Hydrogen in Combustion Turbine Electric Generating Units

Technical Support Document

New Source Performance Standards for Greenhouse Gas Emissions from New, Modified, and Reconstructed Fossil Fuel-Fired Electric Generating Units; Emission Guidelines for Greenhouse Gas Emissions from Existing Fossil Fuel-Fired Electric Generating Units; and Repeal of the Affordable Clean Energy Rule Proposal

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Introduction

Hydrogen does not contain carbon and therefore emits no carbon dioxide (CO_2) when combusted. There is increasing interest in hydrogen as a viable, potentially low-greenhouse gas (GHG) fuel source for stationary combustion turbines in the utility power sector. The direct benefit of combusting hydrogen to produce electricity is zero CO_2 emissions at the stack.

The use of hydrogen in the United States (U.S.) to date has been primarily limited to certain applications in industrial sectors. The nation produced approximately 10 million metric tons (MMT)[1, 2] of hydrogen in 2018 and 70 percent of that total was used by refineries to remove sulfur from petroleum products[3] and 20 percent was used to produce ammonia in the manufacture of fertilizer.[4] The remaining 10 percent was used for treating metals, processing foods, and other miscellaneous applications.[5] Hydrogen is also used in the transportation sector, currently in light duty hydrogen fuel cell vehicles.[6, 7, 8] The fact that hydrogen emits no CO_2 when combusted is the key to its potential for reducing GHG emissions in hard-to-decarbonize industries that require a high heat source, such as cement and steel manufacturing.[9] For example, hydrogen can replace the metallurgical or coking coal and other fossil fuels used in a traditional blast furnace to reduce iron oxides to iron in the direct reduction of iron (DRI) process.

Potential Emissions Reductions from the Use of Hydrogen in Combustion Turbines

Industrial combustion turbines have been burning byproduct fuels containing hydrogen for decades, and combustion turbines have been developed to burn syngas from the gasification of coal in integrated gasification combined cycle units.[10] There are several noteworthy physical

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[1] U.S. Department of Energy (DOE) (n.d.). *Hydrogen Production*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production.
[2] U.S. DOE (2018). *Fact of the Month May 2018: 10 Million Metric Tons of Hydrogen Produced Annually in the United States*. Accessed at https://www.energy.gov/eere/fuelcells/fact-month-may-2018-10-million-metric-tons-hydrogen-produced-annually-united-states.
[3] U.S. Energy Information Administration (EIA) (2016). *Hydrogen for refineries is increasingly provided by industrial suppliers*. Accessed at https://www.eia.gov/todayinenergy/detail.php?id=24612.
[4] New York State Department of Health (2005). *The Facts About Ammonia*. Accessed at https://www.health.ny.gov/environmental/emergency/chemical_terrorism/ammonia_tech.htm.
[5] National Renewable Energy Laboratory (NREL) (2022). *Hydrogen 101: Frequently Asked Questions About Hydrogen for Decarbonization*. Accessed at https://www.nrel.gov/docs/fy22osti/82554.pdf.
[6] Via U.S. Department of Energy, *Alternative Fuels Data Center*: In mid-2021, there were 48 open retail hydrogen stations in the United States. Additionally, there were at least 60 stations in various stages of planning or construction. Most of the existing and planned stations were in California, with one in Hawaii and 14 planned for the Northeastern states. Accessed at https://afdc.energy.gov/fuels/hydrogen_infrastructure.html.
[7] U.S. DOE (n.d.). *Alternative Fuels Data Center Alternative Fueling Station Locator*. Accessed at https://afdc.energy.gov/stations/#/find/nearest?fuel=HY&lpg_secondary=true&country=US&hy_nonretail=true.
[8] U.S. Energy Information Administration (EIA) (2022). *Hydrogen Explained.* Accessed at https://www.eia.gov/energyexplained/hydrogen/use-of-hydrogen.php.
[9] Bartlett, J., Krupnick, A. (2021). *The Potential of Hydrogen for Decarbonization: Reducing Emissions in Iron and Steel Production*. Resources. Accessed at https://www.resources.org/common-resources/the-potential-of-hydrogen-for-decarbonization-reducing-emissions-in-iron-and-steel-production/.
[10] Goldmeer, J. & Catillaz, J. (2021). *Hydrogen for power generation*. Retrieved July 13, 2021, Accessed at https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-for-power-gen-gea34805.pdf.

characteristics of hydrogen that differ from natural gas (*i.e.*, methane) when used as a fuel in utility combustion turbines.

One of the differences between hydrogen and natural gas is the energy density by volume of the gases. To achieve significant GHG reductions from burning hydrogen in a combustion turbine, the volume of hydrogen must be high relative to the volume of natural gas. Blending or combusting such high volumes of hydrogen presents challenges to fuel availability because of limited production and demand from other sectors, infrastructure (*i.e.*, distribution and transportation pipelines, storage), turbine design capabilities, and safety. High hydrogen blends by volume also have the potential to increase nitrogen oxide (NO_X) emissions from the combustion turbine as well as increase any upstream GHG emissions associated with the hydrogen production process. Since hydrogen and methane have different volume energy densities, when blending natural gas and hydrogen, the CO_2 emissions reduction is smaller than the percentage by volume of hydrogen in the mixture. For example, to achieve a 50 percent reduction in EGU stack emissions of CO_2 requires a fuel blend that is approximately 75 percent hydrogen by volume; a 75 percent CO_2 reduction requires a blend of 90 percent hydrogen by volume. As a result, hydrogen-enriched fuels have a lower GHG intensity than typical natural gas fuels. To visualize, estimates of the CO_2 emissions reductions as a function of percent hydrogen by volume for the working fuel is shown in Figure 1.

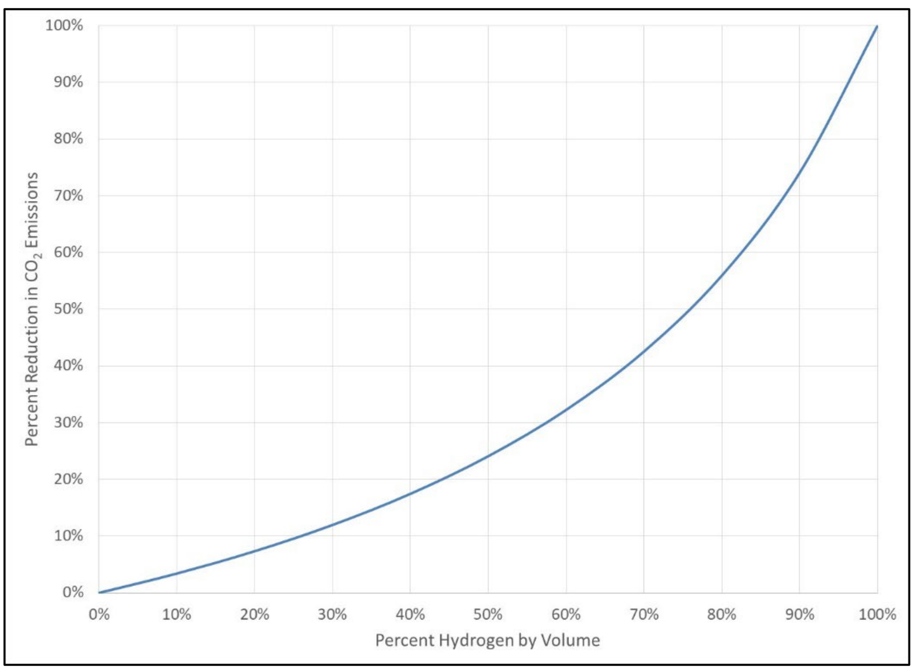

Figure 1: CO_2 Emission Reductions and Percent Hydrogen by Volume

It should also be noted that in a literature review white paper[11] released by the Department of Energy's (DOE) National Energy Technology Laboratory (NETL) in August 2022, the actual percentage by volume of hydrogen used as fuel and correlated CO_2 emission reductions depend on the specific model of combustion turbine, the type or model of combustor (NO_X controls), the combustion system, overall fuel consumption, and other factors.

Technical Feasibility of the Use of Hydrogen in Combustion Turbines

Overview

As discussed in greater detail below, certain models of combustion turbines that are currently available can combust up to 100 percent hydrogen. These are generally smaller industrial or aeroderivative units. Several larger models of new and existing combustion turbines have demonstrated the ability to co-fire up to 30 percent hydrogen by volume without modification. For certain new larger models, combustor upgrades are available from manufacturers that allow the combustion turbines to increase their hydrogen co-firing to as high as 50 percent. In addition, many new facilities have announced plans to initially co-fire up to 30 percent hydrogen by volume and up to 100 percent in approximately 10 to 20 years. According to combustion turbine manufacturers, certain new models can be constructed at present that will, in the near future, be able to install pre-planned upgrades that will align to turbine compatibility and allow up to 100 percent hydrogen combustion. In addition, the world's three largest turbine manufacturers have made commitments to develop advanced technologies by 2030 or sooner that will enable additional models of new heavy-duty combustion turbines to fire 100 percent hydrogen while limiting emissions of NO_X. For certain existing larger models, manufacturers are developing retrofits that will allow those units to safely increase their levels of hydrogen co-firing up to 100 percent.

Discussion

The technical challenges of co-firing hydrogen in a combustion turbine EGU result from the physical characteristics of the gas. Perhaps the most significant challenge is that the flame speed of hydrogen gas is an order of magnitude higher than that of methane; at hydrogen blends of 70 percent or greater, the flame speed is essentially tripled compared to pure natural gas.[12] A higher flame speed can lead to localized higher temperatures, which can increase thermal stress on the turbine's components as well as increase thermal NO_X emissions.[13, 14] It is necessary in

[11] National Energy Technology Laboratory (NETL). (August 12, 2022). *A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOX Control*. A white paper by NETL and the U.S. Department of Energy (DOE). Accessed at https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf.

[12] National Energy Technology Laboratory (NETL). (August 12, 2022). *A Literature Review of Hydrogen and Natural Gas Turbines: Current State of the Art with Regard to Performance and NOX Control*. A white paper by NETL and the U.S. Department of Energy (DOE). Accessed at https://netl.doe.gov/sites/default/files/publication/A-Literature-Review-of-Hydrogen-and-Natural-Gas-Turbines-081222.pdf.

[13] Guarco, J., Langstine, B., Turner, M. (2018). *Practical Consideration for Firing Hydrogen Versus Natural Gas.* Combustion Engineering Association. Accessed at https://cea.org.uk/practical-considerations-for-firing-hydrogen-versus-natural-gas/.

[14] Douglas, C., Shaw, S., Martz, T., Steele, R., Noble, D., Emerson, B., and Lieuwen, T. (2022). Pollutant Emissions Reporting and Performance Considerations for Hydrogen-Hydrocarbon Fuels in Gas Turbines. *Journal of*

combustion for the working fluid flow rate to move faster than the rate of combustion. When the combustion speed is faster than the working fluid, a phenomenon known as "flashback" occurs, which can damage injectors or other components and lead to upstream complications.[15]

Other differences include a hotter hydrogen flame (4,089 °F) compared to a natural gas flame (3,565 °F) and a wider flammability range for hydrogen than natural gas.[16] It is also important that hydrogen and natural gas are adequately mixed to avoid temperature hotspots, which can also lead to formation of greater volumes of NO_X.

Combustor modifications or retrofits have the potential to limit NO_X emissions. For example, a larger selective catalytic reduction (SCR) unit inside the heat recovery steam generator (HRSG) is an option for combined cycle turbines. For combined cycle plants planning to co-fire higher volumes of hydrogen over time, it is important to estimate the increased NO_X emissions when sizing the SCR unit.[17]

The industrial and aeroderivative combustion turbines currently capable of co-firing greater than 30 percent hydrogen by volume are generally simple cycle turbines that utilize wet low-emission (WLE) or diffusion flame combustion. In terms of larger, heavy-duty combustion turbines that can co-fire up to 30 percent hydrogen, these models generally utilize WLE, dry low-emission (DLE), or dry low-NO_X (DLN) combustors.

As mentioned earlier, most turbine manufacturers are working to safely increase the levels of hydrogen combustion in new and existing turbine models while limiting emissions of NO_X. This is true of the three largest turbine manufacturers in the world: GE and Siemens both have goals to develop 100 percent DLE or DLN hydrogen combustion capability in their turbines by 2030.[18, 19, 20] Mitsubishi is targeting development of 100 percent DLN hydrogen combustion capable turbines by 2025.[21]

GE's most recent combustor design, the DLN 2.6e, allows hydrogen gas to be pre-mixed safely and reduces the risk of premature combustion. Turbine models such as the GE 7HA.02 can co-

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Engineering for Gas Turbines and Power. Volume 144, Issue 9: 091003. Accessed at https://asmedigitalcollection.asme.org/gasturbinespower/article/144/9/091003/1143043/Pollutant-Emissions-Reporting-and-Performance.

[15] Inoue, K., Miyamoto, K., Domen, S., Tamura, I., Kawakami, T., & Tanimura, S. (2018). *Development of Hydrogen and Natural Gas Co-firing Gas Turbine*. Mitsubishi Heavy Industries Technical Review. Volume 55, No. 2. June 2018. Accessed at https://power.mhi.com/randd/technical-review/pdf/index_66e.pdf.

[16] Andersson, M., Larfeldt, J., Larsson, A. (2013). *Co-firing with hydrogen in industrial gas turbines*. Accessed at http://sgc.camero.se/ckfinder/userfiles/files/SGC256(1).pdf.

[17] Siemens Energy (2021). *Overcoming technical challenges of hydrogen power plants for the energy transition.* NS Energy. Accessed at https://www.nsenergybusiness.com/news/overcoming-technical-challenges-of-hydrogen-power-plants-for-energy-transition/.

[18] Simon, F. (2021). *GE eyes 100% hydrogen-fueled power plants by 2030.* Accessed at https://www.euractiv.com/section/energy/news/ge-eyes-100-hydrogen-fuelled-power-plants-by-2030/.

[19] Patel, S. (2020). *Siemens' Roadmap to 100% Hydrogen Gas Turbines.* Accessed at https://www.powermag.com/siemens-roadmap-to-100-hydrogen-gas-turbines/.

[20] de Vos, Rolf (2022). *Ten fundamentals to hydrogen readiness*. Accessed at https://www.siemens-energy.com/global/en/news/magazine/2022/hydrogen-ready.html.

[21] Power Magazine (2019). *High Volume Hydrogen Gas Turbines Take Shape.* Accessed at https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/.

fire 50 percent hydrogen by volume with the DLN 2.6e combustor.[22] GE offers other DLE and DLN combustion turbines that can co-fire up to 33 percent hydrogen by volume and a diffusion flame model that can co-fire 85 percent hydrogen by volume.[23, 24] Siemens offers an upgrade package called "H2DeCarb" to enable its E- and F-Class turbines to combust larger quantities of hydrogen (typically 50 to 60 percent).[25] Furthermore, Siemens currently offers heavy-duty combustion turbines with hydrogen blending capabilities of 30 to 50 percent by volume, depending on the turbine model and type of combustion system.[26] Other Siemens models include aeroderivative engines and medium industrial combustion turbines that range from 10 to 75 percent hydrogen by volume capability.[27] Mitsubishi has also been making progress on developing advanced combustors to fire high levels of hydrogen with limited NO_X emissions in addition to supporting hydrogen production and storage infrastructure.[28] For example, the manufacturer has developed several frame models that range between 30 and 1,280 MW in size that can co-fire 30 percent hydrogen with currently available DLN technologies, and each of the available combustion turbine models is being developed to fire 100 percent hydrogen with DLN combustors.[29, 30] One of these models is the JAC gas turbine power island, which is initially capable of operating on 30 percent low-GHG hydrogen, with future capability of operating on 100 percent low-GHG hydrogen.[31] And Mitsubishi's Hydaptive™ and Hystore™ systems are being used in multiple projects throughout the U.S. and Europe.[32] One such project is the Intermountain Power Agency (IPA) project in Utah, discussed below.

Figure 2 reflects examples of the status of specific combustion turbine models and their ability to co-fire various percentages (by volume) of hydrogen. This information was included in NETL's

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[22] General Electric (GE). (February 2022). Hydrogen Overview (online brochure). Accessed at https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-overview.pdf.
[23] General Electric (GE). (2022). Hydrogen Overview for Aeroderivative Gas Turbines. Accessed at https://www.ge.com/content/dam/gepower-new/global/en_US/images/gas-new-site/microsites/en/sa/saudi-industrial/h2-aero-overview-march24-2022-ga-r2.pdf.
[24] General Electric (GE) (2019, February). *Power to Gas: Hydrogen for Power Generation*. Accessed at https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf.
[25] Siemens Energy Zero Emission Hydrogen Turbine Center. Accessed at https://www.siemens-energy.com/global/en/priorities/future-technologies/hydrogen/zehtc.html.
[26] Siemens (2022). Hydrogen power and heat with Siemens Energy gas turbines. Accessed at https://www.siemens-energy.com/global/en/offerings/technical-papers/download-hydrogen-gas-turbine-readiness-white-paper.html.
[27] Siemens (2020). Hydrogen power with Siemens gas turbines. https://www.infrastructureasia.org/-/media/Articles-for-ASIA-Panel/Siemens-Energy---Hydrogen-Power-with-Siemens-Gas-Turbines.ashx
[28] Mitsubishi Heavy Industries. Accessed at https://solutions.mhi.com/power/decarbonization-technology/hydrogen-gas-turbine/.
[29] Mitsubishi Heavy Industries (2021). Hydrogen Power Generation Handbook. Accessed at https://solutions.mhi.com/sites/default/files/assets/pdf/et-en/hydrogen_power-handbook.pdf.
[30] See https://power.mhi.com/special/hydrogen.
[31] Mitsubishi Heavy Industries Group (MHI). (2020). *Mitsubishi Power cuts through the complexity of decarbonization: Offers the world's first green hydrogen standard packages for power balancing and energy storage*. https://power.mhi.com/regions/amer/news/20200902.html.
[32] Mitsubishi Heavy Industries Group (MHI). (2020). *Mitsubishi Power cuts through the complexity of decarbonization: Offers the world's first green hydrogen standard packages for power balancing and energy storage*. https://power.mhi.com/regions/amer/news/20200902.html.

white paper. This list is not exhaustive and focuses on some of the turbines produced by GE, Siemens, and Mitsubishi, as noted above, the three largest turbine manufacturers in the world. Various ones of these models can be operated as peaking load, intermediate load, and/or baseload units. The EPA anticipates additional information regarding the ability of combustion turbines to fire hydrogen will be provided during the public comment period following publication of these proposed rules.

Manufacturer	**Turbine Model/Type**	**Current Hydrogen Capability[1]**	**Future Hydrogen Capability[2]**
GE Gas Power			
	Aeroderivative	85%	100%
	B/E-Class	100%	
	F-Class	100%	
	HA-Class	50%	100%
Siemens Energy			
	SGT5/6-9000HL	50%	
	SGT5/6-8000H	30%	
	SGT-700	75%	
	SGT-750	40%	
Mitsubishi Heavy Industries			
	M501GAC	30%	100%
	M501JAC	30%	100%
	M701JAC	30%	100%
[1] The actual % by volume hydrogen levels may vary based on combustion turbine model, combustion model, combustion system, and overall fuel consumption. Turbines currently co-firing greater than 30% hydrogen by volume typically utilize wet, low-emission (WLE) or diffusion flame combustors. [2] Manufacturers are developing DLN combustor modifications for several turbine models that will allow for increased hydrogen firing while limiting emissions of NO_X. These include pre-planned small modification or retrofits kits for certain models to increase their levels of hydrogen combustion.			

Figure 2: Hydrogen Capabilities in Certain Models of Combustion Turbines

With several models of larger combustion turbines able to co-fire lower percentages of hydrogen by volume with current technologies, many new and existing facilities have announced plans to initially co-fire up to 30 percent hydrogen by volume and up to 100 percent when the additional fuel becomes available. As noted earlier, certain turbine models will require combustor upgrades or retrofits before being ready to fire 100 percent hydrogen in the coming years. These pre-planned retrofits align to turbine compatibility with blending high volumes and operating exclusively on hydrogen and are described by one manufacturer (Mitsubishi) as "small modifications."[33] As an official at Siemens stated: "Plants are designed today so they can be retrofitted to run on 100 percent hydrogen tomorrow. The idea is that you optimize what you do

[33] Puko, T. (May 1, 2023). This power plant offers a peek into the future. *The Washington Post*. Accessed at https://www.washingtonpost.com/climate-environment/2023/05/01/power-plants-hydrogen-climate-change/.

upfront and what you do later, saving time and costs, and ensuring that your plant is built to quickly make the switch to hydrogen."[34] Examples of these new hydrogen projects include:

- The Long Ridge Energy Generation Project in southeast Ohio is a 485-megawatt (MW) GE 7HA.02 combustion turbine facility that successfully completed a test burn of 5 percent (by volume) industrial byproduct hydrogen in 2022.[35, 36] The developers plan to upgrade the turbine to combust 100 percent hydrogen over the next decade.[37, 38]
- The Intermountain Power Agency (IPA) project in Utah will replace an existing coal-fired EGU with a Mitsubishi 840-MW combustion turbine that will have the capability to co-fire 30 percent by volume low-GHG hydrogen in 2025 and 100 percent electrolytic hydrogen by 2045.[39]
- The Los Angeles Department of Water and Power (LADWP), which has agreed to purchase the electricity produced by IPA, has also secured approval from the Los Angeles city council to convert its 297-MW Scattergood Generating Station to a 346-MW combined cycle turbine capable of co-firing at least 30 percent by volume low-GHG hydrogen.[40] LADWP specified the turbine would be ready to co-fire a minimum of 30 percent low-GHG hydrogen, produced by electrolysis powered by renewable energy, when the unit becomes operational by December 30, 2029.[41] The goal of the project is to burn 100 percent low-GHG hydrogen by 2035, consistent with the city's climate objectives, and has the potential to increase its capacity to 830 MW.
- In Illinois, a permit has been issued for the Lincoln Land Energy Center Project. The project is designed to provide 1.1 gigawatts (GW) of power capacity with a combined

[34] de Vos, Rolf (2022). *Ten fundamentals to hydrogen readiness*. Accessed at https://www.siemens-energy.com/global/en/news/magazine/2022/hydrogen-ready.html.
[35] McGraw, D. (2021). World science community watching as natural gas-hydrogen power plant comes to Hannibal, Ohio. *Ohio Capital Journal*. Retrieved September 30, 2021, https://ohiocapitaljournal.com/2021/08/27/world-science-community-watching-as-natural-gas-hydrogen-power-plant-comes-to-hannibal-ohio/.
[36] Defrank, Robert (2022). *Cleaner Future in Sight: Long Ridge Energy Terminal in Monroe County Begins Blending Hydrogen*. Accessed at https://www.theintelligencer.net/news/community/2022/04/cleaner-future-in-sight-long-ridge-energy-terminal-in-monroe-county-begins-blending-hydrogen.
[37] Hering, G. (2021). First major US hydrogen-burning power plant nears completion in Ohio. *S&P Global Market Intelligence*. Retrieved September 30, 2021, https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/081221-first-major-us-hydrogen-burning-power-plant-nears-completion-in-ohio.
[38] McGraw, D. (2021). World science community watching as natural gas-hydrogen power plant comes to Hannibal, Ohio. *Ohio Capital Journal*. Retrieved September 30, 2021, https://ohiocapitaljournal.com/2021/08/27/world-science-community-watching-as-natural-gas-hydrogen-power-plant-comes-to-hannibal-ohio/.
[39] Mitsubishi Power (2020) "Intermountain Power Agency Orders MHPS JAC Gas Turbine Technology for Renewable-Hydrogen Energy Hub," https://power.mhi.com/regions/amer/news/200310.html.[40] Clark, K. (2023). *L.A. authorizes conversion of largest gas plant to hydrogen*. Power Engineering. See https://www.power-eng.com/hydrogen/l-a-authorizes-conversion-of-largest-gas-plant-to-green-hydrogen/#gref.
[40] Clark, K. (2023). *L.A. authorizes conversion of largest gas plant to hydrogen*. Power Engineering. See https://www.power-eng.com/hydrogen/l-a-authorizes-conversion-of-largest-gas-plant-to-green-hydrogen/#gref.
[41] Los Angeles Department of Water & Power (2023*). Initial Study: Scattergood Generating Station Units 1 and 2 Green Hydrogen-Ready Modernization Project*. Accessed at https://ceqanet.opr.ca.gov/2023050366.

cycle turbine that will be ready to co-fire up to 30 percent by volume hydrogen upon initial operation with the capability to utilize 100 percent low-GHG hydrogen by 2045.[42]

- In Texas, El Paso Electric is seeking to convert its Newman Power Station to co-fire 30 percent by volume hydrogen and 100 percent by 2045.[43]
- Also in Texas, Entergy is building a new combined cycle power plant in Port Arthur, the Orange County Advanced Power Station (OCAPS), that will co-fire hydrogen with natural gas. The plant will be ready to co-fire 30 percent hydrogen by volume at initial operation, with the capability to increase hydrogen share to 100 percent with only small modifications.[44]
- In Florida, NextEra has announced plans to convert 16 GW of existing natural gas-fired combustion turbines to co-fire a blend of low-GHG hydrogen. As part of the utility's Zero Carbon Blueprint, the units would burn 100 percent low-GHG hydrogen by 2045.[45]
- In Louisiana, the Magnolia Power Plant in Plaquemine is expected to begin operations in 2025 with a GE 7HA.03 combustion turbine. The 725-MW turbine will be hydrogen-ready with the ability to co-fire up to 50 percent hydrogen by volume as the fuel becomes available.[46]

There have been successful demonstrations of lower volumes of hydrogen co-firing at existing power plants, and according to comments from Constellation Energy,[47] retrofits can achieve higher volumes of blending on certain models of existing combustion turbines:

> "Hydrogen blending is technically achievable with current technology. Many turbines can blend 5-10% hydrogen by volume without modification, and in our fleet, the newer simple cycle turbines can blend up to 25-30% hydrogen by volume without modification. Retrofits using existing technology are available to achieve 50-100% hydrogen combustion by volume at some generators. These retrofits, which include burner and additional balance-of-plant modifications, allow for more substantial CO_2 emissions reductions."

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[42] Construction Review Online (2022). *Proposed 1.1GW Lincoln Land Energy Center Project in Illinois Approved.* Accessed at https://constructionreviewonline.com/news/proposed-1-1gw-lincoln-land-energy-center-project-in-illinois-approved/.

[43] Power Engineering (2021). *El Paso Electric, Mitsubishi Power collaborating on decarbonization plans*. Accessed at https://www.power-eng.com/emissions/el-paso-electric-mitsubishi-power-collaborating-on-decarbonization-plans/#gref.

[44] Timothy Puko, *This Power Plant Offers A Peek Into The Future*, THE WASHINGTON POST (May 1, 2023), https://www.washingtonpost.com/climate-environment/2023/05/01/power-plants-hydrogen-climate-change/; Entergy (2022). *Entergy Texas receives approval to build a cleaner, more reliable power station in Southeast Texas*. Accessed at https://www.entergynewsroom.com/news/entergy-texas-receives-approval-build-cleaner-more-reliable-power-station-in-southeast-texas/.

[45] See https://www.nexteraenergy.com/content/dam/nee/us/en/pdf/NextEraEnergyZeroCarbonBlueprint.pdf.

[46] GE Gas Power (2022). Kindle Energy Awards 7HA.03 Combined-Cycle Plant Equipment Order to GE For Magnolia Power Plant with Hydrogen Capability to Support Energy Transition in Louisiana. Accessed at https://www.ge.com/news/press-releases/kindle-energy-awards-7ha03-combined-cycle-plant-equipment-order-to-ge-for-magnolia.

[47] Constellation Energy comments in response to the EPA's draft white paper titled, *Available and Emerging Technologies for Reducing Greenhouse Gas Emissions from Combustion Turbine Electric Generating Units*, June 6, 2022. Docket ID No. EPA-HQ-OAR-2022-0289.

According to GE, the technological advancements described earlier further support the ability of its existing combustion turbines to utilize hydrogen:

> "Work is underway to increase hydrogen burning capability across the portfolio, with a specific goal of achieving 100% capability for the HA machines. Existing gas power plants can be retrofitted to burn higher volumes of hydrogen than originally contemplated. These upgrades can be scheduled with planned outages to minimize the time the plant is not generating power, and for new units these capabilities can be part of the initial plant configuration or phased in over time as hydrogen becomes available."[48]

GE estimates that more than 100 of its gas turbines currently support hydrogen co-firing globally.[49]

Demonstrations of existing units co-firing hydrogen include:

- A natural gas combustion turbine at Georgia Power's 2.5-GW Plant McDonough-Atkinson co-fired a 20 percent hydrogen blend at both full and partial loads while maintaining emissions compliance and with no impact to maintenance intervals.[50]
- At the Brentwood power plant in September 2022, the New York Power Authority (NYPA) successfully demonstrated the ability to co-fire 44 percent 'carbon-free' hydrogen blended with natural gas in a retrofitted combustion turbine. According to NYPA, this was the first time an existing U.S. natural gas-fired combustion turbine has successfully been retrofitted to co-fire hydrogen, and according to the Electric Power Research Institute (EPRI), the project demonstrated a 14 percent reduction in CO_2 at a 35 percent hydrogen blend. The unit's existing SCR controlled NO_X emissions within permit limits.[51, 52, 53]
- Also in New York, the Cricket Valley Energy Center is planning to demonstrate co-firing a 5 percent blend of hydrogen at a combined cycle facility.[54]

Numerous international projects to build combustion turbines that are capable of combusting up to 100 percent hydrogen are underway:

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[48] https://www.ge.com/content/dam/gepower-new/global/en_US/downloads/gas-new-site/future-of-energy/hydrogen-overview.pdf

[49] Hydrogen-Fueled Gas Turbines | GE Gas Power

[50] Patel, S. (2022). *Southern Co. Gas-Fired Demonstration Validates 20% Hydrogen Fuel Blend.* Accessed at https://www.powermag.com/southern-co-gas-fired-demonstration-validates-20-hydrogen-fuel-blend/.

[51] Palmer, W., & Nelson, B. (2021). *An H_2 Future: GE and New York power authority advancing green hydrogen initiative*. See https://www.ge.com/news/reports/an-h2-future-ge-and-new-york-power-authority-advancing-green-hydrogen-initiative" \t "_blank.

[52] Van Voorhis, S. (2021). New York to test green hydrogen at Long Island power plant. *Utility Dive*. https://www.utilitydive.com/news/new-york-to-test-green-hydrogen-at-long-island-power-plant/603130/.

[53] Electric Power Research Institute (EPRI). (2022, September 15). *Hydrogen Co-Firing Demonstration at New York Power Authority's Brentwood Site: GE LM6000 Gas Turbine*. Low Carbon Resources Initiative. https://www.epri.com/research/products/000000003002025166.

[54] General Electric (GE). (2021, July 20). *The road to zero: New York power plant teams with GE on 'green hydrogen' demonstration project*. https://www.ge.com/news/reports/the-road-to-zero-new-york-power-plant-teams-with-ge-on-green-hydrogen-demonstration-project.

- The Fujiyoshida Hydrogen Power Station is a 320-kW single-fuel power plant that has been operating on 100 percent hydrogen in Fujiyoshida City, Japan, since April 2022.[55]
- In Lingen, Germany, RWE Generation and Kawasaki are piloting a 100 percent hydrogen-fired combustion turbine with an expected output of 34 MW.[56]
- The EU-funded HyFlexPower Project, in Saillat-sur-Vienne, France, will retrofit an existing natural gas-fired power plant and transition to burning up to 100 percent hydrogen with an expected energy output of 12 MW.[57]
- SSE Thermal and Equinor plan to build the Keadby Hydrogen Power Station, a 100 percent hydrogen-fired power station in North Lincolnshire, England,[58] capable of producing 1,800 MW of electricity.[59]
- Ribatejo Power Plant is a combined cycle power plant outside of Lisbon, Portugal, which will be retrofitted to co-fire with hydrogen in a power to hydrogen to power demonstration project.[60]
- In Groningen, the Netherlands, Mitsubishi is piloting a project to convert one of three units at Vattenfall's 1.3-GW Magnum combined cycle plant to 100 percent hydrogen.[61] The project will involve modifying a 440-MW gas turbine and 100 percent hydrogen combustion is expected to be achieved "in the next decade."[62]
- In New South Wales, Australia, EnergyAustralia and GE are constructing a combined cycle peaking plant, Tallawarra B, which will co-fire hydrogen and natural gas.[63]

It should be noted that major combustion turbine manufacturers are developing hydrogen-ready models—including retrofits for existing models—to increase the volumes of hydrogen combustion in response to zero-carbon commitments from many utilities. According to Siemens, as noted above, one of the world's three largest turbine manufacturers, turbines with hydrogen capabilities guard against stranded assets in the future:

> "Apart from the turbines, which are still being developed to run entirely on hydrogen, our complete plant concept is already certified for 100 percent hydrogen readiness," said Peter Seyller, principal key expert in modularization at

[55] *See* Erex. Notice of Start of Operations of "Fujiyoshida Hydrogen Power Plant," a Demonstration Hydrogen Single-Fuel Power Plant. (Apr. 6th, 2022), https://www.erex.co.jp/en/news/pressrelease/360/.
[56] Kawasaki (2021). *One of the World's First 100% Hydrogen-To-Power Demonstrations on Industrial Scale Launches in Lingen, Germany*. Accessed at https://global.kawasaki.com/news_211209-2e.pdf.
[57] European Commission: CORDIS, *First Demonstration of An Integrated Power-To-Hydrogen-To-Power Plant* (May 1, 2020), https://cordis.europa.eu/project/id/884229.
[58] Equinor, *SSE Thermal and Equinor join forces on plans for first-of-a-kind hydrogen and carbon capture projects in the Humber* (Apr. 8, 2021), https://www.equinor.com/news/archive/20210408-sse-thermal-hydrogen-ccs-humber.
[59] Reuters Staff, Equinor, *SSE Aim to Build The World's First Hydrogen Power Plant*, REUTERS (Apr. 8, 2021), https://www.reuters.com/article/us-britain-hydrogen-equinor-sse/equinor-sse-aim-to-build-the-worlds-first-hydrogen-power-plant-idUSKBN2BV15V.
[60] FLEXnCONFU, Demonstration, https://flexnconfu.eu/demonstration/.
[61] Power, *High-Volume Hydrogen Gas Turbines Take Shape*, POWER Mag (May 1, 2019), https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/.
[62] *Id.*
[63] GE, Press Release: EnergyAustralia Modernizes Tallawarra A Power Plant to Support Energy Transition in Australia (Mar. 7, 2023), https://www.ge.com/news/press-releases/energyaustralia-modernizes-tallawarra-a-power-plant-to-support-energy-transition-in.

> Siemens. "We don't know yet how big this will get. But it gives customers the certainty that pre-investment will pay off."

According to Andreas Pick, fuel switch project manager at German energy company Energie Baden-Württemberg AG (EnBW), one of the first companies to develop a 100 percent hydrogen power plant with Siemens:

> "In reality, like so many utilities, we're facing a classic dilemma. On the one hand, a new power plant won't amortize, but on the other if we continue to use natural gas we won't be able to reach climate neutrality. So, what could be more logical than switching to hydrogen and preparing for that switch today?"[64]

Hydrogen Production Methods

While hydrogen creates no GHG emissions when it is combusted, the emissions from the production and use of hydrogen can be significant. To fully evaluate the potential GHG reductions from using hydrogen as a fuel for combustion turbines, it is important to consider the different processes of hydrogen production.[65] Some of the different processes and energy sources for producing hydrogen are listed below in Figure 3. This section describes various hydrogen production methods that are available to supply hydrogen to end users with lower upstream GHG emissions.

Power Source	Production Process
Coal	Gasification with or without carbon capture and storage (CCS)
Natural Gas	Steam Methane Reforming (SMR) and Autothermal Reforming (ATR) with or without CCS, Methane Pyrolysis
Nuclear	Thermal energy for gasification or SMR, Electrolysis (low and high temperature), and Thermochemical
Renewable	Electrolysis, Photoelectrochemical (PEC), Thermochemical
Others	Byproduct hydrogen and hydrogen derived from biomass, byproducts, and refuse

Figure 3: Hydrogen Production Methods

<u>Steam Methane Reforming and Coal Gasification</u>

Most of the dedicated hydrogen currently produced in the U.S. (more than 95 percent) originates from natural gas using a process known as steam methane reforming (SMR). The method works

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[64] de Vos, Rolf (2022). *Ten fundamentals to hydrogen readiness*. Accessed at https://www.siemens-energy.com/global/en/news/magazine/2022/hydrogen-ready.html.

[65] Hydrogen can be produced through any of several different processes that emit varying amounts of GHGs. When these varying levels of GHG emissions associated with hydrogen production, including upstream emissions, are accounted for in an overall system GHG emissions analysis, there is currently no zero-GHG hydrogen. For example, electrolysis powered by solar or wind energy includes indirect upstream emissions of GHGs associated with building the system components and potential land use impacts. To attempt to recognize and differentiate between these varying levels of upstream emissions associated with hydrogen production, some organizations have developed a convention for labeling hydrogen according to a color scheme to characterize the production process (*e.g.*, gray, blue, green, etc.), though such labels are not used in this report.

by adding steam, heat, and a catalyst to methane derived from natural gas. Methane reacts with the steam to produce hydrogen, carbon monoxide (CO), and trace amounts of CO_2. Further, the CO byproduct is routed to a second process, the water-gas shift reaction, to react with more steam to create additional hydrogen and CO_2. The CO_2 is then removed from the gas stream, leaving almost pure hydrogen.[66]

$$CH_4 + H_2O + heat \rightarrow CO + 3\,H_2 \tag{1}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{2}$$

A visual of the SMR process is depicted in Figure 4.

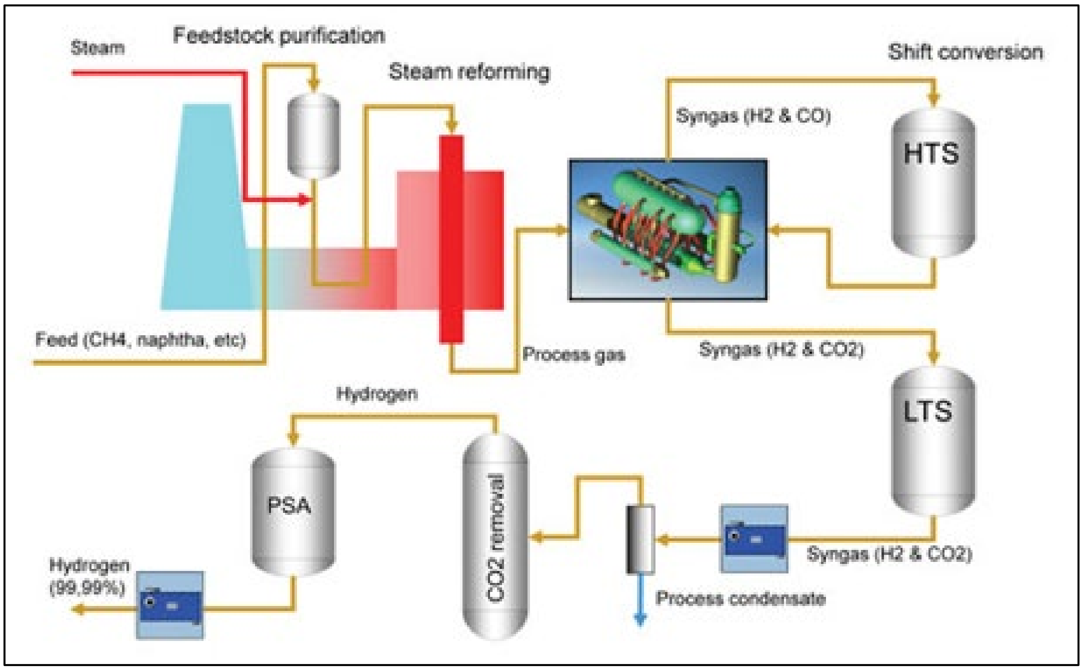

Figure 4: SMR Process Schematic[67]

Coal gasification is the second-largest source of dedicated hydrogen production domestically. Coal gasification is the process of creating hydrogen from coal by heating coal to high temperatures (up to 1,800 °C) in a closed vessel to create synthesis gas (*i.e.*, syngas). The syngas is composed of CO, CO_2, and hydrogen. The hydrogen is then removed from the syngas for usage. To make additional hydrogen, the CO can be routed to a shift reactor, where it is mixed

[66] U.S. Department of Energy (DOE) (n.d.). *Hydrogen Production: Natural Gas Reforming*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming. For each kg of hydrogen produced through SMR, 4.5 kg of water is consumed.

[67] World Oil (2021). *The U.S. DOE works on enhanced hydrogen production.* Accessed at https://www.worldoil.com/magazine/2021/november-2021/features/the-u-s-doe-works-on-enhanced-hydrogen-production/. HTS: High-temperature shift, LTS: Low-temperature shift, PSA: Pressure swing adsorption.

with water, and a water-gas shift reaction occurs (like in SMR) resulting in additional hydrogen and CO_2.[68]

$$Coal + O_2 + Heat \rightarrow CO + CO_2 + H_2 \quad (3)$$

$$CO + H_2O\ (steam) \rightarrow CO_2 + H_2\ \textit{(water gas shift)} \quad (4)$$

A visual of coal gasification is depicted in Figure 5.

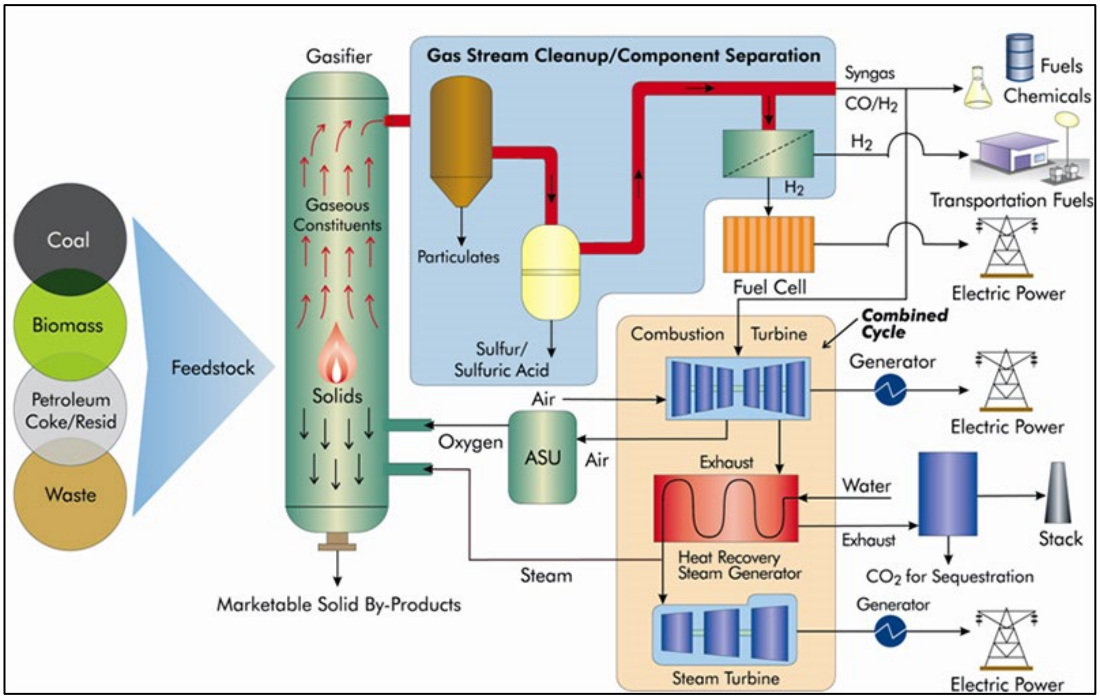

Figure 5: Gasification Process Schematic[69]

During conventional SMR or coal gasification, CO_2 emissions are created during the conversion process itself and from the creation of the thermal energy/steam (assuming the boiler used to create the steam is fueled by fossil fuels). From an overall GHG emissions perspective, the use of hydrogen from SMR would increase emissions compared to using the natural gas directly in a combustion turbine to produce electricity. This is because the thermal efficiency of SMR of natural gas is generally 80 percent or less,[70] therefore, less overall energy is in the produced hydrogen than in the natural gas required to produce the hydrogen. Note that there are ways to improve the efficiency of SMR processes. One way is to use a membrane reactor. Specifically, a lead-based membrane reactor can allow an SMR reaction to occur at lower temperatures (450 to 550 °C) compared to normal SMR reactions, which occur at approximately 850 to 900 °C.

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[68] National Hydrogen Association, *Hydrogen – Production from Coal*. Accessed at https://www.mwcog.org/file.aspx?&A=6lJMMDOHmOUL2TT9fb7pcrAAeY5PdpMxMeZbS9eJzyo%3D.

[69] National Energy Technology Laboratory (NETL). *5.1. Gasification Introduction*. Accessed at https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/intro-to-gasification. ASU: Air separation unit.

[70] Thermal efficiency is the amount of energy in the production (*e.g.*, hydrogen) compared to the energy input to the process (*e.g.*, natural gas). At an efficiency of 80 percent, the product contains 80 percent of the energy input and 20 percent is lost.

Additionally, the lead-based membrane can lead to methane conversion efficiencies of 90 to 95 percent.[71, 72]

GHG emissions associated with hydrogen production can be partially controlled by capturing and sequestering CO_2 via CCS. Carbon capture can occur at different points in the hydrogen production process. Both SMR and coal gasification produce CO_2 in high concentrations (*i.e.*, 15 to 50 percent CO_2) as part of the water-gas shift reaction. Due to the high concentrations of CO_2, carbon capture from shifted syngas is an efficient process. Pressure swing adsorption (PSA) is a common method to separate hydrogen and CO_2 in the shifted syngas stream. PSA works by binding gas molecules, in this case CO_2, to an adsorbent material. In the SMR process, the syngas product steam exiting the SMR reactor can be routed through the PSA process to bind CO_2 and other impurities to an adsorbent. Hydrogen does not adsorb well due to its high volatility and low polarity; thus, hydrogen passes through the PSA to be recovered.[73] The resulting hydrogen stream has a purity of greater than 99.99 percent. The separated CO_2-rich stream is usually sent back to the steam reformer to be combusted;[74] however, it can also undergo a carbon capture process at this point for efficient capturing and storage/utilization.

Through support from the DOE, one facility currently utilizes a type of PSA, vacuum swing adsorption, at the industrial scale. The project, located at the Valero Port Arthur Refinery in Port Arthur, Texas, retrofitted two SMR units to capture more than 90 percent of the CO_2 from the product streams of its SMRs.[75] This project has demonstrated success at the industrial level, capturing more than 1 MMT of CO_2 each year.[76] It is estimated that coal gasification shifted syngas CCS technology costs approximately \$60/tonne of CO_2 generated at an integrated gasification combined cycle (IGCC) power plant, and the DOE has a goal to reduce this cost to \$30/tonne of CO_2.[77] In addition, CCS can be applied post-combustion to capture the CO_2 of the flue gas using various chemical absorption, such as solvent- and cryogenic-based processes.[78]

[71] Nikolaidis, P., Poullikkas, A. (2016). *A comparative overview of hydrogen production processes*. Renewable and Sustainable Energy Reviews. Vol 67 (2017), 597-611. https://www.sciencedirect.com/science/article/pii/S1364032116305366?via%3Dihub.
[72] GHG intensities of hydrogen made using methane (SMR, ATR, and pyrolysis) also depend on the extent of methane leaks during the production and transportation of the natural gas feedstock. Anticipated regulations and advances in methane monitoring are expected to reduce these emissions and provide greater measurement certainty. Methane leakage rates, which have both air quality and air toxic impacts, are challenging to predict and are known to vary considerably by region.
[73] Speight, J. G. (2019). *Heavy Oil Recover and Upgrading*. Chapter 15, Pages 657-697. Elsevier. https://www.sciencedirect.com/science/article/pii/B9780128130254000155.
[74] Reddy, S. & Vyas, S. (2009). *Recovery of Carbon Dioxide and Hydrogen from PSA Tail Gas*. Energy Procedia 1 (2009), 149-154. https://www.sciencedirect.com/science/article/pii/S187661020900023X?via%3Dihub.
[75] U.S. Department of Energy (DOE) (2017). *DOE-Supported CO_2-CaptureProject Hits Major Milestone: 4 Million Metric Tons*. Accessed at https://www.energy.gov/fecm/articles/doe-supported-co2-capture-project-hits-major-milestone-4-million-metric-tons.
[76] Valero (2022). *Carbon Capture: More Than One Million Tons of Carbon Dioxide*. Accessed at https://www.valero.com/responsibility/environmental-stewardship/recycling-process
[77] U.S. Department of Energy (DOE) (n.d.). *Pre-Combustion Carbon Capture Research*. Accessed at https://www.energy.gov/fecm/science-innovation/carbon-capture-and-storage-research/carbon-capture-rd/pre-combustion-carbon.
[78] Madejski, P., Chmiel, K., Subramanian, N., Kuś, T. (2022). *Methods and Techniques for CO_2 Capture: Review of Potential Solutions and Applications in Modern Energy Technologies.* Energies 2022, 15(3), 887. https://doi.org/10.3390/en15030887.

There are varying levels of CO_2 capture between the techniques, but typically a range of 65 to 90 percent of CO_2 is viable.[79]

Autothermal Reforming

A similar method to SMR is autothermal reforming of methane (ATR). The key difference is the reactor design. In SMR, the reactor tubes are externally heated whereas ATRs generate heat within the reactor vessel. This enables the use of high-purity oxygen in ATR, and therefore natural gas, steam, and oxygen are blended. The natural gas is partially oxidized by the oxygen in the furnace. The partial oxidation reaction is exothermic and provides the heat required for the endothermic reforming reaction. ATR's advantage over SMR is that the syngas and flue gas stream are not diluted with nitrogen, so CCS methods are easier to implement.

$$2\,CH_4 + O_2 + CO_2 \rightarrow 3\,H_2 + 3\,CO + H_2O \tag{5}$$

$$CO + H_2O \rightarrow CO_2 + H_2 \tag{6}$$

Two companies have partnered to license ATR technology for the hydrogen market. Technip Energies and Casale SA will offer process design, proprietary equipment, and entire plants with up to a 99 percent carbon capture rate.[80]

Several SMR or ATR projects with carbon capture are being developed:

- ExxonMobil has announced plans for a hydrogen production facility with CCS at its refinery in Baytown, Texas, which could generate 1 billion cubic feet of hydrogen per day. The CCS system is anticipated to capture and permanently store more than 98 percent of the CO_2 produced by the facility.[81] Additionally, ExxonMobil's plan calls for replacing natural gas with hydrogen at its Baytown olefins plant, which may reduce the plant's CO_2 emissions by up to 30 percent. For CCS, the goal is to capture and store 100 MMT of CO_2 by 2040. Moreover, ExxonMobil is investigating a CCS project in Southampton, United Kingdom.[82]
- Air Products is proposing a CCS development in Louisiana that would sequester 95 percent of process CO_2 emissions, storing more than 5 million tons per year. If constructed, the project would produce 750 million standard cubic feet per day of hydrogen for Air Products' pipeline customers.[83]

[79] Powell, D. (2020). *Focus on Blue Hydrogen*. Gaffney Cline. Accessed at https://www.gaffneycline.com/sites/g/files/cozyhq681/files/2021-08/Focus_on_Blue_Hydrogen_Aug2020.pdf
[80] Bailey, Mary Page (2023). *Technip Energies and Casale join forces to license technologies for blue hydrogen*. Accessed at https://www.chemengonline.com/technip-energies-and-casale-join-forces-to-license-technologies-for-blue-hydrogen/.
[81] ExxonMobil (2023). *ExxonMobil awards FEED for world's largest low-carbon hydrogen facility*. Accessed at https://corporate.exxonmobil.com/news/newsroom/news-releases/2023/0130_exxonmobil-awards-feed-for-worlds-largest-low-carbon-hydrogen-facility.
[82] ExxonMobil (n.d.). *Hydrogen.* Accessed at https://corporate.exxonmobil.com/climate-solutions/hydrogen.
[83] Air Products (2022). *Louisiana Clean Energy Complex*. Accessed at https://www.airproducts.com/campaigns/la-blue-hydrogen-project.

- BP and Linde have announced plans to build a CCS project in Texas resulting in low-GHG hydrogen at Linde's existing facilities. The project is scheduled to start up in 2026 and will store up to 15 MMT of CO_2 per year.[84]

- OCI N.V. has recently received its air quality permits from the state of Texas and is prepared to begin construction at a facility that will enhance its existing ammonia plant in Beaumont by producing hydrogen via SMR with 95 percent CCS.[85] The new facility will capture an estimated 1.7 MMT of CO_2 per year and the hydrogen it produces will feed the adjacent ammonia plant by 2025, creating the largest ammonia production facility in Texas that makes hydrogen from natural gas and applied CCS. The ammonia will be used to decarbonize downstream industries, such as the fertilizer, food security, and energy sectors in the region.

<u>Methane Pyrolysis</u>

An alternative method of hydrogen production from natural gas with is methane pyrolysis.[86] Pyrolysis is an endothermic non-combustion process that requires energy to be continuously added to the system. Methane pyrolysis is the thermal decomposition of methane in the absence (or near absence) of oxygen, which produces hydrogen and solid carbon (*i.e.*, carbon black) as the only byproducts. The pyrolysis chemical reaction is given in **Equation 6**.

$$CH_4 + Energy\ \text{(Heat)} \rightarrow C + 2\,H_2 \qquad (7)$$

For complete decomposition of methane, temperatures of 1,000° C or greater are typically required. However, the addition of catalysts can lower the temperature needed for the pyrolysis reaction to take place. Some nickel or iron catalysts can lower the temperature of the reaction to 700° C. Similarly, carbon catalysts can also work to reduce the temperature of the reaction to 800° C.[87] Moreover, because carbon and hydrogen are the only byproducts, there is no process CO_2 that needs to be captured.[88] Methane pyrolysis has a net energy efficiency of approximately 60 percent.

Three different types of pyrolysis systems exist: plasma reactor systems, molten metal reactor systems, and conventional gas reactor systems. Plasma reactor systems use thermal plasma[89] as the heat supply and are highly selective in the process. Due to its fast start up, the process can be

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[84] bp (2022). *bp and Linde plan major CCS project to advance decarbonization efforts across Texas Gulf Coast.* Accessed at https://www.bp.com/en_us/united-states/home/news/press-releases/bp-and-linde-plan-major-ccs-project-to-advance-decarbonization-efforts-across-texas-gulf-coast.html.
[85] OCI N.V. (2022). *OCI N.V. Breaks Ground on 1.1 mtpa Blue Ammonia Site in Texas, USA*. Accessed at https://www.businesswire.com/news/home/20221207005572/en/OCI-N.V.-Breaks-Ground-on-1.1-mtpa-Blue-Ammonia-Site-in-Texas-USA.
[86] Pacific Northwest National Laboratory. (2021). *New Clean Energy Process Converts Methane to Hydrogen with Zero Carbon Dioxide Emission*. Accessed at https://www.pnnl.gov/news-media/new-clean-energy-process-converts-methane-hydrogen-zero-carbon-dioxide-emissions.
[87] Sánchez-Bastardo, N., Schlögl, R., Ruland, H. (2021). *Methane Pyrolysis for Zero-Emission Hydrogen Production: A Potential Bridge Technology from Fossil Fuels to a Renewable and Sustainable Hydrogen Economy*. American Chemical Society. https://doi.org/10.1021/acs.iecr.1c01679.
[88] Thermal energy is required for the pyrolysis and there will be GHG emissions associated with the hydrogen production process.
[89] Thermal plasma is generated by passing an electric current through the natural gas.

powered with renewable, intermittent energy sources (*i.e.*, solar/wind). Molten reactor systems work by injecting methane into a reactor containing liquid metal, whereby carbon will rise to the surface and hydrogen will leave the reactor at the top. Different metals can be used, with selection of a catalytic active metal (Ni, Bi) resulting in a higher hydrogen yield. A gas reactor system works by decomposing methane within a fluidized- or fixed-bed reactor.[90] The three pyrolysis systems result in varying electricity and methane consumptions. These specifications are outlined in Figure 6.

Reactor System	Heat supply	Electricity Consumption (kWh/kg H_2)	CH_4 Consumption (MJ/kg H_2)
Thermal Plasma	Thermal Plasma	13.9 (11.1 – 17.8)	223.0 (222.1 – 242.3)
Molten Metal	CH_4	0 (-0.5 – 0.3)	272.7 (252.6 – 272.7)
Gas Reactor	CH_4	0 (0 – 2.3)	299.0 (266.8 – 332.5)

Figure 63: Comparison of electricity and methane consumption in pyrolysis systems[91]

One company has successfully demonstrated methane pyrolysis at the commercial scale. *Monolith's* Olive Creek 1 plant converts natural gas and nitrogen to carbon black with an ammonia byproduct.[92] The *Monolith* process works by using thermal energy to superheat natural gas in a combustion-free and CO_2-free process that breaks the bonds between the hydrogen and carbon in the natural gas molecules.[93] Note that electricity is used to provide the thermal energy to decompose the methane. However, *Monolith* states that its pyrolysis process has a reduced electricity demand by a factor of 7 when compared to electrolysis.[94]

Hydrogen Derived from Nuclear Energy

There are multiple options for using nuclear energy to produce hydrogen—supplying thermal energy to the gasification, SMR, and pyrolysis processes; thermochemical; and electrolysis. The first option is using thermal energy from the nuclear reaction to replace the thermal energy in the gasification, SMR, or pyrolysis hydrogen production methods. Even though the electrical generating efficiency of the nuclear EGU would be reduced, replacing the fossil fuels needed to generate the thermal energy required for the hydrogen production process would reduce overall GHGs.[95]

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[90] Timmerberg, S., Kaltschmitt, M., Finkbeiner, M. (2020). *Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas - GHG emissions and costs*. Energy Conversion and Management: X. https://doi.org/10.1016/j.ecmx.2020.100043.

[91] Timmerberg, S., Kaltschmitt, M., Finkbeiner, M. (2020). *Hydrogen and hydrogen-derived fuels through methane decomposition of natural gas - GHG emissions and costs*. Energy Conversion and Management: X. https://doi.org/10.1016/j.ecmx.2020.100043.

[92] Department of Energy (DOE) Loan Programs Office (2021). *Environmental Assessment – Monolith Olive Creek Expansion Facility*. Accessed at https://www.energy.gov/sites/default/files/2022-04/fonsi-and-ea-2180-monolith-olive-creek-expansion-facility-2021-12.pdf.

[93] Monolith. *Methane Pyrolysis*. Accessed at https://monolith-corp.com/methane-pyrolysis.

[94] Monolith. *Process Comparison*. Accessed at https://monolith-corp.com/process-comparison.

[95] If a hydrogen production facility were located in close proximity to a nuclear EGU, the EGU could provide the bulk of the thermal energy required for the production of hydrogen. During periods of peak electric demand, the EGU could reduce the thermal energy being sent to the hydrogen production facility to maximize electrical output.

Carbon intensity for SMR hydrogen production can be decreased if steam required for the reaction is provided via a nuclear EGU. It is estimated that a nuclear heat source can reduce natural gas consumption by around 30 percent and eliminate flue gas CO_2 emissions.[96]

Thermochemical water splitting processes use high-temperature heat (500 to 2,000 °C) to drive a series of chemical reactions that produce hydrogen.[97, 98] The chemicals used in the process are reused within each cycle, creating a closed loop that consumes only water and produces hydrogen and oxygen. The high-temperature thermal energy can be supplied as a byproduct of a high-temperature nuclear reactor or concentrating solar thermal array. More than 300 water splitting cycles have been proposed; although, one popular method is the copper chloride (Cu-Cl) water splitting cycle, which operates at around 500 °C.[99] In the Cu-Cl water splitting cycle, copper and chloride compounds are recycled in a closed loop throughout a series of reactions. Thus, the overall products are hydrogen and oxygen, with the copper and chloride compounds being reused. Heat energy from a nuclear reactor's waste heat can be supplied for each of the steps to reach appropriate temperatures.[100]

The final approach to producing hydrogen from nuclear energy is through electrolysis, which is discussed in the next section.

Electrolysis

Electrolysis is the process of splitting water into its components, hydrogen and oxygen, via electricity. During electrolysis, a negatively charged cathode and positively charged anode are submerged in water and an electric current is passed through the water. The result is hydrogen molecules appearing at the negative cathodes and oxygen appearing at the positive anodes.

The energy intensity of electrolysis is high, so potential GHG emission reductions from the use of hydrogen versus fossil fuels in a combustion turbine are largely dependent on the form of energy used to power the hydrogen production process. If that form of energy is renewable (*e.g.*,

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[96] World Nuclear Association (2021). *Hydrogen Production and Uses.* Updated November 2021. Accessed at https://world-nuclear.org/information-library/energy-and-the-environment/hydrogen-production-and-uses.aspx.
[97] DOE. *Hydrogen Production: Thermochemical Water Splitting*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production-thermochemical-water-splitting.
[98] High-temperature reactors could be used to decompose water directly to hydrogen (and byproduct oxygen) using a thermochemical process. See https://www.world-nuclear.org/information-library/energy-and-the-environment/hydrogen-production-and-uses.aspx.
[99] DOE. *Hydrogen Production: Thermochemical Water Splitting*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production-thermochemical-water-splitting.
[100] Orhan, M. F., Dincer, I., Naterer, G. F., & Rosen, M. A. (2010). *Coupling of copper-chloride hybrid thermochemical water splitting cycle with a desalination plant for hydrogen production from nuclear energy*. International Journal of Hydrogen Energy. Volume 35, Issue 4, February 2010, Pages 1560 – 1574. https://doi.org/10.1016/j.ijhydene.2009.11.106.

solar) or nuclear, then the GHG reductions associated with using hydrogen as a fuel could be significant.[101, 102]

$$H_2O + Electricity \rightarrow H_2 + \frac{1}{2}\, O_2 \qquad (8)$$

Electrolysis can be achieved through different configurations. High-temperature (>500 °C) electrolysis is more efficient than low-temperature electrolysis because the increased temperature causes the water molecules to break down more easily. The temperature increase can be raised through nuclear power (or fossil-fired) power plants' waste heat. For comparison, low-temperature electrolysis typically operates at less than 100 °C.[103] Less-efficient, low-temperature electrolyzer technologies currently exist commercially at the MW scale, whereas high-temperature electrolyzer technologies are less developed.[104] High-temperature electrolysis can be 30 to 50 percent more efficient compared to low-temperature electrolysis[105], with low-temperature electrolysis currently reaching efficiencies of around 60 percent.[106] As of 2020, only 1 percent of hydrogen was produced via electrolysis.

The DOE is currently supporting four hydrogen demonstration projects at nuclear power plants:

- In Oswego, New York, a low-temperature electrolysis system has been constructed and installed at the Nine Mile Point Nuclear Power Station. The project started producing hydrogen in February 2023 and will use hydrogen to help cool the plant.[107]
- In Oak Harbor, Ohio, a low-temperature electrolysis system is being constructed at the Davis-Besse Nuclear Power Station. This project's goal is to prove the feasibility and economic benefits of clean hydrogen production, and it is expected to produce hydrogen by 2023.
- In Red Wing, Minnesota, high-temperature electrolysis is going to be implemented for hydrogen production, with production expected to begin in 2024.

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[101] U.S. Department of Energy (DOE) (n.d.). *Hydrogen Production: Electrolysis*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis#:~:text=Electrolysis%20is%20a%20promising%20option,a%20unit%20called%20an%20electrolyzer.

[102] For each kg of hydrogen produced through electrolysis, 9 kg of byproduct oxygen are also produced and 9 kg of purified water are consumed. To reduce the cost of hydrogen production, this byproduct oxygen could be captured and sold. For each gallon of water consumed, 0.057 MMBtu of hydrogen is produced. According to the water use requirements for combined cycle EGUs with cooling towers, if this hydrogen is later used to produce electricity in a combined cycle, EGU overall water requirements would be greater than a combined cycle EGU with CCS.

[103] Badwal, S. P. S., Giddey, S., Munnings, C. (2012). *Hydrogen production via solid electrolytic routes*. Wires Energy and Environment, Volume 2, Issue 5. https://doi.org/10.1002/wene.50.

[104] U.S. Department of Energy (DOE) (2021). *Hydrogen Technologies – 2021*. FY 2021 Merit Review and Peer Evaluation Report. Accessed at https://www.hydrogen.energy.gov/pdfs/review21/2021-amr-04-hydrogen-technologies.pdf.

[105] Boardman, R. D., Ding, D. (2019). *HydroGEN: High-Temperature Electrolysis*. 2019 DOE Annual Merit Review. Accessed at https://www.hydrogen.energy.gov/pdfs/review19/p148B_boardman_2019_p.pdf.

[106] Burton, N. A., Padilla, R. V., Rose, A., Habibullah, H. (2021). *Increasing the efficiency of hydrogen production from solar powered water electrolysis.* Renewable and Sustainable Energy Reviews. Volume 135, January 2021, 110255. https://www.hydrogen.energy.gov/pdfs/review19/p148B_boardman_2019_p.pdf.

[107] U.S. Department of Energy (DOE) (2023). *Nine Mile Point Begins Clean Hydrogen Production*. Accessed at https://www.energy.gov/ne/articles/nine-mile-point-begins-clean-hydrogen-production.

- And in Tonopah, Arizona, the DOE is negotiating an award for a low-temperature electrolysis system at the Palo Verde Generating Station. This station is aiming to produce hydrogen in 2024.[108]

There are three electrolysis technologies currently in use with the main difference between them being the electrolytes within the electrolyzer. Polymer electrolyte membrane (PEM) electrolysis uses a proton exchange membrane as the electrolyte, usually made from a solid specialty plastic material. Typical PEM electrolyzer operating temperature ranges between 70 and 90 °C with an electrical efficiency of 56 to 60 percent.[109] A potential advantage of PEM electrolyzers is their ability to respond quickly to fluctuations, which are typical for variable sources of electricity such as renewables and could be used to produce hydrogen from electricity that might otherwise be curtailed. Alkaline electrolysis uses a liquid solution of sodium or potassium hydroxide as the electrolyte and has a normal operating temperature of less than 100 °C. Electrical efficiency for alkaline electrolysis ranges between 63 and 70 percent. Solid oxide electrolysis uses a solid ceramic material as the electrolyte that selectively conducts negatively charged oxygen ions at elevated temperatures at an electrical efficiency of 74 to 81 percent. Temperatures of 700 to 800 °C are necessary for the solid oxide membranes to function properly.[110] If waste heat is used as a source of thermal energy, the overall efficiency of electrolysis from solid oxide fuel cells could be increased. Anion exchange membrane (AEM) electrolyzer technology is under development and is similar to PEM electrolyzer technology, except the hydroxyl ions are transported across the membrane. A potential advantage of AEM technology relative to PEM technology is the ability to use lower cost catalysts.

Seawater electrolysis is also under development and would allow hydrogen to be produced directly from seawater. Researchers at the University of Adelaide recently developed a method to utilize seawater without pre-treatment systems and the addition of alkali. A cobalt oxide catalyst with chromium oxide on its surface is used to dynamically split water molecules, generate local alkalinity, and prevent precipitate formation. Seawater electrolysis with the cobalt oxide catalyst achieves a comparable performance to a PEM electrolyzer using commercial catalysts.[111]

Electrolysis uses fuel cells to split water into hydrogen and oxygen. Some of these electrolysis systems, such as PEM and alkaline electrolysis, only produce hydrogen and oxygen from the fuel cells. Solid oxide electrolysis has the capability to operate additionally as a reversible technology, in which hydrogen can be used in the fuel cell to produce electricity. Therefore, a solid oxide electrolyzer could produce hydrogen for stored energy and then use the hydrogen to produce electricity. These reversible power-to-gas systems can be used as a source of backup electricity during periods of surging prices and peak demand. They could also potentially

[108] DOE (2022). *4 Nuclear Power Plants Gearing Up for Clean Hydrogen Production*. Accessed at https://www.energy.gov/ne/articles/4-nuclear-power-plants-gearing-clean-hydrogen-production.
[109] IEA (2019, June). *The Future of Hydrogen Report, prepared by the IEA for the G20, Japan*. Accessed at https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf.
[110] Hydrogen and Fuel Cell Technologies Office. *Hydrogen Production: Electrolysis*. Accessed at https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis.
[111] Guo, J., et al (2023). *Direct seawater electrolysis by adjusting the local reaction environment of a catalyst*. Nat Energy 8. https://doi.org/10.1038/s41560-023-01195-x.

produce electricity from hydrogen at cheaper costs than combustion turbines, especially as the cost effectiveness improves as the technology matures.[112]

Given that no GHG emissions are released during the electrolysis process, emissions from electrolysis hydrogen production are largely dependent on the source of electricity.

Example Electrolysis Projects

For the Long Ridge, IPA, Brentwood, and Cricket Valley projects mentioned previously, the objective is for those facilities to eventually transition to hydrogen produced from renewable energy and electrolysis as it becomes available.

- In New Jersey, one of 10 peaking turbines at the Bayonne Energy Center plans to operate on low-GHG hydrogen produced by 125-MW PEM electrolyzers that will be installed by 2025.[113]
- In Texas, Air Products is partnering with energy firm AES to build a $4 billion hydrogen complex that uses electrolysis and low-carbon energy inputs. The site will use water electrolyzers powered by 1.4 GW of wind and solar resources to produce 200 metric tons of hydrogen per day.[114]
- In Europe, several projects have been announced that will utilize offshore wind energy to power onshore electrolysis. Hydrogen produced in this manner can be used to produce electricity and for other industries in the area and likely incorporated into their "low-GHG" products. For example, a Danish energy company has begun a project called "SeaH2Land" in which 2 GW of offshore wind in the Dutch North Sea will power the electrolysis of hydrogen. The hydrogen will then be utilized by industries in the North Sea Port areas of the Netherlands and Belgium—home to industries such as ArcelorMittal (steel), Yara (ammonia), Dow (material sciences), and the Zeeland Refinery (reformed methane).[115, 116]
- At the National Wind Technology Center in Boulder, Colorado, the DOE's National Renewable Energy Laboratory (NREL) has partnered with Xcel Energy on a wind-to-hydrogen demonstration project. Powered by wind turbines and photovoltaic arrays, hydrogen is produced via electrolysis and then stored[117] or converted to electricity by an

[112] Edmund, Andrews (2022, April 20). *Reversible fuel cells can support grid economically, Stanford researcher finds*. https://news.stanford.edu/press-releases/2022/04/20/reversible-fuel-rid-economically/.
[113] Clark, K. (2022). *Green hydrogen cold help decarbonize New Jersey power plant*. Power Engineering. Accessed at https://www.power-eng.com/hydrogen/green-hydrogen-could-help-decarbonize-new-jersey-power-plant/#gref.
[114] Chemical & Engineering News (2022). *Air Products plans big green hydrogen plant in US*. Accessed at https://cen.acs.org/energy/hydrogen-power/Air-Products-plans-big-green/100/web/2022/12.
[115] Frangoul, A. (2021). *Orsted to link a huge offshore wind farm to "renewable" hydrogen production*. CNBC. Retrieved August 4, 2021, https://www.cnbc.com/2021/04/01/orsted-to-link-huge-offshore-wind-farm-to-hydrogen-production-.html.
[116] Orsted. (2021). *Orsted to develop one of the world's largest renewable hydrogen plants to be linked to industrial demand in the Netherlands and Belgium*. Retrieved August 4, 2021, https://orsted.com/en/media/newsroom/news/2021/04/451073134270788.
[117] Currently available utility batteries typically have 4 hours or less of storage and are not used for long-term storage. Longer-term storage is typically done using pumped hydro or compressed air. A potential use of hydrogen is to serve as long-term energy storage. Electricity generated from renewables or nuclear power during periods of

internal combustion engine or fuel cell and fed to the grid ateak demand.[118] The goal of this "Wind2H2" project is to research pathways to improve system efficiencies, reduce costs, and increase competitiveness with traditional fossil fuels.

Multiple electrolyzer factories are under development in the U.S.

- Cummins Inc. will use an existing facility in Fridley, Minnesota, to manufacture 500 MW of electrolyzers annually, with the possibility to expand to 1 GW. Cummins will manufacture PEM electrolyzes that range from 1.25 MW to more than 200 MW.[119]
- Bloom Energy has a high-volume commercial electrolyzer line at its facility in Delaware, bringing its total generating capacity of eletrolyzers to 2 GW.[120]
- Plug Power operates a Gigafactory in New York where it manufactures PEM electrolyzers for low-GHG hydrogen production.[121]

Photochemical

Photoelectrochemical (PEC) water splitting can be used to produce hydrogen with low GHG emissions. In this process, specialized semiconductors called photoelectrochemical materials use light energy from sunlight to directly dissociate water molecules into hydrogen and oxygen. A major advantage of PEC systems is that they possess a wide operating temperature range, with no intrinsic upper temperature limit. The lower temperature limit can be slightly below 0 °C without a warm-up period, and well below 0 °C with a warm-up period. The main challenges for PEC are lifespan, dealing with corrosion, internal resistance losses, high plant capital cost, and material development.[122] Photocatalytic overall water splitting (OWS) is a variation of water splitting. Compared with PEC, photocatalytic OWS does not require the use of a conductive electrolyte such as strong acidic or alkaline solutions. Fresh or sea water can be split into

low electric demand can be converted to hydrogen and stored onsite for long periods. In addition, if this hydrogen is injected into the existing natural gas distribution network, the distribution system itself can act as the storage device. Another advantage of injecting low-GHG hydrogen into the existing natural gas transmission network is that the energy from renewable generation can be transported to end users without using the electric grid—potentially reducing the need for additional transmission capacity and the associated negative environmental and societal impacts.

[118] National Renewable Energy Laboratory (NREL). (n.d.). *Wind-to-Hydrogen Project*. Hydrogen and Fuel Cells. Accessed at https://www.nrel.gov/hydrogen/wind-to-hydrogen.html.

[119] Freight Waves (2022). *Cummins adding hydrogen electrolyzer manufacturing in US. Accessed at https://www.freightwaves.com/news/cummins-adding-hydrogen-electrolyzer-manufacturing-in-us.*

[120] Bloom Energy (2022). *Bloom Energy Inaugurates High Volume Electrolyzer Production Line.* Accessed at https://www.bloomenergy.com/news/bloom-energy-inaugurates-high-volume-electrolyzer-production-line/.

[121] NY Governor's Press Office (2021). *Governor Hochul Announces Opening of $125 Million Plug Power Hydrogen Fuel Cell Innovation Center in Monroe County*. Accessed at https://www.governor.ny.gov/news/governor-hochul-announces-opening-125-million-plug-power-hydrogen-fuel-cell-innovation-center.

[122] James, B. D., et al (2009). *Technoeconomic Analysis of Photoelectrochemical (PEC) Hydrogen Production*. Draft Project Final Report. Accessed at https://www.energy.gov/sites/default/files/2014/03/f12/pec_technoeconomic_analysis.pdf.

hydrogen and oxygen without external bias or circuitry, potentially leading to reduced system cost and safety issues.[123]

Byproduct Hydrogen

Hydrogen can also be produced as a byproduct of other industrial/manufacturing processes. A few examples of additional production techniques where hydrogen is produced include refuse biomass, chlor-alkali plants, and waste hydrocarbons.[124] From refuse biomass, anerobic digestion occurs, which results in biogas. Biogas is a significant portion methane, which can be converted to hydrogen via upgrading processes. As for chlor-alkali production, highly pure hydrogen is a byproduct of the process and carries a low carbon footprint.[125] Currently, approximately 15 percent of the chlor-alkali hydrogen produced is vented.[126] Waste hydrocarbons can be fed into a reformer to convert them into hydrogen, as has been done with Ford Motor Company's 'Fumes-to-Fuel' waste paint exhaust system.[127]

Natural Hydrogen

Natural hydrogen is also present in geologic formations created by chemical reactions between water and iron mineral deposits, namely olivine, under high temperatures and pressure.[128] GHG emissions associated with subsurface hydrogen, if present, would be a result of fossil-based extraction and production process. While no natural hydrogen projects are currently operational, given the tax incentives included in the *Infrastructure Investment and Jobs Act* (discussed in detail below), additional methods of hydrogen production are likely to evolve during the next 10 years.

Transportation and Storage of Hydrogen

A viable hydrogen infrastructure requires that hydrogen be able to be delivered from where it is produced to the point of end use, such as an industrial facility, power generator, or fueling station. That infrastructure also must be able to deliver hydrogen to the point of use at the times needed, requiring storage infrastructure. Infrastructure includes the pipelines, liquefaction plants, trucks, storage facilities, compressors, and dispensers involved in the process of delivering fuel.[129]

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123 Zhou, P., et al (2023). *Solar-to-hydrogen efficiency of more than 9% in photocatalytic water splitting*. Accessed at https://www.nature.com/articles/s41586-022-05399-1.

124 Cox, R. (2011). *Waste/By-Product Hydrogen*. DOE/DOD Workshop, January 13, 2011. Accessed at https://www.energy.gov/sites/prod/files/2014/03/f12/waste_cox.pdf.
125 Euro Chlor (2022). *Hydrogen from Chlor-Alkali Production: High Purity, Low Carbon and Available Today*. Accessed at https://www.eurochlor.org/news/hydrogen-from-chlor-alkali-production/.
126 James, B. D., et al (2009). *Technoeconomic Analysis of Photoelectrochemical (PEC) Hydrogen Production*. Draft Project Final Report. Accessed at https://www.energy.gov/sites/default/files/2014/03/f12/pec_technoeconomic_analysis.pdf.
127 Environmental News Network (ENN) (2007). *Ford 'Fumes-to-Fuel' System Turns Waste Paint Exhaust into Clean Electric Power*. Accessed at https://www.enn.com/articles/22537-ford-fumes-to-fuel-system-turns-waste-paint-exhaust-into-clean-electric-power#:~:text=Installed%20in%20the%20Paint%20Shop,into%20a%20hydrogen%2Drich%20gas.
128 "Hidden Hydrogen: Does Earth hold vast stores of a renewable, carbon-free fuel" Science, February 16, 2023
129 U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *Hydrogen Delivery*, https://www.energy.gov/eere/fuelcells/hydrogen-delivery.

Hydrogen is transported from the point of production to the point of use via pipelines and over the road in cryogenic liquid tanker trucks or gaseous tube trailers. Approximately 1,600 miles of dedicated hydrogen pipelines are deployed in regions of the U.S. with substantial demand (*e.g.*, hundreds of tons per day) that is expected to remain stable for decades. Liquefaction plants, liquid tankers, and tube trailers are deployed in regions where demand is at a smaller scale or emerging. Demonstrations of hydrogen delivery via chemical carriers are also underway in large-scale applications, such as export markets.[130] These carriers (*e.g.*, liquid ammonia, liquid methanol) store hydrogen in some other chemical state (can be liquid or solid) rather than as free hydrogen molecules. For example, it can be transported as a gas by pipelines or in liquid form by ships, much like liquefied natural gas (LNG).[131]

The cost of hydrogen delivery, storage, and dispensing to an end-user varies widely given the mode of supply used. There are four main methods of hydrogen delivery at scale today: gaseous tube trailers, liquid tankers, pipelines (for gaseous hydrogen), and chemical hydrogen carriers. Tube trailers and liquid tankers are commonly used in regions where hydrogen demand is low or developing and not yet stable. Gaseous pipelines are commonly used when demand is predictable for decades and at a regional scale of hundreds of tonnes per day. Chemical carriers are of interest for long-distance hydrogen delivery.

The California Public Utilities Commission (CPUC) commissioned the University of California, Riverside's *Hydrogen Blending Impacts Study* to assess the operational and safety concerns associated with injecting hydrogen into the existing natural gas pipeline system at various percentages to help California establish the standards and interconnection protocols for possibly injecting renewable hydrogen into natural gas pipelines.[132]

The Study's findings include:

- Hydrogen blends of up to 5 percent in the natural gas stream are generally safe. However, blending more hydrogen in gas pipelines overall results in a greater chance of pipeline leaks and the embrittlement of steel pipelines.
- Hydrogen blends above 5 percent could require modifications of certain appliances such as stoves and water heaters to avoid leaks and equipment malfunction.
- Hydrogen blends of more than 20 percent present a higher likelihood of permeating plastic pipes, which can increase the risk of gas ignition outside the pipeline.
- Due to the lower volumetric energy content of hydrogen gas, more hydrogen-blended natural gas will be needed to deliver the same amount of energy to users compared to pure natural gas.

Transporting gaseous hydrogen via existing pipelines is a low-cost option for delivering large volumes of hydrogen. The capital costs of new pipeline construction constitute a barrier to

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[130] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *Hydrogen Delivery*, https://www.energy.gov/eere/fuelcells/hydrogen-delivery.
[131] IEA, *The Future of Hydrogen Report* (June 2019), prepared by the for the G20, Japan. Accessed at https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf.
[132] University of California, Riverside for the CPUC, *Hydrogen Blending Impacts Study* (July 2022), https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-issues-independent-study-on-injecting-hydrogen-into-natural-gas-systems

expanding hydrogen pipeline delivery infrastructure. Research today therefore focuses on overcoming technical concerns related to transmission through existing pipelines, including:

- the potential for hydrogen to embrittle the steel and welds used to fabricate the pipelines;
- the need to control hydrogen permeation and leaks; and
- the need for lower cost, more reliable, and more durable hydrogen compression technology.

As mentioned earlier, the U.S. has an extensive network of approximately 3 million miles of natural gas pipelines and more than 1,600 miles of dedicated hydrogen pipelines. Hydrogen, including hydrogen produced through low-GHG pathways, can be injected into natural gas pipelines and the resulting blends can be used to generate heat and power with lower emissions than using natural gas alone. Blend limits depend on the design and condition of current pipeline materials (*e.g.*, integrity, dimensions, materials of construction), design and condition of pipeline infrastructure equipment (*e.g.*, compressor stations), and design and condition of applications that utilize natural gas (*e.g.*, building appliances, combustion turbines, and chemical processes, such as plastics production). Blend limits can vary greatly based on these variables but have ranged from less than 1 to 30 percent in recently announced demonstrations and deployments.[133] Amounts that can be mixed vary by region. Analysts assert that 20 percent hydrogen concentrations by volume may be the maximum blend before significant pipeline upgrades are required. Other recent analyses of existing pipeline materials indicate that 12 percent may be the maximum blend.[134] In addition, the existing end-use equipment in power plants and industrial facilities may not tolerate higher hydrogen concentrations without modification.[135] If implemented with relatively low concentrations, less than 5 to 15 percent hydrogen by volume, this strategy of storing and delivering low-GHG hydrogen to markets appears to be viable without significantly increasing risks associated with utilization of the gas blend in most end-use devices, overall public safety, or the durability and integrity of the existing natural gas pipeline network. However, the appropriate blend concentration may vary significantly between pipeline network systems and natural gas compositions and must therefore be assessed on a case-by-case basis.[136]

Note that the concerns relating to natural gas pipeline embrittlement from hydrogen transportation have been disputed.[137] Nonetheless, potential solutions exist to protect pipelines from embrittlement caused by hydrogen use. These solutions include using fiber reinforced polymer (FRP) pipelines for hydrogen distribution (FRP can be delivered in lengths of up to 0.5 mile).[138] It should be noted that FRP is not authorized by Pipeline and Hazardous Materials Safety Administration (PHMSA) regulations without a special permit (See 49 FR 190.341). The installation costs for FRP pipelines are about 20 percent less than that of steel pipelines because

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[133] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *HyBlend: Opportunities for Hydrogen Blending in Natural Gas Pipelines* (June 2021)

[134] https://www.ornl.gov/publication/assessing-compatibility-natural-gas-pipeline-materials-hydrogen-co2-and-ammonia

[135] Congressional Research Service, Parfomak, P., *Pipeline Transportation of Hydrogen: Regulation, Research and Policy* (March 2021) https://crsreports.congress.gov/product/pdf/R/R46700

[136] NREL/TP-5600-51995, Melaina, M.W., Antonia O., and Penev, M., (March 2013). *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*

[137] Nationaler Wasserstoffrat (2021). *Wasserstofftransport*. (In German.) Accessed at https://wasserstoffwirtschaft.sh/file/nwr_wasserstofftransport_web-bf.pdf.

[138] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *Hydrogen Pipelines*, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines

the FRP can be obtained in sections that are much longer than steel,[139] minimizing welding requirements. However, FRP generally have a maximum nominal outer width of 6 inches, which can limit the throughput capacity.

Other changes necessary to retrofit natural gas pipeline distribution systems for hydrogen distribution include installing appropriate compressors. One case study estimated the compressor replacement/alterations that would be necessary to transport varying proportions of hydrogen in existing natural gas pipelines in Germany. Findings suggest that when transporting up to 10 percent hydrogen, generally no changes are needed to existing compressors. When transporting between 10 and 40 percent hydrogen, impellers, feedback stages, and gears need to be adjusted on the existing compressors. When transporting greater than 40 percent hydrogen, compressors need to be replaced. Additionally, if transport capacities exceed 750,000 Nm^3/h, it is estimated that turbo-compressors[140] are required.[141]

The integration of hydrogen in pipelines has already been demonstrated. For example, Air Products has constructed 180 new miles of pipeline in the Gulf Coast. Combined, the network consists of more than 600 miles of pipeline and 20 hydrogen plants that can supply nearby refineries with more than 1 billion cubic feet of hydrogen per day.[142] In California, Southern California Gas (SoCalGas) has begun the development of a hydrogen pipeline system that could deliver low-GHG hydrogen equivalent to 25 percent of the company's natural gas capacity. The project would deliver hydrogen from electrolyzers powered by clean energy straight to end users, primarily electrical generation, transportation, and industry.[143] SoCalGas has also submitted proposals to blend up to 20 percent hydrogen in natural gas pipelines for combustion in California.[144]

Hydrogen pipelines can themselves serve as energy storage devices and therefore can also act as an alternative to electric transmission lines for energy transport. Hydrogen electrolysis can be used to convert renewable energy into hydrogen, which can then be sent through pipelines. Building a hydrogen pipeline could be less expensive than building new transmission lines and serve as a cost-effective way to transfer renewable energy to end users.[145]

[139] Argonne National Laboratory, *Natural Gas Pipeline Technology Overview*, https://doi.org/10.2172/925391
[140] Turbo-compressors are estimated to be available "within a few years" according to the case study.
[141] Adam, P., Heunemann, F., von dem Bussche, C., Engelshove, S., Theimann, T. (2021). *Hydrogen infrastructure – the pillar of energy transition*. Accessed at https://assets.siemens-energy.com/siemens/assets/api/uuid:3d4339dc-434e-4692-81a0-a55adbcaa92e/200915-whitepaper-h2-infrastructure-en.pdf?ste_sid=81652be676b733c416f088cae17fccf3.
[142] Air Products (2012). *Air Products' U.S. Gulf Coast hydrogen network*. Accessed at https://microsites.airproducts.com/h2-pipeline/pdf/air-products-us-gulf-coast-hydrogen-network-datasheet.pdf.
[143] Utility Dive (2022). *SoCalGas begins developing 100% clean hydrogen pipeline system*. Accessed at https://www.utilitydive.com/news/socalgas-begins-developing-100-clean-hydrogen-pipeline-system/619170/.
[144] Clean Energy Group (2020). *Hydrogen Projects in the US*. Accessed at https://www.cleanegroup.org/ceg-projects/hydrogen/projects-in-the-us/.
[145] Desantis, et al. (2021). Cost of long-distance energy transmission by different carriers. Accessed at https://doi.org/10.1016/j.isci.2021.103495.

Additionally, hydrogen can be transported via trucking if the appropriate trailers[146] are available.[147] Trucks that haul gaseous hydrogen, called tube trailers, are most common and can haul approximately 380 kilograms; their carrying capacity is limited by the weight of the steel tubes. Gaseous hydrogen is compressed to pressures of 180 bar (~2,600 psig) or higher into long cylinders that are stacked on a trailer. Tube trailers are currently limited to pressures of 250 bar by U.S. Department of Transportation regulations, but exemptions have been granted to enable operation at higher pressures (*e.g.*, 500 bar or higher). Recently, composite storage vessels have been developed that have capacities of 560 to 900 kg of hydrogen per trailer. Such tube trailers are currently being used to deliver compressed natural gas in other countries.[148]

While hydrogen is two times more energy dense than methane on a mass basis, and as discussed earlier in this document, it is three times less energy dense than methane on a volume basis. Consequently, a greater volume of hydrogen is required for the same amount of electric generation from a combustion turbine when compared to natural gas. This requires infrastructure to transport the hydrogen to power plants and combustion turbines capable of combusting increased volumes. A limitation on greater volumes of hydrogen being safely mixed with natural gas in existing natural gas pipelines is the potential embrittlement and weakening of pipes that leads to leakage.

The production method and hydrogen delivery infrastructure both have an impact on the delivered price of hydrogen. Hydrogen transport by pipeline requires additional compression with energy penalties of up to 20 percent of the energy required for compression. Additionally, trucking has shown to be a viable method of transporting hydrogen in high-pressure tube trailers, but costs can limit distances to 200 miles. Lastly, transport via ship may be another alternative for hydrogen transport. A pilot hydrogen transport ship in Japan was launched in 2019 with a storage capacity of 1,250 m^3, which is less than 1 percent of typical liquid natural gas carriers.[149]

The transportation method, and therefore cost, of hydrogen transport is largely dependent on the distance of transport. It has been estimated that, relative to pipeline transportation costs, liquid carrier and truck transport of hydrogen are twice as expensive when transporting 1,000 km and more than 1.5 times as expensive when transporting 3,000 km. The cost of transport is roughly the same for hydrogen and hydrogen/natural gas blends via pipeline; however, transporting pure

[146] Gaseous hydrogen is frequently transported distances up to 200 miles with high-pressure cylinder and tube trailers at ~2,600 pound-force per square inch (psi).
[147] Goldmeer, J. (2019). *Power to Gas: Hydrogen for Power Generation*. General Electric (GE) Power. Accessed at https://www.ge.com/content/dam/gepower/global/en_US/documents/fuel-flexibility/GEA33861%20Power%20to%20Gas%20-%20Hydrogen%20for%20Power%20Generation.pdf.
[148] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *Hydrogen Tube Trailers*, https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers
[149] U.S. Department of Energy (2020). *Hydrogen Strategy – Enabling A Low-Carbon Economy*. Accessed at https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf.

hydrogen is still slightly more expensive. The costs of pipeline hydrogen transportation of each are roughly \$0.05-2.00/kg H_2.[150, 151, 152]

Transmission pipelines are useful for distances greater than 10 km for flows of more than 100 tons per day (t/d). For comparison, distribution pipelines are mostly useful for distances up to 100 km of transport and volumes of between 10 and 100 t/d. The cost of transport for distribution pipelines can be anywhere from \$0.05-1.4/kg H_2 for reasonable distances. Trucks can transport hydrogen for long distances; although, for longer distances (~300 km or greater) will require liquid hydrogen trucks. Prices for compressed hydrogen trucks can range from \$0.55-0.75/kg for transports of 1 to 10 t/d, and prices for liquid hydrogen trucks can range from \$0.75-2.6/kg for transports of 1 to 10 t/d.[152]

On-site hydrogen storage is used at central hydrogen production facilities, transport terminals, and end-use locations. Storage options include insulated liquid tanks and gaseous storage tanks. The four types of common high-pressure gaseous storage vessels are shown in the table below.[153]

Type I	All-metal cylinder
Type II	Load-bearing metal liner hoop wrapped with resin-impregnated continuous filament
Type III	Non-load-bearing metal liner axial and hoop wrapped with resin-impregnated continuous filament
Type IV	Non-load-bearing, non-metal liner axial and hoop wrapped with resin-impregnated continuous filament

Type I cylinders are the most common. Currently the costs of Type III and Type IV vessels are greater than those of Type I and II vessels. It is expected that with additional cost reductions in carbon fiber and improved manufacturing methods, these technologies could ultimately cost less than the traditional metal Type I cylinders. Cryogenic liquid storage tanks, also referred to as dewars, are the most common way to store large quantities of hydrogen. Super-insulated, low-pressure vessels are needed to store liquid hydrogen at -253 °C (-423 °F). The pressure of liquid hydrogen is no more than 5 bar (73 psig). Regardless of the quality of the insulation, however, some heat will reach the tank over time and cause the liquid hydrogen to boil.[154]

Hydrogen infrastructure could require geologic (underground) bulk storage to handle variations in demand throughout the year. In some regions, naturally occurring geologic formations, such as salt caverns and aquifer structures, might be used, while in other regions, specially engineered

[150] Note for the hydrogen/natural gas blend transport, this assumes extraction of hydrogen occurs at a low-pressure location.
[151] Di Lullo, G., Giwa, T., Okunlola, A., Davis, M., Mehedi, T., Oni, A. O., & Kumar, A. (2022). *Large-scale long-distance land-based hydrogen transportation systems: A comparative techno-economic and greenhouse gas emissions assessment.* International Journal of Hydrogen Energy. Volume 47, Issue 83, Pages 35293-35219. October 1, 2022. Accessed at https://www.sciencedirect.com/science/article/pii/S036031992203659X.
[152] Day, P. (2022). *Hydrogen uses to be determined by deliver methods*. Reuters. https://www.reuters.com/business/energy/hydrogen-uses-be-determined-by-delivery-methods-2022-10-12/.
[153] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *On-Site and Bulk Hydrogen Storage*, https://www.energy.gov/eere/fuelcells/site-and-bulk-hydrogen-storage.
[154] U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *On-Site and Bulk Hydrogen Storage*, https://www.energy.gov/eere/fuelcells/site-and-bulk-hydrogen-storage.

rock caverns are a possibility. Geologic bulk storage is common practice in the natural gas industry and there are four existing salt caverns used for hydrogen storage today. The use of geologic storage for hydrogen used in fuel cell electric vehicles requires further investigation into the possible impurities that could be introduced by underground storage.[155] There are projects underway to test and demonstrate the technical, economic, and social viability of underground hydrogen storage.[156, 157]

Deployments of hydrogen storage at these scales typically rely on the construction of salt caverns, as previously discussed, but other potential methods of hydrogen storage are in varying stages of research, development, and demonstration (RD&D) and analysis. These include the use of geographically agnostic technologies such as buried pipes, hard rock caverns, and depleted hydrocarbon reservoirs and aquifers. As the demand for bulk hydrogen storage grows, it is likely to incentivize accelerated RD&D and first-of-its-kind deployments of such innovative technologies, which could in turn reduce the cost of infrastructure across sectors with large-scale hydrogen demand.

Hydrogen carriers, ideal for long-range transport, are hydrogen-rich liquid or solid phase materials from which hydrogen can be liberated on-demand. Ideal hydrogen carriers have high hydrogen densities at low pressure and near ambient temperature. The formation of the carrier and release of hydrogen from the carrier should be as energy efficient as possible to minimize the energy penalty associated with the use of the hydrogen carrier to store and transport hydrogen.[158]

There are two main categories of hydrogen carriers—two-way carriers and one-way carriers. A two-way carrier is a material that is transported to a distribution site in a "hydrogenated" form, dehydrogenated to yield hydrogen, and the dehydrogenated material returned to a processing site where it would be re-hydrogenated for reuse. Proposed two-way carriers include complex hydrides with high hydrogen capacities (e.g., $LiBH_4$) and some hydrocarbon systems, such as decalin-napthalene ($C_{10}H_{18} \leftrightarrow C_{10}H_8$).[159]

A one-way carrier would be decomposed at a distribution site to yield hydrogen and a byproduct that is environmentally benign and has no value. Its production should be cheap and efficient. Ammonia is being considered as one of the best potential options for a one-way carrier due to a number of favorable attributes. Ammonia is one of the only materials that can be produced cheaply, transported efficiently, and transformed directly to yield hydrogen and a non-polluting byproduct. Moreover, it has a high capacity for hydrogen storage (17.6 wt.%), based on its molecular structure. However, to release hydrogen from ammonia, significant energy input as well as reactor mass and volume are required. Other considerations include safety and toxicity issues, both actual and perceived, as well as the incompatibility of polymer electrolyte membrane (PEM) fuel cells in the presence of even trace levels of ammonia (> 0.1 ppm). Some combustion

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155 U.S. DOE EERE Hydrogen and Fuel Cell Technologies Office, *On-Site and Bulk Hydrogen Storage*, https://www.energy.gov/eere/fuelcells/site-and-bulk-hydrogen-storage.
156 IEA (2021), *Proving the Viability of Underground Hydrogen Storage*, IEA, Paris https://www.iea.org/articles/proving-the-viability-of-underground-hydrogen-storage.
157 U.S. Department of Energy (DOE). SHASTA: Subsurface Hydrogen Assessment, Storage, and Technology Acceleration. Accessed at https://edx.netl.doe.gov/shasta/.
158 U.S. DOE EERE, Autrey, T. and Ahluwalia, R. (2018), *Hydrogen Carriers for Bulk Storage and Transport of Hydrogen*, https://www.energy.gov/sites/default/files/2018/12/f58/fcto-webinarslides-hydrogen-carriers-120618.pdf.
159 US DOE - Thomas G., Parks G. (2006), *Potential Roles of Ammonia in a Hydrogen Economy*, https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf.

turbine manufacturers are exploring the potential to combust ammonia directly in combustion turbines, potentially avoiding some of these issues. However, the direct combustion of ammonia could produce more NO_X compared to natural gas.[160]

Urea is also appealing since it does not suffer from the toxicity problems associated with ammonia, but its hydrogen content is only 9.1 wt%—a little more than half that of ammonia. The potential utility of ammonia as a carrier for hydrogen delivery needs to be investigated and is currently under analysis by the DOE and the FreedomCAR & Fuel Partnership's Hydrogen Delivery Technical Team. Since a delivery system using ammonia would use existing technology, research in ammonia delivery should focus on analysis to better understand the economics and safety issues surrounding ammonia use. The ammonia cracking process also needs to be improved. Better catalysts, efficient reactor designs, and inexpensive and reliable purification schemes all need to be developed if ammonia is to be used as a hydrogen carrier. It should be noted that some fuel cell technologies, such as alkaline fuel cells, are ammonia tolerant, so extensive hydrogen purification would not be needed if they were fueled by hydrogen produced from ammonia.[161]

Methanol can serve as a dense hydrogen carrier and can be generated using natural gas. At endpoints, methanol can easily be converted to syngas, a mixture of hydrogen and carbon oxides. In the future, methanol may be created with more renewable feedstocks, such as biogas, which may yield higher potential GHG reductions during methanol production. There are currently eight methanol production plants using renewable natural gas operating, and at least 20 more are expected in the next decade.

Research is being conducted on a fuel cell that can convert electricity into ammonia. By converting renewable electricity into an energy-rich gas that can easily be cooled and squeezed into a liquid fuel, these fuel cells effectively turn solar and wind energy into a commodity that can be shipped anywhere in the world and converted back into electricity or hydrogen gas to power fuel cell vehicles.[162]

Ammonia is emerging as the preferred international distribution mode for hydrogen from GW-scale renewable power and electrolysis projects. Ammonia produced from natural gas and using CCS is still being explored. In Texas, OCI N.V. plans to upgrade an aging natural gas-based hydrogen plant with CCS to produce ammonia, with 95 percent of the CO_2 emissions being captured and sequestered.[163] In Belgium, Air Liquide plans to construct an industrial scale ammonia cracking pilot plant to convert ammonia back into hydrogen.[164] Methanol is another hydrogen derivative that is anticipated to enable low-GHG energy storage and possible energy

[160] Goldmeer, J. (2021). *Ammonia as a gas turbine fuel*. GE Gas Power presentation. Accessed at https://www.energy.gov/sites/default/files/2021-08/8-nh3-gas-turbine-fuel.pdf.
[161] US DOE - Thomas G., Parks G. (2006), *Potential Roles of Ammonia in a Hydrogen Economy*, https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf.
[162] Service, R. (2018), *Ammonia—a renewable fuel made from sun, air, and water—could power the globe without carbon*, https://www.science.org/content/article/ammonia-renewable-fuel-made-sun-air-and-water-could-power-globe-without-carbon.
[163] Business Wire (2022). *OCI N.V. Breaks Ground on 1.1 mtpa Blue Ammonia Site in Texas, USA*. Accessed at https://www.businesswire.com/news/home/20221207005572/en/OCI-N.V.-Breaks-Ground-on-1.1-mtpa-Blue-Ammonia-Site-in-Texas-USA.
[164] Bailey, Mary Page (2023). *Air Liquide constructing ammonia-cracking pilot plant in Antwerp*. Accessed at https://www.chemengonline.com/air-liquide-constructing-ammonia-cracking-pilot-plant-in-antwerp/.

exports. Liquid organic hydrogen carriers, liquid hydrogen, and compressed gaseous hydrogen shipping are also likely to increase.[165]

Truck or rail transportation of compressed hydrogen is relatively expensive. Liquid hydrogen tankers are cheaper, but there is a considerable energy and cost penalty associated with liquefaction (more than 30 percent of hydrogen's energy content is required to liquefy it). Distributed production will certainly play an important role, but the capital investment associated with small reformers may limit their utility. So other more cost-effective options are also being explored. The "wild card" option for distribution of centrally produced hydrogen is some sort of hydrogen carrier. A carrier is defined as a material, other than the H_2 molecule, that can be used to transport hydrogen. An additional requirement is that the transformation required to produce hydrogen from the material is relatively simple, uses little energy, and is low in cost. Note that materials such as methane or ethanol that can be reformed at a refueling station have strong chemical bonds between carbon and hydrogen and are considered raw material feedstocks for producing hydrogen rather than as hydrogen carriers.[166]

Another avenue for hydrogen use is the production of e-kerosene, a synthetic kerosene. Kerosene is largely used as fuel in the aviation industry. E-kerosene can be produced from the combination of CO_2 and hydrogen, and when the hydrogen is produced in a low-GHG manner, the carbon footprint of e-kerosene-based aviation fuels can be greatly reduced. It is estimated that the cost of e-kerosene production in the U.S. was $8.80 per gallon in 2020, but that it could decrease to $4.00 per gallon in 2050.[167]

Costs and Availability of Hydrogen

The costs of hydrogen, including production and distribution, are expected to decrease by 2030 and beyond in response to investments in hydrogen infrastructure and hydrogen production tax benefits established in the 2021 Infrastructure Investment and Jobs Act (IIJA), also known as the Bipartisan Infrastructure Law (BIL), and the 2022 Inflation Reduction Act (IRA). This section describes the estimated costs of hydrogen prior to enactment of these laws then discusses the BIL and the IRA and their impact on current cost estimates.

<u>Cost Estimates Prior to the BIL and IRA</u>

As of 2020, 95 percent of domestic hydrogen was produced via SMR and 4 percent was produced via gasification.[168] According to estimates from the International Energy Agency (IEA), SMR costs in the U.S. are approximately $1.50/kg with CCS, and coal gasification costs can range from $1.34/kg to $2.06/kg when using CCS. Other estimates for the cost of fossil fuel-based hydrogen production range from $1.00/kg without CCS to $1.50/kg with CCS.[169] The

[165] Harrison, S., *Transporting Hydrogen, Ammonia, and Methanol by Ship*, https://www.worldhydrogenleaders.com/courses/transporting-hydrogen-ammonia-and-methanol-by-ship.
[166] US DOE - Thomas G., Parks G. (2006), *Potential Roles of Ammonia in a Hydrogen Economy*, https://www.energy.gov/sites/prod/files/2015/01/f19/fcto_nh3_h2_storage_white_paper_2006.pdf.
[167] Zhou, Y., Searle, S., Pavlenko, N. (2022). *Current and Future Cost of E-Kerosene in the United States and Europe.* Accessed at https://theicct.org/wp-content/uploads/2022/02/fuels-us-europe-current-future-cost-ekerosene-us-europe-mar22.pdf.
[168] U.S. Department of Energy (2020). *Hydrogen Strategy – Enabling A Low-Carbon Economy*. Accessed at https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf.
[169] IEA, *The Future of Hydrogen Report* (June 2019), prepared by the for the G20, Japan. Accessed at https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf.

production costs for methane pyrolysis can be approximately \$2.60/kg to \$3.20/kg, or 30 to 60 percent higher than SMR.[170] Currently, approximately 1 percent of hydrogen produced via SMR, coal gasification, or other fossil-based methods included CCS.[171] The EPA expects that the tax subsidies in Internal Revenue Code (IRC) 45Q for the capture and storage of CO_2 will expand the use of CCS in the hydrogen production sector.

To date, the production of hydrogen via electrolysis remains limited and expensive compared to other production technologies. Some estimates of hydrogen costs for electrolysis, prior to enactment of the BIL and IRA, range between approximately \$5/kg to \$6/kg when utilizing nuclear and wind electricity sources.[172] Other estimates indicate that hydrogen costs range from \$8/kg to \$11/kg, but that these costs can be reduced to approximately \$6/kg by 2050.[173, 174] Specific to the electricity source, electrolysis production prices are estimated to be \$5.58/kg, \$5.96/kg, and approximately \$9.00/kg for nuclear, wind, and solar electrolysis, respectively.[175] Other estimates for electrolysis are similar; although, wind and solar electrolysis production prices have also been estimated to be as high as \$7.25/kg and \$8.30/kg, respectively.[176] These cost estimates have been superseded by the DOE 2023 cost estimates that include the IRA's clean hydrogen production tax credit (PTC) discussed in the following section.

However, even prior to the BIL and IRA, studies estimated that an increase in hydrogen utilization rates from 20 to 80 percent can reduce distribution costs by up to 70 percent.[177] Additionally, for non-transport applications, the delivered low-GHG hydrogen costs could drop by up to 90 percent as the supply chain is expanded. The cost of low-GHG hydrogen production using renewable energy inputs could drop by 60 percent as the renewable energy generation costs decrease.

Technology innovation in the research stage could have a significant impact on future hydrogen systems as well. For example, engineers at RMIT University of Australia have employed sound waves to produce hydrogen via electrolysis more efficiently. The electrical output of electrolysis was about 14 times greater than electrolysis without sound waves and could potentially result in net-positive energy savings of 27 percent.[178] Additionally, researchers at Rice University in

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170 Sánchez-Bastardo, N., Schlögl, R., Ruland, H. (2021). *Methane Pyrolysis for Zero-Emission Hydrogen Production: A Potential Bridge Technology from Fossil Fuels to a Renewable and Sustainable Hydrogen Economy.* Ind. Eng. Chem. Res. 2021, 60, 32, 11855-11881. https://doi.org/10.1021/acs.iecr.1c01679.

171 Zapantis, A. (2021). *Blue Hydrogen.* Accessed at https://www.globalccsinstitute.com/wp-content/uploads/2021/04/Circular-Carbon-Economy-series-Blue-Hydrogen.pdf.

172 U.S. Department of Energy (2020). *Hydrogen Strategy – Enabling A Low-Carbon Economy*. Accessed at https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf.

173 Costs represent median prices of hydrogen.

174 Christensen, A. (2020). *Assessment of Hydrogen Production Costs from Electrolysis: United States and Europe*. Accessed at https://theicct.org/wp-content/uploads/2021/06/final_icct2020_assessment_of-_hydrogen_production_costs-v2.pdf.

175 U.S. Department of Energy (2020). *Hydrogen Strategy – Enabling A Low-Carbon Economy*. Accessed at https://www.energy.gov/sites/prod/files/2020/07/f76/USDOE_FE_Hydrogen_Strategy_July2020.pdf.

176 Ochu, E., Braverman, S., Smith, G., & Friedmann, J. (2021). *Hydrogen Fact Sheet: Production of Low-Carbon Hydrogen*. Accessed at https://www.energypolicy.columbia.edu/research/article/hydrogen-fact-sheet-production-low-carbon-hydrogen#_edn5.

177 Hydrogen Council (2020). *Path to hydrogen competitiveness – A cost perspective*. Accessed at https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.

178 Deena, T. (2022). *Engineers use sound waves to boost green hydrogen production by 14 times.* December 14, 2022. Accessed at https://interestingengineering.com/innovation/sound-waves-boost-green-hydrogen-production.

Texas developed a method to replace iridium with ruthenium, a much more abundant and less expensive material, in an electrolysis anode catalyst.[179]

Increasing the availability of low-cost, low-GHG hydrogen is the aim of regional initiatives as well. For example, the HyDeal initiative in Los Angeles is anticipated to deliver low-GHG hydrogen for less than $2/kg by 2030. This initiative brings together the entire value chain across the LA Basin, including production, transport, storage, and multi-sectoral aggregated offtake. The investment into the different facets involved in hydrogen production and delivery through HyDeal over the next 10 years is expected to represent one-quarter of the business as usual infrastructure spending for Southern California gas and electric utilities over the same time period.[180] Another prediction—again, before the BIL and IRA—estimated that under ideal conditions, by 2040, the delivered cost of hydrogen, which includes production, storage, and pipeline costs, can be less than $2/kg in several major cities. The transportation and storage costs are generally approximately $0.50/kg in those scenarios.[181]

Bipartisan Infrastructure Law (BIL)In November 2021, Congress provided support for "clean hydrogen" in the BIL. The law defined clean hydrogen as "hydrogen produced with a carbon intensity equal to or less than 2 kilograms of carbon dioxide-equivalent produced at the site of production per kilogram of hydrogen produced." The DOE released draft guidance of its "Clean Hydrogen Production Standard" (CHPS) for public comment in 2022, which proposed setting a target for well-to-gate[182] emissions of 4 kg CO_2e/kg H_2 in hydrogen production.[183]

As part of the BIL, a Federal investment is being made into domestic hydrogen infrastructure.[184] For example, the DOE is launching an $8 billion program for developing clean hydrogen hubs (H2Hubs) across America. The intent of H2Hubs is to create a network of hydrogen producers, consumers, and resilient infrastructure to integrate hydrogen into regional economies. Hydrogen production within these hubs can be powered by fossil fuels with CCS, nuclear, or renewable energy, and the DOE must distribute funds for at least four hubs by 2026. Additionally, the BIL authorized $1 billion for the Clean Hydrogen Electrolysis Program to reduce the cost of producing clean hydrogen to less than $2/kg by 2026 and $500 million for Clean Hydrogen Manufacturing and Recycling Initiatives to support hydrogen-related equipment manufacturing

[179] Williams, M. (2022). Rice lab advances water-splitting catalysts. Rice News. Rice University. Accessed at https://news.rice.edu/news/2022/rice-lab-advances-water-splitting-catalysts.

[180] Green Hydrogen Coalition (n.d.). *HyDeal Los Angeles*. Accessed at https://static1.squarespace.com/static/5e8961cdcbb9c05d73b3f9c4/t/6179eb9cf8ac24238842374d/1635380127410/HyDeal+LA+Phase+1+Takeaways.pdf.

[181] Energy + Environmental Economics (2020). *Hydrogen Opportunities in a Low-Carbon Future – An Assessment of Long-Term Market Potential In the Western United States*. June 2020. https://www.ethree.com/wp-content/uploads/2020/07/E3_MHPS_Hydrogen-in-the-West-Report_Final_June2020.pdf.

[182] The well-to-gate analysis represents a subset of the cradle to grave analysis. The energy and emission associated with the manufacturing and recycling of the hydrogen production facility and the energy facilities used to power the hydrogen production facility are not considered.

[183] DOE (n.d.). *U.S. Department of Energy Clean Hydrogen Production Standard (CHPS) Draft Guidance*. Accessed at https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-production-standard.pdf.

[184] The White House (2021). *President Biden's Bipartisan Infrastructure Law*. https://www.whitehouse.gov/bipartisan-infrastructure-law/.

and build supply chains.[185] Ultimately, the goal is to drive down the cost of hydrogen production and transportation and to produce more hydrogen with clean energy.

The DOE also has a "Hydrogen Shot" initiative with the goal of reducing the cost of clean hydrogen to $1 per kilogram within a decade (without consideration of the PTC). This will require innovation and investments in electrolysis technology using solar, wind, and nuclear energy.[186, 187] Reducing the costs of low-GHG hydrogen is a factor driving the DOE's strategic goal for 10 MMT of domestic clean hydrogen to be produced annually by 2030 followed by 20 MMT and 50 MMT by 2040 and 2050, respectively. In fact, announcements of hydrogen projects to date would result in production of 12MMT by 2030, exceeding DOE's goal by 20%.[188] As part of the DOE's strategic goal, several key production targets are outlined with many including electrolysis. [189] Some of these targets include:

- 1.25 MW of electrolyzers integrated with nuclear energy for hydrogen production from 2022-2023;
- 10 or more demonstrations of renewable, nuclear, and/or waste/fossil fuels with CCS being used to produce hydrogen from 2024-2028;
- low-temperature electrolyzers with 51 kWh/kg efficiency, 80,000-hour life, and $250/kW from 2024-2028;
- high-temperature electrolyzers with 44 kWh/kg efficiency, 60,000-hour life, and $300/kW from 2024-2028;
- 20 MW of nuclear heat extraction, distribution, and control for electrolysis from 2024-2028;
- low-temperature electrolyzers with 46 kWh/kg efficiency, 80,000-hour life, and $100/kW uninstalled cost between 2029-2036; and
- high-temperature electrolyzers with 80,000-hour life and $200/kW cost while maintaining or improving efficiency between 2029-2036.

Inflation Reduction Act of 2022

The IRA was signed into law in 2022 and created a new production tax credit (PTC) for qualified hydrogen under Internal Revenue Code (IRC) section 45V. Specifically, the new 10-year PTC provides tiered tax credits dependent on the well-to-gate GHG emissions of hydrogen production methods. At most, facilities can receive $3.00/kg H_2, and the smallest tax credit available is

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185 DOE (2022). *DOE National Clean Hydrogen Strategy and Roadmap*. Draft - September 2022. Accessed at https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf.

186 U.S. Department of Energy (DOE) (2022). *DOE Launches Bipartisan Infrastructure Law's $8 Billion Program for Clean Hydrogen Hubs Across U.S.* Accessed at https://www.energy.gov/articles/doe-launches-bipartisan-infrastructure-laws-8-billion-program-clean-hydrogen-hubs-across.

187 The 2021 Bipartisan Infrastructure Law aligns with DOE's Hydrogen Shot goal by directing the department to work to reduce the cost of clean hydrogen to $2/kg by 2026. This goal is part of the $9.5 billion in funding for research, development, and demonstration of clean hydrogen technologies and the creation of at least four regional clean hydrogen hubs. Significant projects in the U.S. include the Green Hydrogen Coalition's HyDeal Los Angeles (https://www.ghcoalition.org/hydeal-la) and the HY STOR project in Mississippi (https://hystorenergy.com/).

188 DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023 See: https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf

189 DOE (2022). *DOE National Clean Hydrogen Strategy and Roadmap*. Draft - September 2022. Accessed at https://www.hydrogen.energy.gov/pdfs/clean-hydrogen-strategy-roadmap.pdf.

$0.60/kg H_2, assuming prevailing wage and apprenticeship requirements are satisfied. The IRA stipulates that GHG emissions for consideration under this provision are estimated by the Greenhouse gases, Regulated emissions, and Energy use in Transportation model (GREET). Eligible projects for the hydrogen PTC can receive direct pay in lieu of a tax credit for a period of time and credit transferability is also allowed, increasing the net value and fungibility of the tax credits. Figure 7 outlines the tax credits that can be claimed for different tiers of estimated GHG emissions from hydrogen production. Note that IRA projects have stipulations regarding prevailing wage and apprenticeship requirements to obtain these maximum credit values.

Carbon Intensity (CO_2e/kg H_2)	**Max Hydrogen PTC Credit ($/kg H_2)**	**Carbon Intensity (lb CO_2e/MMBtu)**	**Applicable Percentage of 45V Credit**
0 - 0.45	$3.00	0 – 7	100%
0.45 - 1.5	$1.00	7 – 25	33.4%
1.5 - 2.5	$0.75	25 – 41	25%
2.5 – 4.0	$0.60	41 – 66	20%

Figure 74: Hydrogen Production Tax Credit Tiers by GHG Emissions in the Inflation Reduction Act

Additionally, the IRA expanded incentives for carbon capture and storage through 45Q tax credits. To qualify, power generation facilities, industrial facilities, and direct air capture (DAC) facilities must capture 18,750, 12,500, and 1,000 tonnes, of CO_2 annually, respectively. Additionally, power generation facilities must have a capture efficiency of no less than 75 percent to qualify. Tax credits differ depending on whether the captured carbon was stored or utilized and whether it is an industrial, power generation, or DAC facility.[190] Note that all qualifying projects must commence construction by 2033, and these tax credits may not be stacked with other tax credits.[183] Figure 8 outlines the tax credits for the varying scenarios.

Facility Type	**Storage ($/tonne)**	**Utilization ($/tonne)**
Industrial Facilities	85	60
Power Generation Facilities	85	60
DAC Facilities	180	130

Figure 85: IRA Carbon Capture Tax Credits ($/tonne) by Facility Type and Utilization/Storage Scenarios[191]

Lastly, the IRA explicitly expands IRC section 48 tax credits to include hydrogen fuel cells as an Energy Storage Technology with nameplate capacity of 5 kWh or greater. The tax credits expire in December 2024 and transition to a fuel-neutral tax credit of up to 30 percent, including for

[190] Clean Air Task Force (CATF) (2022). *Carbon Capture Provisions in the Inflation Reduction Act of 2022*. Accessed at https://cdn.catf.us/wp-content/uploads/2022/08/19102026/carbon-capture-provisions-ira.pdf.
[191] Clean Air Task Force (CATF) (2022). *Carbon Capture Provisions in the Inflation Reduction Act of 2022*. Accessed at https://cdn.catf.us/wp-content/uploads/2022/08/19102026/carbon-capture-provisions-ira.pdf.

energy storage technologies such as hydrogen storage. Note that the IRA does not stipulate the emissions profile for hydrogen-based energy storage for tax credit eligibility.[192]

The impact of the IRA on hydrogen production and consumption is expected to be significant, as discussed in the next section.

<u>Cost Estimates Accounting for Provisions in the Inflation Reduction Act</u>

Several factors are driving down the cost projections for low-GHG hydrogen. A major determinant of the costs for hydrogen produced via electrolysis is the cost of renewable electricity. However, the investment in renewable energy technologies is driving down the cost of renewable electricity and of hydrogen produced via electrolysis. Other factors expected to reduce the cost of electrolysis include increased electrolyzer module sizes, increasing stack production to automated production, alternative electrolyzer configurations with less costly materials, electrolysis system optimizations, and increased electrolyzer lifetimes.[193] In addition, the IRA production tax incentive of up to \$3/kg for clean hydrogen production is an important driver of cost reduction.

Some estimates of the impact that the tax credits provided by the IRA will have on hydrogen production have compared low-cost and high-cost technological scenarios for hydrogen production via solar electrolysis and compared prices for current policy and IRA scenarios. These estimates assumed, for both options, that the IRA will result in a price that is lower by \$3/kg H_2. This results in hydrogen production prices of between \$0.39-\$1.92/kg H_2 for low-cost and high-cost hydrogen production technology, respectively.[194]

Other estimates place the levelized cost of hydrogen production in 2030 without the PTC between \$1.60/kg and \$1.80/kg. Costs for hydrogen qualifying for the \$3/kg credit tax credit Tier, fall to between \$0.40-\$0.85/kg.[195] For hydrogen production via electrolysis using renewable energy inputs, multiple incentives can be applied. Accounting for the full value chain, including compression, storage, and distribution, the delivered cost of electrolytic hydrogen in 2030 is expected to range from \$0.70/kg to \$1.15/kg.[196] Levelized hydrogen production costs are projected to fall an additional 20 percent by 2040 for PEM electrolyzers and an additional 12 percent for alkaline electrolyzers from 2030 levels.

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[192] Clean Air Task Force (CATF) (2022). *Carbon Capture Provisions in the Inflation Reduction Act of 2022*. Accessed at https://cdn.catf.us/wp-content/uploads/2022/08/19102026/carbon-capture-provisions-ira.pdf.

[193] International Renewable Energy Agency (IRENA) (2020). *Green Hydrogen Cost Reduction – Scaling Up Electrolysers to Meet the 1.5ºC Climate Goal*. Accessed at https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf.

[194] Larsen, J., King, B., Kolus, H., Dasari, N., Hiltbrand, G., & Herndon, W. (2022). *A Turning Point for US Climate Progress: Assessing the Climate and Clean Energy Provisions in the Inflation Reduction Act*. August 12, 2022. Accessed at https://rhg.com/research/climate-clean-energy-inflation-reduction-act/.

[195] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023 See: https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf

[196] DOE Pathways to Commercial Liftoff: Clean Hydrogen, March 2023 See: https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf

Other estimates anticipate that costs for low-GHG hydrogen eligible for the IRA tax credits could approach negative net production costs.[197] In addition, recent analysis by S&P Global Community Insights estimates that the tax credits and subsidies included in the IRA could drive the net production cost of low-GHG hydrogen to less than $0/kg by 2030.[198] Clean electricity tax credits of 2.75 cents/kWh can be combined with the IRC section 45V clean hydrogen production tax credits, and in qualifying cases can also earn domestic content and energy community bonuses of 10 percent each. If these subsidies lower the cost of low-GHG hydrogen below approximately $1.00/kg, the net production costs will be less than the cost of hydrogen produced via SMR without CCS. Credits for projects placed in service in 2032 will be eligible to receive credits for 10 years thereafter. Projects that begin construction in or by 2032 will also be eligible to receive these incentives, though the U.S. Department of the Treasury safe harbor rules for the allowable duration of construction have yet to be established. The primary reason for the low-GHG hydrogen cost advantage is that tax credits available for other production methods under the IRA cannot be stacked. S&P Global predicts this will drive additional investments in the renewable energy sources necessary to produce low-GHG hydrogen, and in many instances, these renewable energy sources will be dedicated to powering electrolyzers. DOE estimates that delivered costs of hydrogen in the power sector in 2030 will be between $0.70/kg and $1.15/kg[199].

US-REGEN Model

The U.S. Regional Economy, Greenhouse Gas, and Energy Model (US-REGEN) is an energy-economy model developed and maintained by the Electric Power Research Institute (EPRI) that includes an explicit representation of hydrogen production.[200] US-REGEN includes current projected future capital costs, fixed costs, variable costs, and efficiency information for multiple hydrogen production technologies. The EPA amortized the capital costs over 10 years for PEM electrolyzer and 12 years for the coal gasification and SMR with CCS at a 7 percent interest rate,[201] used a natural gas price of $3.69/MMBtu, a coal price of $1.88/MMBtu, and an electricity price of $20/MWh to estimate the production costs of hydrogen. The EPA also applied the $3/kg H_2 production tax credit for the PEM electrolyzer, $0.7/kg H_2 CCS tax credit for the SMR, and $1.3/kg H_2 CCS tax credit for the coal gasification.[202] The EPA calculated the

[197] Bowen, I., Madan, D., Rajwani, L., & Muthiah, S. (2022). *How clean energy economics can benefit from the biggest climate law in US history*. Accessed at https://www.icf.com/insights/energy/clean-energy-economic-benefits-US-climate-law.

[198] Mulder, B. (2022). *US green hydrogen costs to reach sub-zero under IRA; longer-term price impacts remain uncertain*. Accessed at https://www.spglobal.com/commodityinsights/en/market-insights/latest-news/energy-transition/092922-us-green-hydrogen-costs-to-reach-sub-zero-under-ira-longer-term-price-impacts-remain-uncertain.

[199] U.S. Department of Energy (DOE). (2023). Pathways to Commercial Liftoff: Clean Hydrogen. Accessed at https://liftoff.energy.gov/wp-content/uploads/2023/03/20230320-Liftoff-Clean-H2-vPUB-0329-update.pdf.

[200] https://us-regen-docs.epri.com/v2021a/assumptions/hydrogen-production.html#technology-cost-and-performance.

[201] The EPA amortized the capital costs over the number of years of the hydrogen production cand carbon storage tax credits.

[202] The carbon storage credit assumes 8 kg of CO_2 and 15 kg of CO_2 are captured from the SMR and coal gasification facilities respectively.

hydrogen production costs assuming a 40 percent, 60 percent, and 90 percent capacity factor for the PEM electrolyzer and 90 percent capacity factors for the SMR and coal gasification processes. Figure 9 shows the estimated hydrogen production costs.[203]

Technology	**Year**			
	2025	**2030**	**2035**	**2040**
PEM (distributed. 40%)	2.0	0.9	0.3	(0.2)
PEM (distributed. 60%)	1.1	0.4	0.0	(0.3)
PEM (distributed. 90%)	0.0	(0.5)	(0.8)	(1.1)
SMR+99% CCS	1.4	1.4	1.4	1.4
Coal+90% CCS	0.6	0.6	0.5	0.5

**Negative values are shown in parenthetical.*

Figure 96: Hydrogen Production Costs with IRA 45V and 45Q tax credits($/kg)

Coal gasification and SMR with CCS have similar hydrogen costs of $2.2/kg H_2 without considering available tax credits. Since coal gasification with CCS captures larger amounts of CO_2 than SMR, the tax credit has a greater impact on coal gasification and results in hydrogen production costs of less than $1/kg. At high capacity factors, the hydrogen production tax credit result in PEM derived hydrogen powered by zero GHG emitting energy at potentially negative production costs in 2030 and later years.

International Hydrogen Use

Hydrogen interest and utilization have been growing internationally. In 2021, global hydrogen demand reached 94 MMT, which was a 5 percent increase from 2020. Of the global hydrogen production, low-emission production accounted for less than 1 percent of the total production; however, the share of low-emission production grew by 9 percent from 2020-2021 and is projected to continue to increase. More than 200 MW of electrolyzers began operation in 2021, with 160 MW in China and 30 MW in Europe.[204]

Note that hydrogen production is expected to grow as governments and industry increase interest and investments in the sector. Globally, 26 governments have committed a hydrogen strategy to their energy system plans, with nine of those governments adopting a strategy within the past year. Global hydrogen targets include deploying an additional 145-190 GW of electrolyzer-produced hydrogen capacity. Based on global interest in hydrogen, it has been estimated that hydrogen demand could reach 115 MMT by 2030; however, 130 MMT is needed to meet existing climate pledges in place by governments across the globe.[205,206]

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[203] These costs are form the REGEN model and are different than cost estimates from the DOE liftoff report.
[204] IEA (2022). *Hydrogen*. Tracking Report – September 2022. Accessed at https://www.iea.org/reports/hydrogen.
[205] IEA (2022). *Hydrogen*. Tracking Report – September 2022. Accessed at https://www.iea.org/reports/hydrogen.
[206] IEA (2022). *Global Hydrogen Review 2022 – Executive Summary*. Accessed at https://www.iea.org/reports/global-hydrogen-review-2022/executive-summary.