- Buyers outside these subsectors can still participate by leveraging their geographic proximity to green hydrogen hubs and establishing early relationships with hub developers. By taking proactive early actions, other sectors could have the opportunity to enter buyers' consortia or teaming agreements with larger buyers to explore innovative procurement options. These early efforts, while not the key pathway to scale, are important in accelerating the growth of the broader hydrogen economy.

We look forward to continuing efforts to make green hydrogen part of a just energy transition and the broader decarbonization movement.

[9] DOE, https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf DOE National Clean Hydrogen Strategy and Roadmap, September 2022. Accessed November 2022. The DOE uses "clean hydrogen" in its publications, while this report uses "low-carbon hydrogen."

[10] As used in this document, "Deloitte" means Deloitte Transactions and Business Analytics LLP, a subsidiary of Deloitte LLP. Please see www.deloitte.com/us/about for a detailed description of our legal structure. Certain services may not be available to attest clients under the rules and regulations of public accounting.

[11] The RTC is the global coalition for companies, institutions, and governments committed to scaling up renewable heating and cooling at their facilities, dramatically cutting carbon emissions. RTC members recognize the growing demand and necessity for renewable heating and cooling and the urgent need to meet this demand in manner that delivers sustainable, cost-competitive options at scale. The RTC was founded in 2017 and is facilitated by the Center for Climate and Energy Solutions, David Gardiner and Associates, and the WWF.

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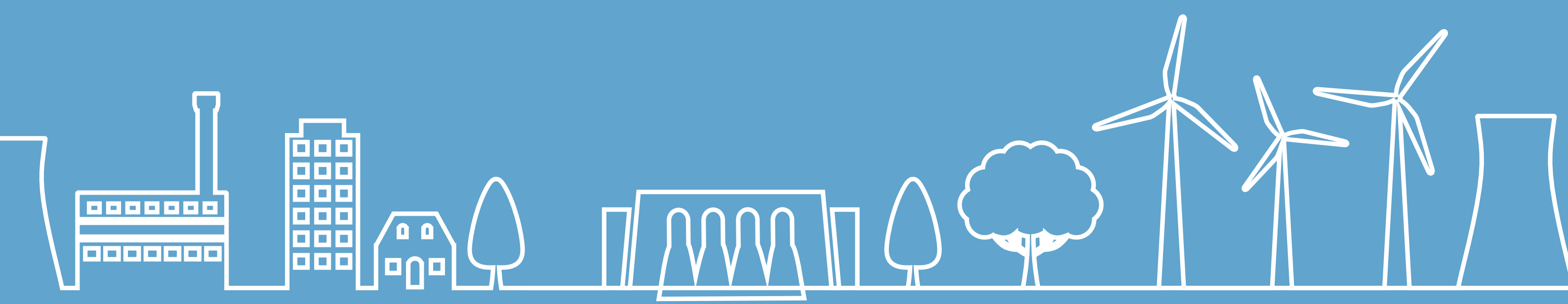
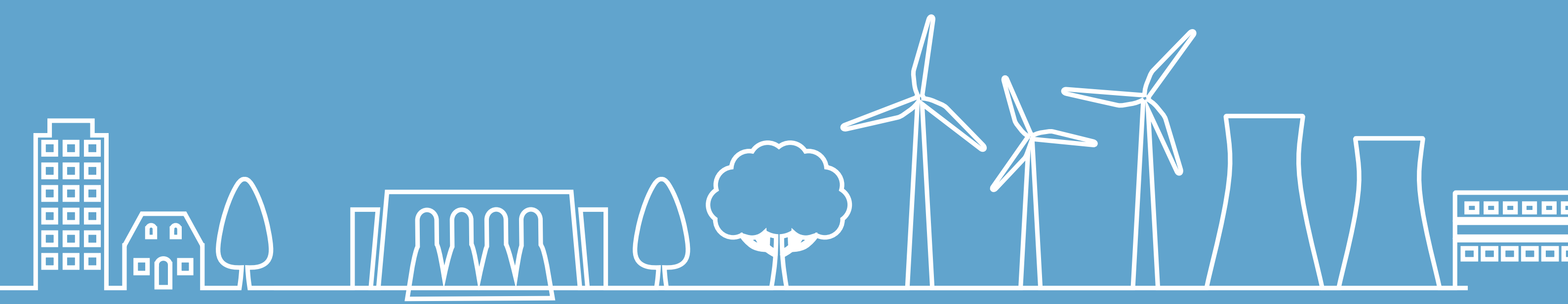


Chapter 5: Evaluating pathways for green hydrogen



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Executive summary

This report covers the technical, economic, social, and political considerations bearing on the adoption of green hydrogen for industrial heat. Green hydrogen, which is produced from electrolysis powered by renewables, is a renewable energy source and heat distinct from other forms of hydrogen produced from fossil fuels or nuclear power. The industrial sector accounts for approximately 24% of US greenhouse gas (GHG) emissions, and heat is the largest single contributor in the industrial sector.[12]

This report focuses on five priority subsectors that, together account for more than 70% [13] of industrial heat demand: oil refining, chemical manufacturing, pulp and paper, iron and steel, and cement. It is recognized that these subsectors have the potential to deploy hydrogen in relation to other processes as part of their operations, but this report focuses on industrial heat uses. Within these subsectors, hydrogen likely will see varying levels of adoption. The presence of free byproduct fuels (such as petroleum coke, "still" gas, waste biomass, etc.) will limit uptake by oil refiners and paper producers, while chemical manufacturers, like makers of ammonia (NH3) and methanol (CH3OH), are likely to use green hydrogen for heat and feedstock. Additionally, green hydrogen is likely to be valuable as a heating source for chemicals and cement manufacturers, as well as a key input for iron reduction in the steelmaking subsector.

Given the early stages of the green hydrogen value chain, it will likely require widespread development to realize opportunities in these subsectors. Alkaline and polymer electrolyte membrane (PEM) electrolyzers are already in service; however, developing the next generation of electrolyzer technologies and scaling supply chains for current ones will need significant investment. Hydrogen is costly to store and transport without infrastructure, such as underground storage and pipelines, especially at large volumes and over long distances. There are many opportunities to develop hydrogen-related technology and infrastructure to bring users into networked contact with hydrogen production.

Because of the nascency of the hydrogen market and the complexity of future considerations, forecasting remains difficult with the large number of unknowns. This report analyzes this challenge by constructing a model to estimate hydrogen adoption rates by industrial heat users across possible scenarios. The model is composed of modules that calculate supply, demand, and the levelized cost of energy (LCOE) for different energy sources. The outputs of these modules are connected via a decision engine, yielding estimates for the uptake of green hydrogen (and other fuels) by various industrial subsectors. Modeling was performed across scenarios representing high and low levels of electrification, as well as high and low levels of policy support for green hydrogen.[14]

The report's scenario analysis supports the strong role of government policy in determining the scope and scale of the green hydrogen economy. Support and funding from legislation—such as the IRA, IIJA, and initiatives the DOE and other government organizations spearhead—will provide vital backing for the green hydrogen economy and help lower production costs to overcome some initial hurdles to fully scaled operations.

As the green hydrogen economy grows, so will its impacts. Areas likely to host significant green hydrogen production, use, and related infrastructure (e.g., California and the Gulf Coast) will see profound changes in their communities. Green hydrogen production requires water, significant amounts of renewable electricity, and the physical footprint of plants, pipes, and storage media; therefore, it should be designed and developed carefully and sustainably. Hydrogen will also bring new jobs, both in the construction and ongoing operation of plants and in the broader hydrogen economy. By displacing fossil fuels, hydrogen use could prevent harmful pollution and damage to the environments where gas, oil, and coal are extracted. Careful, inclusive planning is critical for hydrogen to maintain social license to operate and public support as it decarbonizes economic activity.

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[12] US Energy Information Administration (EIA), https://www.eia.gov/energyexplained/use-of-energy/industry.php "Use of energy explained: Energy use in industry," last updated June 13, 2022. Accessed November 2022.

[13] Ibid.

[14] Electrification refers to the utilization of electricity-powered heating equipment for industrial heating and is primarily considered for low and medium-temperature heating processes. While direct electrification may have the potential to achieve all of the temperature requirements, direct electrification at high temperatures is not commercially viable at this stage. Additional RD&D would likely be required to bring these technologies beyond lab stage and may provide some efficiencies over other decarbonization technologies or processes.

Likewise, it will be required for market participants to begin addressing the challenges facing the green hydrogen economy. There are several policy, market, and technology actions that energy buyers and other stakeholders could try to accelerate hydrogens scope and scale,including:

- Advocating for timely extensions to IRA tax credits (as well as subsidies for end users and other potential policies, such as a carbon price) could enable infrastructure build and allow hydrogen to become cost-competitive with heating fuel long term.
- Building broad hydrogen health and safety standards that address the value chain through collaboration with standard-setting bodies and intentional RD&D efforts may help promote investment and generate broad public support to scale green hydrogen.
- Developing appropriate outreach and education efforts can generate broad public support and grant a social license for the hydrogen economy.
- Building solid relationships with local stakeholders and engaging in open dialogue early on can build trust, better address community circumstances, aid collaboration during hydrogen project design and development phases, and help enable a just transition when scaling green hydrogen.
- Developing sustainability criteria for hydrogen and broad rules about the electricity used to produce hydrogen can help to establish that hydrogen is "green" and that grid-connected electrolyzers produce hydrogen without negative impacts.
- Educating energy buyers on current policies and the environmental benefits of green hydrogen can help foster a greater sense of community among energy buyers and help them define their role in the broader hydrogen economy.
- Increasing standardization of supply contracts and other relevant market instruments related to hydrogen could improve transparency and lower transaction costs, risks, and uncertainty. This could ease entry into contracts, reduce the risk to early adopters, and allow for bilateral and over the counter (OTC) trading, which could eventually enable a hydrogen commodity market with standard contracts.
- Locating industrial heat users geographically around successful hubs (either privately or DOE program-funded) will have more dependable supply and developed logistics that could incentivize transitioning to green hydrogen.
- Planning and deploying renewable generation assets and grid infrastructure early and rapidly, above what will be required to meet current electricity demand, may help avoid long lead times, support current green hydrogen demand, and enable long-term green hydrogen growth.
- Allocating RD&D investments from government and private sector could lower the costs and increase efficiencies across the electrolysis, storage, and transportation of green hydrogen. Innovation to reduce retrofitting and fuel switching costs, especially for high-heat applications, is essential for a green hydrogen economy that includes industrial heating.
- Increasing coordination between different planning, permitting, and approval authorities could reduce time constraints and cost burdens for a rapid build-out of clean energy generation and transmission without compromising valuable regulatory safeguards.

Implementing these and other considerations can let market and policy stakeholders accelerate the just and sustainable deployment of hydrogen for industrial process heat in priority subsectors, realizing meaningful GHG reductions.

Acknowledgments

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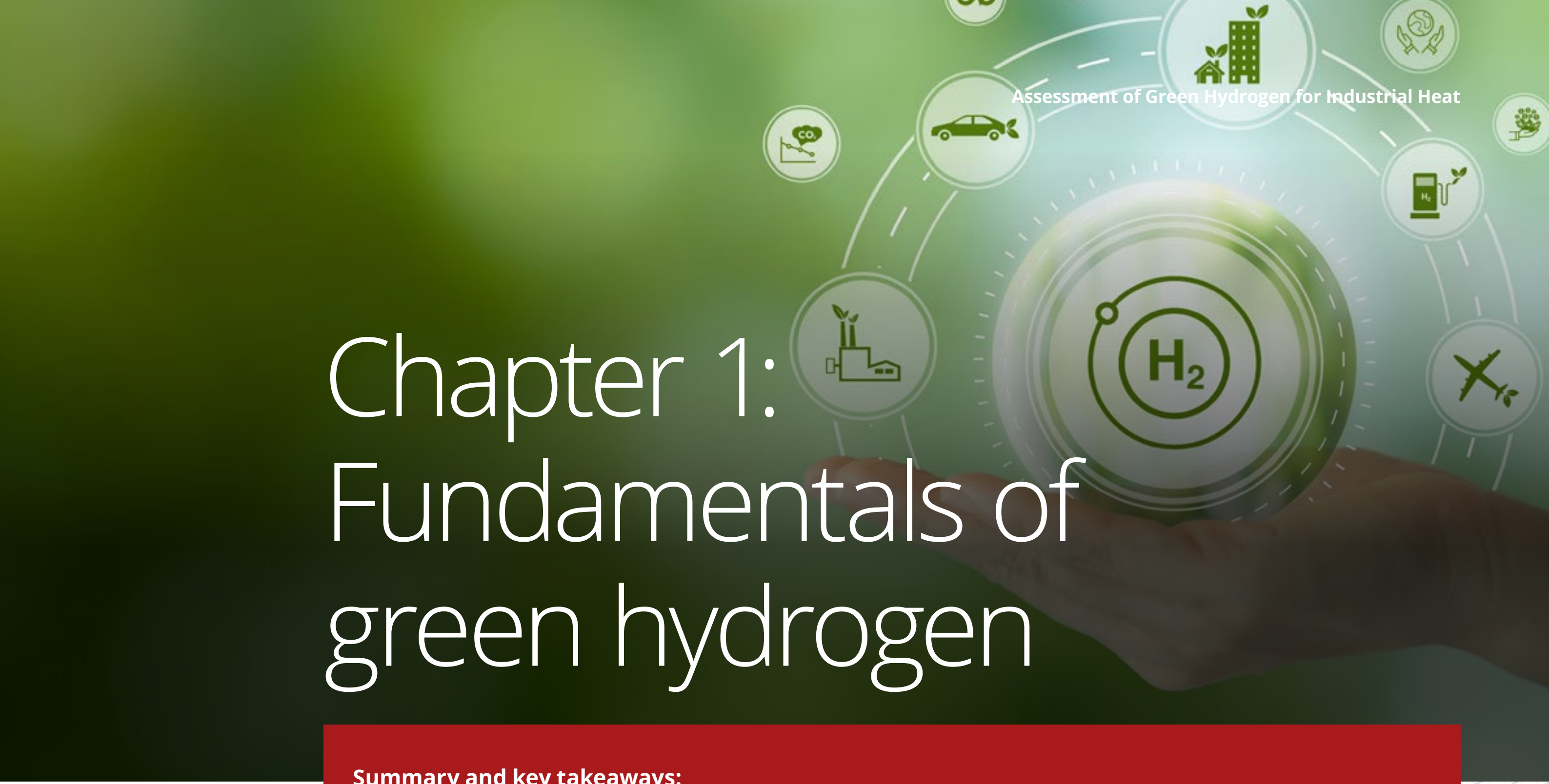

Chapter 1: Fundamentals of green hydrogen

Summary and key takeaways:

Today, hydrogen is mainly used for industrial processes, oil refining, producing ammonia, and methanol. However, given its ability to be burned without emitting carbon dioxide (CO2), green hydrogen may be a solution to help decarbonize hard-to-abate sectors. This chapter provides an overview of hydrogen, including its value chain, low-carbon potential, and market outlook, before focusing on green hydrogen specifically. This discussion reveals the following key takeaways:

- Certain methods of producing hydrogen do not emit large amounts of CO2 depending on the feedstock and energy source used during production. These methods include pink, blue, green, and turquoise, with the emissions abated varying between colors.
- While companies, governments, and countries work to solve the challenges related to scaling green hydrogen and as the energy transition proceeds, a combination of hydrogen types will likely continue to be produced in the United States, including green, pink, blue, and grey.
- The future market for hydrogen is expected to grow significantly (both domestically and globally) and stems from falling costs investments, planned projects, increased government support, geopolitical energy security concerns, and technology advancements.

Section 1: Hydrogen foundations

Molecular hydrogen (H2) is a gas that can be burned into the air to produce a high-temperature flame without emitting CO2, allowing it to store energy and provide an alternative to fossil fuels.[15]

Today, hydrogen is mainly used for industrial processes, including oil refining and producing ammonia and methanol.[16] In the future, it may also be used for electricity generation, energy storage, mobility, and heating applications for both industry and residences (figure 1). If produced from clean sources, hydrogen can potentially drive net decarbonization, especially in hard-to-abate sectors.[17]

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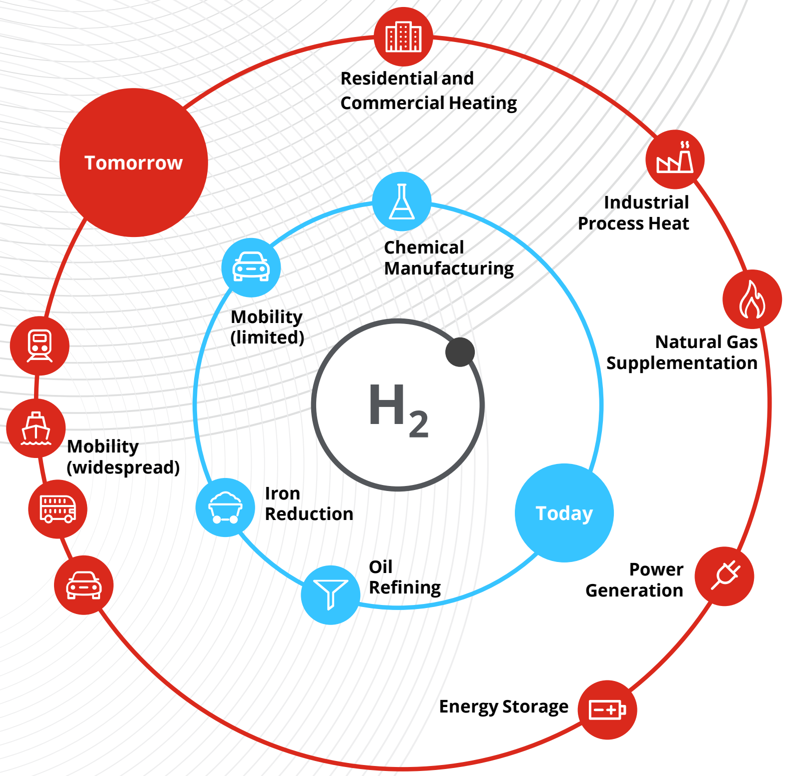
[15] DOE Office of Energy Efficiency & Renewable Energy, https://www.energy.gov/eere/fuelcells/hydrogen-fuel-basics#:~:text=Hydrogen%20is%20an%20energy%20carrier,thermal%20process)%2C%20and%20electrolysis. Hydrogen fuel basics. Accessed January 2023. Actual life cycle emissions for different hydrogen production methods vary from relatively carbon-intense grey hydrogen, through varying degrees of efficient abatement, to functionally zero-carbon green hydrogen.

[16] Mohit Joshi, Ilya Chernyakhovskiy, and Mark Chung, https://www.nrel.gov/docs/fy22osti/82554.pdf Hydrogen 101: Frequently asked questions about hydrogen for decarbonization, National Renewable Energy Laboratory (NREL), July 2022; Accessed January 2023; hydrogen used in green steel production as a reducing gas to produce direct-reduced iron from iron ore; current methods for green steel use electric arc furnaces for heat.

[17] Sectors for which few viable decarbonization options exist (e.g., steel or cement), often because fossil fuels involved are used for required chemical reactions rather than simply generating heat or power; BloombergNEF, https://about.bnef.com/blog/bloombergnef-launches-its-2023-pioneers-competition-for-the-worlds-best-climate-tech-innovations/ "Introducing the 2023 Pioneers Competition for the world's best climate-tech innovations," news release, October 12, 2022.Accessed November 2022.

Figure 1: Primary uses for hydrogen



Colors of hydrogen

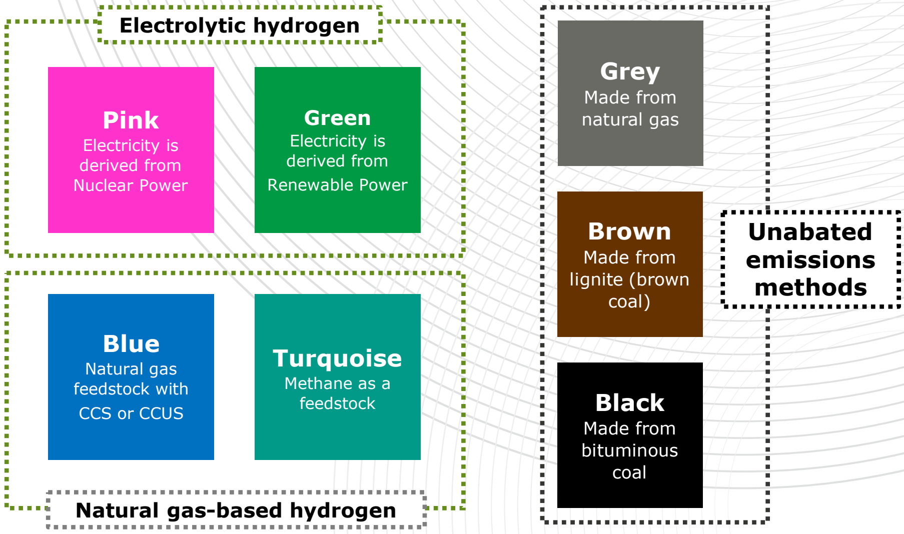
Though hydrogen itself is colorless, "colors" of hydrogen are often used as shorthand to describe the feedstock (the source of the hydrogen atoms) and energy source (to drive extraction processes). Most hydrogen produced today is "grey," "brown," or "black" hydrogen, made from fossil fuels in ways that emit significant amounts of CO2.[18]

Other methods of producing hydrogen that do not emit large amounts of CO2 include "pink," "blue," "turquoise," and "green" hydrogen, but it should be noted that emissions abated can vary greatly between these various colors.[19] Further, the emissions abatement potential of blue hydrogen should consider the methane emissions associated with upstream, midstream, and downstream extraction.

[18] Given the focus of this paper and the broader decarbonization agenda in the United States, brown and black hydrogen are not discussed further in this paper.

[19] © 2022 by Agyekum, E.B.; Nutakor, C.; Agwa, A.M.; Kamel, S. https://www.mdpi.com/2077-0375/12/2/173 A critical review of renewable hydrogen production methods: Factors affecting their scale-up and its role in future energy generation," Membranes 2022, 12, 173. Licensee MDPI, Basel, Switzerland. Accessed January 2023. Note: Grey, brown, and black hydrogen production facilities could theoretically be fitted with CCS or CCUS equipment, allowing them to abate some share of their emissions. Color definitions are based on actual—not potential—production processes; Turquoise hydrogen can avoid more than 90% of emissions if low-carbon electricity is used.

Figure 2: Hydrogen production processes



Electrolytic hydrogen is produced using electric energy to break the chemical bonds of water through a process known as electrolysis. The exhaust of this process is oxygen, and hydrogen made using this method can reduce emissions up to 100%. Types of electrolyzer-produced hydrogen are defined by the source of the electricity, with the most important being green from renewable electricity and pink from nuclear power.

Green hydrogen is produced from renewable electricity such as wind and solar. If using standard grid electricity, only a portion of hydrogen will be green, but 100% green hydrogen could be made through either a virtual power purchase agreement (VPPA) for renewable generation or dedicated "behind the meter" renewable generation either on or offsite. However, the clear standards and emissions accounting rules for use of renewable electricity for green hydrogen production still need to be defined.

Pink hydrogen is also produced by electrolysis, though instead of renewable energy sources, pink hydrogen uses electricity produced by nuclear reactors. Because nuclear reactors produce heat alongside electricity, different electrolyzer technologies can help to make pink hydrogen, leading to higher potential conversion efficiencies.[20]

Natural gas–based hydrogen is produced by heating and reacting the methane (CH4) in natural gas to break its carbon-hydrogen bonds. The process for breaking these bonds defines this group's hydrogen types. Hydrogen produced from natural gas and steam methane reforming (SMR) is most prominent today and is known as grey hydrogen.

Blue hydrogen is produced from natural gas using either SMR or auto-thermal reforming (ATR). Both processes oxidize the carbon in methane to separate hydrogen and usually burn natural gas to provide the energy for the reaction, producing CO2 as a byproduct. At this point, the hydrogen is grey and requires either carbon capture and storage (CCS) or carbon capture, utilization, and storage (CCUS) to abate emissions to become blue. This storage is often in the form of geologic storage in naturally occurring reservoirs and caverns. Blue hydrogen generally has approximately 90% lower emissions than grey hydrogen when considering upstream methane emissions.

[20] A. Ajanovic, M. Sayer, and R. Haas, https://www.sciencedirect.com/science/article/pii/S0360319922007066 "The economics and the environmental benignity of different colors of hydrogen", International Journal of Hydrogen Energy Vol. 47 Issue 57. Accessed March 2023. Pink hydrogen can leverage the heat produced by fission reactors to use high temperature electrolysis processes, such as solid oxide electrolysis, that are more efficient than other forms of electrolysis.

Turquoise hydrogen, like blue and grey, uses methane as a feedstock. Instead of oxidation of the carbon (which produces CO2), it uses a process called pyrolysis to heat the methane in an oxygen-free atmosphere using electricity, splitting off hydrogen and producing solid carbon as a byproduct rather than gaseous CO2.[21] Like green hydrogen, the electricity driving this process can be powered by renewable sources to further reduce the emissions associated with production. The main drawback of turquoise hydrogen is the energy input required for pyrolysis, which comes from external sources rather than energy produced by the reaction, as in SMR and ATR. Turquoise hydrogen has 54% to 90% lower emissions than grey hydrogen, depending on the source of this external heat.

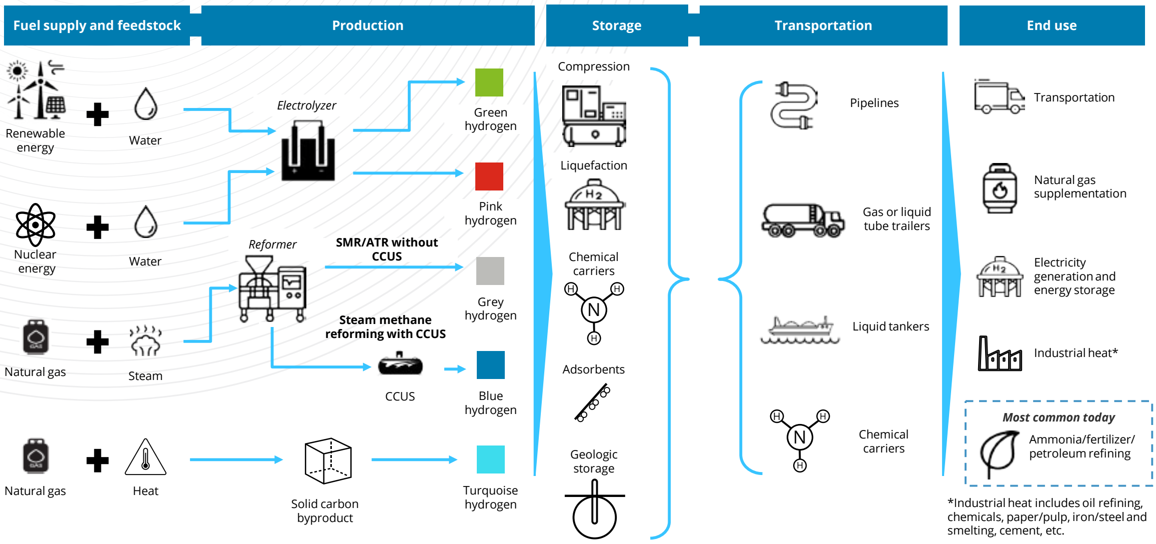
The global movement to define the carbon-intensity of hydrogen

While there is no universally agreed-upon definition of low-carbon hydrogen, governments in the United States, United Kingdom, European Union, Australia, and elsewhere are starting to take action to develop a common standard based on life cycle GHG emissions associated with different production methods so that hydrogen can be effectively classified and factored into energy transition plans. Chapter 2 will discuss policy efforts, including classification and certification schemes, in more depth.

Section 2: The hydrogen value chain

The hydrogen value chain contains three stages: production, storage and transportation, and end use (figure 3).

Figure 3: The hydrogen value chain: From feedstock to end use



Production

In 2021, almost 47% of global hydrogen production came from natural gas, 27% from coal, 22% from oil, and only 4% from electrolysis.[22] As discussed earlier, hydrogen can be produced in several ways, though green hydrogen production lags behind traditional methods and requires investment and supportive policy measures to advance RD&D efforts and reduce costs. To scale the production of green and pink hydrogen, companies and governments

[21] IRENA (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_hydrogen_policy_2020.pdf Green hydrogen: A guide to policy making. International Renewable Energy Agency, Abu Dhabi Accessed March 2023.

[22] International Renewable Energy Agency (IRENA), https://www.irena.org/Energy-Transition/Technology/Hydrogen#:~:text=As%20at%20the%20end%20of,around%204%25%20comes%20from%20electrolysis"Hydrogen overview page." Accessed January 2023.

globally need to ensure a reliable supply of carbon-free electricity, solve the intermittency and variability challenges around renewable energy sources, and build out both grid and hydrogen-specific infrastructure capacity. As the energy transition proceeds, a combination of hydrogen types will likely continue to be produced in the United States, including green, pink, blue, and grey.[23]

Storage and transportation

Hydrogen's physical and chemical properties can make storing and transporting it difficult. Specifically, hydrogen has a low energy density by volume[24], can leak from or damage storage media, and is a liquid only at much lower temperatures than natural gas (–253°C vs. –162°C).[25] It can be stored in certain geological formations, as a compressed gas or liquid in tanks, chemically bonded to a host material, or converted to a chemical hydrogen carrier such as ammonia,[26] and it can be transported in these forms on trucks, trains, and ships, as well as through specialized pipelines in gaseous form. It is possible to safely blend hydrogen in natural gas pipelines, but only 5% to 20% before significant retrofits are required.[27] These issues, and potential solutions to them, are further discussed in chapter 3.

End use

Hydrogen has many potential end-use applications. Today it is used for its chemical properties in controlled industrial reactions for oil refining and producing ammonia, methanol, and steel.[28] In the future, other common uses for hydrogen may likely include transportation, power generation, energy storage, and natural gas supplementation. While hydrogen will continue to be used as a reagent, especially in fuel, chemicals, and steel production, it can expand to significant use in fuel cells and as a combustible fuel for electricity generation and process heat. Chapters 2 and 3 will provide more detail on a sector-by-sector basis for industrial heat.

Section 3: Market sizing and activity in the hydrogen industry

Global demand for hydrogen

The volume of hydrogen produced in the United States in 2021 was approximately 13 million metric tons (Mt), mostly from using SMR (grey hydrogen) outside captive production.[29] In 2030 and 2050, the United States is expected to produce 25 Mt and 72 Mt, respectively, primarily via SMR with CCS or CCUS and electrolyzers, implying a US green hydrogen market of approximately $20 billion in 2030 and $170 billion in 2050 across production, distribution, infrastructure, and retail.[30] The significant uptick from 2030 to 2050 is due to the deployment of electrolyzers and ATR facilities with CCS or CCUS.

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23 Renewable generation that is weather-dependent, such as wind and solar, provides energy intermittently, unlike more dependable, or "baseload" generators, which can guarantee a constant source of power; DOE, https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf DOE National Clean Hydrogen Strategy and Roadmap. Accessed November 2022.

24 Ulf Bossel and Baldur Eliasson, https://afdc.energy.gov/files/pdfs/hyd_economy_bossel_eliasson.pdf Energy and the hydrogen economy, DOE Alternative Fuels Data Center (AFDC).Accessed January 2023

25 U.S. Department of Energy, Energy Efficiency & Renewable Energy, AFDC, https://afdc.energy.gov/fuels/natural_gas_basics.html "Natural gas fuel basics," accessed January 2023.

26 DOE Office of Energy Efficiency & Renewable Energy (EERE), https://www.energy.gov/eere/fuelcells/hydrogen-storage#:~:text=Hydrogen%20can%20be%20stored%20physically,pressure%20is%20%E2%88%92252.8%C2%B0C. Hydrogen storage. Accessed January 2023.

27 Miroslav Penchev et al., https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF Hydrogen blending impacts study final report, Agreement No. 19NS1662, California Public Utilities Commission 2022; Accessed January 2023 DOE EERE, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines#:~:text=Approximately%201%2C600%20miles%20of%20hydrogen,as%20the%20Gulf%20Coast%20region. Hydrogen pipelines. Accessed January 2023; various concerns complicate this problem, including the higher system pressures required to deliver consistent amounts of energy with lower energy density hydrogen.

28 Joshi, Chernyakhovskiy, and Chung, https://www.nrel.gov/docs/fy22osti/82554.pdf" Hydrogen 101"; IEA, HYPERLINK "https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf The future of hydrogen: Seizing today's opportunities, revised July 2019. All rights reserved. Accessed January 2023.

29 Jose M. Bermudez, Stavroula Evangelpoulou, and Francesco Pavan, https://www.iea.org/reports/hydrogen Hydrogen: Energy system overview, IEA, September 2022. All rights reserved. Accessed January 2023.

30 IEA, Bermudez, Evangelpoulou, and Pavan, https://www.iea.org/reports/hydrogen Hydrogen, September 2022. All rights reserved.

While the domestic market is expected to grow more than six times, a full understanding of the US hydrogen economy encompasses global markets due to the potential for exports. According to the International Energy Agency's (IEA) recent global hydrogen review report, hydrogen demand continued to move in a positive direction in 2021, reaching 94 Mt, up from 91 Mt in 2019. While much of this demand comes from traditional uses, new applications such as transport, power generation, hydrogen-derived fuels, and new industrial uses grew 60% from 2020 levels. Hydrogen production from pink, blue, or green was less than 1 Mt, mostly from blue hydrogen.[31]

Investment grew alongside demand in 2021: Green hydrogen saw a surge of new investment with approximately $1.5 billion being spent globally on advanced stage projects, 25 countries having adopted hydrogen strategies and committed public funds to the production of green hydrogen; with Germany and the United Stated pledging significant funds.[32] Even more significant progress, however, is required to meet climate targets.[31]

Growth drivers and barriers

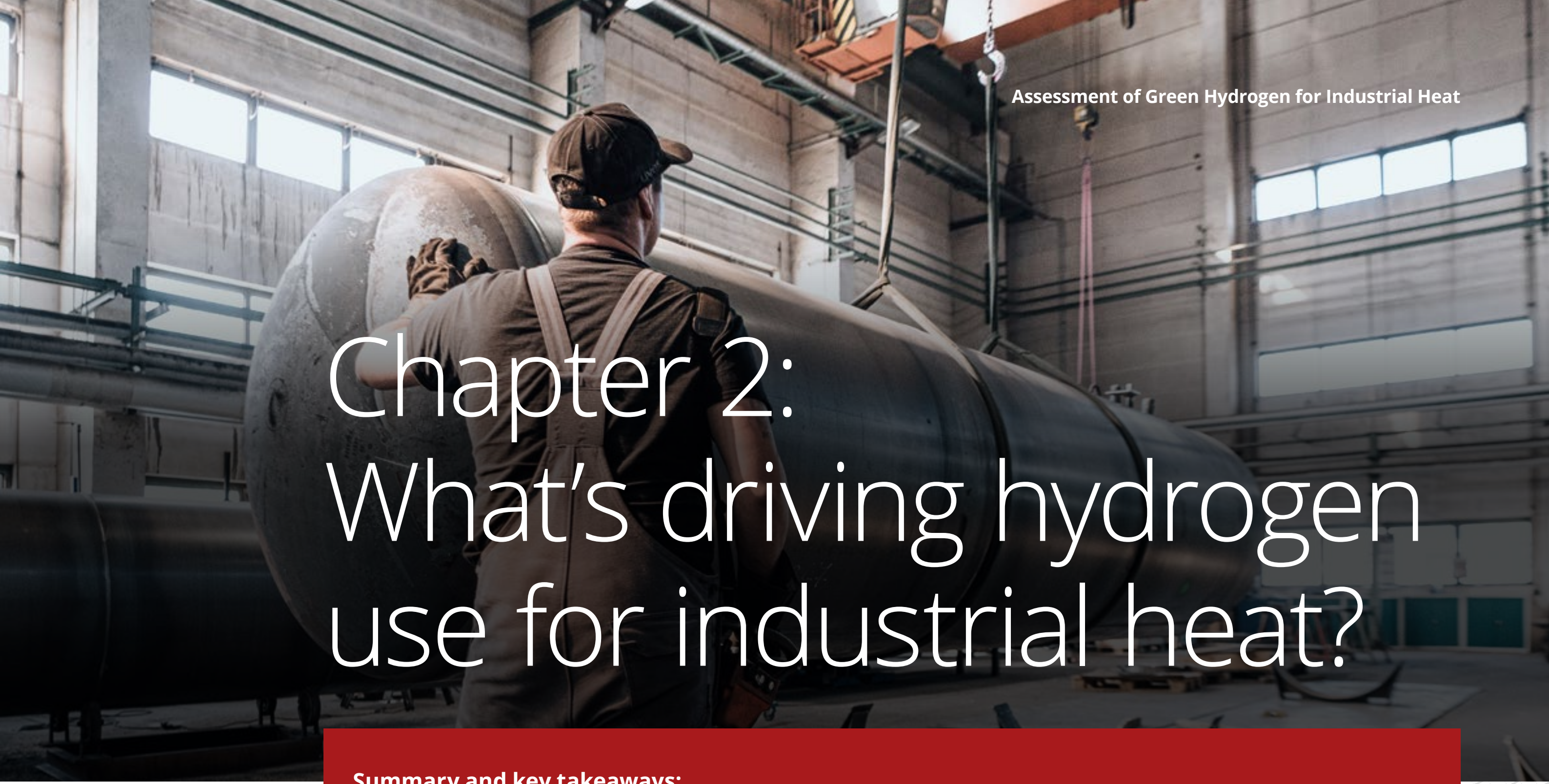
Flows of investment towards hydrogen are accelerating, due to increased attention to the energy transition, public policy, advances in technology, and geopolitical concerns over energy security.[34] While significant challenges exist to producing, storing, and transporting hydrogen generally, and green hydrogen in particular, considerable public and private interest and investment suggest those challenges can be overcome.

[31] Ibid

[32] https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf#page=213&zoom=100,72,142 Global Hydrogen Review 2022. All rights reserved. Accessed March 2023.] Even more significant progress, however, is necessary to meet climate targets.

[33] https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf Global hydrogen review 2022. All rights reserved. Accessed January 2023.].

[34] Ibid. ; current unabated SMR hydrogen prices are $0.7–$1.6/kg ($1.2–$2.1/kg for blue hydrogen), while green hydrogen costs $3.2–$7.7/kg; IEA projections predict green hydrogen to fall to the $1.3–$3.3/kg range, while the US DOE hydrogen Earthshot aims for $1/kg; IEA, https://www.iea.org/data-and-statistics/charts/global-average-levelised-cost-of-hydrogen-production-by-energy-source-and-technology-2019-and-2050 "Global average levelized cost of hydrogen production by energy source and technology, 2019 and 2050," last updated October 26, 2022. All rights reserved. Accessed January 2023.



Chapter 2: What's driving hydrogen use for industrial heat?

Summary and key takeaways:

The use of fuels for industrial heat comprises a significant proportion of US and global emissions. As such, industrial heat should be a significant focus of decarbonization efforts. This chapter reviews the scope of industrial heat usage in the marketplace before turning to a sector-by-sector discussion of hydrogen usage. This chapter reveals the following key takeaways:

- Governments, corporations, and countries have introduced a broad range of climate commitments and policies aimed at decarbonization and net-zero; the industrial sector—which includes industrial heat as well as other processes—is expected to play a vital role in reducing emissions and helping decarbonize US consumption.
- Given that available/existing options for decarbonizing industrial heat include technologies mostly fit for low-heat processes, there is less alternative for hydrogen to provide high-temperature process heat without producing carbon, making it a potential key solution for the energy transition.
- Five major subsectors, including chemical production, oil refining, iron and steel, pulp and paper, and cement and lime, account for the majority of US manufacturing industrial heat demand today with energy demand expected to grow (with chemicals leading energy use, followed by oil refining, and iron and steel) which will require a greater supply of industrial heat. As a result, the overall emissions profile of these subsectors is expected to increase, posing a greater need for decarbonization solutions, like hydrogen.

Section 1: Overview of industrial heat in the United States

The response to climate change requires profound and accelerating changes in how people, firms, and governments conduct economic activity. This includes a broad and growing set of government policies and corporate sustainability commitments aimed at decarbonization. In 2020, total US GHG emissions were 5,981 Mt of carbon dioxide equivalent (CO2e), dominated by the transportation (27%), electric power (25%), and industrial (24%) sectors.[35] The industrial sector, which includes both industrial heat (the focus of this report) and other processes that transform raw materials and energy into complex finished products, is expected to play a vital role in reducing emissions and helping to decarbonize US consumption. It is also the subject of new governmental initiatives, discussed in chapter 4.

[35] EPA, https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions "Sources of greenhouse gas emissions," last updated August 5, 2022. Accessed January 2023.

United States industrial heat—today

Manufacturing accounts for 81% of energy consumption in the industrial sector, followed by mining, construction, and agriculture.[36] Sixty-eight percent of the 21.03 quadrillion British thermal units (quads) consumed by the manufacturing sector in 2021 were used for industrial heat (14.39 quads) and 32% as nonfuel (6.64 quads).[37] The primary energy sources used are natural gas and petroleum, which account for more than 80% of the total.[38]

Industrial heat[39] encompasses many processes conducted at various temperatures, such as smelting metals, driving endothermic chemical reactions, and distilling fuel ethanol. Options for decarbonizing industrial heat production include resistive heating, microwave and infrared heating, solar thermal, nuclear heat, and low-carbon fuels, such as hydrogen. Many of these technologies are well suited only for lower-heat processes—with few options for high-heat processes—leaving little competition for hydrogen to provide high-temperature process heat without producing carbon.[40]

This report focuses on five major subsectors, which account for more than 70% of US manufacturing industrial heat demand:[41]

- Chemical production
- Oil refining
- Iron and steel
- Pulp and paper
- Cement

United States industrial heat—future outlook

The five subsectors outlined above had a total industrial heat demand of 9.11 quads in 2022 and are projected to rise to 10.48 quads in 2050 (figure 4).[42] Chemicals will continue to be the highest energy use subsector, followed by oil refining, iron and steel, pulp and paper, and concrete, cement, and lime. Each industry is expected to grow, requiring an increased supply of industrial heat, so the overall emissions profile of these subsectors is also expected to increase under the EIA reference scenario, which forms the base of our analysis. No clear set of technologies exists to displace fossil fuels in each subsector, and green hydrogen may capture a portion of the fuel mix for high-temperature processes in several subsectors moving forward.

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[36] DOE https://www.energy.gov/articles/doe-launches-new-energy-earthshot-cut-industrial-heating-emissions-85-percent "DOE Launches New Energy Earthshot To Cut Industrial Heating Emissions By 85 Percent," press release, September 21, 2022. Accessed November 2023.

[37] Industrial heat/fuel: Fuel consumption is the use of combustible energy sources to produce heat and/or to generate electricity (which, by manufacturers, is mostly for their use), and the use of electricity to operate equipment and associated manufacturing facilities; EIA, https://www.eia.gov/energyexplained/use-of-energy/industry.php "Use of energy explained" Accessed January 2023.; Deloitte & WWF analysis; nonfuel energy sources include feedstocks and other raw materials used in manufacturing.

[38] Energy consumption includes primary energy consumption and retail electricity sales/purchases and electrical system energy losses associated with the retail electricity sales/purchases; EIA, https://www.eia.gov/energyexplained/use-of-energy/industry.php "Use of energy explained." Accessed January 2023.

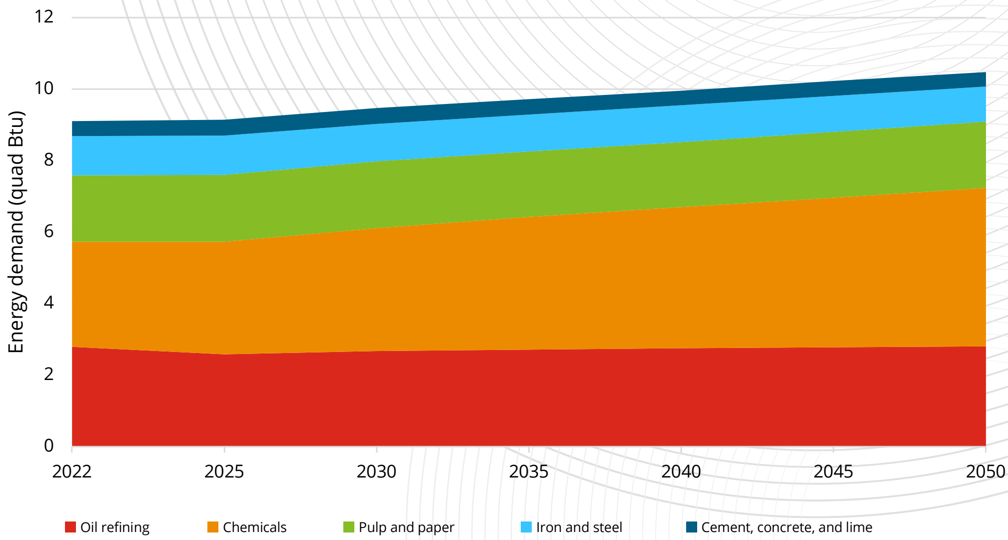
[39] It is recognized that industrial heat is only one process that could deploy hydrogen in relation to industrial applications but is seen as an important area that needs to be considered as companies continue to move towards their net-zero commitments.

[40] EIA, https://www.eia.gov/energyexplained/use-of-energy/industry.php Accessed January 2023; Deloitte & WWF modeling outcomes and analysis extrapolating to the year 2021. Nonfuel energy sources include feedstocks and other raw materials used in manufacturing.

[41] EIA, https://www.eia.gov/consumption/manufacturing/data/2018/index.php?view=data "Manufacturing Energy Consumption Survey (MECS) survey data," 2018. Accessed November 2022. In 2018, the manufacturing industrial heat demand from the five major subsectors in focus was 73% of the total (chemicals, 26%; oil refining, 23%; pulp and paper, 14%; iron and steel, 8%; cement and lime, 3%). The food industry, which accounted for 8% of the manufacturing industrial heat, requires low-temperature processes and, therefore, was not considered as a priority subsector due to limited application of hydrogen fuel as industrial heat. The remaining subsectors (i.e., glass, beverage and tobacco, textile, apparels, machinery, transportation equipment) account for 19% of the manufacturing industrial heat and are not the focus of this paper's assessment.

[42] Deloitte & WWF Analysis based on EIA's https://www.eia.gov/outlooks/aeo/data/browser/ "Annual Energy Outlook 2022 (AEO2022) Reference case". Accessed November 2022. This represents the assessment of US markets through 2050. The key assumptions in the reference case provide a baseline for exploring long-term trends, based on current laws and regulations as of November 2021;IA, https://www.eia.gov/outlooks/aeo/data/browser/ "AEO2022 Reference case - Table 1. Total energy supply, disposition, and price summary.". Accessed November2022.

Figure 4: US industrial heat demand forecast by priority subsectors, 2022–2050 (quads)



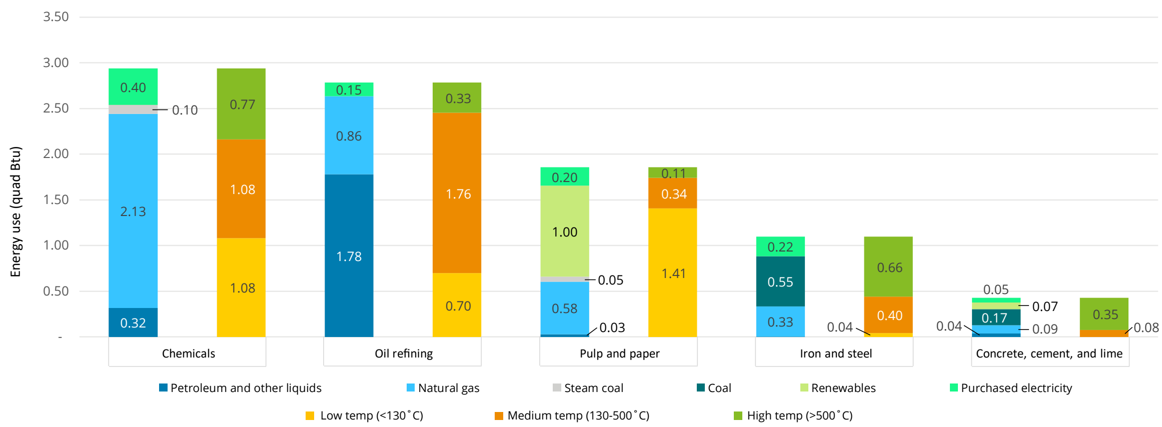
Source: Deloitte and WWF analysis based on EIA's Annual Energy Outlook 2022. Accessed January 2023.

Section 2: Meeting demand for low-carbon energy for industrial heat with hydrogen

Use of green hydrogen in select industrial heat sectors

The subsectors discussed above represent significant sources of demand for industrial heat, but there are notable differences between them. First, they use different fuel mixes for process heat. While natural gas is often dominant, sources such as coal and waste biomass are essential contributors and currently come at a lower price than hydrogen. Second, they vary in temperature requirements and, therefore, potential solutions for reducing emissions (figure 5).[43] In many cases, low-temperature needs (<130°C) can be met with current electric heat technologies, such as heat pumps and infrared heating, while thermal solar and nuclear heat can reach temperatures up to 300°C. Green hydrogen will face competition as a low-carbon heat solution for applications in this range. The majority of high-temperature applications (>500°C) are beyond the capacity of current electrification technology, while hydrogen, which burns up to 2100°C, can supply heat across this range. This section discusses the particular applications of hydrogen across these subsectors, including (in some instances) usage outside of industrial heat.

Figure 5: US industrial subsector energy usage by fuel type and temperature, 2022



Source: Deloitte and WWF analysis based on EIA, AEO2022 Reference case . Accessed November 2022

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[43] Deloitte & WWF modeling outcomes and analysis based on EIA, https://www.eia.gov/energyexplained/use-of-energy/industry.php "Use of energy explained"; Accessed November 2022. EIA, https://www.eia.gov/outlooks/aeo/pdf/AEO2022_ChartLibrary_full.pdf Annual Energy Outlook 2022, March 3, 2022; Accessed November 2022. EIA, https://www.eia.gov/dnav/pet/pet_pnp_capfuel_dcu_nus_a.htm "Petroleum & other liquids – Fuel consumed at refineries," June 21, 2022. Accessed November 2022.

Oil refining
Oil refining is the process of separating and chemically processing crude oil into more useful fuels, which requires process heat. Some products of the refining process, such as kerosene and diesel, are sold to customers, while others, such as petroleum coke or "still" gas, are not marketable; however, they are useful fuels, and modern refineries generate 68% of their heat demand from such waste products. This presents a significant barrier to adopting other fuels for heat generation. Because fuels such as still gas are byproducts of the refining process, they are essentially free fuels (oil companies are often vertically integrated, meaning the organization running the refinery is processing crude oil it already owns, further reducing input costs). Additionally, environmental regulators prevent the dumping or flaring of these byproducts.

Refinery operators could have to buy fuel that used to be a free input and may also incur the cost of disposing of byproducts safely. Changing the fuel mix for this application would require both that the cost of hydrogen fall significantly and that costs for burning byproducts rise due to a carbon tax or similar measure. Until refineries find an alternative purpose for these byproducts, they are expected to continue combusting them to produce thermal energy.[44] Additionally, CCS or CCUS may be an economical option to reduce emissions from the refinery subsector. It is improbable that refiners will adopt green hydrogen for heat.

Some refining processes, however, use hydrogen not as a heat source but as a feedstock. Today, this hydrogen is grey and often made onsite from natural gas or as a byproduct of some refining processes. Because the equipment to produce this hydrogen is already in place and integrated into refinery systems, green hydrogen is unlikely to make inroads without incentives to retrofit or replace existing assets. More likely, these facilities will be retrofitted with CCS or CCUS technology to make blue hydrogen. Additionally, until refineries find an alternative purpose for these byproducts, they are expected to continue to combust these to produce thermal energy. In this context, supply constrained green hydrogen could be prioritized for other sectors that can fully decarbonized their thermal energy consumption. CCS or CCUS could be deployed to reduce the emissions from the refinery subsector while the economy continues to delink from fossil fuel and reduce demand from this sector.

Chemicals
A large wave of new chemical plants in the United States came on-line in the past decade to take advantage of inexpensive shale gas fuels and feedstocks. The low cost of natural gas gives United States chemical producers a competitive advantage globally and switching to other processes for industrial could impact on that advantage. Though newly built facilities may be designed with hydrogen in mind, adopting green hydrogen in this generation of plants could require expensive retrofits (on the order of $1,500/Mt of product in high-temperature processes) and redesigns, and these facilities are unlikely to be replaced before their "end of life" without government incentives.

From a feasibility perspective, many of the heating needs in the chemical industry are low-to-medium heat and thus amenable to both hydrogen and electrical heating. Still, approximately 26% of heating needs are in the more than 500°C range. Here, hydrogen has an advantage over electrification, though it still has some adoption hurdles, such as supply and capex switching costs.

Retrofitting existing plants with CCS or CCUS may also occur to reduce emissions and avoid stranding assets.

The chemical subsector, already a large heat consumer, is expected to grow through 2050, increasing its demand for industrial heat. High costs for retrofitting relatively young plants will mean that the majority of demand for green hydrogen from this subsector, for both heat and feedstock, is expected to grow as new plants are designed, and existing plants are retrofitted where possible to use green hydrogen.[45] Demand for ammonia, which already grows in line with food supply, is expected to expand further as ammonia is deployed as fuel and exported. Further plans for industry-making hydrogen-based chemical, as in Europe, look set to make the chemicals industry a valuable opportunity for green hydrogen to be used as fuel and feedstock.

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[44] Because hydrogen is also a byproduct of some refining processes, the carbon intensity of these self-produced fuels is less than that of natural gas.

[45] EIA, https://www.eia.gov/consumption/data.php" Consumption & efficiency, accessed January 2023; DOE, https://www.energy.gov/sites/default/files/2022-09/Industrial%20Decarbonization%20Roadmap.pdf Industrial Decarbonization Roadmap, DOE/EE-2635, September 2022.Access January 2023.

[46] Dylan D. Furszyfer Del Rio, Benjamin K. Sovacool, Steve Griffiths, Morgan Bazilian, Jinsoo Kim, Aoife M. Foley, and David Rooney, https://www.sciencedirect.com/science/article/pii/S1364032122005950?via%3Dihub "Decarbonizing the pulp and paper industry: A critical and systematic review of sociotechnical developments and policy options," Renewable and Sustainable Energy Reviews 167 (October 2022).Accessed January 2023.

Pulp and paper

Pulp and paper combined make up the third-largest industrial heat consumer in the US manufacturing sector, at about 21% of consumption (1.86 quads) of the five subsectors analyzed here. Manufacturing begins with mechanically or chemically breaking down wood into pulp, which is then mixed with water and other additives, dried, and treated to make paper. Papermaking is more energy intensive than pulping, and boilers to generate heat for papermaking account for roughly 95% of the industry's GHG emissions.[46]

Like refining, pulping produces byproduct fuel that could otherwise incur disposal costs. This byproduct, called black liquor, is a solution of lignin and other undesirable wood constituents for papermaking. It retains a significant portion of the energy of the original wood and supplies roughly 50% of the heat the subsector consumes,[47] with about 30% of the remaining heat needed coming from fossil fuels.[48]

Heat demand is mostly for low- to medium-temperature heat (around 200°C), with limited applications up to 1000°C, and is amenable to electrification (especially nonthermal electric water removal), heat recovery, and energy-efficient processes to reduce emissions. Coupled with the presence of waste biomass heat, hydrogen uptake in this subsector is unlikely to be significant.[49]

Iron and steel

Modern steelmaking relies mainly on one of two furnace types: fuel-burning blast furnace-basic oxygen furnaces (BF-BOF), which make up 33% of US production, and electric arc furnaces (EAF), which use large electrodes and account for 67% of US production.[50] EAF technology, which is already operating commercially, is likely to expand as the primary heat source in steel production, meaning hydrogen is not likely to provide process heat.

Cement

While growth in the cement industry is projected to be relatively flat over the foreseeable future,[51] the cement industry produces significant emissions, mainly by calcinating limestone into calcium oxide ($CaCO3 \rightarrow CaO + CO2$).[52] These process emissions account for 58% of the subsector's total. The remaining 42% of emissions are mostly incurred generating heat for pre-calciners (which operate at 600° to 700°C) and rotary kilns (at 1200° to 1400°C) and are the focus of this section.[53] Because many cement processes are at a high temperature (>500°C), electrification is not feasible without significant technological development.

For specific applications, such as the rotary kiln, physical and chemical differences between burning hydrogen and natural gas may require processes and equipment to be redesigned. For example, hydrogen burns at a different rate and temperature than natural gas or coal, so the rate at which raw mix feeds into the kiln may need to be altered. It is also not well understood how the higher hydrogen concentrations might affect the high-temperature refractory materials used in kilns or with raw materials inside the kiln. This is a potential area for increased RD&D to understand the process and to enable equipment and processes to use hydrogen efficiently. Additionally, hydrogen combustion produces more water vapor than natural gas or coal combustion, which may require redesigning of exhaust systems. In the near term, partial measures requiring limited reworking, such as hydrogen blending into fuel streams, may lessen some emissions while developing experience with alternatives to fossil fuels.[54]

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[47] Renewable energy usage was used as a proxy for the share of heat from black liquor.

[48] EIA, https://www.eia.gov/outlooks/aeo/data/browser/#/?id=41-AEO2022&cases=ref2022&sourcekey=0 "AEO2022 Reference case – Table 30. Iron and steel industry energy consumption." Accessed January 2023.

[49] Michel D. Obrist, Ramachandran Kannan, Thomas J. Schmidt, Tom Kober, https://www.sciencedirect.com/science/article/pii/S2213138821009516?via%3Dihub "Long-term energy efficiency and decarbonization trajectories for the Swiss pulp and paper industry," Sustainable Energy Technologies and Assessments 52, part A (August 2022).

[50] EIA, https://www.eia.gov/outlooks/aeo/ Annual Energy Outlook 2022 presentation, March 3, 2022; Accessed January 2023. World Steel Association (worldsteel), https://worldsteel.org/steel-topics/statistics/annual-production-steel-data/?ind=P1_crude_steel_total_pub/CHN/IND "Total production of crude steel," last updated January 31, 2023

[51] IEA, David Hodgson and Paul Hugues, https://www.iea.org/reports/cement Cement, September 2022. All rights reserved, Access January 2023; US Geological Survey, https://pubs.usgs.gov/periodicals/mcs2021/mcs2021-cement.pdf Mineral commodity summaries: Cement," January 2021.

[52] Lucy Rodgers, https://www.bbc.com/news/science-environment-46455844 "Climate change: The massive CO2 emitter you may not know about," BBC News, December 17, 2018. Accessed January 2023.

[53] Cement production does require significant heat: roughly 88% of the sector's total energy demand.

[54] DOE, https://www.energy.gov/sites/default/files/2022-09/Industrial%20Decarbonization%20Roadmap.pdf Industrial Decarbonization Roadmap. Accessed January 2023.

For applications such as the pre-calciner, however, cement manufacturers are typically fuel-agnostic, as long as sufficient temperatures are achieved, and can likely incorporate green hydrogen as soon as supplies are available. Use of clean hydrogen, as well as hydrogen blending in fuel streams for kilns, represents a possible path to the meaningful use of hydrogen for heat in the cement industry. Pilot projects, for example in the United Kingdom, are underway to use hydrogen (and other alternative fuels) in cement plants. These initiatives are important steps in resolving technical issues and paving the way for the increased use of hydrogen in this industry.[55]

Conclusion

Industrial heat, supplied mostly by fossil fuels today, is a significant source of GHG emissions. Mitigating these emissions will be essential to reaching net-zero, and green hydrogen may have a significant role in decarbonizing industrial heat for chemicals, iron and steel, and cement.

With the growth in green hydrogen spurred by the DOE's hydrogen hubs and the IRA's 45V tax credits, we may start seeing green hydrogen used for heat in these industries before 2030, although it is recognized that industrial heat is expected to compete with other use cases, such as transportation or a chemical feedstock, which may delay significant deployment in industrial heat. Despite these policies, other high-energy-use industries, such as pulp and paper and oil refining, are unlikely to see green hydrogen used for heat (figure 6).

Figure 6: US subsector emissions and energy use by temperature profile

Industry subsector	Reported CO2 emission (Mt CO2e/year)	Opportunities	Challenges	Process heat temperature (°C)	Temperature profile	Energy use (Quads btu)
Chemicals	171.7	Current utilization of H2 in the subsector could enable scale	High temperature processes are expensive to overhaul and highly integrated within plants	<130	Low	1.08
				130–500	Medium	1.08
				>500	High	0.77
Oil refining	186.0	No significant opportunities for green hydrogen	Negligible heating fuel costs make fossil fuels difficult to displace	<130	Low	0.70
				130–500	Medium	1.76
				>500	High	0.33
Pulp and paper	28.0	No significant opportunities for green hydrogen	Significant electrification is expected in the subsector	<130	Low	1.41
				130–500	Medium	0.34
				>500	High	0.11
Iron and steel	66.8	Existing hydrogen utilization could enable scale	Capital intensity of hydrogen utilization	<130	Low	0.04
				130–500	Medium	0.40
				>500	High	0.66
Cement	96.3	Hydrogen can reach temperatures required for production	Utilizing 100% hydrogen doesn't produce the specified flame for kiln heat	<130	Low	—
				130–500	Medium	0.08
				>500	High	0.35

[55] Pavitra Srinivasan and Neal Elliott, https://www.aceee.org/blog-post/2022/12/low-carbon-cement-could-be-sped-market-climate-law-funds Low-Carbon Cement Could Be Sped to Market with Climate Law Funds," American Council for an Energy-Efficient Economy, Dec. 23, 2022. Accessed March, 2023]

Chapter 3: Green hydrogen: Production methods, technology readiness, and current adoption

Summary and key takeaways:

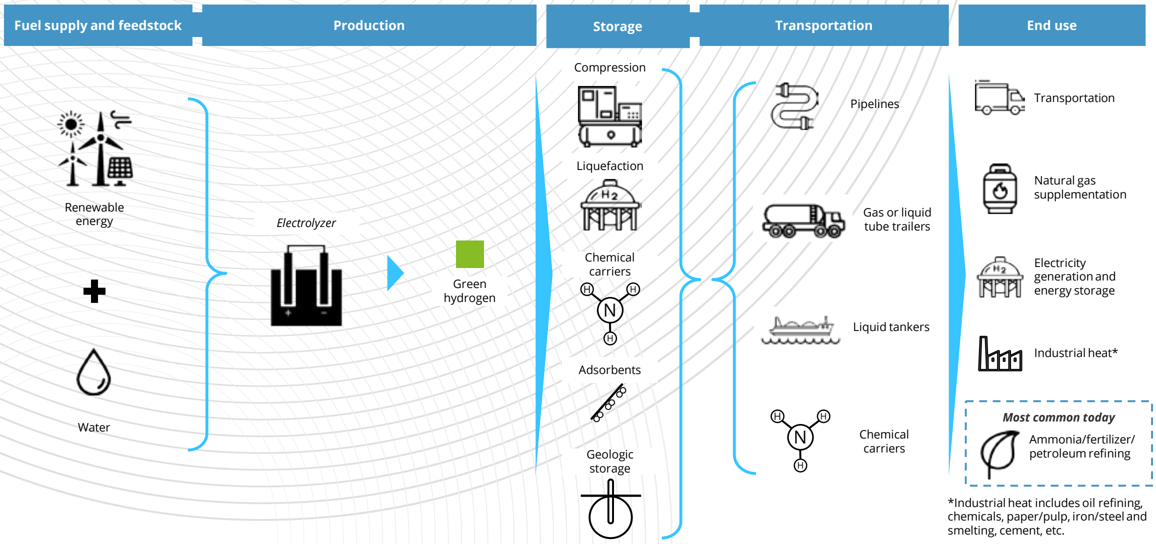
In order to effectively scale green hydrogen, it will be necessary to tackle challenges within the value chain, including unreliable fuel supply and feedstock sources, electrolyzer manufacturing and production capacity, transportation and storage infrastructure, and end-use equipment. This chapter provides detail into each of these and considers current progress made within the United States for short- and long-term use cases. This chapter reveals the following key takeaways:

- Given producers will compete for supply of green electricity, creating access to cheap renewable power and solving intermittency challenges related to renewable generation will be important for electrolyzers to operate at capacity and be able to scale.
- Though manufacturing of electrolyzers is growing and costs are anticipated to fall, forecasts suggest an even more significant increase in capacity will be needed to meet future demand; likewise large-scale storage and cost-effective transportation infrastructure will be necessary to scale green hydrogen.
- Green hydrogen is likely to be first adopted for heavy transport and in applications that already use grey hydrogen (e.g., chemical feedstock). Long-term adoption for energy storage and industrial heat will depend on whether green hydrogen can become cost-competitive with alternatives such as natural gas, diesel, coal, and other forms of hydrogen.

Section 1: Green hydrogen value chain maturity

Today, the value chain for green hydrogen is underdeveloped and not cost-competitive to meet short- and long-term demand projections without strong policy incentives. Challenges include unreliable fuel supply and feedstock sources, electrolyzer manufacturing and production capacity, transportation and storage infrastructure, and end-use equipment (figure 7).

Figure 7: The green hydrogen value chain: From feedstock to end use



Fuel supply and feedstock

The first set of challenges centers on power and feedstock sources. Green hydrogen producers have to contend with the intermittency of renewable generation, which can reduce the effective capacity factor of electrolyzers. Additionally, frequent power cycling can reduce the lifetime of most electrolyzers; addressing intermittency is a major focus of R&D efforts. Green hydrogen producers will also compete with other users to supply green electricity. Although there is growing enthusiasm for electrolyzers to use excess renewable capacity, this further reduces the effective capacity factor of the electrolyzer. Most grid electricity today is generated from high-emissions sources, so producers may build generating assets behind the meter, procure renewable energy certificates, or enter VPPAs to use power that is emissions-free. The US government has set a goal to supply 100% carbon-free grid electricity by 2035, which could allow green hydrogen to be produced more simply and from the grid.[56]

Beyond the electrolyzer plant, renewable power is the main cost driver of green hydrogen. Electrolysis is energy intensive, with energy conversion rates around 66%,[57] so cheap renewable power is crucial for siting green hydrogen production and its long-term growth.[58]

Producers should also secure a supply of clean, fresh water—the other input for green hydrogen. Concerns have been raised over future water scarcity and electrolysis's impact on the water supply. Producing 1 kilogram of green hydrogen via electrolysis requires a theoretical minimum of 9 liters of water, but actual production processes may lose water to evaporation or purification.[59] Water for industrial processes in many regions can be easily sourced from groundwater or municipalities. In regions where water is constrained, desalination, although expensive, is gaining traction as a potential solution, and exploration of other water sources is being examined–including storm water and grey water. These water sources, however, have added purification costs.

[56] White House, https://www.whitehouse.gov/briefing-room/statements-releases/2021/12/08/fact-sheet-president-biden-signs-executive-order-catalyzing-americas-clean-energy-economy-through-federal-sustainability/ Fact Sheet: President Biden signs executive order catalyzing America's clean energy economy through federal sustainability," December 8, 2021. Accessed January 2023.

[57] IRENA (2021), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218 Green hydrogen supply: A guide to policy making. International Renewable Energy Agency, Abu Dhabi Accessed November 2022.

[58] IRENA (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf?rev=4ce868aa69b54674a789f990e85a3f00 Green Hydrogen Cost Reduction: Scaling up Electrolysers to meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi. Accessed November 2022.

[59] Michael E. Webber, https://iopscience.iop.org/article/10.1088/1748-9326/2/3/034007/pdf "The water intensity of the transitional hydrogen economy" Environmental Research Letters 2 (Sept. 2007). Accessed March, 2023.; Rain Saulnier, Keith Minnich, and P. Kim Sturgess, https://watersmartsolutions.ca/wp-content/uploads/2020/12/Water-for-the-Hydrogen-Economy_WaterSMART-Whitepaper_November-2020.pdf Water for the hydrogen economy, WaterSMART Solutions, November 2020. Accessed November 2022]

[60] IRENA (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf?rev=4ce868aa69b54674a789f990e85a3f00 Green Hydrogen Cost Reduction: Scaling up Electrolysers to meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi. Accessed November 2022.

Production process
Electrolyzers are large stacks of electrolytic cells with an average commercial life span of 50,000 to 75,000 operating hours; the useful life of surrounding facility infrastructure is approximately 20 years. Capital costs of electrolyzer equipment constitute a significant component of the cost of green hydrogen production, but these costs are anticipated to fall as manufacturing processes and supply chains mature and electrolyzer life increases.[60] Currently, electrolyzer capital costs vary between $7.20/megawatt (MW) (for large 100 MW installations) and $10/MW (for 5 MW models), highlighting the benefits of scale. Electrolyzer manufacturing is growing, but forecasts suggest an even more significant increase in capacity and corresponding investment will be needed to meet future demand. The International Renewable Energy Agency's (IRENA) projections found that reaching the global electrolyzer capacity of 5 terawatts (TW) by 2050 will require a global manufacturing capacity of 130 to 160 gigawatts (GW) per year, up to 50 times the manufacturing capacity of 2021.[61]

Electrolyzer technologies
Since commercialization in the 1880s, electrolyzer technology has seen significant investment, development, and expansion, resulting in declining costs, increasing electrolyzer capacity, higher energy efficiency, lower capital costs, and increased stack durability.[62] While other green hydrogen production methods exist, this report focuses on the four main types of electrolyzers (figure 10): alkaline, PEM, solid oxide electrolyzer cell (SOEC), and anion exchange membrane (AEM).[63]

Alkaline electrolyzers are the simplest in system design and manufacturing complexity; widespread commercial-scale operations since the 1880s have improved efficiency and cost. Generally, they are slightly more cost-efficient than PEM electrolyzers due to lower equipment costs and longer (20 to 30 years) useful lives. There are also disadvantages to alkaline electrolyzers, including low current density and efficiency rates due to thick diaphragms, which in turn require more cells that can drive up the costs of large-scale systems. Their typically larger system sizes lead to larger minimum loads, which can cause problems when coupled with intermittent renewable generation.[64] Alkaline electrolyzers are the most common today and are a mature, commercialized technology.

PEM electrolyzers are also commercialized and have small footprints compared to alkaline electrolyzers, enabled by high current density and high output pressure.[65] R&D efforts have increased the hydrogen production capacity of PEM electrolysis stacks by orders of magnitude, from about 50 kilowatts (kW) to more than 1 MW. Of all current electrolysis technologies, PEMs cope better with variable power supplies. PEM electrolyzers' main weaknesses include sensitivity to water impurities and high capital expenditure costs compared to alkaline electrolyzers. PEM electrolyzers require expensive materials, including noble metals (e.g., platinum), to withstand acidic environments during hydrogen production.[66]

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[61] IRENA (2021), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218 Green hydrogen supply: A guide to policy making. International Renewable Energy Agency, Abu Dhabi. Accessed November 2022.

[62] IRENA (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf?rev=4ce868aa69b54674a789f990e85a3f00 Green hydrogen cost reduction: Scaling Up Electrolysers to Meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi. Accessed November 2022.

[63] Ibid; commercial scale refers to electrolyzers currently operated at MW scales; extant AEM installations are low kilowatt scale; DOE EERE, https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis "Hydrogen production: Electrolysis," accessed January 2023; S. Shiva Kumar and Himabindu Vurimindi, https://www.researchgate.net/publication/354158680_Hydrogen_production_by_PEM_water_electrolysis_-_A_review "Hydrogen production by PEM water electrolysis—a review," Materials Science for Energy Technologies 2 (March 2019): pp. 442–54. Accessed November 2022; Immanuel Vincent, Eun-Chong Lee, and Hyung-Man Kim, https://www.nature.com/articles/s41598-020-80683-6 "Comprehensive impedance investigation of low-cost anion exchange membrane electrolysis for large-scale hydrogen production," Scientific Reports 11, no. 293 (2021) Accessed November 2022.

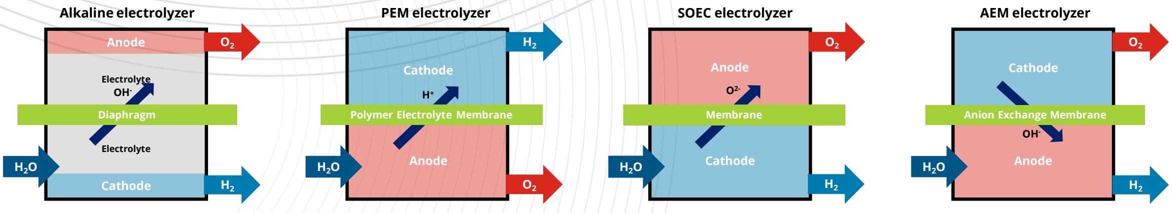
[64] Aliaksei Patonia and Rahmatallah Poudineh, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/01/Cost-competitive-green-hydrogen-how-to-lower-the-cost-of-electrolysers-EL47.pdf Cost-competitive green hydrogen: How to lower the cost of electrolysers?, Oxford Institute for Energy Studies, January 2022

[65] Marius Holst, Stefan Aschbrenner, Tom Smolinka, Christopher Voglstätter, and Gunter Grimm, https://www.ise.fraunhofer.de/content/dam/ise/de/documents/publications/studies/cost-forecast-for-low-temperature-electrolysis.pdf Cost forecast for low-temperature electrolysis – Technology driven bottom-up prognosis for PEM and alkaline water electrolysis systems, Fraunhofer Institute for Solar Energy Systems, October 2021. Accessed November 2022. Current density, usually measured in amperes per cm2, affects water conversion rates. Hydrogen is typically transported and stored at pressure, so higher output pressures of produced hydrogen ease integration into relevant systems. October 2021. Current density, usually measured in amperes per cm2, affects water conversion rates. Hydrogen is typically transported and stored at pressure, so higher output pressures of produced hydrogen ease integration into relevant systems.

SOEC electrolyzers have higher conversion efficiencies from operation at high temperatures. This has the added energy cost of heating large quantities of water. Waste heat can be recycled to reduce this energy burden, but the heat requirements have made these electrolyzers more likely to be used with nuclear power where heat is plentiful. Additionally, continuous operation is desirable because cycling SOECs can cause stack degradation during shutdown or ramping, leading to shorter life spans. Currently, SOEC installations are not at a commercial scale, though a few demonstration projects are reaching 1 MW. Larger-scale deployment could require larger cells (from 300 cm^2 to more than 1,000 cm^2), which currently have electrolyzer failure challenges. With advancement, SOEC could be an electrolysis technology for the future.[67]

AEM electrolysis is the newest low-temperature electrolysis technology, combining alkaline and PEM electrolysis benefits. AEM electrolyzers are simple and efficient and operate in a less acidic environment than PEMs, reducing material costs. Though a promising technology, AEM electrolysis is still at the lab scale due to chemical and mechanical stability issues that can create unstable lifetime profiles. For AEM to compete with other forms of electrolysis, more innovation and R&D needs to be conducted to avoid stack degradation.[68]

Figure 8: Schematic electrolyzer diagrams



Source: Solar Hydrogen Production

Source: DOE

Source: Nature

Source: Materials Science for Energy Technologies

Section 2: Green hydrogen value chain deep dive

Storage

The large-scale storage infrastructure for hydrogen is a crucial enabler in advancing the hydrogen economy. Hydrogen gas can be stored as a gas in certain geologic features or either in gaseous or liquid form in tanks. Liquefaction reduces the volume of hydrogen by a factor of 848,[69] significantly increasing its volumetric energy density. However, hydrogen should first cool to –253°C,[70] adding about $2 to $3 per kgH2,[71] while the gaseous compression process adds $1 to $1.50 per kgH2. Additionally, cooling requires more energy than compression, and both processes can have associated emissions depending on the source of the energy. Alternatively, hydrogen can be bonded to specially coated surfaces (adsorbents) or incorporated into chemical carriers such as ammonia. Today, physical storage is the more mature hydrogen storage technology, with amounts of hydrogen up to a few MWh of energy stored as either liquid or gas.[72]

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[66] IRENA (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf?rev=4ce868aa69b54674a789f990e85a3f00 Green hydrogen cost reduction: Scaling Up Electrolysers to Meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi. Accessed November 2022. [69] Ibid; Patonia and Poudineh, Cost-competitive green hydrogen.

[67] Ibid;. Aliaksei Patonia and Rahmatallah Poudineh, https://www.oxfordenergy.org/wpcms/wp-content/uploads/2022/01/Cost-competitive-green-hydrogen-how-to-lower-the-cost-of-electrolysers-EL47.pdf Cost-competitive green hydrogen: How to lower the cost of electrolysers?, Oxford Institute for Energy Studies, January 2022.

[68] IRENA (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf?rev=4ce868aa69b54674a789f990e85a3f00 Green hydrogen cost reduction: Scaling Up Electrolysers to Meet the 1.5°C Climate Goal, International Renewable Energy Agency, Abu Dhabi. Accessed November 2022.

[69] College of the Desert, https://www1.eere.energy.gov/hydrogenandfuelcells/tech_validation/pdfs/fcm01r0.pdf Module 1: Hydrogen properties, DOE EERE, December 2001. Accessed January 2023.

[70] US Department of Energy, Energy Efficiency & Renewable Energy, Alternative Fuels Data Center, Bossel and Eliasson, https://afdc.energy.gov/files/pdfs/hyd_economy_bossel_eliasson.pdf Energy and the hydrogen economy. Accessed January 2023

[71] Office of Energy Efficiency & Renewable Energy, https://www.energy.gov/eere/fuelcells/physical-hydrogen-storage Physical hydrogen storage," Accessed January 2023; IRENA (2021), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218 Green hydrogen supply: A guide to policy making. International Renewable Energy Agency, Abu Dhabi. Accessed January 2023

[72] Office of Energy Efficiency & Renewable Energy, https://www.energy.gov/eere/fuelcells/physical-hydrogen-storage Physical hydrogen storage." Accessed January 2023.

At the 100 GWh scale, large amounts of hydrogen can be stored in existing or constructed geological formations, such as salt caverns. Depleted oil and gas reservoirs, saline aquifers, and other underground formations may also be suitable for geologic storage, though feasibility and technical hurdles are still being studies as geologic storage media and other salt domes present risks that are poorly understood.[73] The United States and United Kingdom are among the only countries utilizing salt caverns for long-term hydrogen storage, with a combined capacity of 250 GWh.[74]

Material-based storage is less mature but offers a long-term solution to reduce the required storage pressure, increase gravimetric and volumetric density, and reduce costs.[75]

Transportation

Cost-effective transportation infrastructure for hydrogen is also essential to develop the hydrogen economy. Given its low volumetric energy density, hydrogen often undergoes compression, liquefaction, transformation into liquid organic hydrogen carriers (LOHCs), or conversion into ammonia, methanol, or synthetic fuels to ease transportation. For short distances, it's economical to transport hydrogen in liquid or gaseous form using trucks.

Dedicated pipelines are often effective for high-volume, long-distance transportation over land, but the capital cost is significant for building pipeline networks. Today, only 1,600 miles of hydrogen pipelines operate in the United States compared to 3 million miles of natural gas pipelines.[76]

While hydrogen pipelines are a mature technology, they are not without challenges. Dedicated hydrogen pipelines can cost between $0.3 million and $1.2 million per kilometer, depending on the type of pipeline,[77] and compared to natural gas, hydrogen has a greater propensity to leak (through valves, seals, welds, etc.), lower ignition temperature, and lower volumetric density, requiring higher system pressures. Additionally, hydrogen can permeate and weaken solid metals in a process called hydrogen embrittlement. Ongoing R&D for pipeline material and equipment is seeking to address the issue of hydrogen pipeline costs.

A potential lower-cost solution in the short term is to retrofit existing natural gas pipelines to carry a blend of natural gas and hydrogen; rates of 5% to 20% hydrogen are considered safe without significant retrofits depending on the age, condition, and pressure of the pipeline.[78] Due to hydrogen's relatively low volumetric energy density, blending leads to emissions reductions of less than the proportion of hydrogen (e.g., blending 30% hydrogen could reduce emissions by 13%).[79] Until blending becomes more widely accepted and pipeline infrastructure is built, tube trailers and liquid tanks will likely remain popular regional hydrogen distribution methods (figure 9).

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[73] National Energy Technology Laboratory. https://netl.doe.gov/node/11982 "Underground hydrogen storage remains a key research topic for NETL,", August 22, 2022. Accessed March 2023.; Aliakbar Hassanpouryouzband, Edris Joonaki, Katriona Edlmann, and R. Stuart Haszeldine, https://pubs.acs.org/doi/10.1021/acsenergylett.1c00845 "Offshore geological storage of hydrogen: Is this our best option to achieve net-zero?," ACS Energy Letters 6, no. 6 (2021): pp. 2181–6. Accessed November 2023

[74] IRENA (2021), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218 Green hydrogen supply: A guide to policy making. International Renewable Energy Agency, Abu Dhabi, Accessed January 2023

[75] Office of Energy Efficiency & Renewable Energy , https://www.energy.gov/eere/fuelcells/materials-based-hydrogen-storage "Materials-based hydrogen storage." Accessed January 2023.

[76] Office of Energy Efficiency & Renewable Energy , https://www.energy.gov/eere/fuelcells/hydrogen-pipelines "Hydrogen pipelines." Accessed January 2023; IEA, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf The future of hydrogen, All rights reserved. Accessed January 2023. Separately, the https://iea.blob.core.windows.net/assets/5bd46d7b-906a-4429-abda-e9c507a62341/GlobalHydrogenReview2021.pdf IEA (pp. 144 and 156) estimates that pipelines operated at industrial volumes (>100 tons/day) will be the most economical method at ranges of 0–3,000 km. For longer distances, transport as ammonia or LOHCs will be more economical. Pipeline costs/kg fall as volume increases.

[77] IEA, https://iea.blob.core.windows.net/assets/a02a0c80-77b2-462e-a9d5-1099e0e572ce/IEA-The-Future-of-Hydrogen-Assumptions-Annex.pdf G20 Hydrogen report: Assumptions. All rights reserved. Accessed January 2023.

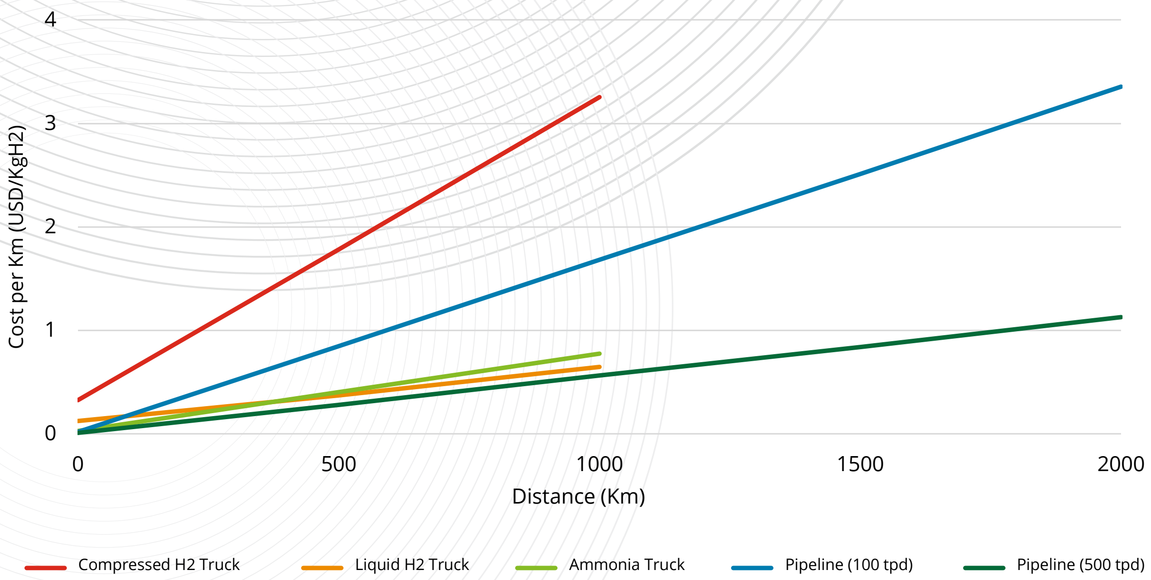
[78] The California Public Utilities Commission, Penchev et al., https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF "Hydrogen blending impacts study final report. Accessed January 2023.; Office of Energy Efficiency & Renewable Energy,, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines "Hydrogen pipelines". Accessed January 2023; various concerns complicate this problem, including the higher system pressures required to deliver consistent amounts of energy with lower energy density hydrogen.

[79] Office of Energy Efficiency & Renewable Energy, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines "Hydrogen pipelines," Accessed January 2023.; Joshua D. Rhodes et al., https://sites.utexas.edu/H2/files/2022/01/TX-H2-Power-Plant-Blending.pdf "Hydrogen blending in Texas natural gas power plants at scale," University of Texas, January 2022. Accessed January 2023

[80] That said, the first-ever marine shipment of liquefied hydrogen was https://www.offshore-energy.biz/suiso-frontier-brings-worlds-1st-lH2-shipment-to-japan/ completed on Feb. 25, 2022

For the longest transportation distances, hydrogen may be transported as ammonia instead of H2.[80] Ammonia transportation is relatively simple and cheap and already occurs at an industrial scale. Avoiding energy costs for the liquefaction of hydrogen and boil-off losses during transport means that both power-to-fuel and transportation efficiencies are higher for ammonia than for liquid hydrogen. However, the cost to convert hydrogen to ammonia ranges from $0.40 to $0.90 per kilogram,[81] and it is also costly to crack ammonia back into H2 of sufficient purity to be useful. For this reason, green ammonia may be more efficiently used directly rather than as a hydrogen carrier.

Figure 9: Cost of hydrogen transport based on distance



Targeted protein degradation (tpd)

Source: IEA [82]

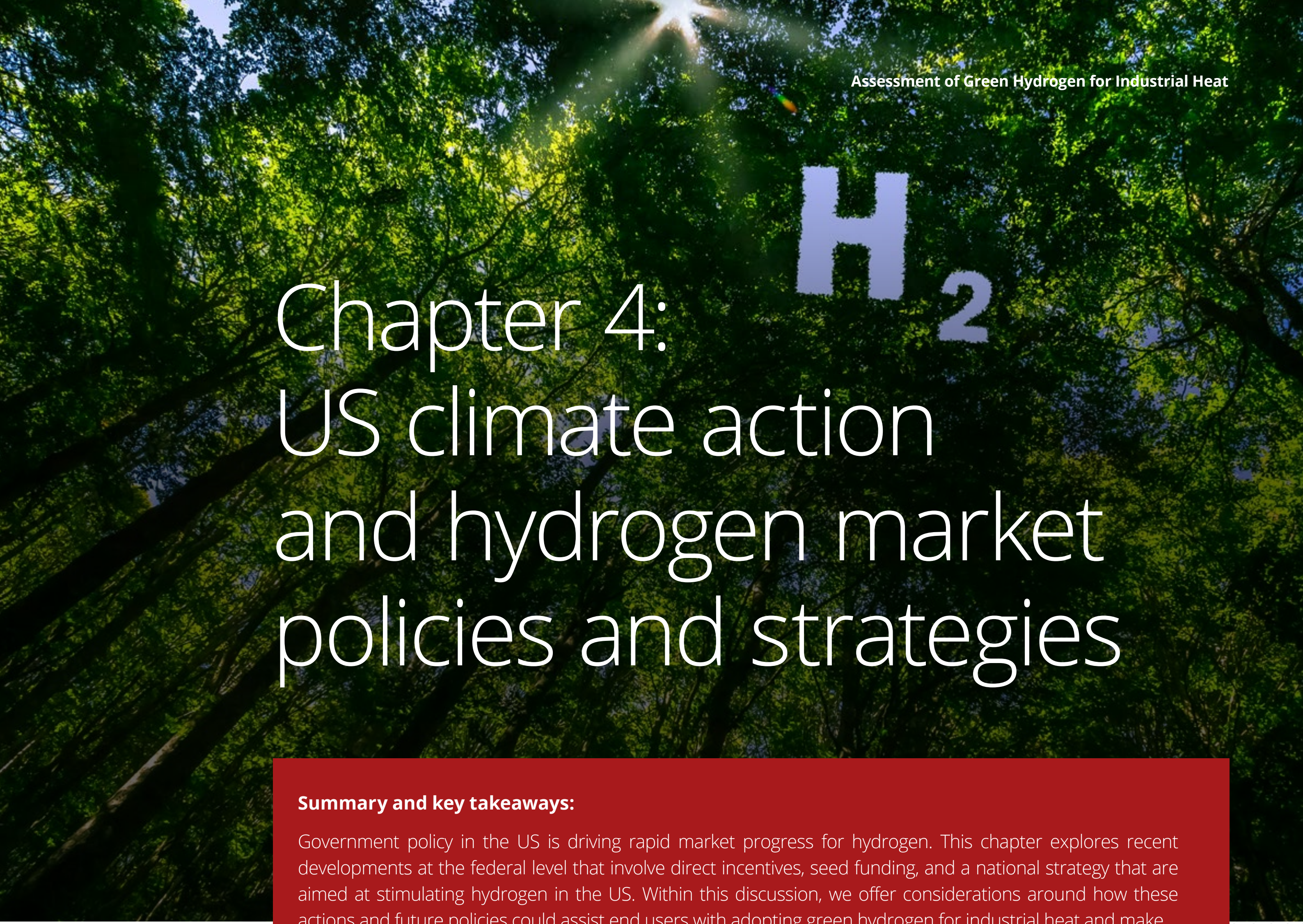
End-use applications

Green hydrogen markets are still developing, with few current energy-use applications. Underlying costs and availability of renewable energy sources vary widely, limiting market development. Suppliers of green hydrogen often need to secure long-term offtake agreements with end-use consumers to bring in investment for projects, but early adopters are not prepared to make long-term commitments on price. The development of hydrogen hubs across the United States is expected to promote the supply of green hydrogen as well as the related infrastructure and offtake agreements in end markets.

Green hydrogen is likely to be first adopted as a fuel for heavy commercial trucking and freight transportation and in applications that already use grey hydrogen (e.g., as a chemical feedstock). Long-term adoption will depend on whether green hydrogen can become cost-competitive with alternatives such as natural gas, diesel, coal, and other colors of hydrogen. Use cases in the longer term include energy storage and industrial heat. For example, hydrogen has the potential to help balance the grid, equalizing supply and demand for power. Electrolyzers can offer dynamic demand to help balance grid load, creating hydrogen when renewable production exceeds demand from other use cases. The resulting hydrogen can then be used to generate electricity to fill gaps in supply when intermittent renewables generate insufficient power. Additionally, blending hydrogen into natural gas pipelines could be an intermediate step for commercial and residential heat as well as onsite power generation. Finally, industrial heat presents opportunities for hydrogen as sectors that use industrial heat are energy intensive. The largest potential use case for hydrogen will be in high-heat industrial processes, as low- and medium-heat processes are likely to use more cost-favorable alternatives, such as the electrification of steam generators. In new hydrogen end uses, materially scaling hydrogen adoption will require retrofitting or replacing equipment in applications.

[81] IRENA (2021), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/May/IRENA_Green_Hydrogen_Supply_2021.pdf?rev=f24d7919eee5433e86ae9dbc4cf10218Green hydrogen supply: A guide to policy making. International Renewable Energy Agency, Abu Dhabi. Accessed January 2023.

[82] IEA, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf The future of hydrogen: Seizing today's opportunities, revised July 2019. All rights reserved. Accessed March 2023.



Chapter 4: US climate action and hydrogen market policies and strategies

Summary and key takeaways:

Government policy in the US is driving rapid market progress for hydrogen. This chapter explores recent developments at the federal level that involve direct incentives, seed funding, and a national strategy that are aimed at stimulating hydrogen in the US. Within this discussion, we offer considerations around how these actions and future policies could assist end users with adopting green hydrogen for industrial heat and make significant progress in addressing the current challenges. This chapter provides the following key takeaways:

- The policies and programs focused on hydrogen within the United States have two main goals: to increase the cost competitiveness of hydrogen relative to alternative fuels and to create market certainty around the future role of hydrogen. These programs could significantly boost the production and usage of hydrogen, either directly or through supportive RD&D, and have the potential to mitigate some of the challenges associated with scaling green hydrogen.
- The IRA and the IIJA's hub funding are critical enablers for lowering production costs of green hydrogen (as well as pink and blue hydrogen), helping build crucial infrastructure, and increasing innovation to expand uptake. However, the cost of adoption, including transportation, storage, and retrofitting, required on the end-use side still poses a barrier and is likely to require additional policy support to overcome cost hurdles.
- Though a number of policies and programs have been put forth by the US government, there is still room to fill existing gaps, including safety regulations, and further public investment in hydrogen RD&D across the hydrogen value chain.

Section 1: Current hydrogen market policies and strategies in the US

DOE decarbonization strategies

The DOE has developed an *Industrial Decarbonization Roadmap*, which identifies four pillars that need to be pursued to achieve the 100% mitigation of GHG emissions: energy efficiency; industrial electrification; low-carbon fuels, feedstocks, and energy sources (LCFFES); and CCS or CCUS.[83]

[83] DOE https://www.energy.gov/sites/default/files/2022-09/Industrial%20Decarbonization%20Roadmap.pdf Industrial Decarbonization Roadmap. Accessed January 2023.

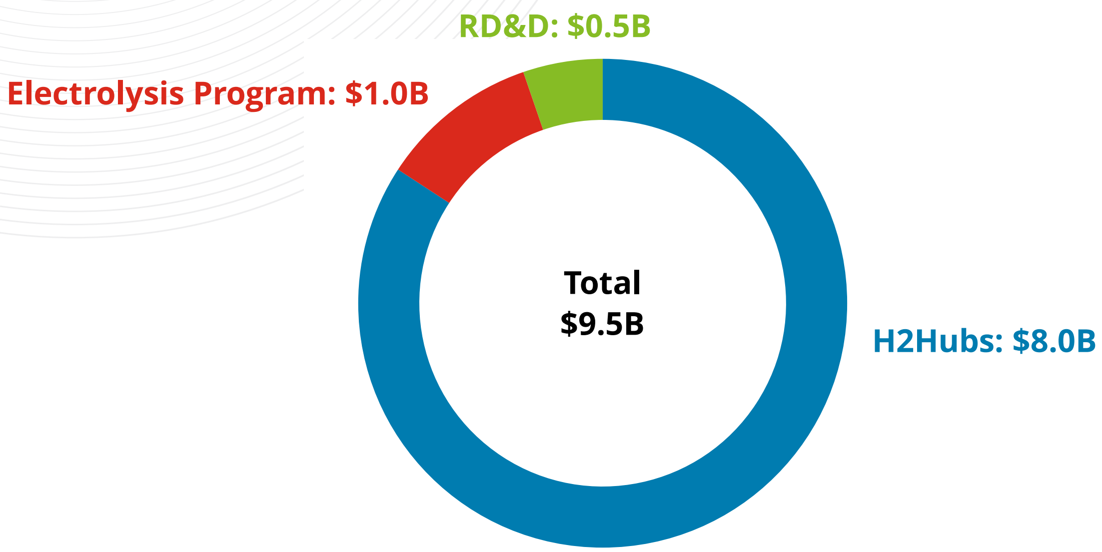
The third pillar, LCFFES, focuses on deploying low- and no-carbon fuel and feedstocks to reduce emissions associated with combustion for industrial process heat. Hydrogen is expected to play a prominent role as an LCFFES and to benefit from associated policies. To activate the hydrogen economy, the DOE developed the National Clean Hydrogen Strategy (NCHS), which, along with other federal policies, aims to accelerate the adoption of hydrogen.

DOE NCHS

The DOE's NCHS provides a snapshot of major initiatives unfolding as part of the IIJA[84] and strategies for the high-impact use of hydrogen in the industrial, transportation, and power sectors. It identifies opportunities to reduce the cost of hydrogen and create regional networks for production, storage, and end use, decreasing transportation and related infrastructure costs.[85] This regional approach has the potential to jump-start the industry and decrease the cost of hydrogen to the point of competition with other fuels, such as natural gas. Major funded initiatives (figure 10) include:

- Regional clean hydrogen hubs (H2Hubs): During the winter of 2023–2024, $8 billion will be awarded to develop connective infrastructure for producers and consumers of clean hydrogen by establishing six to 10 regional "H2 hubs." Concept papers have been submitted, and full applications are due on April 7, 2023.
- A clean hydrogen electrolysis program: As part of this program, $1 billion will improve efficiencies and reduce costs across the hydrogen electrolysis innovation chain. Applications were estimated to open in the fourth quarter of 2022, but only an intent to fund has been released.
- Clean hydrogen manufacturing and recycling RD&D activities: To support domestic supply chains and increase the reusability of hydrogen technologies, $500 million will be used for clean hydrogen equipment and projects. Applications were estimated to open in the second quarter of 2022, but only an intent to fund has been released.

Figure 10: DOE appropriation for clean hydrogen under the BIL



Source: Deloitte and WWF analysis based on DOE National Clean Hydrogen Strategy and Roadmap, Accessed January 2023.

[84] White House, https://www.whitehouse.gov/build/ "Delivering results from President Biden's Bipartisan Infrastructure Law." Accessed January 2023

[85] DOE, https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf DOE National Clean Hydrogen Strategy and Roadmap. Accessed January 2023.

H2@Scale and DOE Energy Earthshots/ Hydrogen Shot

As a precursor to the NCHS, the DOE launched an initiative called H2@Scale in 2016 to demonstrate the diverse sources for hydrogen production and end-use across sectors.[86] Since 2019, the DOE has announced 56 projects, of which the majority are in the demo or feasibility study phase, and the DOE has appropriated approximately $112 million to advance affordable hydrogen production and utilization. As part of efforts to advance clean energy technologies, the DOE released an Energy Earthshots initiative to drive innovation in crucial climate-related technology. One such initiative, the Hydrogen Shot, launched in June 2021, is designed to reduce the cost of hydrogen to $1.00 per kilogram by 2031.[87] The Hydrogen Shot initiative lays a foundation for building the hydrogen economy through funding for hydrogen infrastructure and stakeholder engagement at cross-industry summits.[88] Budget documents indicate that the DOE estimates it will spend $197 million on direct hydrogen projects in fiscal year (FY) 2022, not including spillover spending from other programs and development efforts.[89]

IRA

The IRA, a recent sizable federal law passed by Congress, is intended to accelerate net-zero efforts in the United States through substantial investment in the domestic production of clean energy. The bill provides approximately $400 billion for climate change, environment, clean energy, and climate justice, including $145 billion in appropriations and $217 billion in tax incentives. These incentives are aimed to spur investment in cleaner technologies to drive transformation and reduce emissions, leveraging federal tax policies.[90] The DOE and Internal Revenue Service (IRS) will implement many of its provisions.

The IRA's primary incentives for hydrogen include an investment tax credit (ITC) and a stepped production tax credit (PTC) tied to the emissions intensity of produced hydrogen. Within the law, the IRA extends the provisions of the solar ITC under section 25D of the tax code, allowing residential homeowners who install solar energy systems before 2033 to receive a tax credit of 30% of the cost from their federal income taxes. Additionally, the hydrogen PTC, under Section 45V, gives projects that begin construction before 2033 a substantial 10-year tax credit to reduce the effective cost of hydrogen, incentivizing its production and use (figure 11). The PTC baseline of $0.60 per kilogram of clean hydrogen is multiplied by five if prevailing wages and apprenticeship requirements are met. The effect of the 45V PTC is important: It subsidizes green hydrogen to the point of near-cost competitiveness with grey hydrogen. Today, the cost of green hydrogen with the maximum PTC is $0.50 to $5.00 per kilogram, rivaling the cost of grey hydrogen at $0.50 to $1.79 per kilogram. Our model predicts the cost per kilogram of incentivized green hydrogen could fall to $0.23 to $2.14 per kilogram in 2030, further closing the gap between incentivized green hydrogen and grey hydrogen.[91]

Figure 11: IRA 45V production tax credit by life cycle emission per kilogram of hydrogen

Lifecycle emission Per kg Hydrogen	2.5-4 kg CO_2e	1. 5-2.5 kg CO_2e	0.45-1.5 kg CO_2e	<0.45 kg CO_2e
Credit Value with Prevailing Wages and Apprenticeship	$0.60 (20%)	$0.75 (25%)	$1.00 (33.33%)	$3.00 (100%)

[86] US Department of Energy, Hydrogen and Fuel Cell Technologies Office, https://www.energy.gov/eere/fuelcells/H2scale#:~:text=H2%40Scale%20is%20a%20U.S.,revenue%20opportunities%20across%20multiple%20sectors. "H2@Scale," Accessed January 2023.

[87] DOE, https://www.energy.gov/articles/secretary-granholm-launches-hydrogen-energy-earthshot-accelerate-breakthroughs-toward-net "Secretary Granholm launches hydrogen Energy Earthshot to accelerate breakthroughs toward a net-zero economy," press release, June 7, 2021. Accessed November 2022.

[88] US Department of Energy, Hydrogen and Fuel Cell Technologies Office, https://www.energy.gov/eere/fuelcells/H2scale#:~:text=H2%40Scale%20is%20a%20U.S.,revenue%20opportunities%20across%20multiple%20sectors. "H2@Scale." Accessed January 2023

[89] White House, file:///C:/Users/abaglione/AppData/Local/Microsoft/Windows/INetCache/Content.Outlook/B4BXULIH/EERE. DOE budget for fiscal year 2022. Accessed November 2022.

[90] 117th Congress, https://www.congress.gov/117/plaws/publ169/PLAW-117publ169.pdf Public Law 117–169, 136 Stat. 1818, H.R. 5376 (2022). Accessed January 2023.

[91] IEA, https://www.iea.org/reports/global-hydrogen-review-2021/executive-summary "Global hydrogen review 2021 – Executive summary". All rights reserved. Accessed January 2023; Deloitte& WWF analysis.

Section 2: Future policy considerations

Carbon pricing

Carbon pricing schemes, such as those active in certain states and the European Union, more directly affect end users. The United States does not currently have a federal carbon pricing scheme, though policies in some states, for example, California, have seen some success.[92] Industrial firms must pay for each ton of carbon emitted by their processes (which may be defined broadly or narrowly depending on the specific program), creating an incentive to reduce emissions. Though hydrogen may cost more than, for example, natural gas per unit of energy, the final effective cost of hydrogen may be lower once prices for emitted carbon factor into the bottom line. Under an effective carbon pricing scheme, hydrogen usage may rise even without an immediate fall in its price.

Conclusion

The policies and programs put forward by the US government have two main goals—to increase the cost competitiveness of hydrogen relative to alternative fuels and to create market certainty around the future role of hydrogen. If effective, the programs outlined have the potential to significantly boost the production and usage of hydrogen, either directly or through supportive research and innovation. These programs are expected to materially mitigate or even overcome the challenges that face green hydrogen and its use for industrial heat.

Though policies mentioned in this chapter will likely increase the usage of hydrogen, they each take different approaches. The IRA's tax-credit system is perhaps the most influential policy lever currently in place. The production and ITCs will benefit green hydrogen directly by lowering the market price of hydrogen. Lowered prices could allow hydrogen producers to compete more effectively with other fuels and electric heating sources, in the case of industrial heat.

As for existing gaps, a carbon tax, safety regulations, and further RD&D grants could also aid the hydrogen economy if implemented. Carbon taxes could encourage the use of hydrogen, unlike incentive programs such as the IRA, which focus on production. With stimulus already directed at producers, demand-side incentives could have knock-on effects, creating deeper markets for suppliers and allowing them to invest in equipment and research, ultimately lowering costs.

Additionally, consistent and inclusive safety standards should be developed to scale green hydrogen. Regulations focus on hydrogen leakage; however, policies around system design, materials selection, operation, storage, and transportation will be crucial for market expansion. Safety codes and standards are essential to provide the technical basis to facilitate and enable the safe and consistent deployment and commercialization of hydrogen and fuel cell technologies in multiple applications. In the near term, barriers to the safe deployment of hydrogen include prohibitive separation distances for liquid hydrogen storage, improper deployment of safety sensors, inconsistent fuel-quality, and lack of component failure data. As the industry grows, there is also a need for standards for high throughput fueling for heavy-duty applications and codes for bulk storage.[93]

Outside government policies that aid production or use, public investment in hydrogen RD&D is still needed to drive industry development. This RD&D should seek to manage some of the challenges identified related to transporting and storing hydrogen, retrofitting and operating requirements of existing equipment, and health and safety considerations. Public investment in hydrogen RD&D will likely affect producers and end users depending on the specific project. For example, more efficient transportation and storage systems, with lower leakage risks, may reduce logistical costs for users, while more efficient electrolyzers could benefit producers.

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[92] Center for Climate and Energy Solutions (C2ES), https://www.c2es.org/content/california-cap-and-trade/" California cap and trade, accessed January 2023. California's cap-and-trade system has raised $5 billion in revenue, and emissions dropped by 5% in the first five years of the program (2013–2017).

[93] DOE, https://www.hydrogen.energy.gov/ Hydrogen Program, accessed January 2023.

Chapter 5: Evaluating pathways for green hydrogen

Summary and key takeaways:

This chapter contains a high-level overview of the methodology utilized to create a model that evaluated the potential for green hydrogen in industrial heating under four different scenarios centered on policy variables, market variables, and electrification of industrial process heat over time. The primary policy variables are the IRA incentives for hydrogen production, carbon pricing, and hydrogen supply targets, and the primary market variable is energy cost for various heating fuels over time. The modeling results are then covered in detail by scenario and by sector. The results of the modeling demonstrate the following key takeaways:

- Of the five sectors analyzed, chemicals, iron and steel, and cement have the most potential for green hydrogen utilization. The chemical subsector can utilize hydrogen across a wide range of processes, the iron and steel subsector can utilize hydrogen for the reduction of iron in the production process, and the cement subsector can mix hydrogen with waste biomass as part of a decarbonized fuel mix. The most advantageous scenarios modeled project that these three subsectors could utilize more than double the amount of hydrogen currently in production in the United States by 2050.
- The market for green hydrogen in industrial heat will be dependent on policy support given low energy prices in the industrial sector and the capex required for end users to convert from fossil fuels. Hydrogen must be significantly cheaper than fossil alternatives for firms to invest in fuel switching, and this is most likely through a combination of carbon pricing and hydrogen production incentives.
- Full decarbonization in industrial sectors will require further innovation or policy support to decrease capex costs for switching to hydrogen, particularly for high-heat processes. Chemical cracking and steelmaking are two of the most expensive processes to overhaul and should be focused on for full decarbonization.

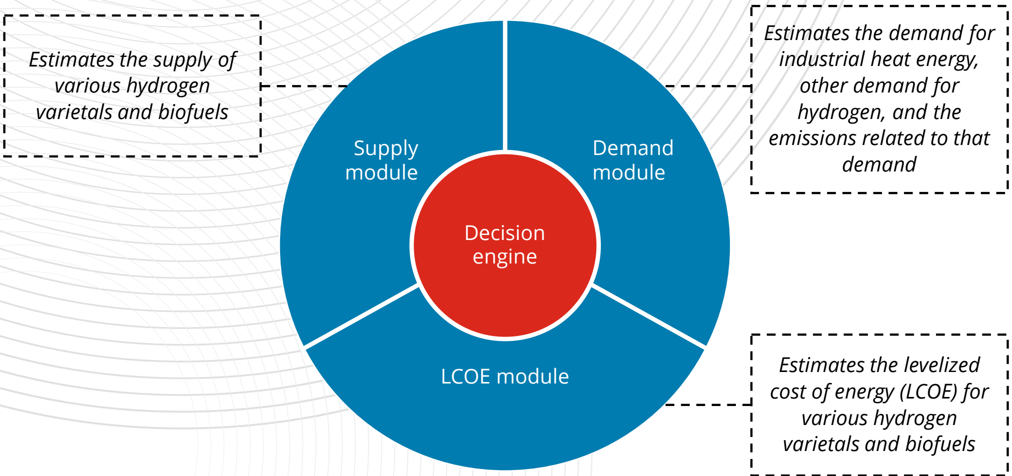
Section 1: Overview of modeling methodology and scenario planning for green hydrogen for industrial heat

Modeling methodology overview

The modeling methodology is based on inputs and assumptions from prior experience and industry research. Our methodology allowed for an assessment of a range of possible future scenarios and quantitatively supports considerations for the potential scaling of green hydrogen for industrial heat applications in the United States.

As seen in figure 12, the quantification process used three specific modules:

Figure 12: Model structure



These modules connect via a central decision engine, which matches supply with demand under various cost restraints.

Each priority subsector's total industrial heat demand is broken into temperature groups for high, medium, and low temperatures and referred to as a "demand point." Each demand point has a top-line demand, an electrification estimate, and the impacts of prior period's adoption, leaving a residual demand in each period sent to the decision engine.

Similarly, the supply module also acts as a waterfall. The DOE and EIA projections and demand signals from prior period activity determined the fuel supply for each of the fuels. This top-line supply was then reduced for demand from non-heat uses (e.g., as a chemical feedstock and in transportation uses), leaving a residual supply for matching in the current period. The levelized cost of energy (LCOE) module estimates the cost of various hydrogen production methods (pink, blue, and green), considering construction costs, fuel and feedstock, incentives, and location. This unit cost of hydrogen ($/kg H2) reduced over time per Wright's law concerning the cumulative doubling of production. This unit cost was extrapolated to a five-year cost of adoption inclusive of storage and transportation costs and costs to refurbish or replace existing combustion equipment. The present value of the all-in cost of adoption was compared to the present value of five years of "status quo" costs to determine the cost-ranking priority.

Residual demand is ultimately met by residual supply under cost constraints. Through Wright's law, adopting one of the hydrogen production alternatives in one period drives subsequent cost reductions in future periods.

See Appendix 2 for detailed modeling assumptions.

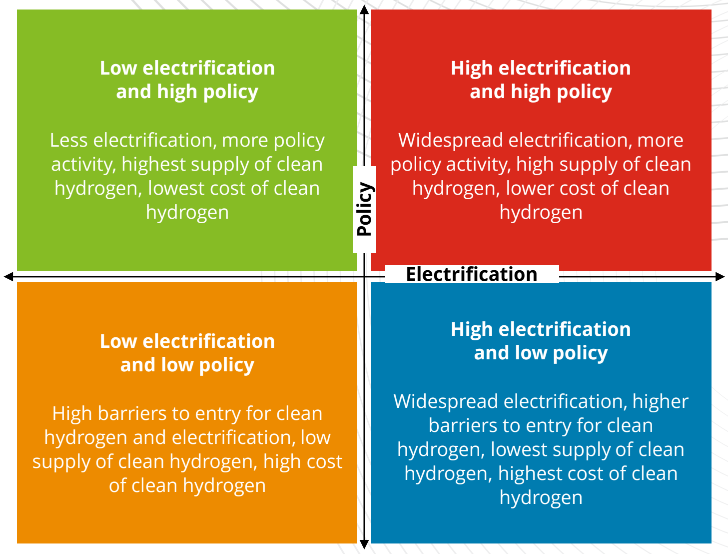
Scenario planning

Scenarios describe hypothetical yet plausible future pathways that can lead to a particular outcome. They are not intended to represent a complete description of the future or to forecast how events will unfold; rather, they are intended to highlight critical elements and drivers of future developments. Scenario analysis is a tool to enhance critical strategic thinking by allowing organizations to challenge assumptions about the future and explore alternatives that may significantly affect strategic decision-making.

Modeling scenarios

Hydrogen adoption across the US industrial sector will likely depend primarily on the federal policy push to create a hydrogen ecosystem and the potential electrification of industrial heat processes compared to fuel-based alternatives. Electrification in these scenarios refers strictly to using electricity-powered technologies for industrial heating and not to the electricity grid or electrification of other processes or technologies across the economy. Electrification is a critical factor in the scenarios because electric heating technologies are incredibly efficient compared to fuel-based technologies, and many end-use customers are already familiar with strategies to procure clean energy to decarbonize electricity use. Further, there are several policies implemented by the US government aimed at increasing the amount of renewable generation into the system and the increased uptake of this green electricity across residential, commercial, and industrial uses. These factors may result in many industrial end users preferring electrification as opposed to fuel switching; however, hydrogen still plays a large role as electric equipment cannot reach the required temperatures for various heating applications. The modeling scenarios for this project consider these two potential levers in a high/low environment and their impact on scaling green hydrogen (figure 13).

Figure 13: Modeling scenarios



Low electrification and high policy

In this scenario, electrification technology is adopted slower, increasing demand for fuel-based replacements such as waste biomass, biofuel, and hydrogen. This scenario (together with the other high policy scenario) utilizes drivers from the IEA's net-zero scenario, but it should be noted that the scenario did not specifically require industrial heat to become net-zero. Rather, plausible assumptions were developed to provide a view on the potential for green hydrogen deployment for industrial heat. This relates to both high policy scenarios developed as part of this analysis.

Government action on climate change will increase in this scenario. It assumes that IRA incentives will carry forward through 2040, and nationwide carbon pricing will be implemented in line with the IEA's net-zero scenario for advanced economies. 2040 was selected as the final year of eligibility for tax credits because production-based tax credits under the IRA are paid back over 10 years. This time frame means there would be government-incentivized hydrogen through the year 2050, aligning with the net-zero date of many organizations. The DOE will expand on its clean hydrogen targets, and 50% more clean hydrogen will be available by 2050 than under the DOE's initial plan.

Hydrogen demand from the transportation sector is highest in the high policy scenarios. This demand curve is based on the National Renewable Energy Laboratory's (NREL) optimistic case for hydrogen utilization in road transport, Federal Aviation Administration (FAA) projections for hydrogen utilization in aviation, and the IEA's net-zero scenario for hydrogen demand in shipping.

High electrification and high policy

In this scenario, electrification technology continues developing rapidly, allowing for relatively efficient and inexpensive electric boilers, electric arc furnaces, and heat pumps as primary decarbonization drivers. As a result, the demand for hydrogen is likely to reduce.

It is assumed government action on climate change will be more efficient in this scenario. It assumes that incentives from the IRA will be carried forward through 2040, and nationwide carbon pricing will be implemented in line with the IEA's net-zero scenario for advanced economies. The DOE will expand on its clean hydrogen targets, and 20% more clean hydrogen will be available by 2050 than under the DOE's initial plan.

Hydrogen demand from the transportation sector is highest in the high policy scenarios. This demand curve is based on the NREL's optimistic case for hydrogen utilization in road transport, FAA projections for hydrogen utilization in aviation, and IEA's net-zero scenario for hydrogen demand in shipping.

Low electrification and low policy
In this scenario, electrification technology develops slower, increasing demand for fuel-based replacements such as waste biomass, biofuel, and hydrogen.

In this scenario, government action on climate change will remain roughly in line with current levels. It assumes there will be no further expansion or extension of incentives from the IRA and that the adoption of nationwide carbon pricing is likely to remain low, gradually phasing in from $0/Mt in 2040 up to $50/Mt in 2050. Supply in this scenario meets the DOE's targets, and demand from the transportation sector is set in line with the NREL's conservative case for hydrogen utilization in road transport, FAA projections for hydrogen utilization in aviation, and the IEA's stated policies scenario for hydrogen demand in shipping.

As shown later in this chapter, the combination of policy and market levers in the low policy scenarios is insufficient to overcome the capital barriers required to switch to hydrogen for industrial users.

High electrification and low policy
In this scenario, electrification technology continues developing rapidly, allowing for relatively efficient and inexpensive electric boilers, electric arc furnaces, and heat pumps.

In this scenario, government action on climate change will remain roughly in line with current levels. It assumes there will be no further expansion or extension of incentives from the IRA and that the adoption of nationwide carbon pricing is likely to remain low, gradually phasing in from $0/Mt in 2040 up to $50/Mt in 2050. Hydrogen supply in this scenario meets the DOE's targets, and demand from the transportation sector is set in line with the NREL's conservative case for hydrogen utilization in road transport, FAA projections for hydrogen utilization in aviation, and the IEA's stated policies scenario for hydrogen demand in shipping.

Section 2: Scenario results

As noted previously, each of our scenarios has different electrification assumptions and policy levers that impact residual demand for combustion-based heat and costs of hydrogen. This combination of factors yields different adoption results under each scenario. This section explores the results from each scenario and the impact on the priority industrial heat subsectors considered.

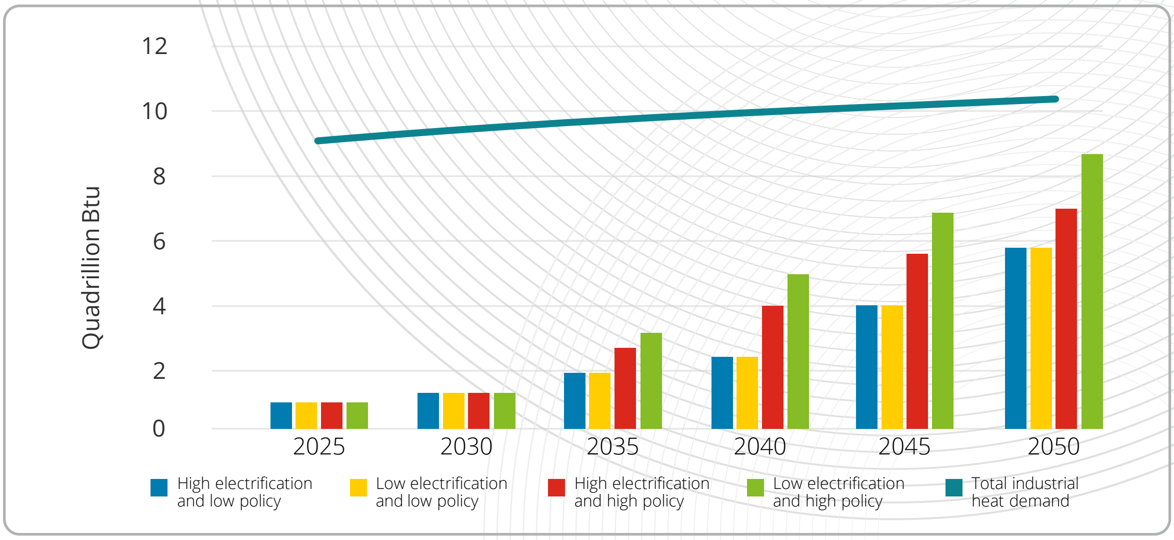
Base hydrogen supply by scenario
The hydrogen supply in the US market is expected to grow at a compound annual growth rate (CAGR) of 8% to 10%, depending upon the policy and electrification scenario. The low electrification–high policy scenario provides the most favorable path for hydrogen supply. This is due to the impacts of policy incentivizing and driving decarbonization efforts and those efforts focused on low-carbon fuels instead of electrifying operations.

Figure 14 shows the base supply of hydrogen over time by scenario.[94] In each of the low policy scenarios, the total supply is in line with the DOE's draft plan for hydrogen development, and the total hydrogen supply is expected to be approximately 5.76 quads by 2050. The total supply increases by 20% in the high electrification and high policy scenario and by 50% in the low electrification and high policy scenario. Values are held constant through 2030, assuming that the DOE cannot increase the scale of hydrogen further than planned in the short term. It is assumed that the production of green hydrogen will use approximately 5% of the country's total renewable energy capacity in 2025 and about 10% of the total renewable energy capacity in 2030.[95] The further years assume that renewable energy supply is sufficient to meet production requirements given the DOE's stated goals to fully decarbonize the grid by 2035. However, the nature of the grid's decarbonization is one of the challenges facing the green hydrogen industry. Careful consideration is likely needed so that renewable supply is developed in regions required for green hydrogen utilization.

[94] The model utilizes a demand signal to reinforce supply when unmet demand exists.

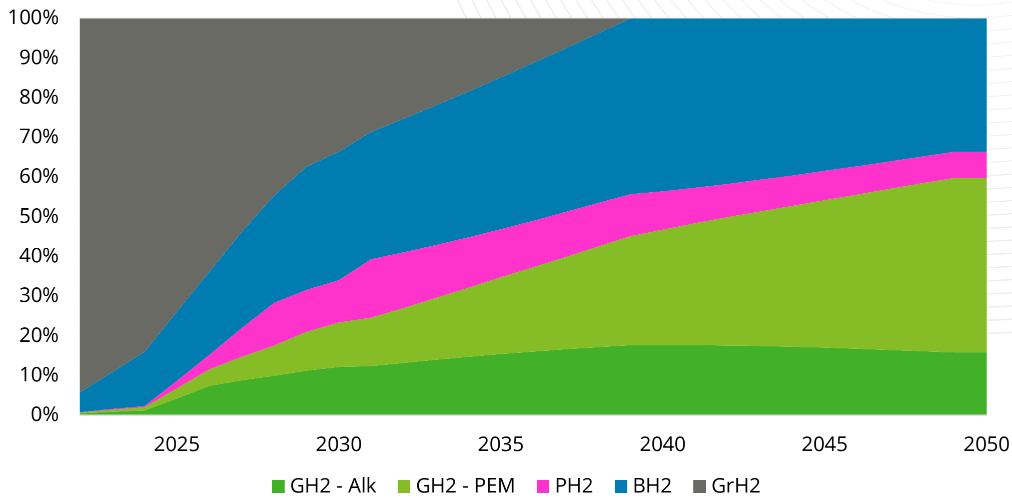
[95] EIA, https://www.eia.gov/outlooks/aeo/ Annual Energy Outlook 2022, March 3, 2022. Accessed November 2022.

Figure 14: Hydrogen supply over time by scenario



The base hydrogen mix by color remains the same throughout each scenario, as shown in figure 15.[96] Grey hydrogen is assumed to phase out by 2040 as incentives for carbon capture and potential carbon prices kick in. The model utilizes a demand signal to reinforce the supply of each fuel if demand goes unmet.

Figure 15: Base hydrogen supply as a percentage by type



Blue hydrogen increases most as a percentage of the total in the first few years of the model timeline. This initial growth is spurred by the conversion of existing grey hydrogen assets to blue hydrogen, which is less capital intensive than new-build blue or green hydrogen costs that are modeled next in figure 16. Additionally, blue grows at a high rate in the early periods as additional production infrastructure is required to scale green hydrogen. Green hydrogen is expected to reach scale around 2025, and this is the year in the model at which green hydrogen begins to grow at the highest percentage relative to total supply.

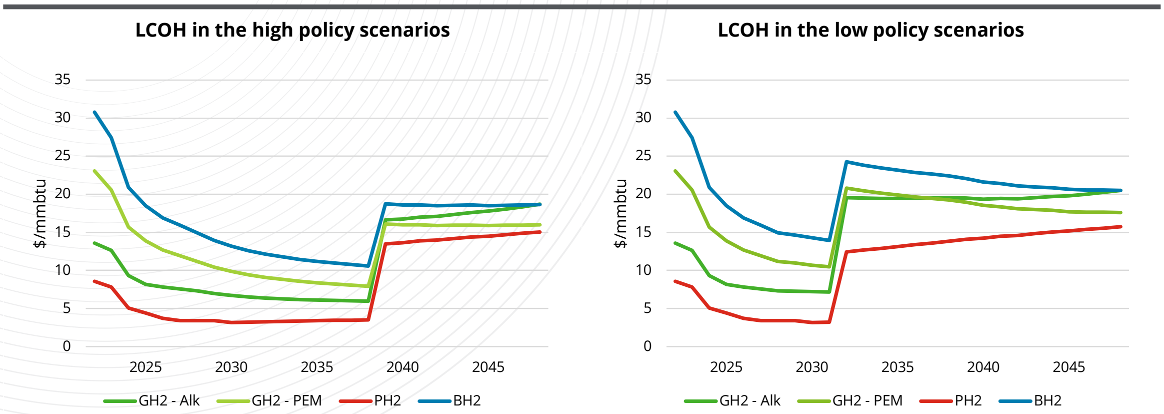
[96] GH2-Alk: Green hydrogen alkaline electrolysis; GH2-PEM: Green hydrogen PEM electrolysis; PH2: Pink hydrogen; BH2: Blue hydrogen; GrH2: Grey hydrogen.

According to the IEA, alkaline hydrolysis comprises 70% of the green hydrogen supply today.[97] IEA projects that the split between alkaline and PEM electrolysis will roughly be 50/50 by 2030. The model continues to assume this trend, which favors PEM production through 2050.[98] By 2050, PEM electrolysis is expected to have the highest share, followed by blue hydrogen, alkaline electrolysis, and pink hydrogen. Although solid oxide electrolysis is an exciting technology expected to gain traction in the market, it was excluded from the model due to the large variance in cost estimations and lack of commercial deployment. Similarly, AEM electrolysis was not considered as it remains on a lab scale with speculative commercial production costs. Wright's law is best applied to a technology that has reached a commercial scale. Cost and adoption-level estimations can be more methodically modeled as these technologies reach commercial scale.

Levelized cost of hydrogen by scenario

Despite the scenario, renewable electricity prices are the primary driver of long-term green hydrogen costs. Increased hydrogen production in high policy scenarios has little effect on long-term LCOH, indicating that significant reductions in capital expenditure will not continue in the long term. As shown in figure 16, nominal costs for green and pink hydrogen begin to level off or rise around 2040 despite continued increases in supply, which drive cost reduction through Wright's law in the model. This suggests that decreases in electrolyzer costs alone are unlikely to be enough to continue to lower the cost of green hydrogen and that low-cost renewable electricity is likely to be required to drive long-term cost reductions for green hydrogen.

Figure 16: Levelized cost of hydrogen (LCOH) by policy scenario



The IRA tax credits for green, pink, and blue hydrogen significantly impact the LCOE.[99] Levelized costs spike in the year when credits are assumed to expire (low policy FY2033, high policy FY2040). Assuming both technologies continue to improve, alkaline electrolysis should remain more cost-effective than PEM in the short to medium term. The $3 incentive per kilogram of green hydrogen, compared to $1 or less for blue hydrogen, drives the total cost of green hydrogen below blue hydrogen. Blue hydrogen is less incentivized, as the carbon capture utilized to make it clean hydrogen still does not capture all emissions. Unincentivized costs for green hydrogen are not competitive with blue hydrogen until 2030 to 2035.

Low policy scenarios

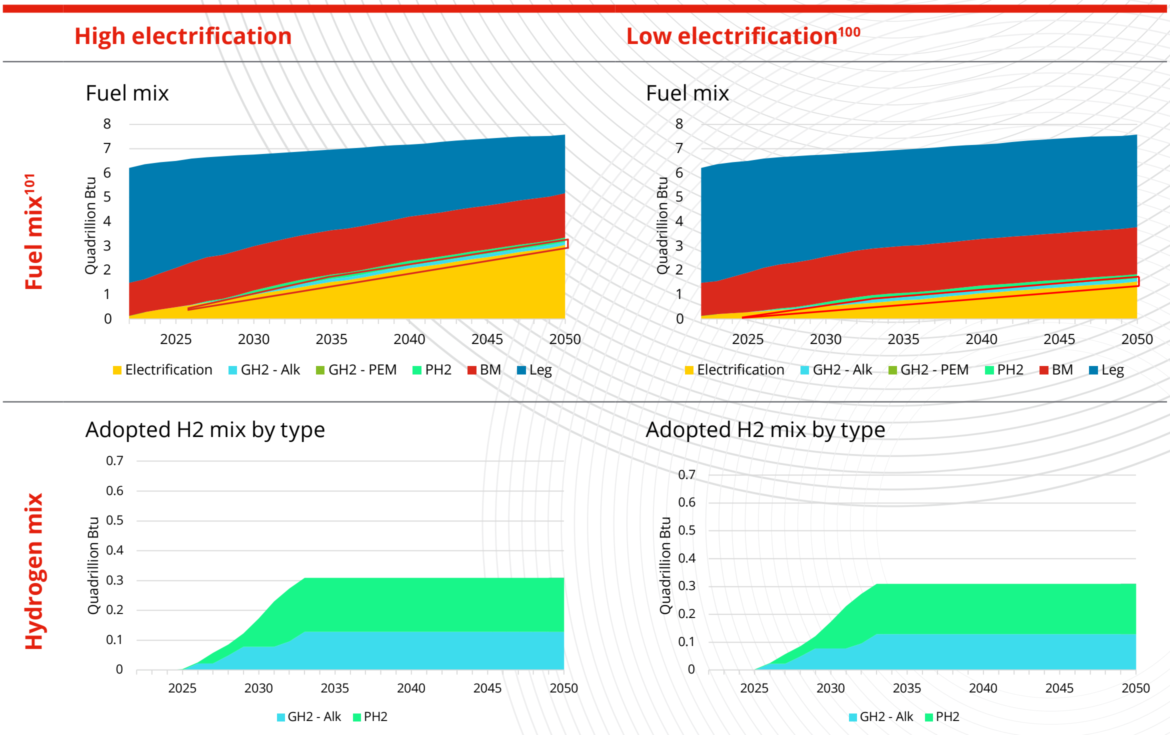
Key assumptions: In these scenarios, the IRA incentives for hydrogen expire in 2033. Carbon pricing is phased gradually after 2040, going from $0 to $67/Mt by 2050. Roughly 40% of industrial fuel use will electrify in the high scenario case, driven by the pulp and paper, chemicals, and iron and steel subsectors. This drops to roughly 20% in the low electrification scenario. Figure 17 shows the fuel mix through 2050 for the low policy scenarios. The hydrogen adoption profile is the same in both low policy scenarios, and as such, the low electrification, low policy scenario is not included in the sector analyses.

[97] IEA, https://www.iea.org/reports/global-hydrogen-review-2021 Global hydrogen review 2021. All rights reserved. Access November 2022.

[98] PEM electrolysis has a smaller physical footprint, scales better with renewable availability, and aligns well with transportation use cases.

[99] These costs account for inflation, with 2050 costs being comparatively lower than early costs.

Figure 17: Low policy scenario fuel mix



Summary results

High electrification

- Electrification, legacy fuels, and waste biomass are likely to be the major industrial heat energy sources accounting for 96%.
- Hydrogen potential in this scenario is limited, accounting for 4% of the total fuel supply.
- Hydrogen adoption occurs before incentives expire in 2033.
- Hydrogen utilization in this scenario is driven by pink hydrogen, with green hydrogen accounting for roughly 1% of total energy utilization by 2050.

Low electrification

- Legacy fuels and waste biomass are likely to be the major industrial heat energy sources in this scenario
- The hydrogen adoption profile is similar to the high electrification scenario, accounting for 4% of the total fuel supply.
- Overall adoption in the low policy scenarios is roughly half of the current hydrogen utilization in the United States.
- Hydrogen utilization in this scenario is driven by pink hydrogen, with green hydrogen accounting for roughly 1% of total energy utilization by 2050.

High policy scenarios

Key assumptions: In these scenarios, the IRA incentives for hydrogen expire in 2040. Carbon pricing begins in 2030 at $171/Mt and increases to $477/Mt by 2050.[102] Roughly 40% of industrial fuel use will electrify in the high case, driven by the pulp and paper, chemicals, and iron and steel subsectors. This drops to roughly 20% in the low electrification scenario. Figure 18 shows the fuel mix for each high policy scenario.

[100] ThThis scenario will not be considered in the sector-specific analysis.

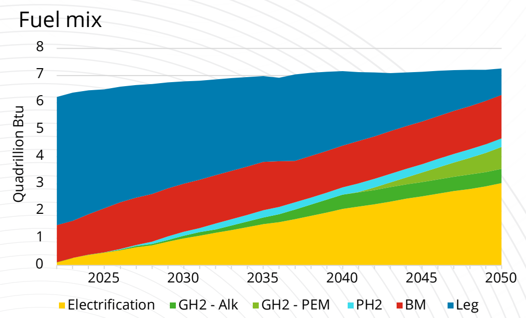
[101] GH2-Alk: Green hydrogen alkaline electrolysis; GH2-PEM: Green hydrogen PEM electrolysis; PH2: Pink hydrogen; BM: Biomass; GrH2: Grey hydrogen; Leg: Legacy fossil fuels.

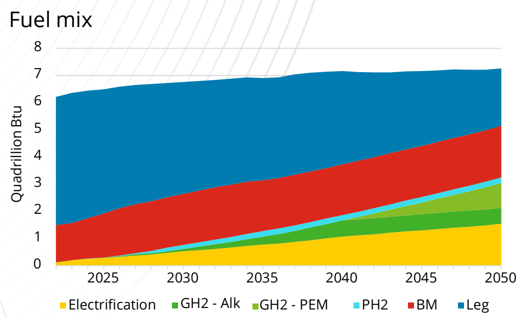
[102] This is in line with the IEA's Net Zero Scenario for developed economies, factoring in inflation.

Figure 18: High policy scenario fuel mix

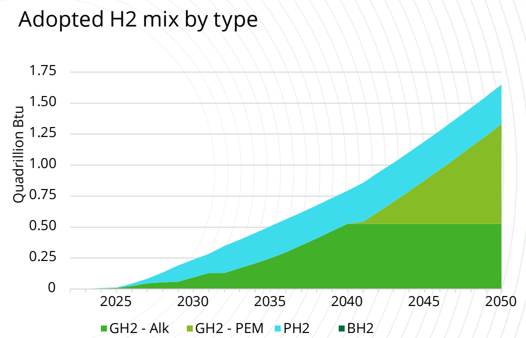
	High electrification	Low electrification[103]

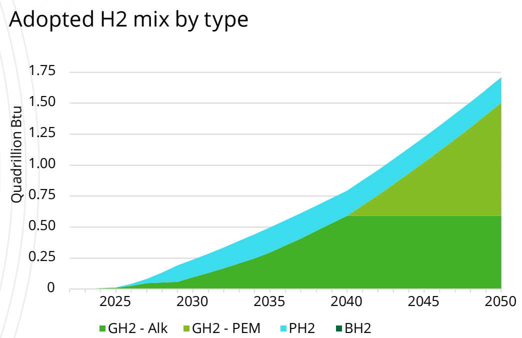
Fuel mix[104]





Hydrogen mix





Summary results

High electrification:

- Electricity and waste biomass are likely to be the major industrial heat energy sources.
- The use of legacy fossil fuels is expected to decline over time and will account for 13% of total thermal energy use in this scenario by 2050.
- Hydrogen adoption will occur consistently through 2050 due to tax credits and carbon pricing.
- Roughly 1.3 green hydrogen quads are likely to be used in industrial heating (twice today's hydrogen use).
- Green hydrogen is likely to account for 18% of total thermal energy use in this scenario.
- PEM overtakes alkaline hydrolysis as the most cost-effective production method around 2040 and is the dominant source of green hydrogen in industrial heating.

Low electrification:

- Electrification will be slow and account for 21% of total thermal energy use in this scenario by 2050.
- The use of legacy fossil fuels is expected to decline over time; however, it will continue to be one of the primary energy sources for industrial heat.
- The potential for hydrogen in industrial heating is relatively unchanged by decreased electrification, primarily due to barriers for adoption in high heat applications.
- 1.5 quads of green hydrogen will be adopted in this scenario vs. 1.3 quads in the high electrification case.
- Earlier adoption of green hydrogen (due to higher supply) crowds out pink hydrogen adoption, decreasing the adoption of pink hydrogen in this scenario by roughly 30%.

Priority subsectors for green hydrogen

Iron and steel manufacturing

The future of green steel production depends on federal policy push, such as decarbonization incentives, and economic growth, which creates new demand for green steel. The overall energy demand for the iron and steel subsector is expected to decline at a CAGR of 0.4% till 2050. Different scenarios showcase different levels of hydrogen adoption in this subsector, which the next section covers.

[103] This scenario will not be considered in the sector-specific analysis.

[104] GH2-Alk: Green hydrogen alkaline electrolysis; GH2-PEM: Green hydrogen PEM electrolysis; PH2: Pink hydrogen; BM: Biomass; GrH2: Grey hydrogen; Leg: Legacy fossil fuels.

High electrification and low policy (HE-LP)

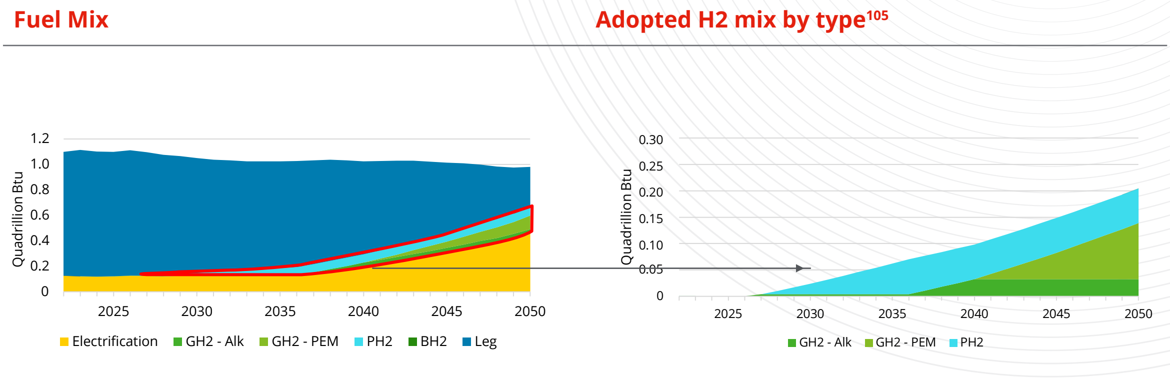
Significant capital investment will be required to overhaul the reducing process to utilize hydrogen, which is not overcome in the low policy scenarios. Primary adoption barriers include the capital cost for a direct reduction shaft—roughly $525/Mt[105] of annual steel production—and costs to upgrade brownfield facilities, such as hydrogen storage, fuel lines, and replacing other equipment. Tax credits will expire before carbon pricing is implemented in this scenario, preventing financial incentives to overcome capital cost barriers. Carbon pricing in 2040–2050 is insufficient to drive end-user hydrogen investment, and carbon capture becomes a more viable option for decarbonization in this scenario.

In this scenario, legacy fossil fuels and electricity will be the two primary industrial heat sources. Electricity will account for roughly 40% of energy utilization within the subsector due to growth in the utilization of electric arc furnaces in the production process.

High electrification and high policy (HE-HP)

In the high electrification and high policy scenario, carbon pricing stimulates the switch from coal to green and pink hydrogen to reduce iron in manufacturing, incentivizing firms to invest significant capital in changing the reduction processes. Carbon pricing in the range of $100/Mt to $200/Mt of CO2e could stimulate the adoption of hydrogen in this subsector through 2040 if tax credits are extended. Figure 19 shows consistent growth in adoption through 2050, demonstrating that the iron and steel subsector is more sensitive to carbon pricing as opposed to incentives due to the emissions profile of coal use. In the absence of carbon pricing, other types of fiscal incentives could be utilized to overcome cost barriers.

Figure 19: Iron and Steel subsector results:HE-HP scenario



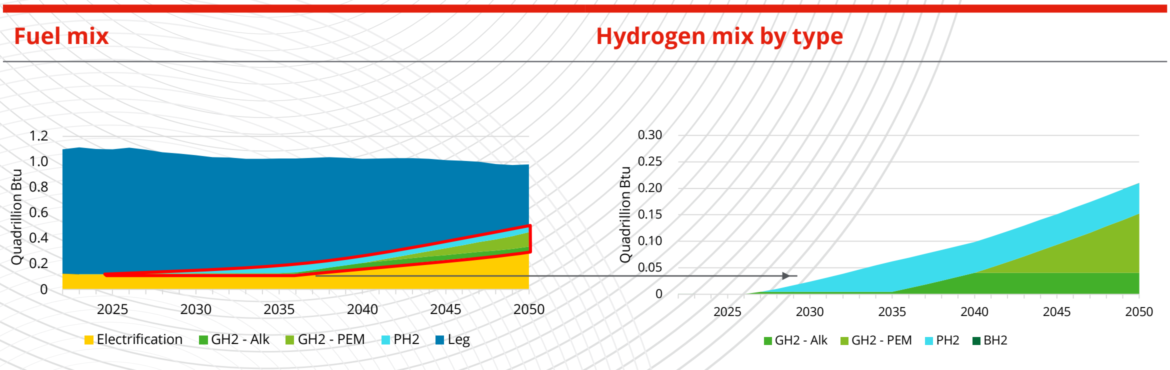
Fossil fuels and electricity are likely to be the two primary industrial heat sources in this scenario. Electricity could account for roughly 48% of energy utilization within the subsector due to growth in the utilization of electric arc furnaces in the production process, but the iron reduction is likely to still utilize some natural gas.

Low electrification and high policy (LE-HP)

Carbon pricing drives some of the iron reduction process away from coal in the low electrification and high policy scenario. Hydrogen potential in the subsector is still limited by the high capital costs required to switch to hydrogen for the reduction process. Lower-cost pink hydrogen drives the early adoption of hydrogen but is not limited by the end of incentives for green hydrogen. Consistent adoption will continue through 2050 (figure 20). Late adoption of green hydrogen results in the bulk of green hydrogen coming from PEM electrolyzers that are projected to be more cost-effective than alkaline by 2040.

[105] Grzegorz Pawelec and Joana Fonseca, https://hydrogeneurope.eu/wp-content/uploads/2022/06/Steel_from_Solar_Energy_Report_05-2022_DIGITAL.pdf Steel from solar energy, Hydrogen Europe and The smarter E Europe, 2022. Accessed January 2023.

Figure 20: Iron and steel subsector results:LE-HP scenario



In this scenario, legacy fossil fuels and electricity will be the two primary industrial heat sources. Electricity could account for roughly 30% of energy utilization within the subsector due to the increased utilization of electric arc furnaces in production.

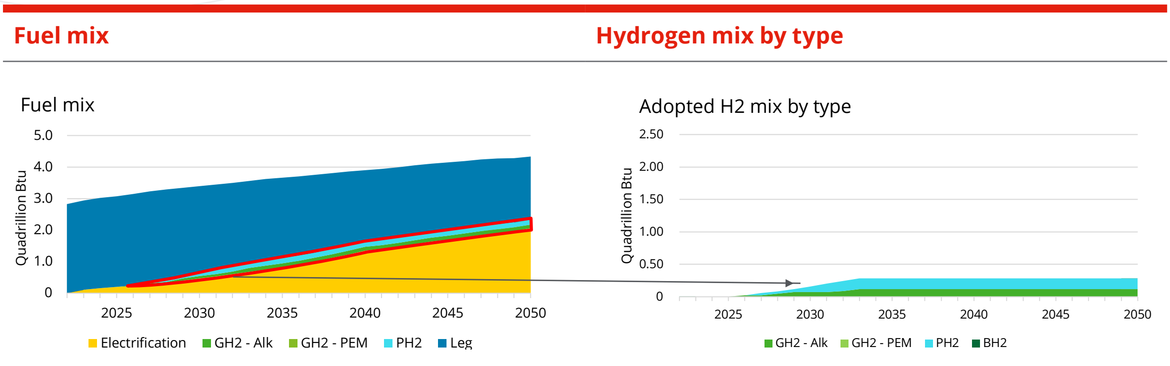
Chemical subsector

The chemical subsector is projected to be one of the earliest adopters of hydrogen for industrial heating, with relatively low capital costs to transition to hydrogen for low- and medium-heat processes and co-locating existing facilities near emerging hub locations. The overall fuel demand is expected to increase at a CAGR of 1.5% until 2050. Different scenarios showcase different levels of hydrogen adoption, as discussed next.

High electrification and low policy (HE-LP)

In the high electrification and low policy scenario, hydrogen adoption depends on tax credits for clean hydrogen, with no further adoption coming after credits expire in 2033. Carbon pricing from 2040 to 2050 is insufficient to drive further hydrogen adoption in the sector, but pricing as low as $50/Mt could drive adoption during the incentive period. In the absence of carbon pricing, it is also possible hydrogen demand is reconverted to other fuels when tax credits expire. Figure 21 shows the chemical subsector's fuel mix and hydrogen adoption over time. Both low policy scenarios demonstrated similar adoption results, so only the high electrification results are shown.

Figure 21: Chemical subsector results:HE-LP scenario



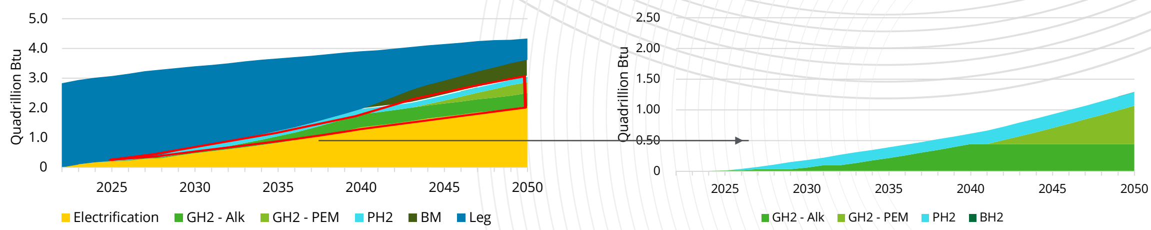
In this scenario, legacy fossil fuels and electricity will be the two primary sources for industrial heat. Electricity will account for roughly 47% of industrial heat utilization by 2050 for low heat processes and many medium heat processes, including steam creation, drying, and distillation.

High electrification and high policy (HE-HP)

In the high electrification and high policy scenario, green hydrogen will account for 25% of the overall heating fuel mix for the chemical subsector, primarily utilized in medium-heat applications such as steam, drying processes, and distillation. Figure 22 shows the fuel mix and hydrogen adoption profile for the chemical subsector in the HE-HP scenario.

Figure 22: Chemical subsector results:HE-HP scenario

Fuel mix **Adopted H2 mix by type**



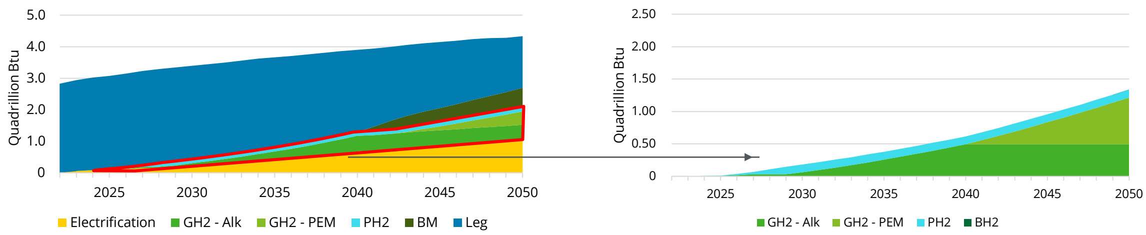
Despite high carbon pricing, capital costs for high-heat chemical-cracking processes remain challenging for hydrogen adoption. This subsector's other industrial heat sources are legacy fuels, waste biomass, and electricity. The use of legacy fuels is expected to decline at a CAGR of 5% until 2050. Electricity will account for roughly 47% of industrial heat utilization for low-heat processes and many medium-heat chemical processes.

Low electrification and high policy (LE-HP)

In the low electrification and high policy scenario, green hydrogen could account for 21% of total fuel utilization by 2050, up from 19% in the HE-LP scenario. Waste biomass could become competitive with hydrogen after the end of the incentive period, limiting the long-term green hydrogen potential. Figure 23 shows the hydrogen adoption and fuel mix through 2050 in the LE-HP scenario.

Figure 23: Chemical subsector results:LE-HP scenario

Fuel mix **Adopted H2 mix by type**



In this scenario, legacy fossil fuels and electricity are the other industrial heat sources. The use of legacy fuels is expected to decline at a CAGR of 2% until 2050. Electricity will account for roughly 25% of heating energy utilization for low-heat processes by 2050. Decreased electrification increases the potential for hydrogen by roughly 6% across high policy scenarios, with a 15% increase in green hydrogen utilization over the high electrification scenario.

Cement

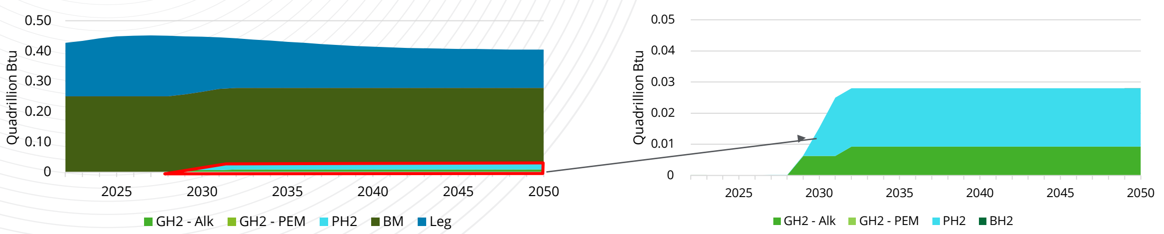
Cement production requires high temperatures throughout the production process. Pre-calciners operate at 600°C to 700°C and rotary kilns at 1200°C to 1400°C. Given the high heat requirements, it is unlikely the subsector will be able to electrify but should be able to utilize hydrogen as a part of the fuel mix. Energy demand is expected to remain roughly stagnant through 2050 due to improved efficiency in utilizing clinker, the primary input for cement production. This section will cover the difference between high and low policy scenarios, as electrification does not affect the subsector.

High electrification and low policy (HE-LP)

Hydrogen has limited potential in the cement subsector in the low policy scenarios, as shown in figure 24. The adoption potential depends on IRA incentives, with no adoption after credits expire in 2033. Decarbonization in this scenario could likely occur primarily through carbon capture and utilization of waste biomass. Green hydrogen could account for roughly 1% of fuel utilization in this scenario and is significantly outpaced by pink hydrogen.

Figure 24: Cement subsector results:HE-LP scenario

Fuel mix **Adopted H2 mix by type**

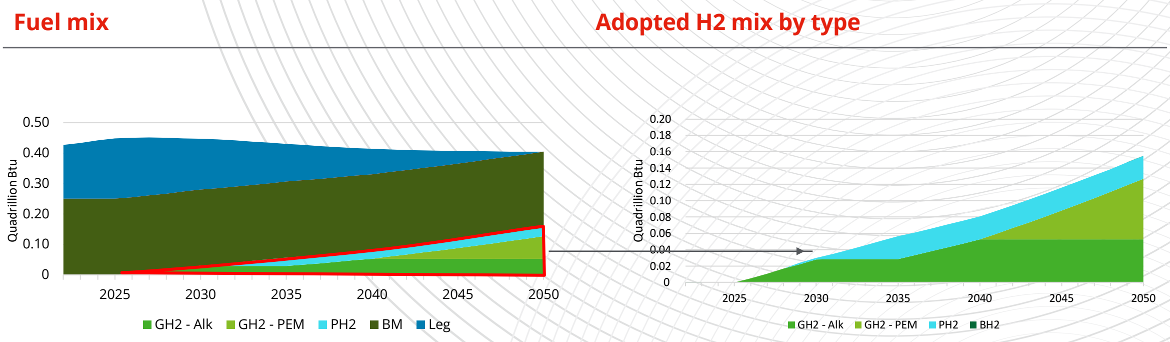


High electrification and high policy (HE-HP

In the high policy scenarios, green hydrogen accounts for 33% of energy utilization in the cement subsector, as shown in figure 25. Hydrogen utilization in the cement subsector faces technical limitations because hydrogen does not produce the specified flame for utilization in rotary kilns.[106] However, equipment to blend hydrogen with the current fuel mix already exists and could be utilized to achieve decarbonization through blending with waste biomass. The cost of capital for blending equipment is lower than other high-temperature processes, so the cement subsector could be an early adopter of green hydrogen.

[106] DOE, https://www.energy.gov/sites/default/files/2022-09/Industrial%20Decarbonization%20Roadmap.pdf Industrial Decarbonization Roadmap. Accessed March 2023.

Figure 25: Cement subsector results:HE-HP scenario



Nonpriority subsectors for green hydrogen

Oil and gas refining

Heat in the refining subsector comes primarily from co-products of the refining process, which, if not used for heat, could create disposal costs. Our analysis assumes the fuel input costs for the refining subsector are zero, with carbon pricing as the only fuel cost within the sector. Given these market dynamics and assumptions, the most viable decarbonization pathway for heating emissions in this subsector is CCS or CCUS, which is now incentivized at up to $85/Mt through the IRA. Additionally, the economy is more broadly moving away from this subsector, with overall refining energy utilization projected to remain roughly even despite growth out to 2050.

Pulp and paper

Similarly, the pulp and paper industry derives a large share of its heating fuel from industrial co-products. In this case, black liquor, a waste biomass byproduct of the pulping process, is used extensively. Waste biomass still produces biogenic emissions, which could be supplemented with CCS or CCUS to maximize emissions reductions. Additionally, many heating processes in this subsector are low temperature, making them prime candidates for electrified heat. The presence of viable, inexpensive, low-carbon alternatives and the switching costs involved in incorporating hydrogen will likely prevent the subsector's adoption of green hydrogen.

Section 3: Subsector pathways and modeling takeaways

Chemical pathway

The chemical subsector has the greatest potential for green hydrogen of the subsectors analyzed due to its scale, relatively low capital costs to utilize hydrogen in some production processes, and location of its center of demand in Texas, a mature renewable energy market with relatively low electricity costs. The following are the pathway elements to unlock the subsector's green hydrogen potential:

- Development of green hydrogen hubs, renewable energy production, and hydrogen transportation infrastructure in the Texas/Louisiana region. These states account for the bulk of heating demand in the chemical subsector, and centralizing green hydrogen production in the region will drive down end-user costs.
- Carbon pricing as low as $50/Mt could drive investment in hydrogen for low- and medium-temperature processes in the subsector during the lifetime of the IRA incentives if extended to 2040.
- Further R&D of hydrogen utilization in high-temperature chemical-cracking processes will be needed to expand the potential for green hydrogen, as hydrogen utilization for cracking is currently cost-prohibitive under the scenarios analyzed.

Iron and steel pathway

Decarbonization in the iron and steel subsector is primed for hydrogen utilization as a component of direct iron reduction, which could replace the significant utilization of coal in the subsector today. This process could accompany significant increases in electrification, as the direct iron reduction process supports the utilization of electric arc furnaces to create steel from iron. Pathway elements to guide this conversion are as follows:

- Development of a green hydrogen hub in the Great Lakes region, Western Pennsylvania, or both. A majority of the energy demand in the subsector is in this part of the country, and there will need to be significant sources of supply nearby to drive down hydrogen's transportation costs.
- Cost reductions for utilizing hydrogen in the direct iron reduction process: High costs to convert existing facilities are the primary barrier to increased hydrogen utilization in the subsector. Reducing these costs or incentivizing process improvements unlocks a green hydrogen pathway in the subsector.
- Carbon pricing in the range of $100/Mt to $200/Mt could also assist in driving change in production processes. This could significantly drive up the cost of coal and facilitate the changeover of production processes.

Cement pathway

The cement subsector has the potential to incorporate hydrogen through blending, but further technical innovation is needed for green hydrogen to account for more than roughly one-third of the subsector's energy mix. The elements to unlock the potential for green hydrogen in the cement subsector are as follows:

- Development of hubs in Texas and the Midwest could place production centers near points of demand for energy in the cement subsector. Texas and Missouri produce the majority of cement in the United States.
- Carbon pricing as low as $60Mt to $110Mt will aid the utilization of hydrogen blending technology in the cement subsector if the IRA credits are extended to 2040.
- Incentives for RD&D of hydrogen-powered kilns is required to increase the hydrogen potential of the cement subsector beyond roughly a third of the subsector's energy demand. Current kilns and burners do not produce the specified flame for cement production utilizing pure hydrogen, and innovation is required to increase hydrogen utilization beyond blending.

Takeaways

The potential utilization of green hydrogen in industrial heating processes is highly dependent on policy in the short term and on the price and availability of green electricity in the long term. In the absence of carbon pricing, utilization in industrial sectors are likely to depend on tax credits for hydrogen production. Extending IRA tax credits through at least 2040, utilizing minimum carbon pricing of $100/Mt by 2030, and decreasing costs for constant renewable energy will be essential for developing the industrial green hydrogen market. Extending the credits will help green hydrogen become more cost-effective than current fossil fuel utilization through direct reductions in price and reductions in costs through scale. This will help industrial end users overcome the capital costs required for end users to utilize hydrogen. Though green hydrogen is projected to be cheaper than both blue hydrogen and fossil fuels for much of the modeling timeline, it will need to remain significantly cheaper to justify the capital investment required at the industry level.

Chapter 6: Current market landscape: Technology drivers, challenges, and social and environmental impacts

Summary and key takeaways:

Predicting precisely where green hydrogen will be used in the future is difficult. Green hydrogen for industrial heat is unlikely to see widespread adoption in isolation, but the major cost levers of hydrogen production can help to narrow the field.

This chapter lays out considerations that could indicate where customers may come to use green hydrogen geographically in the short term, laying the groundwork for industrial heat users in the long term. Additionally, these factors will likely coincide with locations being considered for funding under the DOE's hydrogen hub program. These factors include:

- Existing use cases (applications and methods where hydrogen is currently being used)
- Competing use cases (applications and methods that will be able to compete over and reap the benefits of excess hydrogen supply as the market matures)
- Renewable production (areas with strong current and future renewable generation)

As green hydrogen is scaled, there are a number of considerations industrial heat users must keep in mind. This chapter reveals three takeaways:

- Due to the costs associated with transporting hydrogen over large distances, hydrogen supply and demand will benefit from being located in close proximity especially in the short-term. Existing use-cases, expected competition to hydrogen uptake, renewable generation, and hubs can provide good indications of the geography of tomorrow's green hydrogen economy, especially where these considerations overlap.
- Across both existing (e.g., ammonia, methanol & mobility) and competing use cases (e.g., mobility, biofuels & synfuels), green hydrogen will be cheaper to produce in regions with plentiful and cheap renewable power.
- Scaling green hydrogen across the United States has many potential benefits but must be closely monitored to avoid negative environmental (e.g., ecosystem damage) and social impacts (e.g., job loss).
  - When it comes to environmental considerations, developing lifecycle emissions accounting practices and improving equipment leakage can help ensure that hydrogen emissions are not worse than alternative sources and also prevent potential harmful pollutants, like NOx emissions.
  - From a social justice perspective, growing the hydrogen economy ethically and equitably is central to the DOE's hydrogen strategy. Therefore, public outreach to overcome negative perceptions around hydrogen, consistent communication to build trust, and focused community engagement with local groups and nonprofit organizations will be pivotal in supporting a just transition and to give hydrogen social license to operate.

Section 1: US green hydrogen market overview: Existing vs. competing use cases

Existing use cases

The current uses of hydrogen can serve as guideposts, indicating regions where green hydrogen might initially be scaled and purchased. The existing and anticipated future infrastructure in these regions can help lower the cost of green hydrogen, increasing the likelihood that it could be used for industrial heat.

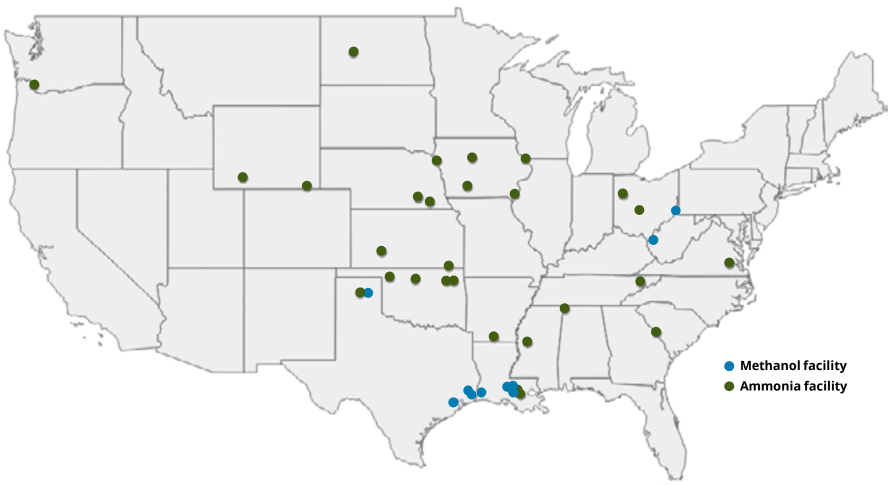
Today, hydrogen is primarily used as a feedstock when producing ammonia and methanol or oil refining. Outside of these, there are also some applications in mobility, including forklifts and certain public transport systems. As green hydrogen becomes more widely available, these areas or applications near them may become crucial first customers, laying the foundation for green hydrogen for industrial heat.

Ammonia, methanol, and oil refining

Ammonia production, accounting for roughly three-quarters of hydrogen usage in the chemical industry, occurs in 32 plants across 17 states.[107] Though current plants are closely integrated with grey hydrogen production facilities, newly built plants will be able to use green hydrogen more readily. Growth in fertilizer demand and new uses as a low-carbon energy carrier and fuel are expected to drive expanded ammonia production. Because it is a high-heat process, new plants can represent a double source of demand for hydrogen as both feedstock and fuel.

Methanol is another major source of hydrogen demand. It is a flexible product that can be used as a fuel for manufacturing plastics and other chemicals, as well as a chemical hydrogen carrier.[108] Like ammonia, many existing production facilities are closely integrated with SMR for grey hydrogen; however, new facilities can be built to use green hydrogen. Assuming the logic for plant siting does not change, the distribution of ammonia and methanol facilities today (figure 26)[109] may point to future green hydrogen production locations.

Figure 26: Ammonia and methanol facilities map



Source: Deloitte and WWF analysis based on EPA Facility GHG Emissions Data. Accessed December 2023.

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[107] IEA, https://www.iea.org/reports/global-hydrogen-review-2021 Global hydrogen review 2021. All right reserved. Accessed January 2023; EIA, https://www.eia.gov/naturalgas/weekly/archivenew_ngwu/2021/04_01/ "Natural gas weekly update," April 1, 2021. All rights reserved. Accessed January 2023.

[108] DOE, https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf DOE National Clean Hydrogen Strategy and Roadmap. Accessed November 2022; IRENA and Methanol Institute (2021), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2021/Jan/IRENA_Innovation_Renewable_Methanol_2021.pdf Innovation outlook: Renewable Methanol, International Renewable Energy Agency, Abu Dhabi. Accessed November 2022[111] EPA, "Facility-level GHG emissions data," 2021. The facility-level GHG data only includes "large emitters" of greater than 25,000 Mt CO2e/year; 85%–90% of total US emissions is reflected in the data.

[109] EPA, https://ghgdata.epa.gov/ghgp/main.do#/facility/?q=Find%20a%20Facility%20or%20Location&st=&bs=&et=&fid=&sf=11001100&lowE=-20000&highE=23000000&g1=1&g2=1&g3=1&g4=1&g5=1&g6=0&g7=1&g8=1&g9=1&g10=1&g11=1&g12=1&s1=1&s2=1&s3=1&s4=1&s5=1&s6=1&s7=1&s8=1&s9=1&s10=1&s201=1&s202=1&s203=1&s204=1&s301=1&s302=1&s303=1&s304=1&s305=1&s306=1&s307=1&s401=1&s402=1&s403=1&s404=1&s405=1&s601=1&s602=1&s701=1&s702=1&s703=1&s704=1&s705=1&s706=1&s707=1&s708=1&s709=1&s710=1&s711=1&s801=1&s802=1&s803=1&s804=1&s805=1&s806=1&s807=1&s808=1&s809=1&s810=1&s901=1&s902=1&s903=1&s904=1&s905=1&s906=1&s907=1&s908=1&s909=1&s910=1&s911=1&si=&ss=&so=0&ds=E&yr=2021&tr=current&cyr=2021&ol=0&sl=0&rs=ALL Facility-level GHG emissions data, 2021. Accessed November 2022. The facility-level GHG data only includes "large emitters" of greater than 25,000 Mt CO2e/year; 85%-90% of total US emissions is reflected in the data.

Like ammonia and methanol, oil refineries are major users of hydrogen. Though an important present use case, existing refineries are unlikely to switch to consuming green hydrogen in the short term. Over time, the presence of hydrogen or chemical handling infrastructure may benefit the use of green hydrogen for new facilities nearby.

Mobility: Forklifts, buses, and trains

Similar to ammonia and methanol, mobility, specifically for fuel cell forklifts, buses, and train systems, is an existing use case that will likely experience earlier uptake of green hydrogen than industrial heat. According to the IEA, the cost of automotive fuel cells fell by 70% due to technological progress and growing sales of fuel cell electric vehicles (FCEVs) since 2008.[110] Green hydrogen has gained more attention with national hydrogen strategies placing a higher value on using hydrogen in transport and policy movements at the state level, such as California's Low Carbon Fuel Standard.

For concentrated fleets that can utilize return-to-base fueling, such as forklifts and buses, hydrogen refueling can occur in one place, reducing infrastructure burdens. For example, small-scale fuel cell bus deployment is already underway in areas like Boston.[111] These mobility users will face the challenge of needing cheap hydrogen to fuel vehicles at scale. Additionally, hydrogen-powered trains have not yet been deployed in the United States but are in service or undergoing trials in various European countries, making them a potential competing use case with industrial heat.

Competing use cases

If investments are made in ammonia, methanol, and mobility, green hydrogen may be easier to deploy for other uses. Supply can increase as these first movers or adopters build crucial infrastructure, and the cost of green hydrogen may decline. Once the regional market becomes more mature, other applications, such as industrial heat, can reap the benefits of excess supply. However, this may also cause competing uses to enter the viability range, potentially outbidding industrial heat users. This section discusses examples of competing use cases: production of biofuels and synfuels, as well as a broader set of hydrogen mobility applications that will compete with industrial heat for green hydrogen supply.

Production of biofuels and synfuels

Today, renewable diesel and sustainable aviation fuel (SAF) are two common biofuels that use green hydrogen as chemical feedstock. They are hydrocarbons generally produced by hydrotreating oils but can also be produced via gasification, pyrolysis, and other biochemical and thermochemical technologies using waste biomass or other wastes as feedstock[112]. Supply for renewable diesel is expected to increase by seven-and-a-half times from the end of 2020 to 2024, reaching 5.1 billion gallons per year.[113] Renewable diesel's potential lies within its chemical makeup —it is the same as petroleum diesel and does not have blending limitations. Similarly, the United States has put forth the Grand Challenge to increase SAF production to 3 billion gallons per year by 2030.[114] This will require a 122% year-over-year growth in production until 2030.[115] In line with renewable diesel and SAF production growth, we will see greater opportunities to develop green hydrogen as a chemical feedstock for both biofuels in the United States.

Additionally, synfuels can be created by reacting hydrogen with captured CO2 (either from the atmosphere or from industrial sources) and can lead to near-zero-net carbon emissions. This process is known as power-to-liquid because it turns electric power into liquid fuels. It requires a source of green hydrogen to synthesize the fuel to be considered zero carbon, making it an enabler and competitor to industrial heat. If synfuels are used for industrial heat, this could essentially be using green hydrogen in a form that may be easier to use or retrofit in existing assets.

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[110] IEA, https://www.iea.org/reports/global-hydrogen-review-2021 Global hydrogen review 2021. All rights reserved. Accessed November 2022

[111] EPA, https://www.epa.gov/greenvehicles/hydrogen-fuel-cell-vehicles" Hydrogen fuel cell vehicles, last updated September 13, 2022. Accessed November 2022.

[112] US Department of Energy, Energy Efficiency & Renewable Energy, Alternative Fuels Data Center, https://afdc.energy.gov/fuels/emerging_hydrocarbon.html#:~:text=Renewable%20diesel%2C%20previously%20known%20as,alkyl%20ester%20produced%20via%20transesterification."Renewable hydrocarbon biofuels. Accessed January 2023.

[113] According to the EIA AEO2022 scenario; EIA, https://www.eia.gov/todayinenergy/detail.php?id=51778 EIA projects U.S. renewable diesel supply to surpass biodiesel in AEO2022," March 24, 2022. Accessed November 2022.

[114] The Sustainable Aviation Fuel Grand Challenge is the result of the US DOE, Department of Transportation, and USDA working together to develop a comprehensive strategy for scaling up new technologies to produce SAF on a commercial scale. The goal includes achieving a minimum of a 50% reduction in life cycle GHG emissions compared to convention fuel and supplying sufficient SAF to meet 100% of aviation fuel demand by 2050; EERE, https://www.energy.gov/eere/bioenergy/sustainable-aviation-fuel-grand-challenge "Sustainable Aviation Fuel Grand Challenge." Accessed January 2023.

[115] US Department of Energy, US Department of Transportation and US Department of Agriculture in collaboration with the US Environmental Protection Agency, https://www.energy.gov/sites/default/files/2022-09/beto-saf-gc-roadmap-report-sept-2022.pdf SAF Grand Challenge Roadmap: Flight Plan for Sustainable Aviation Fuel Report, 2022. Accessed January 2023

Currently, 114 biofuel production plants exist, mostly situated on the West Coast (in California and Washington), the Midwest, and Gulf Coast (in Louisiana). Hydrogen gas is an important input in the production of biofuels, and demand for clean hydrogen will expand alongside demand for renewable fuels and SAF. [116] In this instance, petroleum refinery assets could be converted for renewable diesel production with only modest retrofits.

Mobility: Long-haul trucking, heavy-duty trucking, rail, and shipping

Over the longer term, applications of hydrogen in the mobility industry (including aviation) are expected to expand, building on the limited foundation in place today. Energy costs for some transport applications are often higher than other uses, given that customers are willing to pay more for energy. If the competitive price for hydrogen increases in this instance, mobility applications may have earlier uptake than industrial heat. Transportation-related demand for hydrogen will generate infrastructure, innovation, and production facilities that may lower barriers to adoption in industrial heat.

FCEVs that run on hydrogen in road transport will compete with battery-electric vehicles (BEVs). Currently, higher adoption rates and expansive charging infrastructure make BEVs more attractive for many applications, especially passenger and light-duty. Over longer distances, FCEVs can have more range and fueling times measured in minutes rather than hours.[117] Today, limited hydrogen fueling infrastructure and fuel supply hampers adoption. However, expansion plans are focused on heavy-duty FCEVs, often in places where users are concentrated, such as centralized municipal bus depots or heavily used freight corridors.[118]

As mentioned previously, rail transport is another potential mobility application for hydrogen. Fuel cell trains already operate in parts of Europe and are set to expand, especially to low-traffic routes. Many routes are already electrified in the United States, but expanding electrification infrastructure is costly and may not be feasible in routes with low usage.[119]

Hydrogen rail adoption also faces competition from low-cost diesel alternatives, though set routes and more centralized fueling infrastructure will likely ease adoption for hydrogen uptake compared to trucking.[120]

There is also scope for hydrogen, or hydrogen-based fuels such as green ammonia, to be deployed as maritime fuels. Deploying either at scale could entail substantial expansions of relevant supply chains (for example, ammonia shipping could require three times as much ammonia as is currently produced annually for all uses), new or substantially retrofitted onboard equipment such as engines and storage, and significant expansion of port facilities including storage. Policy support, including incentives for hydrogen production like those in the IRA as well as carbon pricing or sector-specific policies, will likely motivate firms to switch.[121]

The competing use cases discussed may transition to green hydrogen before industrial heat users, and generating consistent demand and supporting infrastructure development will substantially reduce barriers to broader uptake. Once enough green hydrogen is produced to satisfy early adopters, new capacity can more cheaply expand production. This could help drive adoption by lowering effective costs for industrial heat users.

Renewable energy generation

Across both existing and competing use cases, significant renewable generation will be a geographic enabler to scale green hydrogen. States with strong current and future renewable generation will likely have an advantage in applying green hydrogen to industrial heat (figure 27).[122] This applies especially to renewable generation located near industrial heating facilities, existing and competing use cases, and hydrogen hubs. The grid network infrastructure will also be important to satisfy electrolyzer power demand from diverse renewable sources and enable electrolyzer grid services. Hydrogen hubs are expected to accelerate this effort as continued renewable generation infrastructure development is required.

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[116] EIA, https://www.eia.gov/biofuels/renewable/capacity/ "U.S. renewable diesel fuel and other biofuels plant – Production capacity," August 8, 2022. Accessed November 2022.; DOE, https://www.energy.gov/sites/prod/files/2020/09/f78/beto-sust-aviation-fuel-sep-2020.pdf "Sustainable Aviation Fuel Review of Technical Pathways. Accessed March 2023.]

[117] Transport and Environment, https://www.transportenvironment.org/wp-content/uploads/2021/07/2020_06_TE_comparison_hydrogen_battery_electric_trucks_methodology.pdf "Comparison of hydrogen and battery electric trucks," June 2020. Accessed November 2022

[118] DOE, https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf DOE National Clean Hydrogen Strategy and Roadmap. Accessed November 2022.

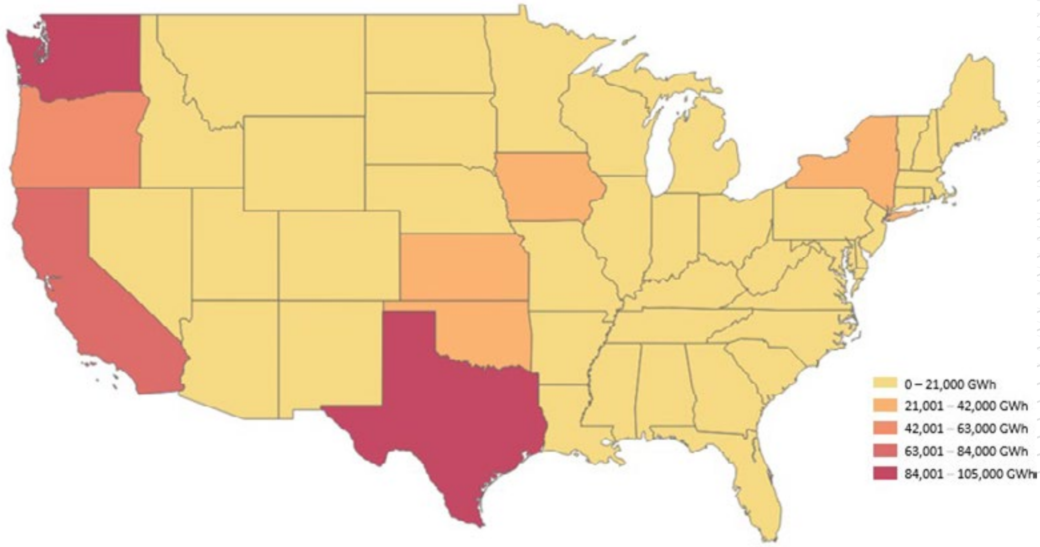
[119] IEA, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdfThe future of hydrogen, p. 142. All rights reserved. Accessed November 2022.

[120] DOE, https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf National Clean Hydrogen Strategy and Roadmap. Accessed November 2022

[121] IEA, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf The future of hydrogen. All rights reserved. Accessed November 2022.

[122] EPA, "eGRID with 2021 data," January 30, 2023.

Figure 27: Renewable energy generation by state



Source: Deloitte and WWF analysis based on EPA eGrid2021 data. Accessed November 2022.

Hydrogen hubs
One of the strongest geographic indicators for the future of green hydrogen comes from plans for hydrogen hubs. If hubs accelerate green hydrogen uptake for existing and competing use cases and spur the development of renewable infrastructure, then industrial heat may see a quicker uptake of green hydrogen.

Hubs are groups of hydrogen-related assets that are centrally located and interconnected to reduce transportation and infrastructure costs. Hubs can be supply-driven when hydrogen producers form the nucleus of the association or demand-driven when hydrogen consumers are major players. Supply hubs can be especially advantageous for industrial heat users as hubs will aim to produce steady and large amounts of hydrogen without the burden of extensive transportation costs. Proximate industrial heat users can benefit from the excess supply if these hubs are in regions with few competing uses.

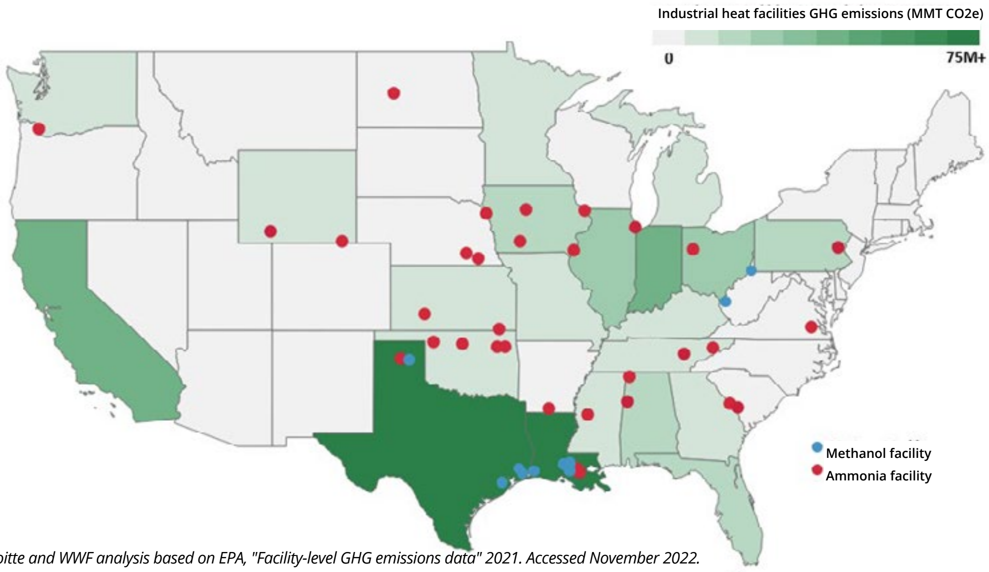
Corporations, funds, and government agencies are collaborating in regions and hubs to capitalize on the newly developing markets and to create synergies (e.g., value chain integration, innovation potential, and the attraction of a talented workforce). The Bipartisan Infrastructure Law (BIL) included $9.5 billion in funding to accelerate the development of clean hydrogen technologies across the value chain, and $8 billion is specifically earmarked for developing at least six to 10 clean hydrogen hubs across the United States, with at least one producing green hydrogen.

Each state is expected to take its own approach to hydrogen infrastructure development in line with state and local policy priorities, in addition to the support being provided by the DOE. Therefore, where barriers around offtake agreements can be overcome and enough renewable generation installed, prime hub locations have the potential to help scale green hydrogen in their region. In the months and years to come, it will become clear which hubs willmove forward and which will likely be effective.

Takeaways
Existing use cases, expected competitors, renewable generation, and hubs provide good indications of the geography of tomorrow's green hydrogen economy. The signal is especially strong where these considerations overlap. Though still uncertain, this line of reasoning points to likely loci of expanded hydrogen industry development and uptake of green hydrogen in the Gulf Coast, Midwest, and California. In the Houston region, for example, refineries and chemical facilities use hydrogen; hydrogen pipeline infrastructure already exists; a hub application is pending; and significant renewable energy is available. The Midwest fairs well in its existing use cases to produce green ammonia for fertilizer and availability of renewable energy, whereas California has existing hydrogen transportation infrastructure, strong renewable energy, and favorable policy. Applications for DOE hub funding are proceeding for hubs in these three regions.

The presence of a cluster of industrial heat facilities in proximity to early use cases (ammonia and methanol) offers the opportunity forearlier adoption of green hydrogen for industrial heat (figure 28).[123] Our analysis of hub locations and industrial heat users indicates that some hub regions could put significant numbers of industrial heat consumers into close contact with hubs, reducing potential transport costs for hydrogen. For example, an active hub in Pennsylvania could bring the weighted-average distance from steel within about 43 miles.[124]

Figure 28: Emissions from industrial heat facilities by state with ammonia and methanol facilities



Source: Deloitte and WWF analysis based on EPA, "Facility-level GHG emissions data" 2021. Accessed November 2022.

As trends unfold related to current and competing use cases and DOE hub funding becomes more solidified, industrial heat users will be presented with a stronger understanding of where green hydrogen supply will be available for use. In the meantime, industrial heat stakeholders could start engaging in green hydrogen market development to secure early supply and first-mover benefits. In chapter 7, considerations and actions are provided and discussed in detail to aid in short-term strategic planning.

Section 2: Challenges for the deployment of green hydrogen for industrial process heat

Green hydrogen can be an effective, carbon-free solution to the demands of industrial heat in various subsectors, but it faces competition from incumbent fuels and other low-carbon technologies or processes. This section explores the competitive challenges, focusing first on legacy fuels and electrification before discussing trade-offs among the colors of hydrogen.

Legacy fuels

Incumbent fuels for industrial heat, such as natural gas, oil, coal, and waste biomass, are significantly less expensive than hydrogen. For example, green hydrogen, on a per-unit-energy basis, remains approximately nine times more expensive than natural gas, and some incumbent fuels, such as waste biomass for pulp and paper and refinery gas in oil refining, are byproducts with little sale value and have almost no cost for the fuel user.[125] Beyond the cost of the fuel itself, hydrogen typically has higher transportation and storage costs than legacy fuels, and switching to hydrogen entails significant transition costs. The biggest challenge for green hydrogen is its cost competitiveness with other energy sources. To see the widespread adoption of hydrogen as a fuel, the all-in delivered cost of hydrogen needs to be lower than or equal to that of legacy fuels.

[123] EPA, https://ghgdata.epa.gov/ghgp/main.do#/facility/?q=Find%20a%20Facility%20or%20Location&st=&bs=&et=&fid=&sf=11001100&lowE=-20000&highE=23000000&g1=1&g2=1&g3=1&g4=1&g5=1&g6=0&g7=1&g8=1&g9=1&g10=1&g11=1&g12=1&s1=1&s2=1&s3=1&s4=1&s5=1&s6=1&s7=1&s8=1&s9=1&s10=1&s201=1&s202=1&s203=1&s204=1&s301=1&s302=1&s303=1&s304=1&s305=1&s306=1&s307=1&s401=1&s402=1&s403=1&s404=1&s405=1&s601=1&s602=1&s701=1&s702=1&s703=1&s704=1&s705=1&s706=1&s707=1&s708=1&s709=1&s710=1&s711=1&s801=1&s802=1&s803=1&s804=1&s805=1&s806=1&s807=1&s808=1&s809=1&s810=1&s901=1&s902=1&s903=1&s904=1&s905=1&s906=1&s907=1&s908=1&s909=1&s910=1&s911=1&si=&ss=&so=0&ds=E&yr=2021&tr=current&cyr=2021&ol=0&sl=0&rs=ALL"Facility-level GHG emissions data," 2021. Accessed January 2023. The facility-level GHG data only includes "large emitters" of greater than 25,000 Mt CO2e/year; 85%–90% of total US emissions is reflected in the data.

[124] Deloitte & WWF modeling outcomes & analysis. Figures mentioned include the weighted-average distance for chemical users in the West South-Central census district and iron and steel producers in the Middle Atlantic census district.

[125] Deloitte & WWF's calculation using the https://www.iea.org/reports/the-future-of-hydrogen IEA's Future of hydrogen report analysis (All rights reserved) and the https://afdc.energy.gov/fuels/properties DOE's Alternative Fuels Data Center. Both accessed November 2022.

Approaches to this challenge focus on lowering the effective cost of hydrogen, raising the effective cost of legacy fuels by pricing in their negative externalities, such as with a carbon tax, or tax credits for low-carbon-intensity fuels such as the 45V hydrogen production tax credit (PTC) in the IRA. Lowering the cost of hydrogen is a broad challenge involving changes in production, transport, storage, and end use, and these changes will likely need to involve industry and government participation. Because the 45V PTC can make green hydrogen cost competitive in the short term, it may drive a cycle of increasing innovation and expanding uptake, and the IIJA hub funding is also likely to help in this regard. The long-term effects of these policies remain to be seen, and strong incentive policies have also been built around carbon capture.

Point source CO2 emitters, such as industrial heat users, are potential adopters of CCS or CCUS technology. This has become an increasingly likely pathway to extend the use of legacy fuels in the United States because of policies such as 45Q tax credits and CCS or CCUS hub funding through the IIJA. Investment is already being made in transport and storage based on emitters with higher CO2 concentration waste streams such as ethanol and hydrogen. With this infrastructure in place, further CCS or CCUS adoption is likely, and there will need to be a significant build-out in renewable energy infrastructure and cost reductions in the production of green hydrogen to compete with hydrocarbon fuels in the United States.

Color-agnostic hydrogen challenges

Whatever its color, hydrogen faces general challenges that are required to be overcome to enable widespread adoption.

Lack of infrastructure

One major challenge relates to transporting and storing hydrogen. Other fuels have established networks and can be moved and stored more cheaply, making it easy for producers and consumers to access a geographically broad market. For producers to reach distant industrial heat consumers, pipeline networks are likely need to be built to reduce costs. Unfortunately, the location of hydrogen production facilities and pipelines is unlikely to be optimized for industrial heat users because industrial heat is widely considered a secondary use for hydrogen.

Co-location with other hydrogen consumers will drive down hydrogen costs for industrial heat in certain areas, and the location of hydrogen clusters may be a factor in the planning for new facilities requiring high-temperature industrial heat.

Equipment retrofitting or replacement

Separately, hydrogen requires significant retrofitting or replacement of equipment for end-use industrial heat production. These “transition costs” include the purchase of new equipment and the remaining years of value for the equipment being replaced. Several new designs for hydrogen-compatible equipment are under development. Though, even if available today, industrial heat users may be unlikely to replace current equipment before its “end of life” without incentives. These are likely to come from policies such as a carbon tax or from buyback programs.

Hydrogen energy efficiency

Hydrogen incurs significant energy loss throughout its life cycle. For example, relative to the energy renewables supply, 30% to 40% of energy losses occur during electrolysis in green or pink hydrogen production, and all hydrogen faces losses during conversion to other fuels (13% to 25%) and use in fuel cells (40% to 50%).[126] This makes hydrogen more suited to applications with few other carbon-free options, such as creating SAF or providing high-temperature industrial heat.[127]

Technical and commercial standards Implementing globally or nationally recognized technical and commercial standards is important for hydrogen to gain acceptance into applications that have not yet been used, such as industrial heat. Quality standards unsuited for newly proposed use cases of hydrogen hinder its adoption. Additionally, buyers will need clearer standards for green hydrogen market instruments and comprehensive GHG accounting rules to make credible claims for voluntary procurement practices. Although developing widely recognized standards could take time, it is a vital step to reduce risks and increase the interoperability of hydrogen technologies.

[126] IRENA (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_hydrogen_policy_2020.pdf Green hydrogen: A guide to policy making. International Renewable Energy Agency Abu Dhabi. Accessed February 2023

[127] Ibid.

[128] American Petroleum Institute, The Natural Gas Solution, http://naturalgassolution.org/natural-gas-affordable/ "Is natural gas affordable?," January 2023.

Contract transparency
Potential hydrogen suppliers and users also contend with the opacity of the current market for hydrogen, which leaves future market conditions uncertain. A fully developed hydrogen economy could likely feature some degree of spot pricing. In this arrangement, multiple sellers of hydrogen compete on price in a relatively short-term market, as is the case in some deregulated electricity markets. This market could enable contract transparency, giving consumers and suppliers good knowledge of the price environment, and could expose suppliers to dynamic risks and rewards. A deeper, more dynamic, transparent market operating on standardized terms could provide better information to producers and facilitate secondary trading.

Colors of hydrogen: competition or collaboration
There remains much debate over whether only green hydrogen should be employed moving forward or whether blue hydrogen and other options might play a positive transition role as renewable energy infrastructure is built. In the US, it is likely that a combined network effect will occur, in which the increased production of green, blue and pink hydrogen benefits value-chain development. This is especially important under insufficient supply conditions, where restricting one color could hinder overall hydrogen adoption.

Challenges facing green hydrogen, specifically
Interest in green hydrogen is gaining traction nationwide; however, without regulatory requirements, there is still only voluntary demand and little value recognition for using green products today (e.g., green steel). Measures to make hydrogen value viable for markets are limited (e.g., fuel mandates, blending quotas, and public procurement requirements). To scale green hydrogen, buyers and other stakeholders need the market to provide certain instruments, certification methods, or mechanisms supporting their claims to confirm they are using green hydrogen.

Additionally, green hydrogen production is still capital intensive, and production costs almost three times as much as grey hydrogen and nearly 12 times as much as natural gas.[128] It requires large-scale electrolyzers, which currently have under-developed supply chains. Further, these electrolyzers will require renewable power, which will likely be in short supply until the grid and generation infrastructure can be built. Lastly, water is scarce in some geographies with significant solar resources.

Hydrogen production and use can have significant energy loss, and its total energy loss depends on its final use. The more energy lost, the more renewable electricity capacity will be needed. Using renewable energy to make green hydrogen thus incurs a "carbon opportunity cost"—the energy could have been used elsewhere, possibly with higher efficiency. Producers should adhere to a practical rule called "the principle of additionality" to sustainably produce green hydrogen: Electrolyzer energy consumption should not increase fossil fuel consumption elsewhere. This applies equally to other forms of hydrogen production where this principle also applies. In practice, this means that true green hydrogen should not, for instance, be compressed or transported using fossil energy, which would add to emissions over the life cycle of green hydrogen, as is the case with many carbon-free energy sources.

The major concern is whether the development of renewable electricity generation (solar and wind) will be fast enough to meet the demands of both end-use electrification and green hydrogen supply chain going forward. As the green hydrogen market grows, there will be a need for a greater portfolio of renewable energy generation and storage to ensure the hourly matching requirement for electricity demand and supply.[129] This is likely to be even more applicable with onsite self-generation, given its inability to get support from the grid. Therefore, as demand grows, market instruments will be crucial to allow stakeholders to track the electricity used and confirm it is from renewables and not just grid electricity.[130]

Solving these problems may be a straightforward operation of aligning economics once an investment is made and future demand becomes more certain, but green hydrogen is likely to face strong competition for renewable electricity for decades. Current electricity demand already uses the renewable electricity capacity available, with nonhydroelectric renewables accounting for 14% of US electricity.[131] More than 60% of US electricity still comes from fossil fuels.[132] Some argue that renewable electricity should first go toward reducing these emissions, particularly from coal use in the power sector. Another topic to consider is

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[129] It should be noted that the issue of hourly matching would apply equally to pink hydrogen.

[130] Wilson Ricks, Qingyu Xu, and Jesse D. Jenkins, https://zenodo.org/record/7641487#.Y-0_yezMI0Q"Minimizing emissions from grid-based hydrogen production in the United States, Zenodo, 2022. Accessed November 2022.

[131] EIA, https://www.eia.gov/energyexplained/electricity/electricity-in-the-us.php "Electricity explained," last updated July 15, 2022. Accessed November 2022.

[132] EIA, https://www.eia.gov/tools/faqs/faq.php?id=427&t=3#:~:text=In%202021%2C%20about%204%2C108%20billion,facilities%20in%20the%20United%20States.&text=About%2061%25%20of%20this%20electricity,%2C%20petroleum%2C%20and%20other%20gases. What is U.S. electricity generation by energy source?," last updated November 8, 2022. Accessed November 2022

the electrification of transportation, which is estimated to require 20% to 50% more electricity than the United States currently produces.[133] Finally, the electrification of home, office, and industrial heat—and replacing the natural gas used for US residential and commercial heating alone could require 50% more electricity than today.[134] Industrial heat alone could require more than that. These trade-offs will define the next half century of energy and are the biggest barrier to green hydrogen growth. Moving forward, these can be used as opportunities to assist in making sure that limited supply of green hydrogen goes towards sectors where there are fewer alternatives and can help guide where to electrify first.

In solving the renewable electricity dilemma, efficient permitting should be considered. The physical assets in the green hydrogen value chain are subject to federal, state, and often local regulation and permitting processes. Nevertheless, the overlapping system of multiple permit requirements and multilayered regulation can tie up projects for years, delaying the construction of facilities that could drive decarbonization. Streamlining this system to increase coordination both between and within different levels of government is a crucial first step.

Despite these challenges, green hydrogen is an important tool to achieve net-zero emissions, especially in hard-to-decarbonize industries such as long-haul trucking, maritime shipping, and industrial heat. US federal funding for regional hydrogen hubs, RD&D, and tax credits for hydrogen projects and end-use consumption are expected to transform the US hydrogen economy by stimulating investments and developing hydrogen projects at scale.[135] In the meantime, stakeholders, including energy buyers, can begin taking action on these challenges to promote green hydrogen for industrial heat applications. In doing so, they should consider the social and environmental impacts of building a green hydrogen economy, aligning with the DOE's vision for a just transition.

Section 3: Social and environmental considerations

Throughout 2022, the United States saw historical climate and social action in response to unprecedented climate disasters and increased international pressure to transition to a net-zero world. The Biden administration made a concerted effort to put environmental justice issues at the forefront and advance justice and equity through federal investments and policies (e.g., the IRA and BIL). The Justice40 Initiative is an example of this—setting the goal that 40% of certain federal investments in areas such as climate change, clean energy, clean transit, and affordable housing flow to disadvantaged communities that are historically underserved and negatively affected by pollution.[136]

Green hydrogen will likely feature in these efforts, driving emission reductions and the potential to achieve net-zero. By expanding the low-carbon hydrogen market (including green), the United States is expected to also benefit from job growth, improved human and environmental health, increased resiliency of energy systems, and enhanced energy security by creating regional economic opportunities.

Section 1 discussed the usage geography and incipient hydrogen hubs to predict where green hydrogen may be used for industrial heat. To analyze the environmental and social considerations of scaling green hydrogen, we'll consider these potential future markets to understand some of these impacts.

Hub and regional impact analysis

While the geography of hydrogen hubs is still uncertain, many environmental and social impacts of green hydrogen, especially in the hub format, will be common across locations that see green hydrogen adoption. This section explores hubs' probable social and environmental effects, drawing on some prominent hub applications. However, proposals for large-scale investment in hydrogen production, transportation, and use are still emerging, and their effects on the local human and physical environment remain uncertain.

One such hub in the Houston area represents a significant share of today's hydrogen market and hosts much of the existing limited hydrogen infrastructure (e.g., hydrogen pipelines The refining and chemical industries, which both have significant local concentrations, use hydrogen. More broadly, the Gulf Coast is a major maritime transport hub and, through the Mississippi River, Houston Ship Channel, and rail links, it has good connections to markets farther inland. The potential exists for multiple hydrogen users for manufacturing or mobility to drive production, which could help create the opportunity for industrial heat users.[137]

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133 USAFacts, https://usafacts.org/articles/how-much-electricity-would-it-take-to-power-all-cars-if-they-were-electric/#:~:text=Given%20that%20comparison%2C%20it%20would%20take%20roughly%20800,the%20US%20would%20have%20consumed%2020-50%25%20more%20electricity. "How much electricity would it take to power all cars if they were electric?," December 15, 2022. Accessed January 2023

134 EIA, https://www.eia.gov/energyexplained/us-energy-facts/" U.S. energy facts explained, last updated June 10, 2022. Accessed November 2022.

135 IEA, https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf" The future of hydrogen. All rights reserved. Accessed November 2022.

136 White House, https://www.whitehouse.gov/environmentaljustice/justice40/ "Justice40," Accessed January 2023.

137 Elizabeth Abramson, Emma Thomley, and Dane McFarlane, https://scripts.betterenergy.org/CarbonCaptureReady/GPI_Carbon_and_Hydrogen_Hubs_Atlas.pdf An atlas of carbon and hydrogen hubs for United States decarbonization, Great Plains Institute, February 2022. Accessed January 2023.

Employment

Like other large tranche of industrial investment, a hub is likely to create new jobs in the hydrogen industry and implicated region, while the green transition generally may displace others. Houston Hydrogen Hub estimates from the Center for Houston's Future indicate that a fully developed hydrogen hub could result in 30,000 net jobs in Houston by 2050, including direct employment at hub facilities and induced jobs in the broader industry.[138]

The IRA contains strong incentives for labor quality: Both the ITC and PTC are multiplied by five for employers who pay prevailing wages and offer apprenticeships. In areas and industries with significant union activity, trade unions will be crucial stakeholders in hub development. Organizations such as the United Steel Workers have registered support for increased investment in hydrogen infrastructure, among other clean transition measures. Support of unions will be especially crucial in areas where unionized industries are major potential consumers, for example, in steel-producing Appalachia.[139]

Community engagement and public perceptions

Hydrogen, like many nascent technologies, often struggles with negative perceptions. This may be due to misunderstandings about risks and safety protocols or worries about effects on employment, pollution, water usage, and new construction projects. For production to be socially feasible, green hydrogen producers and users should engage deeply with the communities that will host the valuable, though potentially disruptive, infrastructure. Working with communities to enable renewable hydrogen production considers improved energy and water access to local communities can help pave the way for a just transition. Additionally, providing chances for local ownership across the hydrogen value chain and training programs for locals, including women, youth, and ethnic minorities, could help create local jobs and future opportunities for historically disadvantaged groups.

Given our history of using grey hydrogen for years in the industry, many safety protocols are not new and are, in some cases, more familiar than other low-carbon technologies. However, overcoming negative perceptions of hydrogen, communicating the advantages of the hydrogen economy, and generating broad support from stakeholders through public outreach and engagement will be important activities to enable a just and stable social foundation for the green hydrogen economy. Thoughtful planning processes and sustained public outreach can be strategies to aid local climate plans and decarbonization measures to enable the clean energy transition is fully inclusive across communities.

Planning and siting

Constructing new hydrogen facilities, especially pipelines that may have to cut through existing developed areas, can be fraught with delicate trade-offs. The exact requirements and locations of new construction are not yet known. Still, many hub organizations have already begun developing frameworks for engagement with communities to enable a just siting-decision process as part of a broader push to secure environmental justice. The Pacific Northwest Hydrogen Association, a hub contender in Washington and Oregon, boasts one of the more fullsome protocols. Plans call for project sponsors to put forward Equity, Environmental, and Energy Justice (EEEJ) plans as part of their application,[140] per state laws and guidance (such as the Healthy Environment for All Act[141] and Washington state equity provisions)[142] and
to use data-driven approaches to model and mitigate environmental health disparities.[143]

Proper siting of hydrogen production sites and renewable electricity generation needed for hydrogen production should also avoid negative impacts on water, land, and biodiversity. When designing, planning, and evaluating a hydrogen project, full life cycle emissions should be considered, including land use, land-use change and forestry (LULUCF), upstream emissions, direct emissions from hydrogen production, and emissions from the transport and storage of hydrogen (including leakage).

Hourly matching and additionality

A study by Princeton University has shown that matching electricity consumption on an hourly basis with locally procured, "additional" clean generation is required to enable emissions saving from clean hydrogen production. Without more granular temporal matching (e.g., hourly), increasing hydrogen production will incentivize not only new and additional renewable electricity but also coal and gas as marginal generators in the system. According

[138] Center For Houston's Future, https://www.centerforhoustonsfuture.org/H2houstonhub "Introducing HyVelocity Hub: A commitment to advance clean, affordable, at-scale hydrogen in Texas and Louisiana." Accessed January 2023.

[139] United Steelworkers (USW), https://convention.usw.org/resolutions/resolution-no-24-environmental-responsibility-acting-today-to-protect-usw-jobs-now-and-in-the-future "Resolution No. 24: Environmental responsibility: Acting today to protect USW jobs now and in the future." Accessed January 2023.

[140] Pacific Northwest Hydrogen Association, https://pnwH2.com/about-us" About our work, Accessed January 2023.

[141] Washington State Department of Health, https://doh.wa.gov/community-and-environment/health-equity/environmental-justice "Environmental justice," Accessed January 2023.

[142] Washington State Department of Commerce, https://www.commerce.wa.gov/wp-content/uploads/2021/01/WA_2021SES_Chapter-A-Equity.pdf Build an equitable, inclusive, resilient clean energy economy, December 2020. Accessed January 2023.

[143] Washington State Department of Health, https://fortress.wa.gov/doh/wtnibl/WTNIBL/ "Washington Tracking Network (WTN)." Accessed January 2023.

to this study, without hourly matching of local, additional renewable electricity, emissions from grid-based electrolysis are roughly double those of grey hydrogen.[144]

Many other studies have pointed out the deficiencies of annual matching, largely owing to mismatches between the profile of renewable energy supply and energy demand.[145] Without hourly, location-based matching, producers will be incentivized to match 100% of their annual demand with renewable energy certificates (RECs) from the lowest-cost sources that may have been generated far from the actual grid where hydrogen is being produced and only for portions of the year.

REC registries are adapting to growing demands for granularity, making hourly matching across the United States increasingly feasible. Midwest Renewable Energy Tracking System (M-RETS), which currently covers 15 states across the Midwest and is expanding to cover the remaining area of the West, has offered hourly RECs since January 2021. PJM GATS, another widely used registry, expects to offer hourly RECs by the end of 2022.

Renewable electricity and associated RECs should be sourced from generation within the same balancing authority of the hydrogen production site so that renewable capacity is being developed in the regions where there is demand. This is an increasing expectation in renewable electricity sourcing and should be incorporated into the requirements for qualified clean hydrogen production today.[146]

Hourly matching and other additionality considerations for green hydrogen production as well as broader sourcing practices for renewable electricity are emerging trends in policy and standard-setting discussions and in corporate climate leadership. Energy buyers and hydrogen producers should track and engage in relevant discussions to better understand and contribute to the development of clear standards for the use of renewable electricity in green hydrogen production.

Water

As these plans grow, developers and organizations are aware that they should consider the possible environmental disruptions. One such risk factor is the potential to overburden water resources as green hydrogen is developed at scale. Green hydrogen production involves electrolysis, which requires a significant amount of water as an input. Producing 1 kilogram (with an energy content of about 33 kWh)[147] of hydrogen requires a theoretical minimum of 9 liters of water, with actual usage dependent on the efficiency of the electrolyzer. [148]

As communities around the globe begin to feel the impacts of climate change, including drought, water security has become a growing concern. California, home to potential hubs such as ARCH2ES and HyBuild Los Angeles, has 17 hydrogen production facilities and several petroleum refining, natural gas processing, cement and steel manufacturing, and ethanol production facilities.[149] However, despite its diverse concentration of industries, strong transport infrastructure, and storage capabilities, the Western United States has faced water challenges for some time and experienced the worst drought in 1,200 years in 2022. Similarly, states like Kansas and other areas in the High Plains saw extreme drought in 2022, raising the question of the risks of expanding water-intensive green hydrogen production in these areas.[150]

Finally, with seawater electrolysis becoming more popular, developing safe and environmentally friendly disposal methods for brine will be important. Communities could face negative environmental impacts with the wastewater or brine produced from the desalination of available

[144] Ricks, Wilson, Qingyu Xu, and Jesse D. Jenkins. "Enabling Grid-Based Hydrogen Production with Low Embodied Emissions in the United States." Zenodo, October 10, 2022. https://doi.org/10.5281/zenodo.7183516. Accessed January 2023.

[145] See, for example:

Rocky Mountain Institute, https://rmi.org/insight/clean-power-by-the-hour/" Clean Power by the Hour: Assessing the Costs and Emissions Impacts of Hourly Carbon-Free Energy Procurement Strategies." July 2021. Accessed January 2023.

Lott, Melissa and Bruce Phillips. https://www.nbgroup.com/docs/Corporate_Procurement_CGEP_Report_120821.pdf" Advancing Corporate Procurement of Zero-Carbon Electricity in the United States: Moving from RE100 to ZC100." Columbia Center on Global Energy Policy, December 2011. Accessed January 2023.

[146] Jacques A. de Chalendar and Sally M. Benson, https://www.cell.com/joule/fulltext/S2542-4351(19)30214-4 Why 100% Renewable Energy is Not Enough, Joule 3, 1389-1393 (June 2019). Accessed January 2023.;

Quinju Xu, et al., Princeton University Zero Lab, HYPERLINK "https://zenodo.org/record/7082212#.ZBjUDsLMKM9"Electricity System and Market Impacts of Time-based Attribute Trading and 24/7 Carbon-free Electricity Procurement, September 15, 2021. Accessed January 2023.

[147] Patrick Molloy, https://rmi.org/run-on-less-with-hydrogen-fuel-cells/#:~:text=In%20electrical%20terms%2C%20the%20energy,as%20a%20gallon%20of%20diesel. Run on less with hydrogen fuel cells," RMI, October 2, 2019. Accessed January 2023.

[148] Michael E. Webber, https://iopscience.iop.org/article/10.1088/1748-9326/2/3/034007/pdf The water intensity of the transitional hydrogen economy" Environmental Research Letters 2 (Sept. 2007). Accessed March, 2023.;

[149] Elizabeth Abramson, Emma Thomley, and Dane McFarlane, https://scripts.betterenergy.org/CarbonCaptureReady/GPI_Carbon_and_Hydrogen_Hubs_Atlas.pdf An atlas of carbon and hydrogen hubs for United 2States decarbonization, Great Plains Institute, February 2022. Accessed January 2023.

[150] National Drought Mitigation Center at the University of Nebraska-Lincoln, the United States Department of Agriculture and the National Oceanic and Atmospheric Administration, https://droughtmonitor.unl.edu/ "US Drought Monitor." Accessed January 2023.

water sources, along with the demineralization process needed to achieve appropriate water quality for electrolysis. Therefore, developing safe disposal methods will be crucial to minimize negative impacts on waterways as the capacity of green hydrogen production increases and heavily becomes location dependent.

Atmospheric pollution

Outside of water security, hydrogen can, in some cases, harm the environment. Concerns over hydrogen's global warming potential (GWP) and the possibility of leakage should be addressed for green hydrogen to be a clean energy solution. If emitted into the atmosphere, hydrogen can increase the amounts of other GHGs, causing indirect warming[151]. Given the small size of hydrogen molecules, leaks are a growing concern, especially as the value chain grows and new markets are developed.[152] As hydrogen becomes widely used, leaks are likely to be concentrated in a few processes—including green hydrogen production, delivery, road transport, and chemical production. Economywide leakage rates could reach up to 5.6%.[153] As production increases, leakage rates become increasingly damaging.[157] As the green hydrogen market grows and looks to meet new demand in the United States, sensors, leak detection, improved infrastructure, and supportive policy measures are required to decrease environmental damage. While hydrogen is more liable to leak than natural gas, it has a global warming potential half as serious as methane.[154]

Additionally, a combustion reaction that heats air to high temperatures may create harmful pollutants called nitrogen oxides (NO and NO2, known together as NOx).[155] While the production and use of green hydrogen is free of CO2, hydrogen combustion does produce NOx. Due to a variety of factors, introducing hydrogen into gas turbines and other burners can increase the production of NOx[156]. According to the EPA, NOx can be linked to damaging health impacts, such as asthma and respiratory infections, as well as smog, acid rain, and other adverse environmental effects.[157] Given that California has seen record-breaking levels of air pollution and increased air quality concerns,[158] environmental justice groups are aware of the negative impacts and highlight the need to protect communities already overburdened with pollution and related health effects. Though hydrogen systems can potentially produce significantly more NOx than natural gas-burning systems, NOx mitigation is a well-established and effective pollution abatement process.[159]

Conclusion

Scaling green hydrogen across the United States has many potential benefits; however, market expansion should be closely monitored to avoid negative environmental and social impacts. As with any major transition, the potential to use this opportunity to build a more equitable, clean energy economy exists if communities are properly engaged and considered in future planning. When considering possible green hydrogen markets and hubs, note similarities regarding social and environmental implications. When the question of where green hydrogen may be used is resolved, more detailed environmental and social impact estimates can be made, and localized problems presented by the production and use of hydrogen may be mitigated. Burning fossil fuels drives climate change and air pollution, whose effects fall mainly on disadvantaged communities, and hydrogen usage may displace fossil fuels. On balance, then, the transition to green hydrogen has the potential to be a boon to society at large and within regional communities.

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[151] Zhiyuan Fan, Hadia Sheerazi, Amar Bhardwaj, Anne-Sophie Corbeau, Kathryn Longobardi, Adalberto Castañeda Vidal, Ann-Kathrin Merz, Caleb M. Woodall, Mahak Agrawal, and Julio Friedmann, https://www.energypolicy.columbia.edu/publications/hydrogen-leakage-potential-risk-hydrogen-economy" Hydrogen leakage: A potential risk for the hydrogen economy, Columbia University Center on Global Energy Policy, July 5, 2022. Accessed January 2023.

[152] Ibid.

[153] Ibid.

[154] The https://assets.publishing.service.gov.uk/government/uploads/system/uploads/attachment_data/file/1067144/atmospheric-implications-of-increased-hydrogen-use.pdf UK government estimates hydrogen's GWP as 11 +/- 5, whereas the https://www.epa.gov/ghgemissions/understanding-global-warming-potentials#:~:text=Methane%20(CH4)%20is%20estimated,less%20time%20than%20CO2. EPA estimates methane's GWP at 27–30. CO2 defines the GWP scale, with a value of 1.

[155] Christopher Douglas, Benjamin Emerson, Timothy Lieuwen, Tom Martz, Robert Steele, and Bobby Noble, https://research.gatech.edu/sites/default/files/inline-files/gt_epri_nox_emission_H2_short_paper.pdf NOX emissions from hydrogen-methane fuel blends, Georgia Tech University's Strategic Energy Institute, January 2022.

[156] Department of Energy, https://www.energy.gov/eere/fuelcells/H2iq-hour-addressing-nox-emissions-gas-turbines-fueled-hydrogen-text-version "H2IQ Hour: Addressing NOx Emissions from Gas Turbines Fueled with Hydrogen: Text Version," Accessed March 2023]

[157] EPA, https://www.epa.gov/no2-pollution/basic-information-about-no2#Effects"Basic information about NO2, last updated August 2, 2022. Accessed November 2022.

[158] Dustin Jones, https://www.npr.org/2022/04/21/1093205632/air-quality-pollution-state-of-air-report "More than 137 million Americans live in areas with poor air quality, report finds," NPR, April 21, 2022.

[159] See above, note 155; c.f. Christopher Douglas, Benjamin Emerson, Timothy Lieuwen, Bobby Noble, and Neva Espinoza, https://research.gatech.edu/sites/default/files/inline-files/EPRI_GT_H2_WhitePaper.pdf Hydrogen Utilization in the Electricity Sector: Opportunities, Issues, and Challenges, Georgia Tech University's Strategic Energy Institute, July 2021.

Chapter 7: Opportunities and considerations for scaling green hydrogen for industrial heat

Summary and key takeaways:

Significant uncertainties will determine the future of green hydrogen and, more specifically, its deployment for industrial heat. In this chapter, we analyze the United States' policy, technology, and market landscape to help us understand how the green hydrogen economy may develop. Given the nascency of the market, buyers and producers are likely to behave differently, resulting in more cooperation across the value chain until maturity is reached. As the market matures/develops more traditional and developed market, the risk associated with the hydrogen market is expected to change, and more conventional risk-mitigation methods will be deployed. For the green hydrogen market to develop, risk will likely be spread across value chain players until the "chicken-or-the-egg" question is answered. In the interim, we identify key actions that stakeholders could consider to help scale green hydrogen. This chapter reveals the following key takeaways:

- Policies and programs like the IRA and permitting reform can help increase infrastructure and significantly bring down the production costs for hydrogen. Financial barriers for end users to adopt green hydrogen may still exist; however, which will require additional policy support.
- Developing education campaigns, clear safety standards, and community engagement plans can help ensure a just transition and grant social license for the hydrogen economy so infrastructure can be deployed early and rapidly. Building hub ecosystems and renewable generation assets are critical to foster dependable supply and demand for players throughout the value chain to scale green hydrogen.
- Targeted investments in RD&D to develop consistent health and safety standards and to improve technology across the value chain are necessary to lower costs and increase efficiencies; additional RD&D efforts toward retrofitting and transportation could help reduce location constraints and connect different layers of infrastructure to grow the green hydrogen market.

Considerations and actions for energy buyers

This report focuses primarily on a subset of the broader hydrogen market: green hydrogen used for industrial heat. The results should not necessarily be applied to the broader hydrogen economy. Considering all types of hydrogen, with the exception of brown, black, and grey, and potential end uses will give a much broader economic picture. Hydrogen will likely be deployed globally in mobility applications, such as feedstock for low-net-carbon fuels, and for inter-seasonal energy storage.

In the least advantageous scenarios, our model shows that green hydrogen could still account for up to 3% of total industrial heating energy in the United States by 2050. This could equal roughly half of all hydrogen currently produced in the United States. If the considerations below are implemented, and some of the challenges facing green hydrogen are mitigated, our model indicates that green hydrogen could comprise up to 12% of industrial heating energy by 2050, making it a key component of industrial decarbonization and comprising roughly 22% of green hydrogen utilization, according to our model's supply projections. In all scenarios, green hydrogen is set to become an essential tool in the energy transition.

Challenges can arise when adopting green hydrogen for industrial heat applications, but actions can be taken to address them—creating pathways for widespread adoption. The industry has several options for process heat, each with its own technical, economic, and environmental trade-offs.

Below, we consider a series of 11 policy, market, and technology levers and initial actions that could accelerate green hydrogen adoption and inform strategic planning for stakeholders. Appendix 3 contains further considerations.

1. Long-term policy creates market certainty

Modeling indicates that policy support will be an important determinant in future hydrogen production. Recognizing that the emissions-scaled ITC and PTC incentives have only recently been implemented, extending these incentives to 2050 will likely increase renewable capacity and reduce the LCOE for green electricity sources, including hydrogen. Tax credits and incentives under 48C may also need to complement the incentives available under 45V for producers by considering retrofitting and investments for chemicals, cement, and iron and steel to switch to green hydrogen and to enable increased uptake by end users. Additionally, as renewable power peak load exceeds grid demand, hydrogen can balance renewable power usage to create a more reliable and efficient grid. The net effect of additional demand from electrolyzers and additional supply from incremental renewable projects could allow the highest-value energy from new renewable projects to flow to the grid while green hydrogen producers absorb the rest.[160] Over time, access to cheaper renewables and increased grid capacity will likely create greater potential for producing green hydrogen.

Though less likely, carbon pricing could be another powerful policy lever that affects hydrogen value chain players differently, especially on the end-use side. If an effective carbon tax were implemented within the United States, industrial heat users could have stronger fiscal incentives to shift to low-carbon alternatives, like green hydrogen. Additionally, a carbon pricing scheme could offset price risks for early investment in hydrogen by raising the effective cost of competing fuels like natural gas, oil, and coal.

Policies like the IRA will have implications for stakeholders across the value chain. Though the IRA will be important in reducing production costs, cost barriers will still be on the end-use side and the broader ecosystem (e.g., infrastructure support for transport and storage). This reinforces why advocating for timely extensions to IRA tax credits through 2040 or 2050 (as well as less likely policies, such as a carbon price) could bring down hydrogen cost curves, enable adequate infrastructure build, and allow hydrogen to become cost competitive with fossil fuels over the long term.

Hydrogen producers, industry associations, policymakers, and nonprofits are critical stakeholders when it comes to extending current policies as well as encouraging new measures. In the short term, stakeholders will need to develop a unified industry perspective and deploy advocacy campaigns to share how programs such as the IRA can foster economic growth and positive outcomes for the industry.

In the immediate term, energy buyers and other value chain stakeholders should take advantage of current policies to benefit from the cost advantages associated with green hydrogen production. Looking forward, they can actively provide feedback during public commenting periods for new legislation, which may be critical to guide policymakers to enable the green hydrogen economy. Staying involved in dialogue with local, state, and federal actors to voice the benefits of supportive policy is a leading practice. This will help legislation to continue incorporating benefits to scale green hydrogen for industrial heat users long term.

[160] Dev Millstein, Ryan Wiser, Andrew D. Mills, Mark Bolinger, Joachim Seel, Seongeun Jeong, https://www.sciencedirect.com/science/article/pii/S2542435121002440 Solar and wind grid system value in the United Stated: The effect of transmission congestion, generation profiles, and curtailment, Joule, Volume 5, Issue 7, 2021, Pages 1749-1775

2. Consistent technical and safety standards can ill policy gaps

To scale green hydrogen, legitimate safety concerns should be addressed through appropriate health, safety, and environment (HSE) standards and regulations. Currently, many regulations around safety focus on leakage; however, inclusive standards that address the full value chain are still needed. For example, no overall framework is in place to help businesses understand the long-term regulatory implications of transporting large volumes of hydrogen across geographies. The DOE is currently working with code development organizations, code officials, industry experts, and national laboratory scientists to draft new model codes and standards across the hydrogen value chain for domestic and international purposes.[161]

The codes being developed will need to be recognized by federal, state, and local governments to enable the commercialization of hydrogen. To scale green hydrogen, stakeholders throughout the hydrogen value chain should form working groups to engage with national and global standard-setting bodies.

RD&D, alongside policy reform, can also mitigate present safety hazards. Efforts that prioritize reducing the risks of ignition and developing advanced sensors, tracers, and new odorants are important to improve safety and reduce the threat of leakage. Despite these safety concerns, switching from legacy fuels could decrease several risks. For example, hydrogen is nontoxic. It is lighter than air, preventing it from concentrating close to the ground, and it is also less explosive and has a lower radiant heat when compared to many conventional fuels.[162]

Some of the public is still confused about the colors of hydrogen and the trade-offs of each. A standard industry definition of low-carbon hydrogen is likely to help with public understanding and acceptance while spurring hydrogen development. Additionally, many countries are at various stages of developing thresholds for low-carbon hydrogen, and the requirements continue to evolve. If major leaders can define low-carbon hydrogen, this could spur major market developments and avoid greenwashing when it comes to offsets.

To advance health and safety standards, energy buyers can consider collaborating with industry associations through working groups to establish and implement industry leading practices for industrial heat end uses and a clear message on safety. Though these leading practices may be specific to industrial heat, they can build off other early movers in the hydrogen value chain to better establish a clear position. By developing alignment, the industry can better create a blueprint for future safety standards and partner with standard-setting organizations and government actors to fill policy gaps. These actions will help the industry to operate safely and ease concerns, so the public is ready to embrace the transition to hydrogen.

3. Heightened public awareness and education can increase social license to operate

Green hydrogen has limited public awareness compared to more developed low-carbon renewable and nuclear energy technologies. As with many new technologies, concerns exist but may be mitigated by increasing public awareness and educating communities on the benefits of green hydrogen as an energy source.

The US government views hydrogen as a critical aspect of decarbonization, especially for hard-to-abate applications such as industrial heat. Nonetheless, understanding public attitudes toward new technologies is crucial for widespread adoption. A consumer-focused survey found the largest concerns for hydrogen were related to hydrogen's flammability, storage difficulties, and high costs.[163]

Despite these concerns, hydrogen is safely used in many applications today, and costs are projected to decrease as technology is further adopted. Action across the hydrogen value chain is crucial to widespread adoption. Hydrogen value chain participants may utilize public surveys to better understand their customers and the specific preferences of the communities. Public education and market campaigns can focus on dispelling myths and raising awareness of green hydrogen's benefits to the community.

Energy buyers can conduct ongoing outreach individually or in collaboration with other hydrogen value chain players to get involved in the communities that are set to host green hydrogen plants and related infrastructure. This could involve providing spaces where communities can ask questions, engage in dialogue, and interact with content that shares the benefits of new projects. Through these efforts, energy buyers can become trusted partners and gain social license to operate in communities.

[161] DOE Hydrogen Program, https://www.hydrogen.energy.gov/codes_standards.html "Codes and standards." Accessed January 2023.

[162] Christian Tae, https://www.nrdc.org/experts/christian-tae/hydrogen-safety-lets-clear-air "Hydrogen safety: Let's clear the air," National Resources Defense Council, January 14, 2021. Accessed January 2023.

[163] Emily Cox, https://ukerc.ac.uk/news/public-perceptions-of-low-carbon-hydrogen/ "Public perceptions of low-carbon hydrogen," UK Energy Research Centre, January 6, 2022. Accessed January 2023.

4. Community engagement during design and development for a just transition

While the build-out of the green hydrogen economy can decarbonize many sectors, including industrial heat, the clean energy transition should be intentional in incorporating environmental and climate justice. Growing the hydrogen economy ethically and equitably is central to the DOE's hydrogen strategy. Therefore, public outreach and community engagement with local groups and nonprofit organizations will be pivotal in enabling a just transition.

Different actors across the hydrogen value chain should consider public surveys and host community events to foster an open dialogue and gather feedback as the green hydrogen market grows. Project developers, industry associations, policymakers, and nonprofits could begin by collaborating with labor unions and building job trainings for communities to upskill themselves to protect workers and mitigate potential economic impacts. Likewise, working with environmental groups during the planning phase to aid proper permitting and nature conservation can help prevent negative impacts and allow green hydrogen to truly be part of the clean energy solution. Energy buyers should focus on building trust and working closely with local communities and other value chain stakeholders to address these economic, environmental, and social concerns throughout new hydrogen projects' design and development phases. Working to create consistent communication plans to share updates will be crucial to building trust over the long term as communities undergo change through the scaling of green hydrogen.

5. Developing sustainability criteria for hydrogen can clearly de ine green hydrogen

Given hydrogen incurs significant energy loss throughout its life cycle, the total energy loss depends on the final use. As more energy is lost, more renewable electricity capacity will be needed for green hydrogen production. This challenge means that producers should aim for electrolyzer energy consumption not exceeding fossil fuel consumption elsewhere. In order for hydrogen from electrolysis to have lower overall emissions than grey hydrogen, CO2 emissions per unit of electricity should be lower than 190 grams of CO2 per kW hour (gCO2/kWh).[164]

Without proper requirements for grid-connected hydrogen producers to procure clean electricity, emissions from hydrogen produced through electrolysis could be worse than those produced via conventional, unabated fossil pathways. Additionally, failure to meet requirements for hourly matching, locality, or additionality of procured clean generation can lead to significant excess emissions.[165] Therefore, as the demand for green hydrogen grows, stakeholders are likely to need to have methods in place to confirm that hydrogen is truly green.

Energy buyers and other stakeholders can make progress by participating in public commenting periods for supportive policies, such as the IRS clean hydrogen standards for tax credits and other proposed measures to determine sustainability criteria. Additionally, these market players should consider teaming with nonprofits and standard-setting organizations to update processes and GHG emission accounting protocols to help green hydrogen be truly a decarbonization solution.

6. Information campaigns on green hydrogen can educate and outline roles for energy buyers

Due to green hydrogen's role as a new energy solution, end users may not be aware of its potential to decarbonize hard-to-abate sectors. The nuances of a nascent market may appear daunting, but the advantages of investing early may be determined to be worthwhile. Educating energy buyers on green hydrogen's benefits for their business is essential to enabling their social license to operate while improving customer and shareholder value.

Nonprofits and industry associates will be at the forefront of education initiatives to introduce and expand energy buyers' knowledge of green hydrogen. These stakeholders can work to host webcasts and industry events to foster community dialogue and communicate the current benefits of the policy in place. Additionally, they can help energy buyers better understand the appropriate roles they can play in the broader hydrogen economy. Given the need for existing value chain players to build relationships with energy buyers, these stakeholders can serve as an important educational resource for those looking to explore market entry. Through this collaboration, energy buyers can learn if green hydrogen is an option for their decarbonization strategy, when it is appropriate to engage in the market, and how much influence they could have in the future.

[164] IRENA (2020), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Nov/IRENA_Green_hydrogen_policy_2020.pdf Green hydrogen: A guide to policy making, International Renewable Energy Agency, Abu Dhabi. Accessed January 2023.

[165] Ricks, Xu, and Jenkins; https://zenodo.org/record/7641487#.Y-0_yezMI0Q "Minimizing emissions from grid-based hydrogen production in the United States." October 10, 2022. Accessed January 2023.

For energy buyers, engaging with industry associations, nonprofits, and hydrogen value chain members will be a crucial first step to making strategic decisions and defining their role in the broader energy transition. This type of collaboration with end users across the value chain can improve and accelerate these strategic actions moving forward.

7. Innovative procurement models and standardization of contracts to streamline supply

The risk and uncertainty of supply contracts are widely seen as a barriers for hydrogen projects; altering the contracting environment for the supply of hydrogen could enable more dynamic hydrogen markets. Current contracts are often bespoke, bilateral, and opaque. This increases transaction costs, risk, and uncertainty for new market entrants. If firms choose to establish standardized, transparent contracting protocols for hydrogen supply, it could eventually shift hydrogen materially toward becoming a widely traded commodity similar to natural gas (although it is recognized that the standardization of bilateral contracts is only the first step).

Traditional contract structures such as "take or pay" have helped emerging markets in the chemical industry grow to become commodities. In this scheme, both buyer and seller hedge against uncertainty with an exit clause under which the buyer pays the seller a fee if they do not purchase the contracted amount of hydrogen. This reduces the risk to early adopters and hydrogen producers when hydrogen costs may fall over the course of the contract. This and various other risk mitigation measures could be implemented early to manage risk for producers and end users.

As the market evolves, industry players can consider the evolution of the power purchase agreement (PPA) market to draw on insights. As the PPA market has matured, players on the generation and offtake sides have increased, creating an uptick in new PPA models and arrangements. With increased pressure to meet environmental and sustainability goals, there has been less emphasis on longer offtake terms and a growing popularity for aggregated PPAs where multiple buyers are involved in a single project. These types of projects show the possibility of increased transparency where buyers know the identities of other buyers and contracting terms, serving as a potential case study for hydrogen supply contracts in the future.

Additionally, it is important to understand the carbon intensity of the hydrogen being purchased. A standard definition of low-carbon hydrogen, applied globally, could help contract transparency and greatly spur green hydrogen development. Many countries are at various stages of developing thresholds for low-carbon hydrogen and the requirements continue to evolve. If major leaders can define low-carbon hydrogen, this could help improve the contracting environment and avoid greenwashing.

Increasing standardization of supply contracts and other relevant market instruments related to hydrogen could improve transparency and lower transaction costs, risks, and uncertainty. This can ease entry into contracts, reduce the risk to early adopters, and allow for bilateral and OTC trading. Hydrogen producers, policymakers, and energy suppliers and buyers can collaborate to develop contract standardization and a low-carbon hydrogen definition. For example, working groups driven by industry associations can align stakeholders on common contracting processes and methodologies. Later, they can facilitate an industry position on hydrogen contract transparency or aid in standing up hydrogen commodity trading departments, and the cross-collaboration could lead to a fully developed wholesale hydrogen commodity market with standard contracts.

Energy buyers can enter regional buying consortia with other industrial heat applications or end uses to enable green hydrogen for industrial heat by aligning on standard terms and conditions to develop industry leading practices. These consortia could increase the volume of hydrogen purchased, which gives certainty to hydrogen producers, minimizes transport costs due to high volumes going to the same region, and results in more efficient contracting.

As the industry market evolves and different contracting practices come into play, it is also likely that participants across the value chain may also consider how different business models may be deployed to mitigate risk and promote hydrogen industry development.

8. **Hub ecosystems foster dependable supply and demand**
Green hydrogen for industrial heat is often thought of as a distant use case but is likely to experience accelerated adoption in regions with proximity to DOE or privately funded hubs and where value chain collaboration is encouraged. Infrastructure requirements remain one of the main barriers to hydrogen, driving up costs and decreasing attractiveness compared to legacy fuels, and hubs are meant to accelerate the deployment of hydrogen and the related infrastructure. Established hydrogen infrastructure could allow for an increased supply of potentially cost-competitive green hydrogen for industrial heat in these regions.

   Additionally, to secure highly demanded excess green hydrogen supply for industrial heat, energy buyers should geographically assess their proximity to operational hubs and track early movers for hydrogen end uses to leverage the infrastructure and transportation already developed. Using hydrogen hub explorer tools and following project proposals competing for the DOE's public funding can help buyers stay informed of clean hydrogen hub locations and projects that have been publicly announced or could be in the future.[166] If within a cost-competitive distance, fixing early relationships with hub developers and entering into offtake agreements could enable expanding access to green hydrogen.

9. **Rapid deployment of renewable generation assets supports green hydrogen expansion**
When renewable power generation exceeds grid demand, green hydrogen production can be an attractive use for excess electricity. This green hydrogen can be used for energy storage or sold for other applications. Because wind and solar are intermittent power sources, they are likely to generate excess power during peak production, especially as renewable power expands and accounts for a larger percentage of US electricity generation. This would create a supportive environment for green hydrogen production.

   The intermittency of wind and solar also has a drawback. The intermittency means that continuous green hydrogen production may be challenging for the majority of renewable power in the US. Significant excess renewable energy generation and storage could need to be installed to run electrolyzers effectively and continuously to produce green hydrogen at scale. While policies like the IRA help create additional renewable energy supply, this issue will require significant private investment in infrastructure, and given the long lead times for these developments, announced planning, permitting, and construction can serve as signposts that green hydrogen will have more favorable production conditions in regions where these investments are being made.

   If energy buyers take an industry stance on green hydrogen for industrial heat, renewable power demand will follow. An early stance on green hydrogen for industrial heat will enable rapid planning and deployment of renewable generation assets and grid infrastructure above what will be required to serve current electricity demand. Energy buyers can team with hydrogen producers or other high-demand end uses to scale renewable energy projects to secure VPPAs. To enable development and expedite the process, energy buyers could engage in early conversations and team with network infrastructure providers, hydrogen producers, and regulatory and approval authorities.

10. **RD&D and investments enable scale and decrease costs across the value chain**
Although critically important, low electricity costs and increased renewable energy generation are insufficient to enable competitive green hydrogen production. RD&D investments driven by the government and private players are critical to decreasing costs for electrolyzer, storage, and transportation technologies, enabling breakthrough levels of adoption of green hydrogen. Significant reduction in green hydrogen production costs will likely require continued RD&D focus on improving the overall efficiency of electrolyzers, increasing production, building standardization, and scaling new electrolyzer technologies.

    Focusing additional RD&D efforts toward retrofitting natural gas pipelines to transport hydrogen could be a solution to remove location constraints and connect different layers of infrastructure at the scale needed to grow the green hydrogen market. RD&D focused on developing embrittlement-resistant pipe linings, hydrogen-safe valves, leak detection systems, and further investigation of hydrogen-natural gas blending could increase the value of existing infrastructure for the hydrogen economy. Beyond RD&D for transporting hydrogen, investment to improve retrofitting costs for end users will increase the uptick of hydrogen for use cases such as industrial heat. The ability to retrofit a process to blend hydrogen with existing fuels (e.g., natural gas) or use pure hydrogen or a hydrogen derivative could have an oversized impact on green hydrogen's adoption. In the short term, industrial heat

[166] Yuqi Zhu, Lucie Bioret, and Alan Krupnick, https://www.rff.org/publications/data-tools/hydrogen-hub-explorer/" Hydrogen hub explorer, Resources for the Future, updated January 31, 2023. Accessed March 2023.

users can begin discussions with their equipment providers to understand the work already undertaken to use hydrogen in equipment and processes as well as additional requirements needed for retrofitting.

Enabling RD&D and investments to improve the hydrogen value chain will require public and private parties across the value chain to work together to identify and allocate capital for development. Value chain players can coordinate advocacy for policy to support RD&D budgets and foster teaming arrangements with startups, national labs, investors, and research universities. Additionally, investment in and action toward piloting new technologies is critical to moving from lab-scale to commercial-scale, which is required for mass adoption of green hydrogen.

In the short term, energy buyers can communicate with equipment providers to understand the work done to incorporate hydrogen into existing processes and the requirements for retrofitting. Energy buyers can also enter into collaborations with universities and nonprofits, allowing for greater R&D, especially for end uses, including retrofitting existing equipment and understanding how hydrogen will work in existing processes—both challenges for future scaling. Additionally, buyers may be able to leverage findings from similar work in other end uses to advance their collaborations and give them a strong starting point.

11. Planning, permitting, and approval reduce costs and time constraints

The growth of green hydrogen requires permitting across multiple segments of the value chain and permitting jurisdictions, including those associated with new renewable generation, network infrastructure, new hydrogen production, hydrogen transportation infrastructure, and even some end uses. These permitting processes have many steps and involve state, local, and federal regulatory bodies, and the exact type and number of permits for each endeavor depends on its size, geography, technology, and jurisdictions. At a minimum, many projects require approval from local, state, and federal authorities.[171] Coordination across permitting bodies and a common set of requirements could accelerate and reduce the costs of construction projects without compromising regulatory safeguards. In recent years, permitting processes have received significant attention for a perceived slowing of energy transition projects. If action is taken, there could be a significant increase in realized projects in green hydrogen and across the energy transition.

Action from stakeholders in the short term could help reduce time constraints and cost burdens for a swift build-out of clean energy generation and transmission. Hydrogen producers, other value chain stakeholders, and industry associations will likely have to work with policymakers and nonprofits to highlight beneficial reforms with planning, permitting, and approval authorities at the local, state, and federal levels. If the industry can develop a strong, cohesive perspective on permitting and what's needed to drive green hydrogen development, this could help foster alignment with policymakers as they develop and implement new legislation and permitting processes.

Energy buyers will also play an important role in establishing the need to swiftly deploy these new projects. It is likely that buyers will need to work with project proponents and other value chain stakeholders, including executing commitment letters or other agreements, to establish the need and demand for the project.

Conclusion

Many concurrently followed paths could lead to net-zero GHG emissions. All of them will require a suite of approaches working in concert, and the pathway for the abatement of industrial heat emissions is no exception. Renewable electricity, carbon capture, bio-based fuels, hydrogen-based fuels, and energy efficiency will play a role, and because of competition for renewable electricity and advances in low-temperature heat electrification, it appears likely the role for green hydrogen will be for heating applications above 300°C and, even more likely, above 550°C where combustion is more efficient for heating.

This, however, is not a foregone conclusion. Renewable power capacity and hydrogen infrastructure need to be expanded to make green hydrogen available. Either costs need to come down or subsidies need to be continued for green hydrogen markets to be sustained beyond current policy time period, and hydrogen-fired steam generators and furnaces should replace legacy equipment for hydrogen to be used for industrial heat. Further, financial institutions and lending and risk practices are likely to play an important role in deploying capital across the hydrogen value chain and the uptake of hydrogen for industrial heat. Green hydrogen provides a significant opportunity to decarbonize high-heat industrial applications. Still, it will require coordination between policymakers, regulators, end users, and producers to maintain momentum in RD&D and lead to the wide-scale deployment of hydrogen.

[171] Rayan Sud and Sanjay Patnaik, "How does permitting for clean energy infrastructure work?," Brookings Institution, September 28, 2022.

Appendices

Appendix 1: Detailed modeling methodology

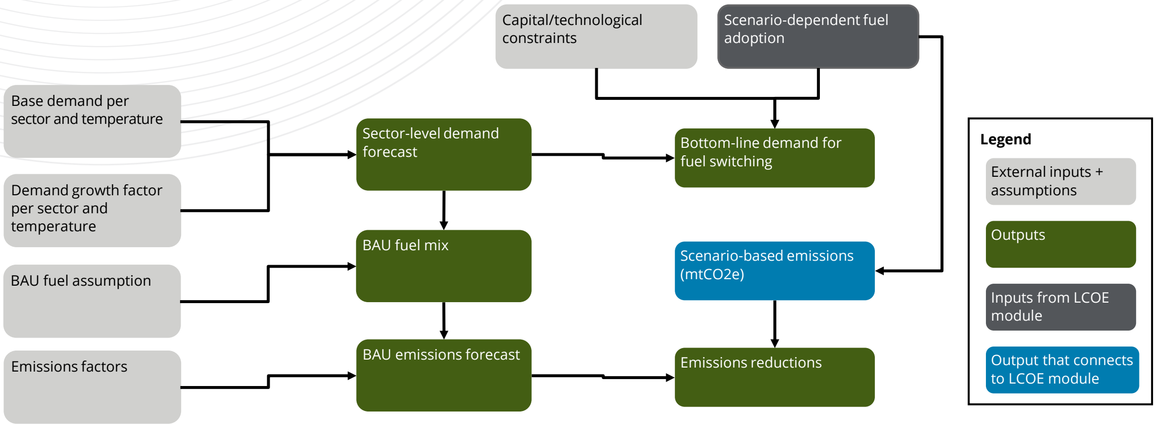
The modeling work undertaken for this project was used to inform and guide our considerations concerning the techno-economic assessment of green hydrogen, its ability to decarbonize industrial heat, and the requirements for accelerating the adoption of green hydrogen. The purpose of the model is to quantitatively support our considerations and prepare visualizations of certain outputs to inform the final report. The model uses on inputs and assumptions based on prior experience and industry research to assess a range of possible futures of demand for industrial heat, which sources will meet that demand, and other factors driving the adoption of green hydrogen. The quantification process was split into three specific modules, covered below.

Demand module

The demand module contains 17 distinct demand curves according to each industrial heating process's subsector and temperature category. The module assumes that natural gas is used for processes besides refining oil and gas iron and steel production. The refining subsector typically utilizes a combination of oil and gas byproducts (flue gas) and natural gas to create industrial heat. The iron and steel subsector utilizes coal to reduce iron for steelmaking. Demand is forecast in quadrillion British thermal units (quads) for the demand points.

Two demand curves account for hydrogen utilization as a chemical and petroleum feedstock and utilization of hydrogen in the transportation subsector. These use cases are likely to eat into the overall hydrogen supply before industrial heating use cases due to higher energy costs in the transportation ssubector and inelastic demand for hydrogen as a chemical and petroleum feedstock.

Figure 29: Demand module logic map

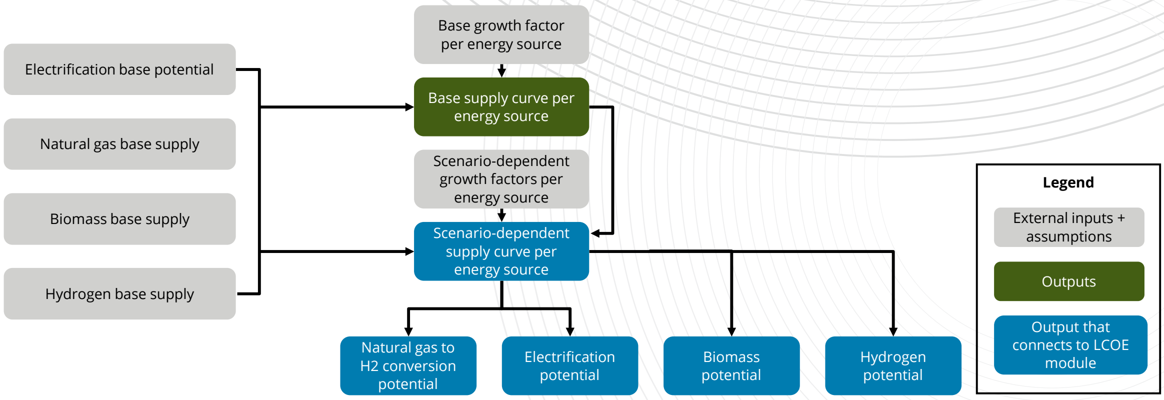


The output of the demand module is the marginal demand for fuel switching in industrial heating. This calculation is linked to both the supply module and the decision engine. The decision engine calculates cumulative demand that has already been switched to a clean alternative and amortizes this amount from the top-line demand to create the bottom-line demand for fuel switching. The amount of fuel that can be switched annually is limited by capital constraints within each subsector.

Supply module

The supply module houses scenario-dependent supply curves over time in quads. This includes curves for the electrification of industrial fuel utilization, waste biomass, and traditional fossil fuels. Electrification curves are based on the RTC's *Renewable thermal vision* report.[167] The high electrification scenarios align with the electrification potentials outlined in the report, while the low electrification scenarios will reach half the total potential by 2050.[168] Waste biomass scenarios are sourced from the Net-Zero America Project's (NZAP) scenarios. The high electrification and high policy scenario utilizes the NZAP E+ scenario, the low electrification and high policy utilizes the NZAP E-B+ scenario to align with more fuel use; both low policy scenarios utilize the E- scenario.[169] Hydrogen supply is covered in more detail in chapter 4.

Figure 30: Supply module logic map



The supply module estimates the magnitude of base and scenario-dependent supply for each energy source: electrification, natural gas, biofuels, and hydrogen (green/blue/yellow/grey, under four scenarios. It houses base-case and scenario-dependent supply curves over time.

The supply module output required to enable the decision engine is marginal supply that shifts across the given four scenarios. The supply for each scenario will be forecast by energy source, utilizing 24 different supply curves for waste biomass, clean hydrogen (blue, pink, green, and electrification. The electrification assumptions will utilize only two curves: a high and a low case. Marginal supply is calculated by taking the total supply and subtracting out the fuel that has already been adopted in prior periods, as well as demand for hydrogen from the transportation sector and demand for hydrogen as a feedstock in the chemical and petroleum subsectors.

LCOE and cost reductions through Wright's law

LCOE is a model concept that allows for comparing energy economics, regardless of variations in the energy source. LCOE is calculated by dividing the present value of lifetime costs by the present value of total energy generation. For different types of hydrogen, LCOE was calculated by modeling the full operations of a representative hydrogen plant, including capital expenses, operating expenses, tax credits, depreciation, and financing costs. LCOE was then back-to-back calculated based on the present value of total expenses over the present value of the energy generated. LCOE was recalculated on a rolling annual basis through our timeline from 2022 through 2050, which provided an annual "marginal cost" of hydrogen sold by hydrogen producers.

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[167] RTC, https://www.renewablethermal.org/vision/ Renewable thermal vision, 2022. Accessed January 2023.

[168] E. Larson, C.Greig, J. Jenkins, E. Mayfield, A. Pascale, C.Zhang, J. Drossman, R. Williams, S. Pacala. R. Socolow, EJ Baik, R. Birdsey, R. Duke, R. Jones, B. Haley, E. Leslie, K. Paustian, and A. Swan, https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf "Net-Zero America: Potential Pathways, Infrastructure, and Impacts, interim report, Princeton University, Princeton, NJ, December 15, 2020.," Accessed January 2023.

[169] Ibid.

While the LCOE module gives a "marginal cost" for the energy sources themselves, it does not include the cost of transportation and distribution or the cost of refurbishing or replacing equipment for the end user. These costs are incorporated into the decision engine. We estimate representative costs to each demand driver (sector x temperature) to estimate the true "marginal cost of adoption" of a lower emissions technology. Each demand driver has its assumptions for end-user capital costs and transportation costs.

Adoption of low-emissions energy technology through the decision engine works to reduce the costs of clean hydrogen options in subsequent periods through Wright's law. Wright's law is not a function of time; rather, it's a function of cumulative doubling in production (that is, it may take one year to double production from 100 to 200, but 20 years to double from 1 billion to 2 billion units). As the supply of hydrogen increases in each scenario, overall costs for hydrogen decrease. Figure 31 conceptually demonstrates the application of Wright's law within the model. The model assumes a 15% decrease in cost for every cumulative doubling of production, which is an assumption made from the lifetime cost decreases of traditional renewable electricity technologies.

Figure 31: Cost and learning curves

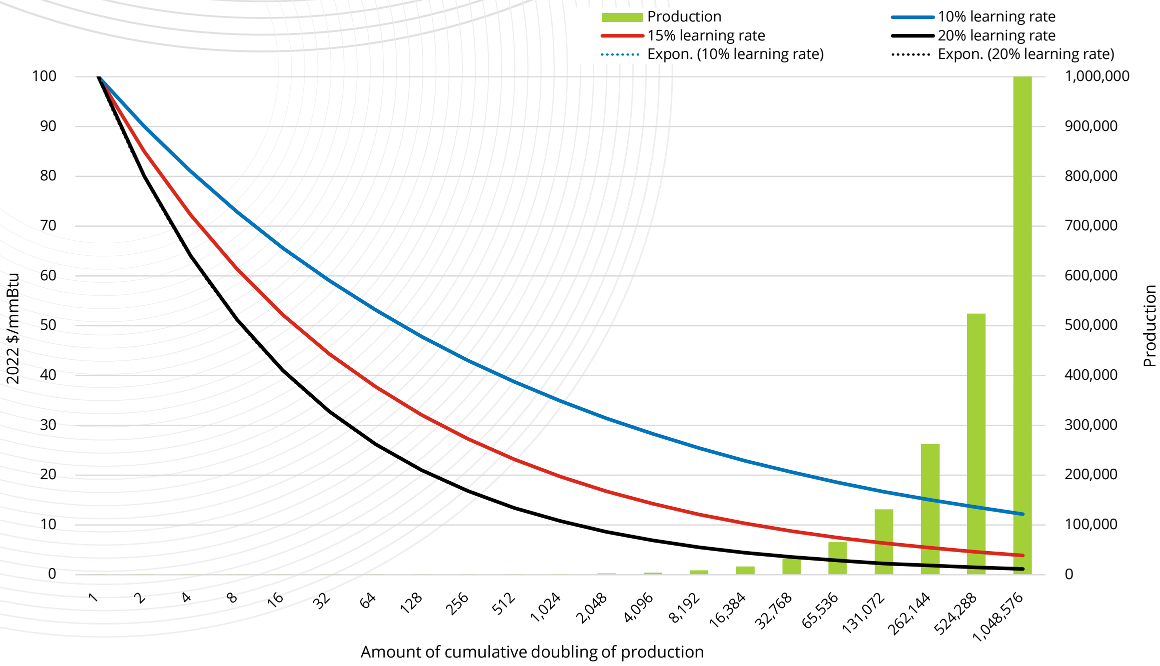

Figure 32: Levelized cost of energy (LCOE) formula

$$LCOE = \sum \frac{(I_t + O_t + F_t)}{(1+r)^t} / \sum \frac{E_t}{(1+r)^t}$$

Where:

I = Investment	t = Time
O = O&M expense	r = Discount rate
F = Fuel cost (as applicable)	E = Energy generation

Cost-comparative decision engine

The decision engine utilizes the outputs of the LCOE module to compare the relative cost of adoption of fuels both within and between sectors. To emulate typical corporate timelines for return on investment, it compares the present value of relative energy costs between legacy fossil fuels, hydrogen, and waste biomass over five years. The decision engine factors in capital upgrade costs for end users to incorporate hydrogen as well as transportation costs when comparing hydrogen to other fuel options. Assumptions on capital upgrade costs are outlined in Appendix 3.

Adoption prioritization

The model ranks the present value of each alternative compared to the present value of the legacy fossil fuel. It then creates a cumulative net present value (NPV ranking for all fuels and demand points. Ranking occurs from highest to lowest NPV. Ranking occurs at demand points of both sector and temperature (e.g., chemical high heat, cement medium heat).

Adoption only occurs for demand points where the differential between the present value of the adopted fuel and the legacy fossil fuel is positive. The decision engine matches supply with demand until one or the other is exhausted.

Annual capital constraints limit adoption to prevent unrealistic levels of hydrogen adoption in a given year along the timeline. These constraints were created by sourcing the capital expenditures of the top five firms in each of the five subsectors evaluated from public financial reporting. Over the past five years, the expenditures were taken to create an annual expenditure curve that was then inflated over time through 2050. The capex-to-revenue ratio for the top five firms was then applied to overall industry revenue projections to create a "capital budget" for each subsector. If the capital budget is exhausted before all hydrogen can be implemented, the remaining fuel demand is not switched over to hydrogen.

Appendix 2: Modeling assumptions

Adoption only occurs for demand points where the differential between the present value of the adopted fuel and the legacy fossil fuel is positive.

Electrification

The electrification scenarios within the model are based on the RTC's *Renewable thermal vision* report.[170] The amount of electrification projected in the decarbonization scenarios in that report aligns with the high electrification scenarios within the model. The low electrification scenarios assume that the long-term potential for electrification within each subsector is roughly half the potential utilized in the high electrification scenarios. This model divides each subsector's demand points by temperature grouping: high, medium, and low. Electrification is assumed to apply first to low-temperature processes and then to medium-temperature processes. No electrification is assumed to meet the demand for high-temperature processes due to technological constraints of producing heat with electricity.

Electrification applies only in the chemical, iron and steel, and pulp and paper subsectors. This model assumes that the refining subsector will not electrify its low-temperature processes due to the inherent cost advantages of utilizing fossil fuels within the subsector, and the cement production process utilizes too high of temperatures to be electrified within the time frame of this analysis.

Electrification in the chemical subsector is projected to occur through heat pumps and electric boilers for low- and medium-temperature processes. Roughly 47% of heating energy in the chemicals subsector is assumed to electrify by 2050 under the high case scenarios. Meanwhile, 24% of heating energy is assumed to electrify by 2050 under the low case scenarios.

Electrification in the iron and steel subsector is expected to occur through electric arc furnaces to provide high heat for the steelmaking process. This model assumes that the remaining facilities utilizing coal-based steelmaking processes will begin to further electrify around 2035. In the high case, electricity will rise from roughly 11% of the energy utilized to 47% of the energy utilized in the subsector by 2050. In the low case, electricity will rise from roughly 11% of the energy utilized to 30% of the energy utilized in the subsector by 2050.

Electrification in the pulp and paper subsector if it occurs, may happen primarily through heat pumps. This model assumes that electricity will account for 28% of the energy utilized in the subsector by 2050 in the high case scenarios, while roughly 14% of energy in the subsector will electrify by 2050 in the low case scenarios.

Carbon pricing

The model utilizes the IEA's net-zero scenario pricing for advanced economies in the high policy scenarios. Accounting for inflation, the pricing they provide amounts to \$171/Mt of CO2e in 2030, \$313/Mt of CO2e in 2040, and \$477/Mt of CO2e in 2050.

In the low policy scenarios, the model assumes there is no carbon pricing until 2040, at which point the carbon price is gradually raised from \$0/Mt of CO2e to \$67/Mt of CO2e in 2050, which is \$50/Mt in today's value accounting for inflation. This scenario was chosen to simulate continued inaction in pricing policy in the United States.

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[170] RTC, https://www.renewablethermal.org/vision/ Renewable thermal vision, 2022. Accessed January 2023.

Energy pricing

Green electricity prices in the model are assumed at an average of $55/MWh nationally. This assumption factors in a premium for 24/7 renewable energy provision to hydrogen plants. Our model accounts for regional variability in pricing utilizing regional industrial electricity prices from the EIA's Annual Energy Outlook 2022 Reference case scenario.[171] The price differential from region to US average in the reference case is then applied as a ratio to $55/MWh, where $55 is assumed as an increase over traditional renewable prices to account for constant renewable operations.

The model assumes green hydrogen facilities will utilize a PPA structure to procure electricity to operate at a 98% utilization rate. A pricing option is also built into the model's decision logic for behind-the-meter operations, where energy is procured at a wholesale rate of $35/MWh, though the utilization rate in this pricing example is only 35%, in line with standard renewable capacity factors.

Nuclear electricity pricing for pink hydrogen is assumed at $45/MWh and inflated over time. This accounts for a conservative estimate of the levelized cost of nuclear energy. Pink hydrogen, at this price, operates at a 98% utilization rate and assumes an agreement for a backup supply of carbon-free electricity if nuclear supply is unavailable for certain periods. The model also includes a behind-the-meter option where nuclear pricing is $35/MWh wholesale, but the utilization factor is 72% to account for the downtime of nuclear facilities and also assumes the electrolyzer does not operate during peak hours.

Natural gas prices align with the EIA's Annual Energy Outlook 2022 Reference case for the low policy scenarios, while the high policy scenario utilizes the outlook's low oil supply scenario. This scenario was selected to mimic the pressure a high policy environment may put on fossil fuel prices.

Waste biomass prices are projected utilizing the current average EIA biomass price.[172] Prices are inflated over time utilizing the Organisation for Economic Co-operation and Development's (OECD) inflation rates.

Demand from other sectors

Natural gas prices align with the EIA's Annual Energy Outlook 2022 Reference case for the low policy scenarios, while the high policy scenario utilizes the outlook's low oil supply scenario. This scenario was selected to mimic the pressure a high policy environment may put on fossil fuel prices.

Waste biomass prices are projected utilizing the current average price for biomass from EIA.[173] Prices are inflated over time utilizing OECD inflation rates.

High policy scenarios utilize IEA's net-zero scenario as a basis for assumption, while low policy scenarios utilize IEA's stated policies scenario as a basis for assumption. Shipping demand includes hydrogen in ammonia and as a feedstock for biofuel that may be utilized within the sector.[174] Aviation demand assumptions are sourced from the FAA's projections of SAF utilization and internal analysis of the hydrogen content of SAF by source.[175]

Growth in these sectors is historically well aligned with GDP growth, which aligns with the assumed demand used in the modeling analysis undertaken. As such, we utilized our analysis and grew the demand for hydrogen out to 2050 by OECD's projected growth for domestic GDP.

Capital upgrades

The model assumes capital upgrades are likely to be necessary for industrial end users to incorporate hydrogen into their processes. Except for the cement subsector, where 100% utilization is not feasible due to chemical and technical constraints of the production process, blending hydrogen is not considered in the model. Blending is currently performed in most sectors at around 15% hydrogen by weight.

Costs to switch to hydrogen are based on equipment replacement costs of key components. Sources are indicated in figure 33; where it was impossible to source data, the model utilizes assumptions based on input from sector advisors and internal research. All values are converted to a dollar or quad of energy in the model based on an assumed 20-year equipment lifetime and utilizing sector average-energy intensities from the EIA.

[171] EIA, https://www.eia.gov/outlooks/aeo/tables_ref.php AEO2022 Reference case. Accessed January 2023.

[172] EIA, https://www.eia.gov/biofuels/biomass/#:~:text=Domestic%20sales%20of%20densified%20biomass,and%20averaged%20%24220.15%20per%20ton "Monthly densified biomass fuel report. Accessed January 2023.

[173] Ibid.

[174] IEA, https://www.iea.org/data-and-statistics/charts/energy-consumption-in-international-shipping-by-fuel-in-the-net-zero-scenario-2010-2030 "Energy consumption in international shipping by fuel in the Net Zero Scenario, 2010–2030," last updated October 26, 2022. All rights reserved. Accessed January 2023.; Elizabeth Connelly, https://www.iea.org/reports/international-shipping International shipping, IEA, September 2022. All rights reserved. Accessed January 2023.; IEA, https://www.iea.org/data-and-statistics/charts/low-and-zero-carbon-fuel-shares-in-international-shipping-by-scenario-2019-2030-and-2050 "Low- and zero-carbon fuel shares in international shipping by scenario, 2019, 2030 and 2050," last updated October 26, 2022. All rights reserved. Accessed January 2023.

[175] Nate Brown and Anna Oldani, https://www.faa.gov/sites/faa.gov/files/2022-03/508.20220322_1545_Brown_Oldani_SAF_Update_v04.pdf Sustainable aviation fuels (SAF): Update to FAA REDAC E&E Subcommittee, March 22, 2022. Accessed November 2022.

Figure 33: Capital upgrades

High-temperature processes	Low-to medium-temperature processes	Biomass
• $1,500/Mt ton of product for chemical steam cracking[176] • $524/Mt ton of steel production (1 MMT capacity)[177] • $35/MMBtu for hydrogen blending in the cement subsector[178]	• $2,600/kW average cost of steam boilers, gas turbines, and reciprocating engines used[179] • Applied as a proxy for low-and medium-heat temperatures in the chemical and pulp and paper subsectors	• Negligible costs for the incorporation of biomass in the pulp and paper subsector given current utilization • Negligible costs for incorporation in the subcement sector given current utilization

Spend limitations

The model utilizes sector-level budget limitations to prevent unreasonable levels of hydrogen adoption within a given year. Research was conducted on the annual capital expense of top firms within each subsector to create a sector-level proxy budget for capital upgrades utilizing the ratio of capital expense to total revenue.[180] The model assumes up to 10% of a subsector's annual capex budget could get utilized for investment in decarbonization, aligning roughly with sector decarbonization pathways produced in the RTC's *Renewable thermal vision* report in high policy scenarios.

[176] IEA, https://www.iea.org/reports/the-future-of-petrochemicals The future of petrochemicals, October 2018. All rights reserved. Accessed December 2022.

[177] Grzegorz Pawelec and Joana Fonseca, https://hydrogeneurope.eu/wp-content/uploads/2022/06/Steel_from_Solar_Energy_Report_05-2022_DIGITAL.pdf Steel from solar energy, Hydrogen Europe and The smarter E Europe, 2022. Accessed January 2023.

[178] Deloitte & WWF modeling outcomes and analysis.

[179] Average of costs from DOE's https://www.osti.gov/biblio/5205292 Office of Scientific and Technical Information (OSTI); https://www.epa.gov/sites/default/files/2015-07/documents/catalog_of_chp_technologies.pdf Combined Heat and Power Partnership (CHP); and https://www.epa.gov/chp/chp-technologies EPA.

[180] Deloitte & WWF analysis: Top 5 firms from each sector sourced from IBIS World industry reports. 5-year historic capex for each firm data sourced from CapIQ (2017-2022). Sector growth rates from 2022 through 2030 from Grandview Research. GDP growth rates used for long term inflation sourced from https://data.oecd.org/gdp/gdp-long-term-forecast.htm OECD. All data was sourced and analyzed 11/10/2022

Appendix 3: Considerations for scaling green hydrogen for industrial heat

Figure 34: Opportunities and considerations for scaling green hydrogen

Technology | Market | Policy and Regulatory

Considerations	General opportunities	Energy buyer actions
Hydrogen policy extensions, and new policy create market certainty Advocating for timely extensions to IRA tax credits through 2040 or 2050 (as well as less likely policies, such as a carbon price) could bring down hydrogen cost curves, enable adequate infrastructure build, and allow hydrogen to become cost competitive with other heating fuels over the long term.	Form working group to: • Develop industry perspective • Create advocacy campaigns • Participate in public commenting periods for local, state, and federal proposed policy and programs • Work with government actors to develop and implement policy	• Take advantage of current policies and benefits to green hydrogen development • Stay active in conversations with policymakers on benefits of current legislation • Participate in public commenting periods for local, state, and federal proposed policy and programs
Planning, permitting, and approval reduce costs, and time constraints Increasing coordination between different planning, permitting, and approval authorities can reduce time constraints and cost burdens for a rapid build-out of clean energy generation and transmission, without compromising valuable regulatory safeguards.	Form working group to: • Develop an industry perspective • Share desired reforms with planning, permitting, and approval authorities at the local, state, and federal levels	• Work with project proponents, including executing commitment letters or other agreements, to signal demand for projects
Hub ecosystems foster dependable supply, and demand Locating industrial heat users geographically around effective hubs (either funded by the DOE program or privately) will provide more dependable supply and developed logistics that could incentivize using or transitioning to green hydrogen.	• Develop industry coalitions between private and public sector to create DOE or privately funded hubs • Coordinate across the value chain to enable community engagement throughout design and development	• Geographically assess hub proximity to operations • Secure relationship with hub developers • Enter offtake agreement to secure supply

Considerations	General opportunities	Energy buyer actions
Rapid deployment of renewable generation assets supports green hydrogen expansion Planning and deploying renewable generation assets and grid infrastructure early and rapidly, above what will be required to meet current electricity demand, can help avoid long lead times, enable current green hydrogen demand, and enable long-term grid decarbonization. Deployment in grid regions and regions with low-average electricity prices could accelerate the deployment of green hydrogen.	• Develop working groups to create industry coalition and unified voice on renewables to enable green hydrogen • Invest in renewable energy project to secure PPAs and VPPAs • Collaborate with regulators and approval authorities for rapid infrastructure deployment	• Take early stance on demanding green hydrogen supply for industrial heat • Team with hydrogen producers, network infrastructure providers, and regulatory and approval authorities to enable scaling of renewable energy projects and related hydrogen infrastructure
Increase social license to operate Developing appropriate outreach and education efforts can generate broad public support and grant social license for the hydrogen economy.	• Develop industry message • Leverage existing relationships and engagement models to reinforce the community benefits of hydrogen • Roll out public surveys to gauge public perception on hydrogen • Develop public education and marketing campaigns	• Provide spaces where communities can ask questions and engage in dialogue • Develop educational and interactive content to share benefits of new projects
Community engagement during design, and development for a just transition Building strong relationships with local groups and engaging in open dialogue early to build trust, understand community circumstances, and enable collaboration during the design and development phases for hydrogen projects can help enable a just transition when scaling green hydrogen.	• Develop and share transparent design and development plans with local groups, nonprofits, and nature conservation organizations • Create public surveys to gather community feedback • Host local events to educate and encourage dialogue • Build job and skills training programs for green hydrogen roles	• Develop and share transparent design and development plans • Share consistent communications with local communities and consumers

Considerations	General opportunities	Energy buyer actions
Information campaigns on green hydrogen for potential value chain players Educating energy buyers on the environmental benefits of green hydrogen and current policy instruments can help foster a greater sense of community among energy buyers and help them define their role in the broader energy transition.	• Develop educational content on green hydrogen (e.g., decarbonization benefits) • Create marketing materials on current/available policies and cost benefits to green hydrogen production • Host webcasts and events to create open dialogue and answer questions to develop buyer community	• Engage in working groups to improve overall knowledge of green hydrogen • Collaborate with nonprofits and industry coalitions to increase participation in the broader hydrogen movement
Standardizing supply contracts eases market entry Increasing standardization of supply contracts and other relevant market instruments related to hydrogen could improve transparency and lower transaction costs, risks, and uncertainty in order to ease entry into contracts, reduce the risk to early adopters, and allow for bilateral and OTC trading, which could eventually enable a wholesale hydrogen commodity market with standard contracts.	• Develop point of view, set industry standard, and encourage regulatory adoption of low-carbon hydrogen definition • Align stakeholders on common contracting process and methodology • Develop position on contract transparency • Understand and develop hydrogen commodity trading department	• Understand carbon intensity of supply to purchase green hydrogen specifically • Collaborate with buying consortia to increase overall volume purchased and price certainty to help reduce transport costs
Develop sustainability criteria for hydrogen Developing sustainability criteria for hydrogen and confirming only electricity is being used from renewables can increase certainty that hydrogen is "green" and that grid-connected electrolyzers provide hydrogen without negative impacts.	• Develop point of view, set industry standard, and encourage regulatory adoption of sustainability criteria • Participate in public commenting periods for local, state, and federal proposed policy and programs • Work with government actors to develop and implement policy	• Participate in public commenting periods for supportive policies and standards • Work with NGOs and organizations to update GHG accounting protocols

Considerations	General opportunities	Energy buyer actions
Consistent technical and safety standards can ill policy gaps Building hydrogen health and safety standards that address the full value chain through collaboration with standard-setting bodies and intentional RD&D efforts can help promote investment and generate public support to scale green hydrogen.	• Establish leading practices and a clear message on safety future blueprints with standard-setting organizations • Work with government actors to develop and implement policy • Collaborate with national labs, universities, and corporations to promote RD&D efforts	• Collaborate with industry associations to establish blueprint for future safety standards • Work with government actors to fill policy gaps
RD&D, and investments enable scale, and decrease costs across the value chain Allocating RD&D and investments from government and private ssector (especially for high-heat applications) to lower the costs and increase efficiencies across electrolysis, storage, and transportation of green hydrogen, as well as innovating to reduce retrofitting costs for use in industrial heating, is essential for a sophisticated green H2 economy. Retrofitting high-temperature processes like chemical cracking is prohibitive and may limit adoption in industry.	• Identify and allocate capital for RD&D investment (e.g., developing the green hydrogen value chain) • Advocate for policy to incentivize RD&D • Pilot new technologies and solutions	• Develop teaming arrangements with startups, national labs, investors, and universities to develop end-use considerations • Communicate with equipment providers to understand work done to incorporate hydrogen into existing process and the requirements for retrofitting • Develop focused RD&D to address environmental issues (e.g., NOx emissions and fugitive emissions)

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