NATIONAL PETROLEUM COUNCIL

Report

Harnessing Hydrogen

A Key Element of the U.S. Energy Future

April 23, 2024

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Chapter 2 - Production at Scale

NATIONAL PETROLEUM COUNCIL

Harnessing Hydrogen: A Key Element of the U.S. Energy Future

Chapter 2: Production At-Scale

April 23, 2024

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TABLE OF CONTENTS

I. OVERVIEW

Low carbon intensity (LCI) hydrogen will be essential to achieving net zero in the United States by 2050. In the U.S. 95% of hydrogen production is from fossil fuels, and fossil fuels in general account for around 80% of the U.S. energy mix. Modeling conducted for this study projects annual carbon dioxide emissions of 2,300 million metric tons (MMT) in 2050 for a National Petroleum Council (NPC) "Stated Policies" scenario incorporating current state and federal policies, including the Inflation Reduction Act (IRA) (2022). According to the Modeling conducted as part of this study, LCI hydrogen (LCI H_2) could account for 8% of the emissions reductions under the Net Zero by 2050 (NZ2050) scenario.

This chapter will explain how the production of LCI H_2 depends on different factors that vary by region. The regionality aspects of hydrogen production are not new, but the factors of influence are changing, driven by a desire to meet net zero by 2050.

This study will focus on two general types of production methods to supply the ~75 million metric tons per annum (MMTpa) needed for market demand by 2050. These technologies are fossil fuel reforming and electrolysis. It will also discuss nascent technologies that are currently not commercially ready to be considered at scale or that need additional research development and demonstration (RD&D) to make them technologically ready.

As of 2021, the U.S. Department of Energy (DOE) reports that 99% of the 11 MMTpa of U.S. hydrogen production is unabated hydrogen and 1% is from electrolyzers.[1]

This chapter content is divided into six sections:

- Section II provides an overview of the existing hydrogen production and pipeline landscape, the case for centralized vs. distributed production and how the market could develop regionally in the future.
- Section III discusses the phases of LCI H_2 production, what number and scale of different LCI H_2 production will be required for NZ2050.
- Section IV provides an overview of different LCI H_2 production technologies, both natural gas-based with carbon capture and electrolyzers, as well as other complementary technologies.
- Section V provides the levelized cost of LCI H_2 and carbon intensities for the different production pathways on a regional basis while highlighting regions that possess attractive production, demand, and natural resource elements.
- Section VI discusses several factors that influence LCI H_2 production buildout, including policy, manufacturing impacts, renewables availability, LCI H_2, potential resource limitations and permitting.

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[1] Fuel Cell and Hydrogen Energy Association, "Road Map to a U.S. Hydrogen Economy," Fuel Cell and Hydrogen Energy Association, Washington, DC, 2020; https://www.fchea.org/us-hydrogen-study

- Section VII discusses societal considerations and impacts associated with the buildout of LCI H_2.

Note: The study presents forecasts based on modeling, leveraging Massachusetts Institute of Technology USREP and SESAME modeling platforms and sensitivity analyses conducted outside these platforms. The modeling efforts leveraged two scenarios to provide insights: 1) a Stated Policies scenario calibrated to the International Energy Agency (IEA) World Energy Outlook (WEO) 2022 Stated Policies scenario and 2) a U.S. Net Zero by 2050 (NZ2050) scenario calibrated to the IEA WEO 2022 Announced Pledges Scenario, which for the U.S. is set to achieve a policy objective of net zero emissions by 2050. The goal of the modeling was to project how the U.S. economy could most cost effectively meet the emissions reduction trajectory adopted for each scenario. The results are a product of the methodology and inputs adopted to meet this objective. In particular, a shadow price on carbon was used as a proxy for unspecified policies that would produce the imposed emissions reduction over time, which drove adoption of low-carbon technologies including hydrogen. Therefore, projected costs for renewables and traditional energy sources, like natural gas, do not align with current market dynamics. While these choices were informed by existing literature and refined by study participant expertise, they retain levels of uncertainty that translate to uncertainty in the outputs, including for future costs, carbon intensities, and technology adoption rates for hydrogen and other energy options, as well as for U.S. macroeconomic and emissions trajectories. The modeling made simplifying assumptions, including exclusion of some technologies, and did not consider all possible constraints. The report addresses these considerations in the narrative. Details on the modeling approach, assumptions, and quantitative input parameters are available in Appendix X: Modeling Methodology. The collective modeling efforts may be referred to as "the Model" or "the MIT model" or "the NPC model."

FINDING: *Hydrogen production will be mainly driven by the industrial sector, which has the highest demand for LCI H_2. However, other sectors that are difficult to decarbonize, such as transportation and power, also need to be addressed by the scale-up of LCI hydrogen production. The location of hydrogen production, the distance to the end users, and the shift from conventional to low-emissions production methods are key factors that affect the technology selection and cost of hydrogen production.*

FINDING: *The LCI H_2 market in the United States has entered the Activation phase, aided by recent legislation such as the IRA and Infrastructure Investment and Jobs Act (IIJA), and is poised to increase LCI hydrogen production in advantaged regions (those regions with abundant wind and solar and/or those with generous quantities of natural gas and attractive geology for carbon capture and storage (CCS)). LCI hydrogen production is a strategic opportunity for the United States to leverage its natural resources and technological capabilities to contribute to the global transition to a low-carbon future. The United States has several advantages in producing hydrogen, such as abundant and low-cost natural gas, access to renewable energy resources, and experience with CCS. The United States can produce LCI hydrogen from both fossil* *fuels (via CCS) and renewables competitively and reliably. This study has also identified likely locations for hydrogen production centers and export hubs based on resource availability, infrastructure, and market access. The United States can support its domestic decarbonization ambitions by leveraging export opportunities through developing transportation and storage technologies and collaborating with international partners and customers. By investing in LCI hydrogen production, the United States can position itself as a leader in the emerging global hydrogen economy.*

FINDING: *The LCI hydrogen supply mix will be driven by speed to scale, reduction in cost, and carbon intensity (CI) of various hydrogen pathways. Hydrogen from natural gas reforming with CCS and hydrogen from electrolysis using renewable electricity are the main options for LCI hydrogen production. (LCI hydrogen that is produced from electrolysis via renewable energy is abbreviated RE* H_2*.) The speed to scale for both methods depends on factors such as the availability and cost of natural gas with carbon capture and renewable energy, as well as the technological maturity and efficiency of the processes. Some constraints to overcome include reducing the capital and operational costs of electrolyzers and CCS systems, ensuring sufficient supply and transport of natural gas and carbon dioxide, and increasing the reliability and flexibility of renewable power sources. These variables can change over time due to market dynamics, policy interventions, and technological innovations. Therefore, the optimal mix of hydrogen production methods to achieve the lowest cost and the highest carbon abatement will also vary over time, depending on the evolution of these variables.*

FINDING: *A large cost gap exists between incumbents and LCI hydrogen in hard-to-abate applications. Technology advancement will continue to support closing the cost gap; however, current federal and state policies, as well as modeled system cost reduction, will not be sufficient to close the cost gap to parity by 2050. LCI hydrogen production is essential for the LCI hydrogen value chain, as it influences hydrogen's price, supply, and sustainability. However, hydrogen production faces many challenges to replace incumbent fuels, such as the variability of renewable power sources, the limited manufacturing capacity of the equipment suppliers, the long lead time for engineering, constructing, and building large-scale facilities, the huge amount of renewable power needed to produce hydrogen, and the need for large-scale storage infrastructure to balance supply and demand.*

FINDING: *The U.S. hydrogen production policy landscape is complex and dynamic and requires careful analysis and coordination to ensure the best outcomes for LCI hydrogen production. The IRA and IIJA (described in detail in Chapter 6: Policy) support hydrogen production development in regions with favorable conditions, such as abundant natural gas, renewable energy, or CCS potential. These policies aim to create the availability of an LCI hydrogen supply by reducing its cost and emissions and fostering innovation and collaboration in the hydrogen sector. However, these policies have some limitations that could affect the optimal deployment of hydrogen production. For example, the IRA provides tax credits for hydrogen production from low-carbon sources, but only for projects that begin construction before January 1, 2033. The IIJA also authorizes $8 billion for hydrogen demonstration projects, but only $1 billion is* *available for fiscal year 2023, and the rest is subject to annual appropriations by Congress putting at risk the goal of achieving the United States' net zero goal in 2050. While the IRA has been helpful for initiating interest in LCI hydrogen production, clarifications to the IRA will be required. Furthermore, to enable the cost reductions and scale necessary to meet the NZ2050 ambition, funding support is needed in the very early stages of the journey. Full details on policies impacting hydrogen production and the hydrogen supply chain are found in Chapter 6: Policy.*

FINDING: *Permitting for new hydrogen production is both complex and lengthy. This process involves complying with various environmental laws and regulations that aim to protect the air and water quality, such as the Clean Air Act (CAA) and the Clean Water Act (CWA). These laws and regulations control the emissions and discharges of pollutants from hydrogen production sources and technologies, such as fossil fuels, biomass, and water electrolysis. While the benefits to society of the CAA and the CWA are clear, a streamlined environmental permitting process would accelerate the deployment of LCI hydrogen. By producing LCI hydrogen, we can improve the public health and environment of the communities impacted by hydrogen production through enhanced community engagement practices and clear communication of long-standing safety standards and practices to ensure the safe and reliable operation of hydrogen production facilities.*

FINDING: *The lack of a prioritized investment roadmap for technology is a hindrance to further levelized cost of hydrogen (LCOH) reduction and a reliable LCI hydrogen value chain. A priority should be to target technology development to reduce the cost of electrolytic hydrogen through lower-cost and more accessible alternative inputs and components for electrolyzers. Continued focus on RD&D is needed to increase the size of electrolyzer stacks and support scale-up of "gigafactories." The standardization and modularization of electrolyzer components could reduce electrolytic hydrogen plants' installation and operation costs. Additionally, for natural gas with carbon capture routes, alternative catalysts, pyrolysis, and carbon capture advancements all merit further development.*

FINDING: *Without long-term sourcing and supply of critical materials, a robust and resilient LCI hydrogen value chain may not materialize. Approaching at-scale deployment of LCI hydrogen in the U.S. will require considerable deployment of many critical technologies along the LCI H_2 value chain at a massive scale. The current challenges of sourcing critical minerals and essential supplies for manufacturing critical equipment (e.g., fuel cell, electrolyzer) could hinder the development of the LCI hydrogen value chain. For example, platinum and iridium catalyst materials make up less than 10% of the cost of a Proton Exchange Membrane (PEM) electrolyzer, but the cost is likely to increase with higher demand and these materials could become a supply bottleneck.[2] A series of potential actions, with consideration for key material recycling, could ensure a robust and resilient value chain for critical equipment and*

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2. IRENA (2020), Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5ºC Climate Goal, International Renewable Energy Agency, Abu Dhabi.

could be addressed within the federal and state levels, thus mitigating risk to private investors and unlocking capital:

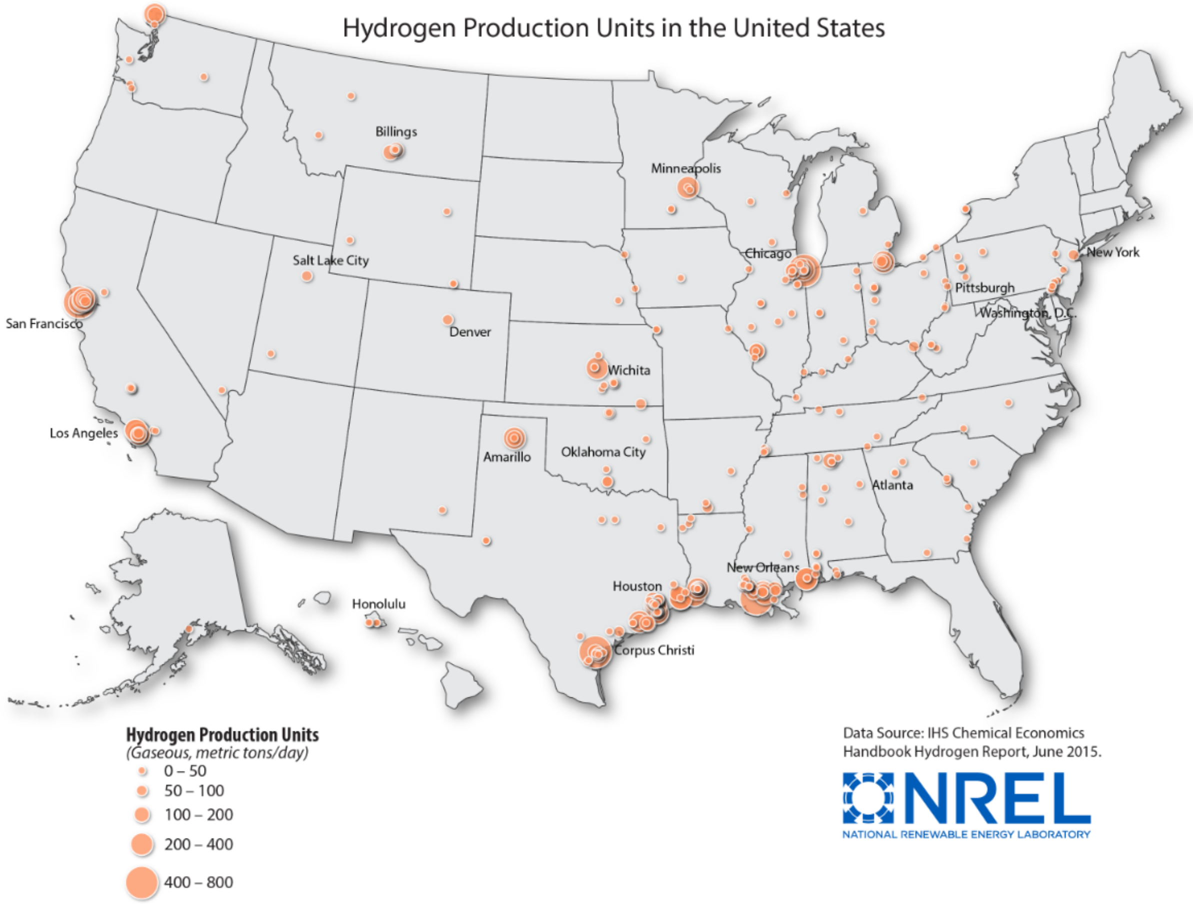
- ***Identifying vulnerable elements** within the hydrogen production and utilization value chain that could create supply-related challenges (e.g., essential supplies for electrolyzer manufacturing)*
- ***Fostering research** to replace difficult-to-source materials (e.g., critical metals) with those more readily available domestically or through stable international sources*
- ***Assistance with the development and deployment** of alternative materials and methods to prepare for the potential risk of supply disruptions (e.g., natural disasters)*
- ***Coordinated and strategic procurement of** rare materials (e.g., platinum, iridium) essential for different types of fuel cells and electrolyzers in consultation with companies that already make regular bulk purchases or have existing long-term agreements is crucial for maintaining stable markets and prices. Furthermore, any onshoring efforts within the LCI hydrogen value chain should adhere to responsible sourcing commitments as part of the Activation phase.*

II. REGIONAL HYDROGEN SUPPLY OUTLOOK

A. Current Production of Hydrogen

Presently, hydrogen serves as a crucial component in the chemical and petroleum refining sectors, primarily utilized as a raw material for industrial processes rather than as an energy carrier. In the chemical industry, its principal role lies in serving as a feedstock for methanol and ammonia production, the latter for fertilizer manufacturing. Meanwhile, in petroleum refining, hydrogen finds application in reducing the sulfur content of liquid fuels through a process known as hydrotreating.

The overall magnitude of hydrogen supply and demand, inclusive of hydrogen generated as an intermediate stage in ammonia production (via the Haber-Bosch process), stands at approximately 10 MMT of hydrogen or roughly 1.1 quadrillion British thermal units (quad Btu) in energy terms for the year 2020. This hydrogen production is almost entirely derived from the reforming of natural gas through steam methane reformers. As shown below in Figure 2-1, a disproportionate percentage of large-scale steam methane reforming (SMR) plants are concentrated in the Gulf Coast region, where there is a large industrial base for refining, petrochemical, and chemical manufacturing. The Gulf Coast region also has almost 1,600 miles of hydrogen pipeline connecting hydrogen production plants to demand centers. As illustrated, hydrogen production exists in California and certain other regions of the United States primarily linked to refining and petrochemical processes. However, these areas do not constitute significant production centers when compared to the Gulf Coast region, which traditionally enjoys the advantage of a low-cost natural gas supply and mature infrastructure pipeline networks.



Source: National Renewable Energy Laboratory (NREL), November 16, 2021, "The Potential of Hydrogen in a Decarbonized Future"

Figure 2-1. U.S. Hydrogen Production

Dependence on natural gas means that hydrogen production generates CO_2 emissions: ~10 tons of CO_2 per ton of H_2 (tCO_2e/tH_2) on a well-to-gate basis.[3] At this intensity, the 11 MMT of H_2 produced annually equates to ~100 MMT of CO_2e emissions (~1.6% of overall CO_2 emissions). Traditionally, these emissions did not require CCS, but many existing SMR facilities are now considering retrofits with bolt-on CO_2 capture systems to minimize CO_2 emissions. One facility in Port Arthur has led the industry for LCI H_2 by retrofitting two steam methane reformers. Through 2017, this facility has captured and sequestered >4 MMT of CO_2 since

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[3] Sun, P., Elgowainy, A., Updates of Hydrogen Production from SMR Process in GREET, 2019, Argonne National Laboratory

operation in 2013.[4] Additional details on carbon capture and sequestration can be found in the NPC's CCS study.

B. Central vs. Distributed Production

When evaluating hydrogen production pathways, careful consideration of the trade-offs between centralized and distributed production systems is essential, as each approach brings its advantages and challenges that can significantly impact efficiency, cost-effectiveness, and scalability. By examining the trade-offs between centralized and distributed hydrogen production, we gain valuable insights into each approach's contrasting advantages and challenges.

Centralized hydrogen production, facilitated through large-scale manufacturing facilities strategically located in resource-rich or strategically positioned regions, leverages economies of scale to optimize production processes and resource utilization. This approach offers the advantage of streamlined operations, resulting in efficient resource deployment and substantial cost savings. This concentration of production activities also facilitates centralized monitoring and control, enhancing quality assurance and safety protocols. Moreover, these facilities stand poised to harness advanced technologies and innovative approaches, leading to heightened production efficiency and reduced environmental impact.

Distributed hydrogen production involves the establishment of smaller-scale production units in proximity to end users or demand centers, offering distinct advantages that align with evolving energy needs. This approach aligns well with contemporary energy trends, offering advantages such as reduced transmission losses, enhanced energy resilience, and potential integration with renewable energy sources. At the same time, the flexibility of smaller-scale units enables rapid deployment and scaling based on local demand fluctuations. Furthermore, the distributed production approach can capitalize on locally available renewable energy sources by strategically locating production units near consumption points, potentially reducing dependence on centralized infrastructure, enhancing energy security, and mitigating disruptions. However, distributed production also poses challenges. A more extensive infrastructure network, including storage and distribution systems, is required to ensure a reliable hydrogen supply to end users. Coordinating multiple smaller-scale production units may present logistical complexities, and providing consistent quality control across distributed facilities can be more challenging than centralized production. Furthermore, distributed production may face scalability constraints, making it more suitable for certain localized applications rather than large-scale industrial needs. Also, smaller distributed hydrogen systems will likely be more expensive than larger scale central systems, although incentives such as the 45V credit may offset those higher costs.

To determine the optimal production approach, it is essential to consider various factors, including the specific application requirements, available resources, infrastructure capabilities, and demand clustering. In some cases, a hybrid approach that combines centralized and distributed production elements may be the most effective solution. This allows for leveraging the benefits of economies of scale while maintaining localized production capabilities to cater to

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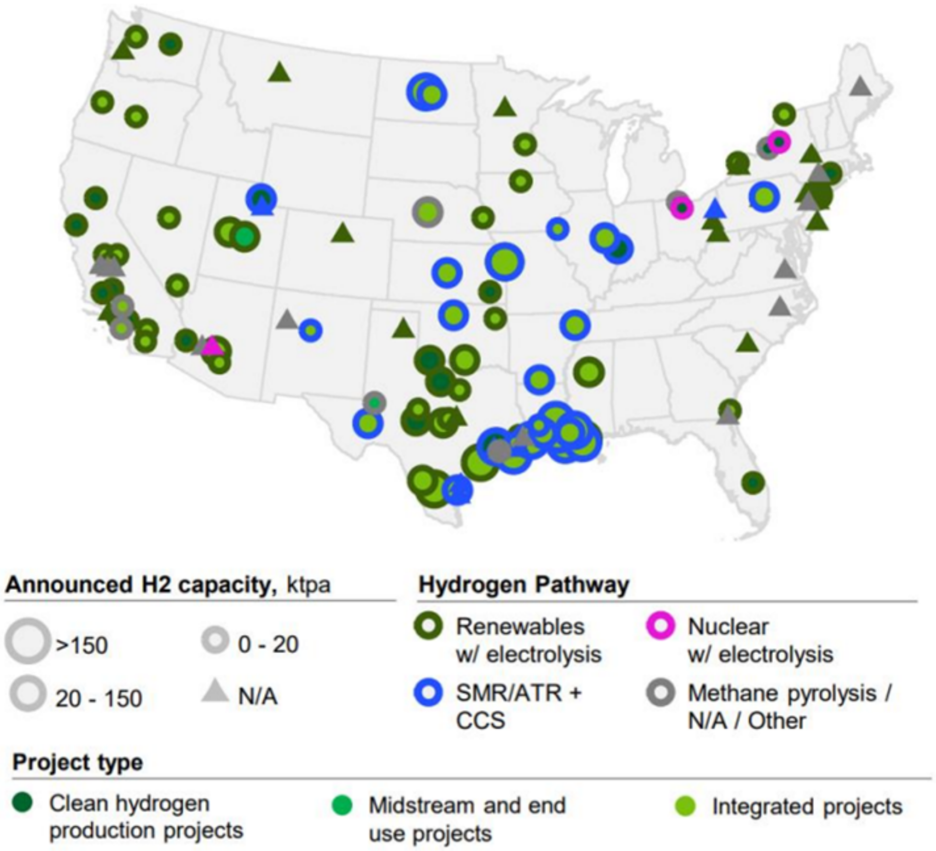
[4] 2018-05 The CCS Project at Air Products' Port Arthur Hydrogen Production Facility.pdf

specific needs and enhance energy resilience. The end-use impact on which production approach is optimal can be illustrated by comparing low carbon intensity transportation and refining applications. In the nascent hydrogen transportation market, distributed production enables redundant supply nodes and reducing transportation and storage costs while reducing the scale of investment required while demand develops. In refining applications, centralized production enables reliable delivery of a large quantity of LCI H_2 at the lowest unit cost, which improves the margin on the final product.

C. Future Regionality

The announcement of the IRA and the updated 45Q Carbon Sequestration Tax Credit provisions have catalyzed an industry push to transition from unabated hydrogen to LCI H_2. Many refineries and petrochemicals plants are actively exploring adoption of LCI H_2, both for existing and new plants with carbon capture rates of more than 90%. Based on publicly available information, several large-scale projects have also been announced on the Gulf Coast to meet domestic and international demand of LCI H_2. As the pace of these announced projects continues to increase, many states are pursuing LCI H_2 projects through production and end use at the national level. More recently, DOE's National Clean Hydrogen Strategy and Roadmap compiled a list of all announced low carbon intensity projects across the nation (see Figure 2-2). If all announced projects proceed through to final investment, construction, and commissioning by 2030, these projects will create LCI H_2 supply of 12 MMTpa, surpassing the DOE goal of additional 10 MMTpa LCI H_2. However, many of these projects await a final investment decision as project developers are in the process of securing long-term creditworthy offtake contracts.



Source: DOE, 2023, https://www.hydrogen.energy.gov/library/roadmaps-vision/clean-hydrogen-strategy-roadmap

Figure 2-2. Announced LCI H_2 Projects

As the LCI H_2 market develops, there are many uncertainties and scenarios in estimating future supply. Our study compares two scenarios of hydrogen production in the U.S.: a Stated Policies scenario and an NZ2050 scenario. The Stated Policies scenario assumes a moderate growth of hydrogen demand and supply, while the NZ2050 scenario assumes a faster growth of hydrogen demand and supply, driven by more aggressive policies and investments. We use a technoeconomic Model to estimate the cost and carbon footprint of hydrogen production in both scenarios, as well as the optimal mix of natural gas with CCS and electrolysis using renewable energy. While small nuclear reactors could bring additional benefits to reliable, sustainable power, it also comes with many challenges and an unclear path to commercialization. As such, the Modeling only included renewable power from wind and solar.

Figure 2-3 shows the total hydrogen production from natural gas-derived LCI H_2 and renewable electricity based LCI H_2 for both scenarios from 2030 to 2050. As shown, the hydrogen production in the U.S. increases markedly in both scenarios, from 11 MMTpa in 2020 to about ~20 MMTpa per year in 2050 in the Stated Policies scenario, and to ~75 MMTpa in the NZ2050 scenario.

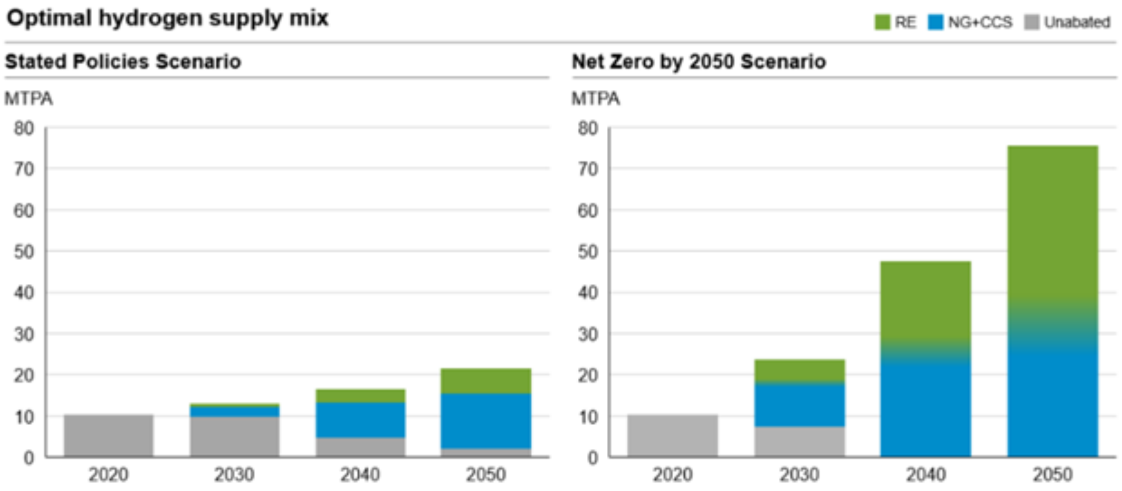


Figure 2-3. Contribution of LCI H_2 for Two Scenarios: Stated Policy and the NZ2050 Scenario

For the Stated Policies scenario by 2030, there is a modest increase in LCI H_2 by 2 MMTpa (compared to 2020) for industrial use, primarily supplied by natural gas-derived LCI H_2. For the years 2040 and 2050, H_2 supply is projected to increase significantly, reaching up to 18 and 22 MMTpa, respectively. Much of this increase is due to contributions from LCI H_2, with an increasing portion of renewable H_2 as more renewable infrastructure is expected to develop. By 2050, under the Stated Policies scenario, unabated H_2 contribution to total supply is reduced drastically (<3 MMTpa) but not eliminated. Under the Stated Policies scenario, natural gas-derived LCI H_2 kick-starts production and continues to dominate the supply mix throughout the year 2050 with electrolytic H_2 playing a much more significant role in the year 2040 and beyond.

For the NZ2050 scenario, LCI H_2 plays a key role, as a decarbonization energy vector, in driving the scenario's target. As a result, hydrogen demand increases sharply to ~75 MMTpa when compared to 22 MMTpa as in the Stated Policies scenario for 2050. While the supply of natural gas-derived LCI H_2 dominates throughout the next decade, this scenario accelerates the market share of electrolytic H_2 - increasing more than 15-fold, from ~3 MMTpa in 2030 to 45 MMTpa in 2050. As shown, electrolytic H_2 is expected to dominate the supply in the later stages, but natural gas-derived LCI H_2 still plays a significant role in the NZ2050 scenario, accounting for 30-35% of the total supply in 2050.

Figure 2-4 shows regional production distribution of LCI H_2 for the NZ2050 scenario in 2030 and 2050. As shown, the Gulf Coast consistently leads in supply for both scenarios, with the West Coast region following closely. For 2030, under the NZ2050 scenario, the Gulf Coast's supply is primarily driven by natural gas-reformed LCI H_2, while the West Coast's supply is predominantly from renewable H_2. Each of these regions possess distinct characteristics, resulting in a unique production mix for 2030.The West region has a high potential for renewable hydrogen production from wind and solar energy, as well as a strong policy support and incentive for LCI H_2 development, especially in California. The Gulf Coast region has abundant natural gas supply and CO_2 storage, as well as high-quality renewable resources, with concentrated regional high demand for LCI H_2, especially in Texas and Louisiana. By 2050, driven by the NZ2050 ambition, RE H_2 contribution to the supply mix significantly increases across all regions, with the most significant increase coming from the Gulf Coast.

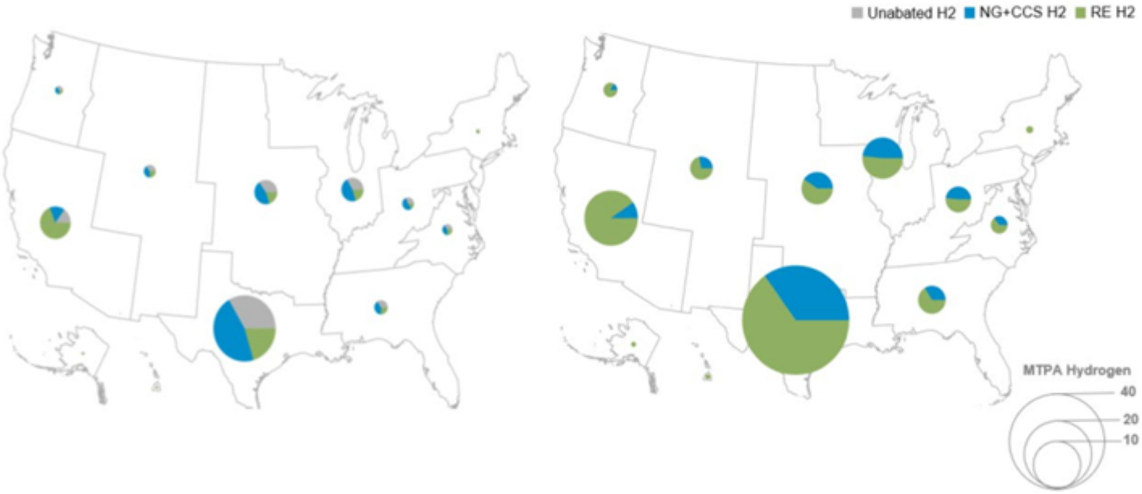


Figure 2-4. Outlook of Regional Supply Development by Hydrogen Type in 2030 and 2050 Under NZ2050 Scenarios

III. PHASES AND MARKET DEVELOPMENT

Hydrogen production is the first step in the hydrogen supply chain. It is important to recognize that the journey toward large-scale hydrogen production is a long-term endeavor that requires collaboration, innovation, and commitment from various stakeholders. A concerted effort involving policy support, technological innovation, infrastructure buildout, financial backing, and collaborative initiatives is essential for establishing a robust market for LCI H_2 and achieving broader decarbonization goals. In this study, LCI H_2 deployment at scale under the NZ2050 scenario is described in three phases: Activation, Expansion, and At-Scale. The volume of LCI H_2 needed in the NZ2050 scenario will require growing U.S. LCI H_2 production through multiple production pathways.

As described in Chapter 5: Demand, industrial customers could lead the adoption of LCI H_2 in the Activation phase and form the foundation of new demand. As such, large-scale production of LCI H_2 will likely first rely on production from the NG+CCS pathways enabled by CCS advancement and retrofitting of existing steam methane reformers to add CCS. The NG+CCS pathway in this phase is driven by the production characteristics of NG+CCS hydrogen's ability to rapidly scale-up near term costs and infrastructure advantages.

In the Activation phase, implementing effective CCS technologies is crucial for retrofitting conventional hydrogen production to low carbon intensity pathways. CCS allows for capturing and storing carbon emissions from hydrogen production, thus reducing the carbon footprint associated with conventional hydrogen. Successful pilot projects and demonstrations of retrofitting natural gas hydrogen production to add CCS can showcase the economic and sustainable viability of the transition. These demonstrations, supported by the DOE Hydrogen Hub funding, federal and state tax credits, and subsidy/grant programs can instill confidence in industrial customers and encourage further adoption of LCI H_2 production methods that will lead the market into an Expansion phase.

In the Expansion phase, large-scale development of renewables and cost reductions in RE H_2, along with construction of hydrogen storage and connective infrastructure, will be needed to support the NZ2050 scenario. NG+CCS hydrogen will continue to provide LCI H_2 at low costs, but the CI of the hydrogen will need to start being offset through negative carbon technologies such as Direct Air Capture (DAC). In this phase, developing and commercializing LCI H_2 production technologies are critical. This includes advancements in electrolysis, and emerging technologies that enable the decarbonization of hydrogen production processes.

In the At-Scale phase, scaling LCI H_2 will require massive infrastructure buildout as well as strong policy support and financial incentives. As we near 2050, the net zero ambition will drive production to be more electrolyzer based powered by renewable electricity sources. DAC will also play a role as the means to mitigate the remaining carbon not captured.

A. Capacity Implications

In the NZ2050 scenario, deployment of ~75 MMTpa of LCI H_2 will be needed to meet the hydrogen demand in 2050, with 50 MMTpa supplied by electrolysis. Reaching this scale of LCI H_2 production will require a significant increase in production capacity. Currently, the U.S. hydrogen demand and production are approximately 11 MMTpa, which is largely comprised of unabated hydrogen. Scaling hydrogen production to meet the increase in demand and transition to LCI H_2 will require massive buildout of the relevant facilities and infrastructure and extensive growth in capacity.

The increase of demand in the NZ2050 scenario will require monumental investments in production, equating to approximately 100 world scale (250+ million standard cubic feet per day (mmscfd) of H_2) natural gas-based facilities and to meet the electrolytic hydrogen production rates projected under the NZ2050 scenario (~7 MMTpa in 2030 increasing to ~50 MMTpa in 2050), installed electrolysis capacity has to grow from less than 1 GW today to about 65 GW in 2030 to nearly 400 GW by 2050, with annual capacity additions of 12 to 18 GW per year over that period. In order to supply sufficient renewable energy to run these electrolyzers at a capacity factor in the 60-65% range, a renewable overbuild ratio of 1.5 to 2.6 is needed (depending on the region, averaging 1.8), so the required renewable resource capacity is over 700 GW by 2050, with annual capacity additions of 22 to 33 GW over that period. As a reference, the state of Texas, which has one of the highest renewable grid capacities, is currently only at ~40-45 GW of renewable capacity.

Current natural gas hydrogen production units can produce 250 mmscfd of hydrogen, which is about 200,000 MMTpa hydrogen, and is operational virtually 24/7 at 100% capacity compared to electrolyzer production, which operates at a lower capacity factor if intermittent renewable resources are used as the input. Electrolyzers will only produce RE H_2 when there is enough electricity available from nuclear or renewable energy sources such as wind, solar, hydro, etc., which may vary depending on the weather and the demand. The dependence of electrolyzer production on renewable energy reduces its operational capacity, due to the availability of renewable energy sources. As an example, if an electrolyzer is only operating at a 60% capacity due to the availability of renewable energy, the RE H_2 produced will only be 60% of its maximum possible output. In this case, to reach the production output to meet the demand, additional electrolyzers are needed.

To meet the NZ2050 ambition, more RE electrolyzer LCI H_2 production will be needed at significantly larger scale than exists today. Currently, there are no GW-scale electrolyzers in operation, with the largest size operating unit reported to be 250 MW.[5] To achieve the hydrogen production levels modeled in the NZ2050 scenario much larger systems will be needed.

Electrolyzers only produce LCI H_2 when there is electricity available from nuclear or renewable energy sources such as wind, solar, hydro, etc. Powering electrolyzers using variable sources, particularly wind and solar, means the electrolyzers will operate at less than nameplate capacity. For example, a combination of wind and solar may only provide enough electricity to operate the electrolyzer at 60% of full load, on average, over the course of a year (i.e., annual capacity factor of 60%). In that case, more electrolysis capacity is needed to produce a target amount of hydrogen. For example, a capacity factor of 60% means 1.67x more nameplate electrolysis capacity is needed to make the same amount of hydrogen—and 1.67x the capex.

As discussed below in this chapter, Modeling by MIT projected capacity factors for renewable-powered electrolyzers based on regional wind and solar resource potential (hydro or nuclear energy were not modeled). Capacity factors in the low to mid-60% range were obtained by optimizing the wind/solar mix and overbuilding the electricity generation capacity relative to electrolysis capacity. Storing excess renewable electricity in batteries, while feasible, was not found to be cost-effective. This type of Modeling was extended to include infrastructure supply chain elements (hydrogen storage and pipelines), with results presented in Chapter 4: Integrated Supply Chain.

While there are many types of electrolyzers, their current production capacities are similar. For example, the largest single stand-alone Proton Exchange Membrane (PEM) electrolyzer manufactured in 2023 is 20 MW[6] and can produce 3,000 tons/year of H_2 at a 100% capacity factor. The largest, single solid oxide electrolyzer operating in 2023 is the Bloom Energy 4 MW unit in California.[7] The largest single alkaline stack is 10 MW.[8] The current maximum size of an electrolyzer facility is 250 MW, production 20,000 MT of RE H_2 per year from solar power.[9]

CCS enabled natural gas-based LCI H_2 production benefits from economies of scale in a way that electrolytic LCI H_2 production does not. The analogy being a natural gas power plant

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[5] http://www.sinopecgroup.com/group/en/Sinopecnews/20230704/news_20230704_299217593563.shtml

[6] https://www.airliquide.com/group/press-releases-news/2021-01-26/air-liquide-inaugurates-worlds-largest-low-carbon-hydrogen-membrane-based-production-unit-canada

[7] https://newsroom.bloomenergy.com/news/bloom-energy-demonstrates-hydrogen-production-with-the-worlds-largest-and-most-efficient-solid-oxide-electrolyzer

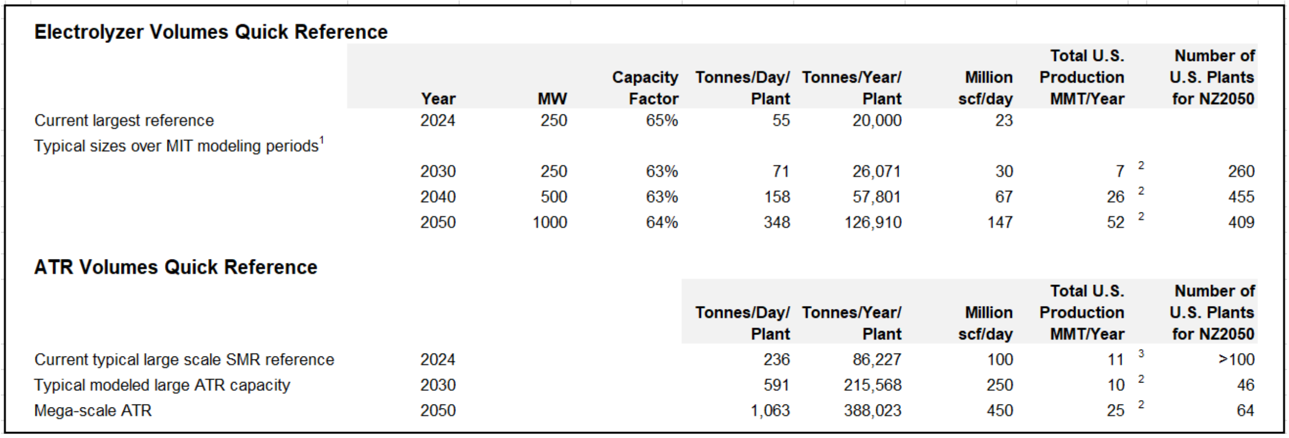
[8] https://www.internationales-verkehrswesen.de/worlds-largest-single-stack-alkaline-water-electrolysis-system/

[9] https://www.hydrogeninsight.com/production/exclusive-worlds-largest-green-hydrogen-project-has-major-problems-due-to-its-chinese-electrolysers-bnef/2-1-1566679

vs. a solar facility. A result of this difference in technology is that CCS enabled LCI H_2 can scale its way to economic viability in a way that electrolytic cannot and thus technology advancement is even more critical in electrolytic production if it is to be a meaningful contributor to the volumes of LCI H_2 needed in either scenario.

It should be recognized that, to attain the additional hydrogen production, a tremendous increase in manufacturing and construction capabilities will be required. Moreover, there are also very large-scale existing hydrogen facilities, which will require significant capital investment from hydrogen producers and their suppliers to add carbon capture to their unabated hydrogen production. A comparison of the production technologies volume, scale, and an estimated number of units for each technology needed in the NZ2050 case is shown in Table 2-1 below.

Table 2-1. Scale of Hydrogen Production Units and Approximate Number of Units for NZ2050 Scenario



Electrolyzer Volumes Quick Reference

	Year	MW	Capacity Factor	Tonnes/Day/ Plant	Tonnes/Year/ Plant	Million scf/day	Total U.S. Production MMT/Year	Number of U.S. Plants for NZ2050
Current largest reference	2024	250	65%	55	20,000	23		
Typical sizes over MIT modeling periods[1]								
	2030	250	63%	71	26,071	30	7 [2]	260
	2040	500	63%	158	57,801	67	26 [2]	455
	2050	1000	64%	348	126,910	147	52 [2]	409

ATR Volumes Quick Reference

		Tonnes/Day/ Plant	Tonnes/Year/ Plant	Million scf/day	Total U.S. Production MMT/Year	Number of U.S. Plants for NZ2050
Current typical large scale SMR reference	2024	236	86,227	100	11 [3]	>100
Typical modeled large ATR capacity	2030	591	215,568	250	10 [2]	46
Mega-scale ATR	2050	1,063	388,023	450	25 [2]	64

1: Using MIT modeled efficiencies, capacity factors, and total US annual production
2: MIT modeled annual production in net zero scenario
3: Current U.S. production

IV. PRODUCTION TECHNOLOGIES FOR LCI HYDROGEN

Hydrogen has been manufactured in the United States for many decades, mainly for the refining and chemicals markets. In 2020, it was estimated that approximately 11 MMT of hydrogen was produced annually with more than 95% of it being made via unabated manufacturing processes (i.e., without carbon capture). To reach our net zero goals in 2050, we need to transform our manufacturing to have a low carbon intensity, and we can achieve this through several processes.

Making hydrogen requires energy. Although hydrogen is the universe's most abundant element, its presence as pure hydrogen (natural hydrogen) on Earth remains limited due to its high reactivity. Extracting hydrogen from other substances requires energy.

This study focuses on examining two primary methods of hydrogen production:

- **Natural gas reforming with carbon capture:** Natural gas (or other fossil fuels) can be reacted with steam at high temperatures over a catalyst to produce mostly hydrogen and carbon monoxide ("syngas"). Through the "water-gas shift" reaction, syngas is further reacted with additional steam to produce a mixture of hydrogen and CO_2. The principal technologies for producing syngas, and thus hydrogen, from natural gas are SMR, autothermal reforming (ATR), and partial oxidation (PO_x). These technologies all produce unabated hydrogen and must be combined with CCS to qualify as LCI H_2. By integrating CCS, the resulting carbon emissions from natural gas reforming can be significantly reduced, and the captured carbon can be stored underground or used in various industries. The Modeling estimates that natural gas reforming coupled with CCS would have an emissions intensity of ~2 kg of CO_2e per kg of H_2 in 2030, marking a substantial reduction from ~10 kg of CO_2e per kg of H_2 for unabated hydrogen (see Figure 2-18 later in this chapter) Further reductions in CI can be achieved by incorporating levers such as LCI natural gas (i.e., differentiated natural gas), renewable natural gas, or maximizing plant efficiency (e.g., steam exports). While biogas utilization can lead to net negative LCI H_2, when used as a feed to a reforming plant with CCS, its scalability for widespread adoption is limited due to the restricted availability of biogas volumes.
- **Electrolysis of water:** The second primary pathway is electrolysis where water or steam is split into hydrogen and oxygen. Electrolysis, while not inherently carbon-free if power is provided from conventional grid electricity, has the potential for significant decarbonization if powered primarily by zero-emissions renewable sources like solar, wind, hydro, or nuclear energy. Also, small modular nuclear reactors, which produce high-temperature steam could improve electrolysis efficiencies.

A. Hydrogen Production from Natural Gas

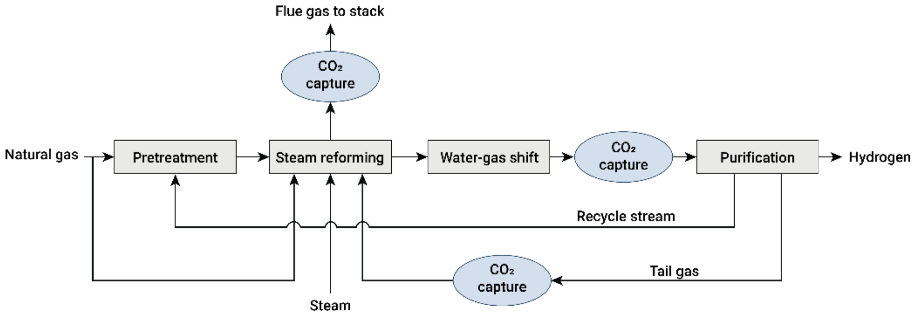
Natural gas reforming remains the most developed technology for hydrogen production. Fossil fuels remain the predominant source in hydrogen-driven production, partly because production costs are strongly associated with the cost of natural gas, which has remained globally competitive and with broad supply availability. The principal technologies for producing syngas from natural gas: SMR, involves using only steam and is an endothermic process; ATR involves using both O_2 and steam; and natural gas PO_x involves only using O_2, producing syngas (H_2 and CO) and is an exothermic process. These technologies all produce unabated hydrogen and must be combined with CCS to produce LCI H_2. While all of the natural gas-based hydrogen production technologies provided below include carbon capture as an essential step in the process of producing LCI H_2, the various technologies for such are not described herein as they were investigated and presented in the NPC Report: *Meeting the Dual Challenge, A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage*, *Volume III, Chapter 5 – Carbon Capture*.

To produce hydrogen from natural gas, the process involves separating hydrogen atoms from carbon atoms in methane, converting it into syngas, a mixture of hydrogen and carbon monoxide. This syngas is further processed to obtain pure hydrogen. Utilizing natural gas reforming with CCS significantly reduces carbon emissions compared to conventional methods, as it captures and stores the generated carbon dioxide underground, mitigating its climate impact.

This established technology offers a reliable, cost-effective, and low-carbon source of hydrogen, addressing challenges like intermittent and scalability associated with renewable electricity and electrolysis. Positioned as the early at-scale solution, natural gas reforming with CCS can allow industries to lower emissions and transition toward a low-carbon economy. Continued research and investment in diverse low-carbon pathways are crucial for achieving a sustainable, fully decarbonized hydrogen economy.

1. Steam Methane Reforming with Carbon Capture and Storage

Steam methane reforming occurs at high temperatures with a catalyst to convert the hydrocarbons and steam into H_2 and other gases. The SMR process can be best described as having three phases and is depicted in Figure 2-5. First, natural gas and steam react together with a catalyst to produce hydrogen, carbon monoxide, and carbon dioxide. Next, steam and carbon monoxide react together with a catalyst to produce carbon dioxide and more hydrogen, this is known as the water-gas shift reaction. Third, hydrogen is purified through pressure swing adsorption where the carbon dioxide and other impurities are removed.



Source: Air Liquide, 2024
Note: A Steam Methane Reforming plant (SMR) consists of a Natural Gas Process Feedstock Hydrogenation and Desulfurization, Pre-reformer (may not always be required), Steam Methane Reforming Section, Process Gas Boiler and High-Temperature CO Shift Reactor, Flue Gas Waste Heat Recovery System, Shift Gas Cooling Section, Pressure Swing Adsorption (PSA) System, Internal Plant Steam System.

Figure 2-5. Steam Methane Reforming (SMR) Plant Schematic

Feedgas Pretreatment: Natural gas feedstock from the unit battery limit is preheated. Hydrogen is required for hydrogenation of sulfur components. The installation of a hydrogen-desulfurization stage is necessary to remove sulfur traces, such as hydrogen sulfide and odorizing agents from the natural gas to protect the downstream steam reforming catalyst from sulfur poisoning. Organic sulfur is totally converted to hydrogen sulfide in a catalyst bed of the Hydrogenation Reactor. Hydrogen sulfide is adsorbed on zinc oxide by conversion of zinc oxide

(ZnO) to zinc sulfide (ZnS). Feed gas leaving the ZnO beds will have a residual sulfur content of less than 0.1 ppmv. This enhances the lifetime of the downstream reforming catalyst.

Desulfurization Reaction

$ZnO + H_2S \longrightarrow ZnS + H_2O$

The feedstock is converted through an endothermic reaction (requires heat) along the tube axis into reformed gas, which contains H_2, CO, CO_2, N_2 unconverted CH_4, along with nondecomposed steam.

Steam reforming of methane:

$CH_4 + H_2O + \text{Heat} \Leftrightarrow CO + 3\ H_2$

$CH_4 + 2H_2O + \text{Heat} \Leftrightarrow CO_2 + 4\ H_2$

Additional hydrogen is created through the exothermic (releases heat) water-gas shift reaction.

Water-gas shift reaction:

$CO + H_2O <=> CO_2 + H_2 + \text{Heat}$

The CO Shift reaction is exothermic. The CO content at the outlet of the high-temperature CO Shift reactor is approximately 3 to 4.5 mol-% (dry). The remaining undesired components are removed with the molecular sieves using a PSA process and are sent to the reformer as a PSA Tail Gas fuel stream.

Prior to entering the PSA, the shifted gas is cooled in the shift gas cooling section by heating other process streams for heat integration. Process water condensate is separated and sent to the deaerator where it is recycled as boiler feedwater (BFW). Cooling water is needed for the hydrogen production process and is designed to be recirculated. An elevated flare will serve as an emissions control device for routine process operation emissions, including startup, shutdown, and maintenance operations. The flare also serves as a safety control device in the event of an upset or overpressurization. As a standard process operation, some flaring of hydrogen may occur when PSA vessels are regenerated.

2. Autothermal Reforming with Carbon Capture and Storage

Autothermal Reforming (ATR) is a process for producing syngas, composed of hydrogen, carbon monoxide, and carbon dioxide, and, when combined with CO Shift and CCS technology, is one of the most cost-effective solutions to produce LCI H_2 at scale due to its scalability and competitive efficiency.

It combines partial oxidation and steam methane reforming in a single reactor, where oxygen, steam, and methane react to produce a hydrogen-rich gas (syngas), carbon dioxide, and water with such facility being referred to as an autothermal reforming reactor as depicted in Figure 2-6.

Autothermal reforming is an important process for hydrogen production as it offers higher efficiency and lower greenhouse gas (GHG) emissions than conventional SMR. The feedstock for the process is typically a mixture of methane (CH_4) and steam (H_2O). Oxygen (O_2) is also introduced into the reactor to enable the partial oxidation reaction. The ATR reactor is a high-temperature catalytic reactor that facilitates the reactions between methane, oxygen, and steam. A typical ATR reactor consists of an upper section for partial oxidation of the methane with oxygen and a lower section with a catalyst bed to react to the methane and water. In the partial oxidation reaction, a controlled amount of oxygen reacts with methane to produce carbon monoxide (CO) and hydrogen (H_2) through partial oxidation:

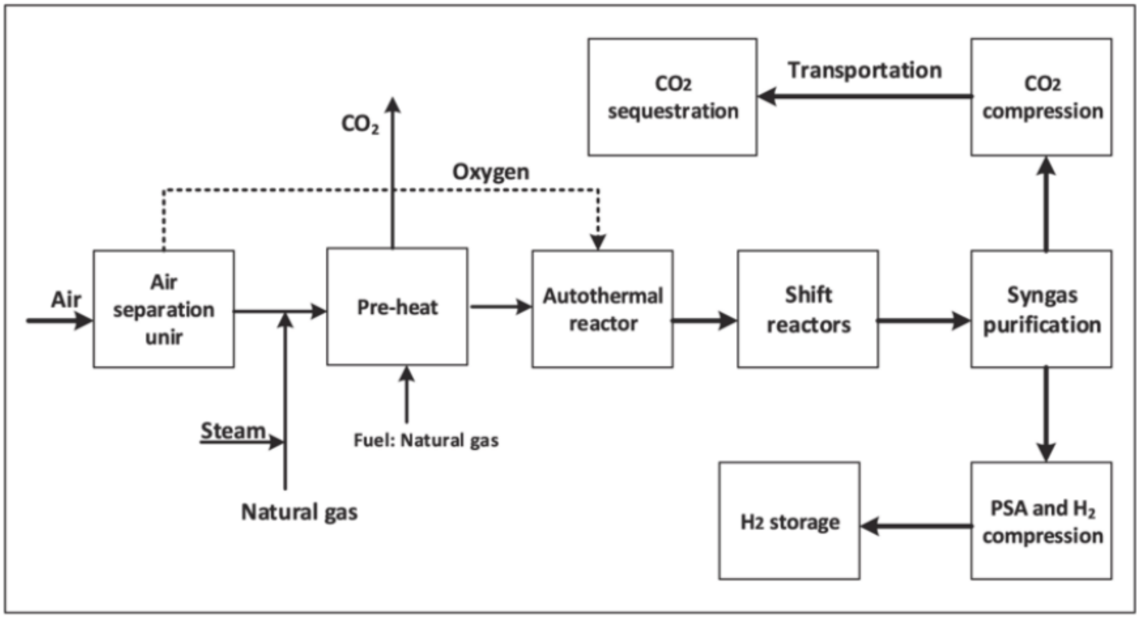
$$CH_4 + \tfrac{1}{2} O_2 \rightarrow CO + 2H_2$$

The steam reacts with the remaining methane reforming it to produce additional hydrogen and carbon monoxide:

$$CH_4 + H_2O \rightarrow CO + 3H_2$$

The partial oxidation reaction is exothermic, while the steam methane reforming is endothermic. Proper heat management is crucial to simultaneously maintain the optimal temperature for both reactions and is primarily achieved with control of the O_2 flow to the reactor. The ATR process aims to reach an equilibrium point where the partial oxidation and SMR reactions occur efficiently, resulting in a high hydrogen yield and reduced production of unwanted byproducts. After the reforming process, the resulting gas contains hydrogen, carbon dioxide, water vapor, and unreacted methane. Gas separation processes are employed to separate and purify the hydrogen gas, ensuring high purity.

$$CH_4 + H_2O + O_2 \text{ --> ATR Reactor --> syngas } (H_2 + CO) + CO_2 + H_2O$$



Simplified process flow diagram of autothermal reforming with a carbon capture and storage (ATR-CCS) plant.

Source: Oni et al., 2022, "Comparative assessment of blue hydrogen from steam methane reforming, autothermal reforming, and natural gas decomposition technologies for natural gas-producing regions"
Note: An ATR consists of a Natural Gas Process Feedstock Hydrogenation and Desulfurization, Pre-reformer (may not always be required), Air Separation Unit, Autothermal Reactor, Process Gas Boiler and High-Temperature CO Shift Reactor, Shift Gas Cooling Section, Pressure Swing Adsorption System, Internal Plant Steam System.

Figure 2-6. Autothermal Reforming Plant Schematic

3. Partial Oxidation with Carbon Capture

Partial oxidation (PO_x) is a way of making hydrogen gas and other gases, classified as syngas, from methane and other hydrocarbons as depicted in Figure 2-7.[10] Hydrocarbons are molecules with carbon and hydrogen atoms, like natural gas or methane. PO_x does not use a catalyst, which is a material that helps chemical reactions happen faster and more efficiently. While the PO_x reaction itself is uncatalyzed, the generated syngas may undergo catalytic reactions for further processing. PO_x can work with different kinds of hydrocarbons, even if they have some impurities or contaminants.

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[10] https://netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/gasifier-intro
https://www.airproducts.com/applications/syngas-solutions/gaseous-hydrocarbons#:~:text=Chemical%20customers%20around%20the%20world,oxo%2Dchemicals%2C%20polycarbonate
https://netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/oxidation
https://www.mdpi.com/1996-1073/16/6/2916
https://www.sciencedirect.com/science/article/abs/pii/S0360319910017659
https://netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/water-gas-shift

This method uses oxygen to partially oxidize the methane and make syngas. PO_x is very fast and simple, but it produces a syngas with a slightly lower hydrogen to CO ratio than ATR. Additionally, the reaction requires very high temperatures (higher than SMR or ATR).

PO_x has four main steps:

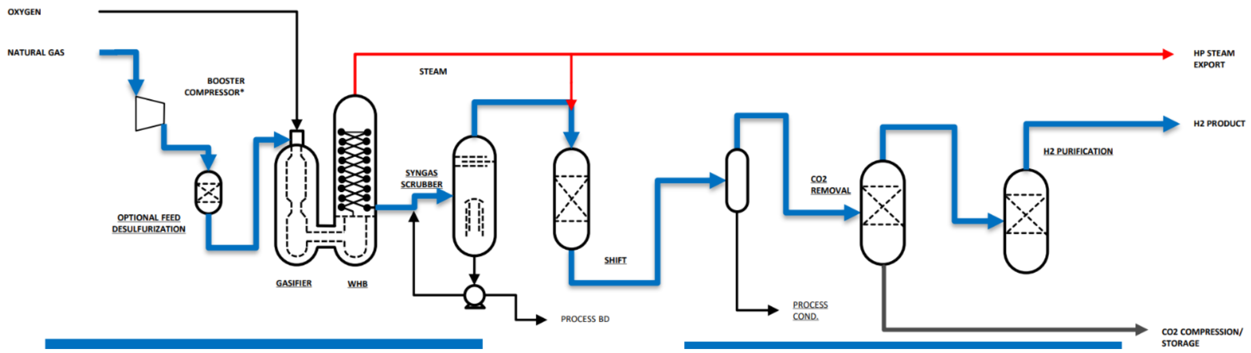
a. Methane and water are heated up before they go into the PO_x reactor. The PO_x reactor is a container that can handle high temperatures and pressure. Oxygen is also added to the reactor. The methane may have some sulfur-containing constituents, which can damage some downstream catalysts. The sulfur can be removed before or after the PO_x reactor, depending on the process.

b. The PO_x reactor makes hydrogen and carbon monoxide, which is later shifted to CO2, from methane and oxygen. This is called the PO_x reaction. The PO_x reaction gives off heat, so it does not need any external energy source to work, which is advantageous. The PO_x reaction also makes a small amount of carbon dioxide. The amount of oxygen is controlled to optimize the amount of hydrogen and carbon monoxide, and to avoid making too much carbon dioxide or burning all the methane. The PO_x reaction also makes a small amount of carbon, which is a black solid. The carbon is removed in a later step.

c. The gas from the POx reactor is cooled down by either making steam or by adding water. The gas then goes through a scrubber, which is a device that removes the carbon and other impurities from the gas. The gas may also need some more water before it goes to the next step. The next step is called the water-gas shift reaction. In this step, water and carbon monoxide react with a catalyst to make more hydrogen and carbon dioxide. The water-gas shift reaction also gives off heat. The chemical equation for the water-gas shift reaction is:

$$CO + H_2O \rightarrow CO_2 + H_2$$

d. The gas from the water-gas shift reaction goes through a carbon capture unit, which is a device that separates the carbon dioxide from the gas. The gas then goes through a PSA unit, which is a device that separates and cleans the hydrogen gas. The PSA unit removes the remaining methane, carbon monoxide, and other impurities from the gas. The final product is nearly pure hydrogen gas.



Source: Sean Yan, 2021, “Air Products POx Technology for Low Carbon Hydrogen Production”

Figure 2-7. Partial Oxidation Process Schematic

B. Natural Gas-Based LCI Hydrogen – Technology Selection

There are reasons for choosing one type of natural gas-based hydrogen production technology over the others.

SMR stands out as the predominant historically prevalent method of hydrogen production. However, as demand escalates and the focus turns to the CI associated with hydrogen production, a strategic shift toward an oxygen-based approach becomes increasingly practical. This pivotal transition aims to avoid the complexities of duplicating technology and typically occurs when a steam methane reformer nears its operational limit, which generally hovers around 220 mmscfd of hydrogen.

As we push for larger quantities of LCI H_2 and the desired hydrogen production surpasses the steam methane reformer’s practical limit of 220 mmscfd, the integration of oxygen into the production process becomes imperative. This strategic decision entails an additional investment in an air separation unit. The underlying rationale to efficiently manage the dual investment requires optimizing the reformers functional capacity. This leads to two primary design approaches: ATR and PO_x.

Ultimately, at the scale of production contemplated in this study, ATR with carbon capture technology was the modeled technology, however, other factors may tip the scales in favor of PO_x vs. ATR. Furthermore, if the hydrogen demand is in a market that is low in industrial density, then SMR technology could be a better economic fit.

1. Natural Gas-Based LCI Hydrogen – Research, Development & Demonstration Opportunities

Steam methane reformers are a mature and widely used technology for hydrogen production, but they also face several challenges and opportunities that need to be addressed to facilitate the transition to LCI H_2 production and consumption. These challenges and opportunities include carbon emissions, efficiency and performance, and feedstock availability and cost, which require further research, development, and innovation to overcome. By addressing these challenges and opportunities, steam methane reformers can contribute to the decarbonization and diversification of the hydrogen sector and the energy system.

Reformers are subject to various losses and inefficiencies that affect their performance and hydrogen output. For example, steam methane reformers require high temperatures (700°C–1,000°C) and pressures (3–25 bar) to operate, which consume a significant amount of energy and reduce the overall efficiency of the process. Moreover, natural gas processes are prone to catalyst deactivation and fouling, which can lower the conversion rate and the selectivity of the reforming reaction. Improving the efficiency and performance of steam methane reformers is crucial to optimize the energy and resource utilization and increase the hydrogen production capacity.

One of the opportunities to improve the efficiency and performance of steam methane reformers is to develop and apply advanced materials, catalysts, and designs that can enhance the reaction kinetics, heat transfer, and mass transfer of the reforming process. For example, research into novel catalysts, such as metal oxides, nanomaterials, or bifunctional catalysts, can increase the activity and stability of the reforming reaction and reduce the energy and pressure requirements.[11]

Diversifying the feedstock sources and reducing the dependence on natural gas are important to ensure the security and affordability of hydrogen production from steam methane reformers. One of the opportunities to diversify the feedstock sources and reduce the dependence on natural gas is to use renewable or low-carbon alternatives, such as biogas, biomethane, or synthetic methane, which can be produced from organic waste, biomass, or renewable electricity. These alternatives can reduce the carbon emissions and the fossil fuel consumption of steam methane reformers, as well as create synergies with other sectors, such as waste management, agriculture, or power generation.[12] However, these alternatives also face several challenges, such as limited availability, high costs, low quality, and technical compatibility that need to be addressed to enable their integration with steam methane reformers.[13]

C. Hydrogen from Water Electrolysis

Water electrolysis involves the splitting of water into hydrogen and oxygen.[14] In this section we describe the main types of electrolyzers on the market today, but there are more under development. They all have a simple reaction in common:

$$2H_2O \rightarrow O_2 + 2H_2$$

The feedstocks for hydrogen production through electrolysis are electrical energy and water. The theoretical amount of water required (from the stoichiometry of the above equation) is 8.9 kg of water for every kilogram of hydrogen. On a volume basis 8.9 liters (2.4 gallons) of water is required theoretically to produce a kg of hydrogen. This is true regardless of electrolyzer technology or electrical efficiency, however the actual amount of water required can be slightly above or several times higher, depending on the amount of water treatment (which usually has a reject stream) required or other process losses. In published specifications from electrolysis

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[11] https://www.degruyter.com/document/doi/10.1515/revce-2020-0038/html
[12] https://www.energy.gov/sites/default/files/2021-09/h2-shot-summit-panel2-methane-pyrolysis.pdf
[13] https://www.energy.gov/sites/default/files/2021-09/h2-shot-summit-panel2-methane-pyrolysis.pdf
14 https://www.electrochem.org/birth-of-electrochemistry

equipment providers, water consumption ranges in liters per kg of hydrogen are 9.5 to 17 for alkaline, 10 to 13 for PEM, and 9.1 to 11 for solid oxide.[15]

The theoretical amount of electrical energy needed to produce 1 kg of hydrogen from liquid water is 32.7 kilowatt-hours (kWh). Production of water from water vapor requires less electrical energy, 31.5 kWh per kg. These theoretical values describe the electrical energy needed to electrolyze water at 25°C. In addition to electrical energy some thermal energy would support the reaction at constant temperature. Electrolysis energy requirements are often compared to hydrogen heating values – the theoretical amount of heat released when hydrogen is burned to produce liquid water (the Higher Heating Value, HHV, of 39 kWh/kg) or water vapor (the Lower Heating Value, LHV, of 33.3 kWh/kg) at 25°C. Electrolysis performance is typically characterized by referring to the actual kWh needed per kg of hydrogen production. It is also sometimes expressed as an efficiency by dividing the LHV or HHV by the actual kWh/kg, which is then expressed as LHV efficiency or HHV efficiency. However the performance is characterized, it is important to state whether the performance is for the electrolysis stack alone, or whether it includes balance of system energy requirements.

The decomposition of water into hydrogen and oxygen is accomplished electrochemically, with the reaction split between two halves of an electrochemical cell. One-half of the cell (the cathode) receives electrons from an external power supply and produces hydrogen while the other half of the cell (the anode) produces oxygen and supplies electrons to complete the power circuit. The circuit of electrons is closed with a transfer of ions from one cell half to the other. The ion involved is the distinguishing characteristic of various electrolysis technologies.

In all commercially available electrolysis systems, the cells are configured into stacks which provide a series electrical connection of what is usually hundreds of individual cells, and which provide liquid and gas flow channels for water input and hydrogen and oxygen output. Figure 2-8 shows a stack of electrolysis cells based on the PEM electrolysis technology.

Electrolysis stacks are used in systems that include equipment for converting AC power to DC power for the stacks and mechanical equipment for handling water, hydrogen, and oxygen gas. These auxiliaries are often referred to as "balance of plant." They consume energy, which is often not included in quoted efficiency values, but which needs to be included in an evaluation of the efficiency of the complete electrolysis system. Electrolyzer balance of plant systems are typically designed to last the economic life of the system with routine maintenance (e.g., on the order of 20 or more years). The actual stack life varies depending on the technology, but is typically less than 20 years, requiring periodic stack replacement as the system operates.

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[15] https://nelhydrogen.com/wp-content/uploads/2020/03/Electrolysers-Brochure-Rev-D.pdf; https://www.sunfire.de/en/hydrogen#content_alkaline; https://www.cummins.com/brochures; https://www.plugpower.com/hydrogen/electrolyzer-hydrogen/electrolyzer-products/; https://nelhydrogen.com/wp-content/uploads/2022/06/High-Purity-Brochure-Rev-J-Single-Pages.pdf; https://www.bloomenergy.com/wp-content/uploads/bloom-energy-electrolyzer-datasheet-june-2023.pdf; https://go.fuelcellenergy.com/hubfs/solid-oxide-electrolyzer-spec-sheet.pdf; https://www.sunfire.de/en/hydrogen#content_soec; https://hydrogen.johncockerill.com/wp-content/uploads/sites/3/2023/04/dq-1000-def-2-hd-en.pdf

Source: Plug Power, Date, website/report

Figure 2-8. Electrolyzer Stack

There are three types of electrolysis systems currently commercially available: alkaline, PEM, and solid oxide. These offer a range of advantages, trade-offs, and maturity levels. Some of the most important features are hydrogen production pressure and electrical efficiency. Table 2-2 provides a summary of performance characteristics for the three types of electrolyzers based on published performance specifications.

Table 2-2. Electrolyzer Performance Characteristics

System	H_2 Supply Pressure, bar(g)	Electrical Efficiency at 30 bar(g)	
		HHV Efficiency	Electrical Energy Use kWh/kg H_2
Alkaline	0 to 30	65% to 76%	52 to 61
PEM	0 to 40	61% to 73%	54 to 64
Solid Oxide	0 to 1	82% to 86%	46 to 48

Notes: Efficiency for electrolyzers below 30 bar(g) adjusted by adding 2.0 kWh/kg compression from 0 to 30 bar(g) and 0.7 kWh/kg compression from 10 to 30 bar(g). All efficiency values are full system efficiencies with water input, with internal steam generation for solid oxide systems. External steam supply can reduce solid oxide energy use from 46 to 38 kWh/kg.
Sources: Alkaline system: https://www.sunfire.de/en/hydrogen#content_alkaline;%20https://www.cummins.com/brochures, https://www.electrochem.org/birth-of-electrochemistry, and Sunfire-Factsheet-HyLink-Alkaline_2023Nov.indd; PEM system: Plug Power, 2022, https://www.cummins.com/brochures; https://www.plugpower.com/hydrogen/electrolyzer-hydrogen/electrolyzer-products/; https://nelhydrogen.com/wp-content/uploads/2022/06/High-Purity-Brochure-Rev-J-Single-Pages.pdf; Solid oxide system: Bloom Energy, 2023, https://www.bloomenergy.com/wp-content/uploads/bloom-energy-electrolyzer-datasheet-june-2023.pdf; https://go.fuelcellenergy.com/hubfs/solid-oxide-electrolyzer-spec-sheet.pdf; https://www.sunfire.de/en/hydrogen#content_soec

Electrolysis systems also offer a wide range of configuration options and have a range of footprint requirements and utility needs. Aspects of system performance, which are not often represented in manufacturers' published specifications, such as stack life, utility requirements, turndown limits, load following ability and cost are key drivers in selecting an electrolyzer technology.

1. Alkaline Electrolysis

Alkaline electrolysis (AWE) is the most mature electrolyzer technology, having been the first to be deployed commercially, with more than 400 systems operating commercially by 1900[16]. In an alkaline electrolyzer, a porous diaphragm immersed in a liquid alkaline solution of either potassium hydroxide (KOH) or sodium hydroxide (NaOH) separates the electrodes. In many applications, the alkaline solution is pumped through the cell stacks. Hydroxyl ions (OH-) are the only species that can diffuse across the porous diaphragm and serve as the charge transfer carriers. The electrolysis cell reactions and basic system components are illustrated in Figure 2-9.

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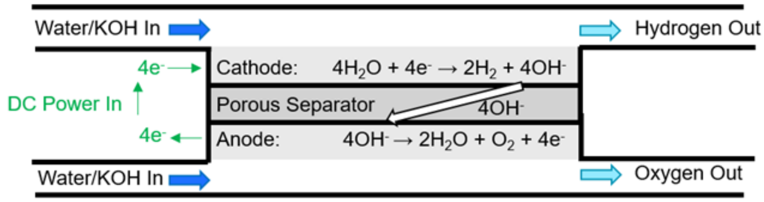
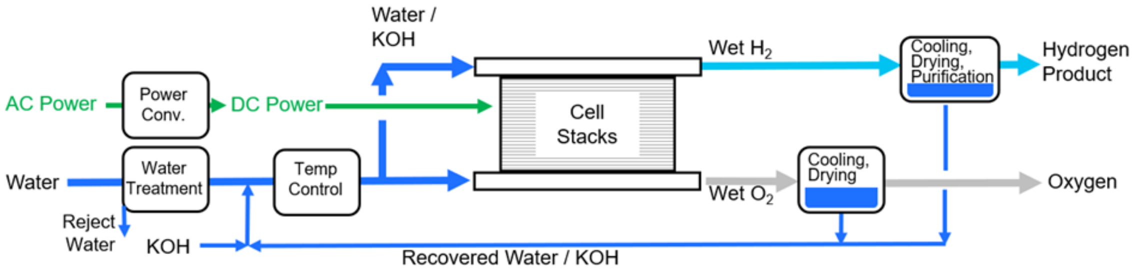
16 The History of Water Electrolysis from its Beginnings to the Present; Smolinka, Tom; Bergmann, Henry; Garche, Jürgen; Kusnezoff, Mihails; https://publica.fraunhofer.de/entities/publication/3f2f1ae4-590c-4b96-b932-63eb27000d6b/details



Alkaline Electrolysis Cell Reactions



Alkaline Electrolysis Simplified System Schematic

Source: FuelCell Energy

Figure 2-9. Alkaline Electrolysis Cell Reactions and System Components

The cathode portions of the cells produce hydrogen by reacting water with electrons to produce hydrogen and hydroxyl ions. The hydroxyl ions diffuse across a porous membrane to the anode portions of the cells, where they react to form water, oxygen, and electrons that complete the electrical circuit. Alkaline stacks typically operate at 70 to 90 °C, and the kinetics of the alkaline electrolysis reactions are rapid enough that platinum group catalyst materials are not needed on the electrodes, which are typically nickel based.

An alkaline electrolysis system consists of mechanical equipment that contains an alkaline electrolyte solution and delivers it to the electrolysis stacks. Hydrogen and oxygen coming from the cathode and anode portions of the cells must be separated from the electrolyte solution, with the solution recovered and recycled back to the process. The stacks produce heat, which is managed by cooling the recirculating electrolyte stream. Water is continuously fed into the electrolyte stream to make up for water consumed in the electrolysis reaction. Depending on the source of the water supply, some level of water treatment is typically needed to provide sufficient purity for the stack and system's optimal operation. The electrolysis stacks are fed direct current power, supplied by a rectifier connected to an AC source.

Alkaline systems historically have been low-pressure systems, operating near atmospheric pressure. The need to ensure that hydrogen and oxygen gases produced in the anode and cathode chambers do not mix due to differential pressures across the porous membrane introduces complexity to pressurized operation, however some equipment providers have begun to offer pressurized alkaline systems in recent years. In general, operating an electrolysis system at some elevated pressure provides the advantage of reducing the power consumption needs of subsequent stages of gaseous hydrogen compression.

Alkaline electrolysis is the most mature electrolyzer technology, but there are trade-offs against this maturity with the complexities of handling caustic KOH solutions and the difficulty of pressurization. While there is some literature that suggests the cost of uninstalled equipment in China is much lower than for Western manufacturers, this literature fails to consider the cost of any electrolyzer is dependent on its size, scale, location, and the supply chain and logistical impacts.[17]

A picture of an Alkaline Electrolyzer is provided below in Figure 2-10.

Source: Name, date, website

Figure 2-10. Alkaline Electrolyzer

2. Proton Exchange Membrane Electrolysis

PEM electrolysis refers to systems using a solid polymer membrane with protons (hydrogen ions) as the ion charge transfer carrier. PEM systems were introduced in the early 1960s using polystyrene-based polymers, which have since been replaced with fluoropolymer-based materials with improved life and performance. The electrolysis cell reactions and basic system components are illustrated in Figure 2-11.

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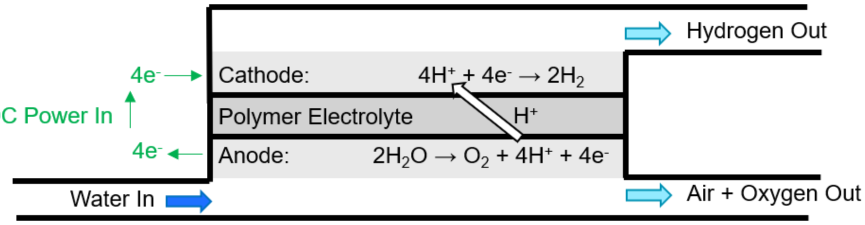
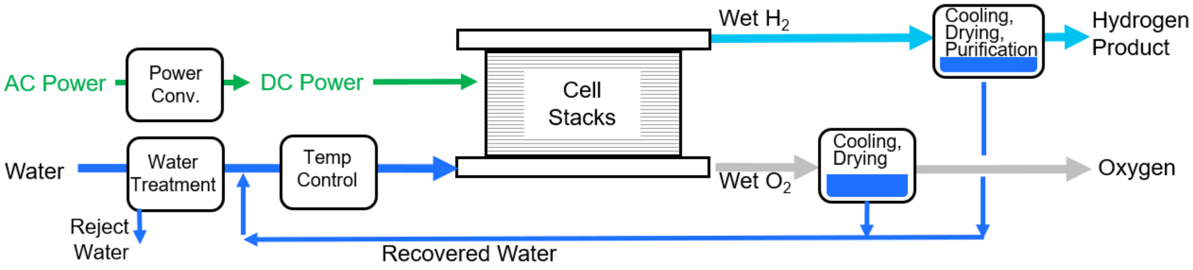
[17] Bloomberg; "China Leading Race to Make Technology Vital for Green Hydrogen", Dan Murtaugh, September 21, 2022; https://www.bloomberg.com/news/articles/2022-09-21/china-leading-race-to-make-technology-vital-for-green-hydrogen?sref=5zLpogqK



PEM Electrolysis Cell Reactions



Polymer Electrolyte Membrane (PEM) Electrolysis Simplified System Schematic

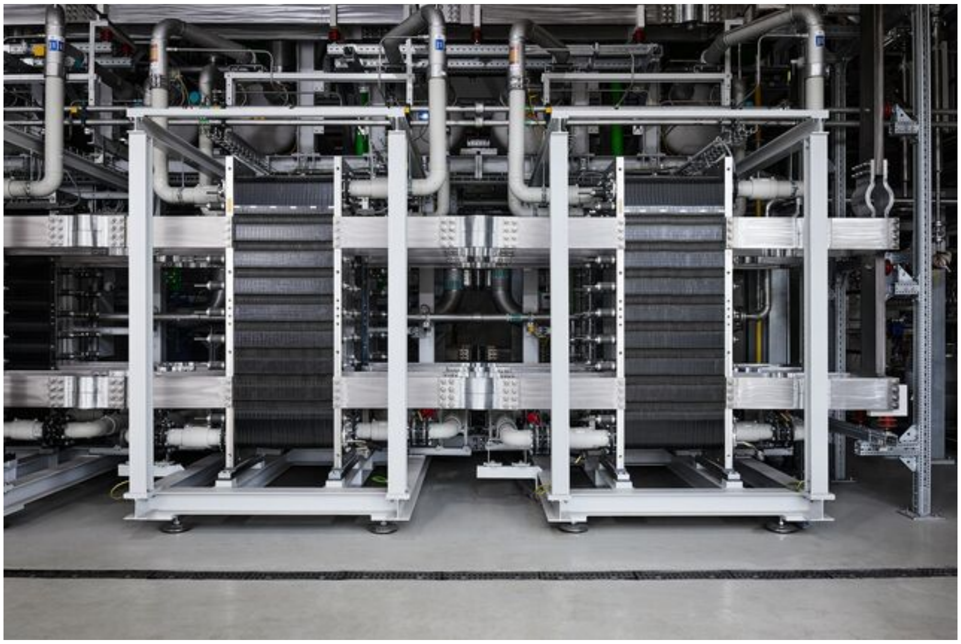
Source: FuelCell Energy

Figure 2-11. Polymer Electrolyte Membrane Electrolysis Cell Reactions and System Components

The anode portion of each cell splits water into oxygen, protons (hydrogen ions, H+), and electrons, which flow into the power circuit. The protons produced in the anodes diffuse across the polymer membrane to the cathode side of the cell, where they react with electrons from the power circuit to produce hydrogen. PEM cells operate at 50 to 80 °C. To achieve acceptable performance, platinum group metals are used as catalysts on the electrodes, typically iridium and platinum.

A PEM system is less complex than an alkaline system primarily because it does not have to manage the caustic recirculation system, and separation of product gas from liquid water is easier.

Major advantages of PEM electrolysis include the ability to rapidly startup to produce hydrogen and the ability to operate at a wide range of vendor specified pressures. The strength and low porosity of the membrane protects against hydrogen crossover of anode and cathode products, even under pressure differential conditions. Because pressurizing the water being fed to the stacks requires less energy than pressuring the hydrogen product coming from the stacks, this can be a significant efficiency advantage for a system supplying pressurized hydrogen. A PEM stack is depicted in Figure 2-12. The trade-off against the low complexity of PEM systems is the need for platinum group catalysts, the higher (at present) cost compared to alkaline systems, and the emerging concern around per- and polyfluoroalkyl substances (PFAS), which include the fluoropolymers used in PEM membranes. PEM suppliers are working on reducing cost and catalyst content as the technology matures, and these suppliers have developed approaches to responsibly manage handling of fluoropolymers.



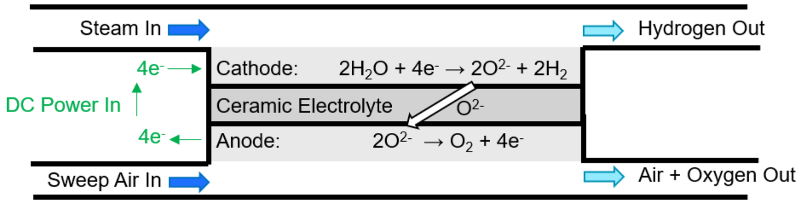
Source: Air Liquide, 2023, Oliver Bellendir Photography

Figure 2-12. PEM Electrolyzer Stacks

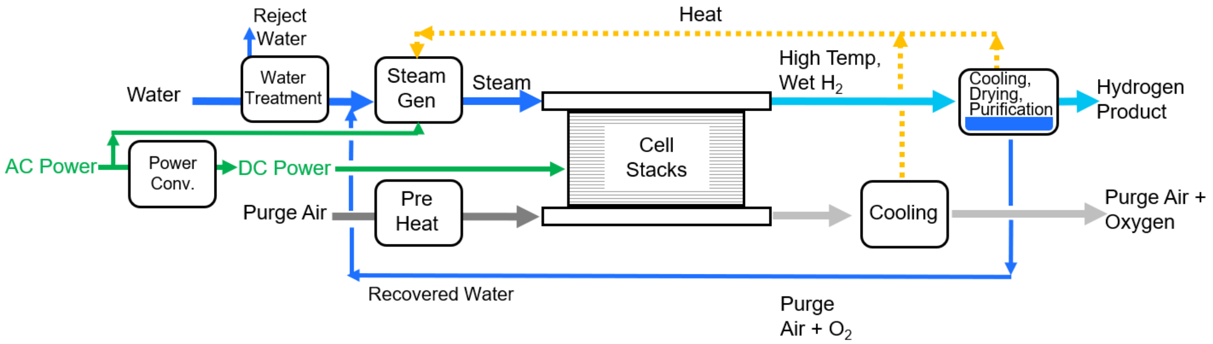
3. Solid Oxide Electrolysis (SOE)

Solid oxide water electrolysis is the least mature of the commercially available electrolysis technologies, highly dependent on the specific manufacturer's level of experience, with systems just now coming to market. Given the high similarities to solid oxide fuel cells that produce power, it is a technology that has been developed over the last two decades. NASA had a program developing SOE technology in the late 1990s as a part of the Mars program. That technology was privatized in the early 2000s and solid oxide technology has been used commercially for fuel cells since that time. The use of the cells for electrolysis has been explored at the research level for longer than that, but the offering of commercial electrolysis systems based on solid oxide cells started early in this decade. Interest in technology is growing due to the high efficiency of the system, which can be a significant factor in lowering the cost of hydrogen production.

The electrolyte separating the electrodes in a solid oxide cell is a dense, ceramic material, (e.g., yttria or scandia stabilized zirconia or ceria-based materials). Oxygen ions (O_2-) can diffuse through these electrolytes and serve as the charge transfer carriers. Most commercial systems operate with a stack temperature in the range of 700 to 850 °C. The electrolysis cell reactions and basic system components are illustrated in Figure 2-13.



Solid Oxide Electrolysis Cell Reactions



Solid Oxide Electrolysis Simplified System Schematic

Source: FuelCell Energy

Figure 2-13. Solid Oxide Electrolysis Cell Reactions and System Components

In the cathode portion of each cell, water (in the form of steam) reacts with electrons from the external power circuit to produce oxygen ions and hydrogen. The oxygen ions diffuse through the ceramic electrolyte membrane to the anode portion of the cell, where they are converted to oxygen and electrons, which complete the power circuit. The gas coming from the cell anodes could be pure oxygen, but most equipment suppliers dilute the oxygen stream with purge air to avoid safety issues associated with handling high-temperature pure oxygen. Solid oxide cells do not require noble metal catalysts, typically using nickel-based electrode substrates, which offers a mitigated supply chain risk compared to systems that require noble metal catalysts.

Solid oxide systems are unique due to the high temperature of the stacks and the need to deliver steam instead of liquid water to them. A solid oxide system typically contains a boiler (unless the system is being supplied from an external steam supply) and feed gas preheat heat exchangers. The preheat is provided by heat from the high-temperature hydrogen and oxygen streams leaving the stack, as well as electrical heat as needed. Thermal management of the system is done by adjusting air supply and managing the heat transfer between inlet and exit streams.

The major advantage of SOE is high electrical efficiency. Solid oxide cell stacks can operate at 100% electrical efficiency or even higher (but heat needs to be provided to the stacks, which will be endothermic at >100% electrical efficiency). If external heat is available, as with many chemical processes such as ammonia production, renewable fuel refining, traditional refining, at a nuclear power facility, or other chemical processes with excess heat the overall site efficiency can be improved by utilizing that heat in the SOE process. Solid oxide systems producing atmospheric pressure hydrogen from water can operate up to 90% HHV efficiency, and if steam is supplied to the system efficiency can be increased to 100% HHV or higher. This high efficiency can have a significant impact on the resulting cost of hydrogen given power is often 50-80% of the total cost of ownership for electrolysis hydrogen production. The trade-off against the high efficiency is the high inlet temperature of the stacks, increasing the complexity of the balance of plant with the need to exchange heat between hot exiting and cold incoming streams. The high operating temperature could also possibly impact stack life. In cases where steam is available, using a steam feed instead of water can reduce system complexity. The other trade-off with SOE is the relatively low maturity of the system as an electrolysis platform. While it may change as the technology matures, at present all commercially offered systems supply hydrogen at near atmospheric pressure, with no pressurized systems offered to date, which can be a partial offset against the high efficiency for systems requiring pressurized hydrogen.

4. Emerging Electrolysis Technologies

In addition to the commercially available electrolysis systems developed above, there continues to be research and development on new types of electrolysis cells that could offer performance advantages in the future.

Anion Exchange Membrane (AEM) cells are similar to PEM in that the anode and cathode are separated by a low-temperature polymer material. In an AEM, hydroxyl ions (OH-) instead of protons (H+) are the charge transfer carriers, so the cell chemistry is like that in an alkaline electrolyzer. These systems could have the pressure capabilities of PEM combined with performance characteristics of alkaline.

Among high-temperature technologies, developers are evaluating proton conducting ceramic electrolyte materials (vs. the oxygen conducting solid oxide membranes). The cell chemistry would be similar to PEM, with the advantages of higher efficiency at high temperatures.

These and other technologies in development could start to play a role among electrolysis systems as we approach the At-Scale phase of hydrogen deployment.

5. Balance of Plant Considerations

The electrolysis process requires not only the electrolyzer stacks but various systems and equipment to support its efficient and safe operation in the production of LCI H_2.[18] These are called the balance of plant (BOP) components of an electrolysis-based production system. Depending on the specific type of electrolysis system, the BOP components may differ, but they generally consist of the following: power electronics, power distribution/control (substations, transformers, control systems), safety/environmental systems, hydrogen compression, lye tanks/systems (AWE), water treatment process, hydrogen processing units, compression units, and other miscellaneous components.

Figure 2-14 showing BOP components is provided below.

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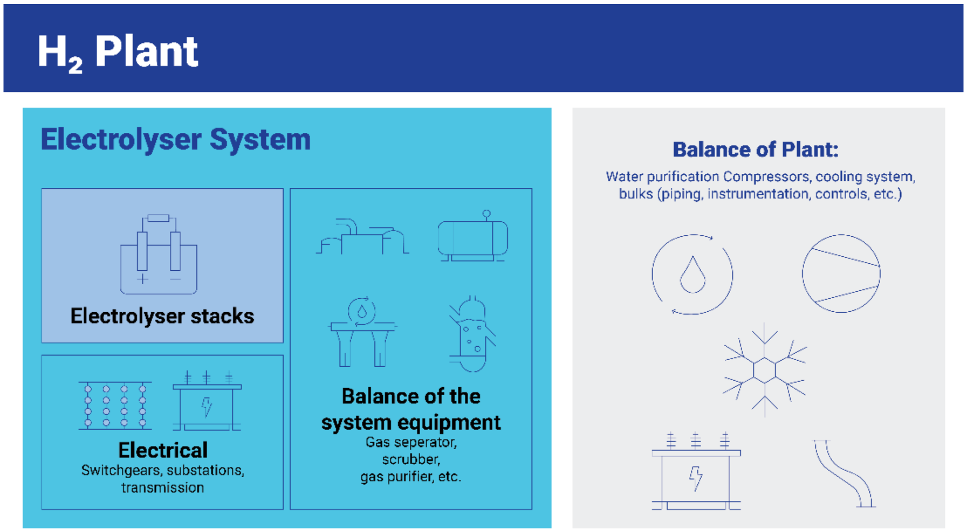
[18] What will it take to reduce CAPEX in green hydrogen production? (ramboll.com)



Source: Air Liquide, 2024

Figure 2-14. Balance of Plant Scheme

The BOP components are essential for achieving high performance and efficiency of the electrolysis system, and their design and optimization are critical for reducing costs and improving the economic viability of the system. There are 1-10 MW standard electrolysis stacks available in the market. A single large-scale BOP installment can support multiple standard size electrolysis stacks for a plant that has more than 20 MW project capacity. This is a centralized system that needs both factory and field construction. The centralized system might have higher engineering and installation costs than buying individually specified equipment for a single site, but it can save on cost per unit of production due to economies of scale with larger BOP train.

Power electronics: To connect electrolyzers to the grid, AC-to-DC rectifiers are needed. These devices change the alternating current from the grid to the direct current that the electrolyzer stack uses. Depending on the voltage difference between the grid and the electrolyzer system, transformers may also be required. For off grid applications that use renewable sources like solar and wind that produce DC power, a DC-to-DC converter may be required. The other components of the electrolyzer system, such as pumps, sensors, controls, and compressors, may also need a power conversion device or a DC-to-AC inverter.

The power from renewable sources is expected to be often at least partially intermittent. PEM and AEM electrolyzers can respond more quickly to changes in power than AWE electrolyzers. SOE cells (SOEC) can also ramp up and down production quickly, though it has a long startup time to heat the unit from ambient temperature to its high operating temperature. PEM and AEM may have a trade-off between load following and hydrogen pressure (30–35 bar). A power handling unit for an electrolysis system may need batteries or capacitors to smooth out short-term power fluctuations, but this study does not include the cost of such batteries as it depends on the scenario. For SOEC technology, an idle system heater may be needed if the power supply is intermittent to keep it in hot standby.

Water Treatment and Recirculation: High purity water is needed as feedstock for the electrolysis process. The American Society for Testing and Materials defines high purity water as Type 1 or 2 depending on conductance (<0.056 or <1 microsiemens per centimeter μS/cm). Most electrolyzers are able to use Type 2 water. If the water quality requirements are not met, then the lifetime of the electrolyzer stack and efficiency decreases. Usually a combination of primary desalination (reverse osmosis or thermal distillation) followed by a mixed bed ion exchange polisher is needed to prepare water for electrolysis when using city water (<1,000 mg/L total dissolved solids) as a source. More advanced treatment processes (e.g., evaporation technologies like multistage flash, multiple effective distillation, or mechanical vapor compression) may be deployed when dealing with more challenging higher-TDS water sources. The water treatment system is not typically provided by the electrolyzer original equipment manufacturers and must be sourced as a separate item in most cases.

System Cooling: Cooling is needed at several stages in the process of making hydrogen by electrolysis. First, heat is generated when alternating current electricity is changed into direct current. Depending on the local temperature conditions, the power electronics may be naturally air cooled, or may require housing in an air-conditioned building. In PEM and AWE systems, the stacks produce heat during electrolysis operation (SOEC stacks operate close to thermally neutral). Next, the oxygen and hydrogen gases formed must be cooled before purification. This way, more water is removed from the gases by condensation, and the drying section in the plant can be smaller. Then, the hydrogen gas is compressed, which requires cooling between and after the compression stages. The cooling options available for these processes are diverse, encompassing wet, dry, and hybrid methods, each with its own set of advantages and disadvantages. The choice of cooling system is influenced by a variety of factors, including the availability of water, local climate conditions, local and state regulations, and the size of the systems involved. A close-loop system can be used but it comes with a penalty of increased capex and electricity usage. For a large-scale electrolyzer system, evaporative cooling towers can be used, but require addition of make-up water, and management of a warmer and more concentrated blowdown stream.

Compression: Compression units that compress hydrogen to above 30 bar are normally not part of electrolysis package and have to be procured separately. Many studies, in the open literature, on electrolysis system costs do not account for compression costs. Compression technology is more economical at a larger scale, meaning that using fewer large compressors is less expensive than using many small ones.

6. Source of Electricity

LCI H_2 production means producing hydrogen with minimal GHG emissions. One way to achieve this is to use nuclear, hydroelectric, or variable renewable energy sources (VRE)—such as solar, wind, or a combination of both—to power the hydrogen production process.

The source of the VRE influences a number of associated hydrogen production decisions. One of these decisions has to do with providing as constant a flow of VRE to the electrolyzer as much as possible. Due to the fact that VRE is inherently intermittent, electrolyzers coupled to VRE energy sources run at a low-capacity factor. Batteries could be used to smooth out the output from intermittent renewables, but the Modeling done for this study indicated that this approach is more expensive than using hydrogen storage to levelize the hydrogen output.

Another way developers seek to smooth out hydrogen production so that it is more predictable is by drawing electricity from multiple VRE sources that are not temporally aligned. In fact, the more temporally unaligned the VRE sources (meaning the peak electricity production times do not overlap), the more the electrolyzer benefits from a high degree of VRE output distribution over time by operating at a higher capacity factor.

Such temporal unalignment is especially beneficial when there are multiple nonoverlapping periods during which the capacity factor for the VRE production method is maximized. Renewable developers refer to this temporal unalignment of peak electricity production periods as "complementarity."

Geographical complementarity can also exist. Different regions of the United States have different VRE profiles. The West region has abundant solar resources, while the Central and Great Lakes regions have very high wind resources. The state of Texas is known to have both. For example, researchers at Rice University have shown that parts of Texas provide excellent complementarity between wind and solar resources over both daily and annual periods.[19] The researchers examined the solar and wind resources in West Texas and the wind resources in South Texas at different times of the year. Unsurprisingly, solar production was the highest during the summer, while wind production in West Texas and South Texas was highest in the winter. Just from this observation alone, it is clear to see how pairing solar in West Texas with wind in West and/or South Texas can provide a more reliable source of VRE because the peak production periods do not overlap. This ability to level out VRE production so that it is more consistent can also be done daily by pairing West Texas solar with West Texas wind or South Texas wind.

While complementarity of VRE sources that are not temporally or geographically aligned helps solve the problem of producing an uninterrupted flow of hydrogen from an inherently stochastic energy source, additional considerations must be considered to maximize the volume of electrolytic hydrogen production.

NREL's benchmark for the national average annual capacity factor for solar photovoltaics is 26.8[20] and for wind, it is 35%.[21] To increase the utilization of an electrolyzer powered only by VRE, developers can overbuild the VRE assets (which was included in the MIT Modeling) and sell any curtailed power back to the grid (sale of excess power was not included in the Modeling). Overbuilding means that the power output of the VRE assets providing electricity to the hydrogen facility is sized so that the actual VRE output more closely matches the input needs of the electrolyzer.

Complementarity and overbuild are not mutually exclusive; rather, developers will seek to use both to maximize the output of the electrolyzer while also making it more constant.

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[19] https://repository.rice.edu/server/api/core/bitstreams/4ee13970-c149-4527-ad89-c585499517f0/content

[20] https://atb.nrel.gov/electricity/2021/utility-scale_pv

[21] https://www.eia.gov/todayinenergy/detail.php?id=52038

Discussion of the overbuild and VRE mixing assumptions used in the Modeling is provided in section III.C.

The technoeconomics used to assess low carbon intensity, considered the hourly variability and availability of renewable energy sources, such as solar and wind, and the transmission constraints and costs between different regions. The Model was used to analyze the feasibility and cost of achieving 100% carbon-free electricity by 2030 or 2035, as well as the environmental and economic benefits of such a transition. It also compared different scenarios and policies, such as the impact of adding new transmission lines, storage systems, or demand-response programs utilizing data and analysis from various sources, such as the NREL, the U.S. Energy Information Administration, and the Massachusetts Institute of Technology Energy Initiative. Hourly capacity factor onshore wind/solar generation is an important parameter that affects the availability and variability of renewable energy sources for hydrogen production. A higher capacity factor means that the renewable energy source can produce more electricity per unit of installed capacity, and thus reduce the cost and land use of hydrogen production. However, a higher capacity factor also means that the renewable energy source is more dependent on weather and seasonal conditions, and thus may require more backup or storage systems to ensure a stable hydrogen supply. The capacity factor of onshore wind and solar generation varies by location, time, and technology, and can range from 10 to 40% for wind and from 5 to 25% for solar.

Offshore wind is a potential renewable energy source for hydrogen production, in coastal regions where land availability and environmental impacts are limited. It has a higher capacity factor than onshore wind, as the wind speed and consistency are higher over the sea. Offshore wind also has a lower correlation with solar generation, which can improve the diversity and reliability of the renewable energy mix. However, offshore wind also has higher capital and maintenance costs, and technical and regulatory challenges, such as grid connection, environmental impact assessment, and maritime safety.

In addition to renewable energy, nuclear energy can also be used as a zero-carbon source of power for electrolyzers. The advantage is that nuclear power is more consistent than VRE sources. The disadvantage is the limited availability of nuclear power, although the emergence of new technologies, such as small modular reactors, could provide a new generation of nuclear power sources for electrolyzers.

VRE can be complemented by energy storage to increase utilization factors. Significant investment in various forms of energy storage is occurring, particularly in batteries at grid scale. These are being increasingly deployed by utilities and renewable developers to smooth out grid supply and demand. If energy storage costs decrease, it could be a key enabler for hydrogen production via electrolysis enabling utilization factors like natural gas pathways.

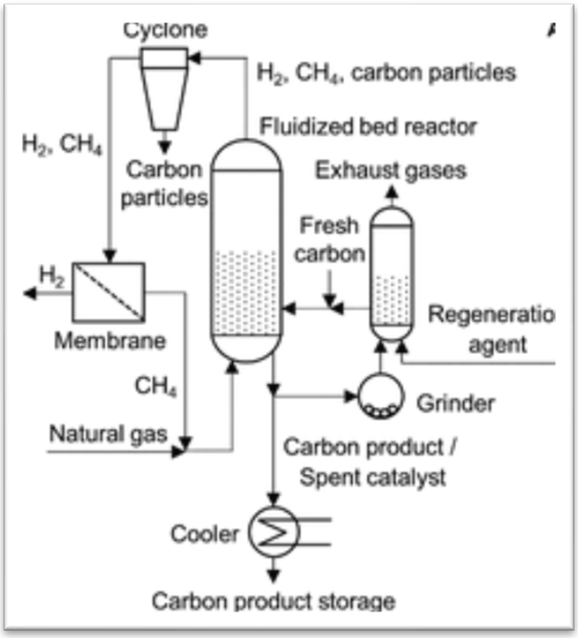
D. Other Production and Complementary Technologies

While hydrogen does exist naturally as a gas, tapping into this resource remains in its early stages, requiring dedicated time and technological advancements for efficient extraction. The development of methods and technologies to harness hydrogen directly from its natural occurrence is an evolving process, as discussed in Chapter 1: Role of LCI Hydrogen.

The following technologies, while not explicitly included in the Modeling, can provide additional paths to producing decarbonized hydrogen.

1. Methane Pyrolysis

Methane pyrolysis is the thermal decomposition of hydrocarbons at elevated temperatures and inert atmospheric conditions into their elemental constituents, namely, hydrogen and carbon, with the carbon being deposited in solid form. A schematic depicting this process is provided in Figure 2-15. The conversion will occur rapidly at temperatures >900°C and has been demonstrated to approach 100% without the need for catalysts at temperatures >1,300°C.[22, 23] Today it is deployed to produce carbon black (CB) commercially and is not utilized for producing hydrogen as the primary product; hydrogen is a byproduct consumed within the process as fuel.[24] More than 95% of the global CB production is by pyrolysis of heavy aromatic feedstock and only 2% by methane (known as thermal black). However, new methane feed process designs targeting hydrogen as the main product have been tested. Some are at a Technology Readiness Level 6 with existing challenges in optimizing heat transfer to drive the reaction while minimizing carbon buildup.



Source: Sanchez-Bastardo et al., 2020, “Methane pyrolysis for carbon dioxide-free H_2 production: A green process to overcome renewable energies unsteadiness”

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[22] Amin, Croiset, Epling “Review of methane catalytic cracking for hydrogen production” International Journal of Hydrogen Energy, 2011

[23] Gaudernack, Lynum “Hydrogen from natural gas without release of CO_2 to the atmosphere” International Journal of Hydrogen Energy, 1998

[24] Dagle et al., “R&D opportunities for the development of natural gas conversion technologies for co-production of hydrogen and value-added solid carbon products” PNNL technical report 26726, 2017

Figure 2-15. Typical Fluidized Bed Reactor Design for Methane Pyrolysis

Hydrogen's theoretical thermal efficiency limit is ~60%, as ~40% of the energy is stored in carbon. As a natural consequence, there is an inherent economic disadvantage when based solely on hydrogen compared to methane reforming pathways. Valuing the carbon byproduct can shift this paradigm, but existing markets would not support the volumes produced for scenarios where hydrogen is used as an energy carrier; for scale, three tons of solid carbon is produced as a byproduct for every ton of hydrogen Hence, good-quality carbon byproducts will have to be produced, and new large markets (or economical routes for carbon disposal) will have to be developed for the economics of methane pyrolysis to compete with other technologies and advance the deployment at scale.[25]

2. Hydrogen Production and Renewable Natural Gas

Renewable natural gas (RNG) can enable LCI H_2 production by reducing the net CI of the natural gas feedstock used in a steam methane reformer or autothermal reformer. Colocation of the RNG production with hydrogen production may not be necessary if the RNG is moved via pipeline and/or a book and claim mechanism is used. The primary challenges to widespread use of RNG at scale include total size of the RNG market and its cost as, in some cases, there may be greater economic value for RNG being used directly rather than for generation of LCI H_2.

RNG is pivotal in producing Renewable Identification Numbers (RINs), a critical element within the United States Renewable Fuel Standard (RFS) program. RINs are distinctive serial numbers utilized to track and validate renewable fuels' production, import, and utilization, including RNG.

When RNG is derived from organic waste sources and subsequently introduced into natural gas pipelines or employed as transportation fuel, it qualifies as a renewable and low-carbon energy source. This qualification empowers it to generate valuable RINs, which can be traded within the market. These RINs indicate that a specific volume of renewable fuel has been produced and utilized. This verification process greatly assists obligated entities like refiners and importers in fulfilling their mandated renewable fuel blending targets stipulated by the RFS program.

The production of RNG is aptly incentivized through the establishment of RINs, thereby fostering a revenue stream for RNG producers, and actively nurturing the expansion of the renewable natural gas industry. This synergistic interplay encourages the growth of RNG production, which plays a pivotal role in curbing GHG emissions while fostering the progression of a lower carbon energy landscape.

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[25] Parkinson et al., "Hydrogen production using methane: Technoeconomics of decarbonizing fuels and chemicals" International Journal of Hydrogen Energy, 2018

3. Small Modular Nuclear Reactors

Small modular nuclear reactors (SMNR) are smaller than conventional reactors and can be assembled in a factory setting, lowering the cost and reducing construction time. Other advantages include enhanced safety features and the flexibility to be deployed in various applications besides baseload power generation. One of these is production of LCI H_2 through thermochemical or high-temperature electrolysis processes.

- In the thermochemical process, high-temperature heat from the SMNR is used to drive a series of chemical reactions to split water (H_2O) into hydrogen (H_2) and oxygen (O_2). The most common thermochemical process for hydrogen production is the sulfur-iodine cycle.
- SMNRs could enable cost-effective at-scale hydrogen using solid oxide electrolyzers and integrating small modular nuclear reactors heat with its electrical power to create a high efficiency, high utilization factor production system. Such a system could be located inside refineries or other industrial processes to deliver large amounts of LCI H_2 independent of renewable power availability or pipelines.

SMNR hydrogen production presents an opportunity to generate LCI H_2 and contribute to decarbonizing various sectors, including heavy industries, transportation, and power generation. However, several challenges need to be addressed, such as:

- **Regulatory hurdles:** The deployment requires appropriate regulatory frameworks that ensure safety while facilitating commercialization and operation.
- **Public perception:** Nuclear energy may face public resistance and concerns about safety and waste management.
- **Cost competitiveness:** SMNR design helps reduce costs through standardization, replication and enduring mature supply chains compared to large nuclear reactors. The challenge is who is going to lead us to this mature steady state.[26]
- **Hydrogen infrastructure:** The need for extensive infrastructure could be mitigated if it is permitted near the end user.

As technology and regulatory advancements continue, SMNR hydrogen production can play a significant role in meeting the growing demand for LCI H_2 and contributing to lower emissions.

V. PRODUCTION COSTS AND CARBON INTENSITY

This section summarizes the cost and CI of hydrogen production, i.e., up to the fence line of the production facility. The cost and CI associated with hydrogen storage and delivery are discussed in Chapter 3: Infrastructure. These two pieces of the hydrogen supply chain are

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[26] https://www.science.org/content/article/deal-build-pint-size-nuclear-reactors-canceled

brought together in Chapter 4: Integrated Supply Chain, providing a view on the total cost and CI of delivered hydrogen as seen by the end user.

Costs are expressed on a levelized basis. A levelized cost for a product is the amount to be charged in the market so the resulting revenue stream is sufficient to 1) cover all operational expenses, and 2) generate enough profit to meet the desired return on investment over a given timeframe. As such, it represents the “break even” price where the net present value of the project is zero.[27] Levelized costs account for all capital and operating costs, providing a reasonable way to compare the economics of different pathways to the same product.

The levelized cost of hydrogen (LCOH) is commonly expressed in \$/kgH_2, although other units are useful in some contexts (e.g., \$/mtbu-H_2 to compare to natural gas). Separate levelized costs can be calculated for the production, storage, transmission, and distribution steps along the supply chain; the sum of these is the LCOH seen by the end user. Using subscripts to distinguish the contributions from these steps, the total LCOH is:

$$\boxed{\underset{\text{end user}}{\mathrm{LCOH}} = \underset{\text{production}}{\mathrm{LCOH}_p} + \underset{\text{storage}}{\mathrm{LCOH}_s} + \underset{\text{transmission}}{\mathrm{LCOH}_t} + \underset{\text{distribution}}{\mathrm{LCOH}_d}}$$

For this study, costs are expressed in real terms using 2020 as the reference year; i.e., in 2020 dollars. Calculations are made in five-year increments from 2025 to 2050. The levelized cost identified with a particular year represents the fixed value (in real terms) for a project that starts production in that year; it is independent of the future market price of H_2.[28] A real return on investment of 10% is assumed for all levelized cost calculations.[29]

The CI of hydrogen delivered to the end user can be broken out in a similar way, based on contributions along the supply chain:

$$\boxed{\underset{\text{end user}}{\mathrm{CI}} = \underset{\text{production}}{\mathrm{CI}_p} + \underset{\text{storage}}{\mathrm{CI}_s} + \underset{\text{transmission}}{\mathrm{CI}_t} + \underset{\text{distribution}}{\mathrm{CI}_d}}$$

The CI at the point of production (CI_p) consists of just two contributions in this study:

- CO2 emitted during H_2 production (i.e., Scope 1 emissions). These are nonzero for fossil-based H_2 but are absent from electrolysis-based production. Contributions from non-CO2 greenhouse gases to CIp are negligible in comparison, so not considered in the Modeling.

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[27] Meeting the desired return on investment includes payback of the initial capital. The timeframe for calculating a levelized cost is a financial decision; it can be equal to or less than the physical lifetime of the plant. Herein, this timeframe is called the ‘capital recovery period’. The NPV is calculated using a discount rate equal to the desired rate of return on investment over the capital recovery period. A similar approach is taken for calculating the levelized costs of storage and delivery in later chapters.

[28] Selling at less than LCOH_p due to subsequent market entrants having a lower cost structure, thereby potentially depressing the market price, means the project NPV<0.

[29] That is, the weighted cost of capital (WACC) is 10% for all projects.

- Carbon dioxide and methane emitted along the natural gas and electricity supply chains.

As is common practice, CH_4 emissions are converted to CO_2 equivalents (CO_2e) using the Intergovernmental Panel on Climate Change (IPCC) estimate of its global warming potential relative to CO_2 on a 100-year timeframe (GWP100); i.e., 30 $kgCO_2e/kgCH_4$.[30]

The impact of imported or exported steam would also be included, but these are negligible for the stand-alone plants modeled in the study. This CI_p is equivalent to the "well-to-gate" CI. Unlike the levelized cost, which is a fixed value (in real terms), each CI term associated with a given project can vary over time. This will occur if inputs or plant operations change; for example, the natural gas supply chain may become "cleaner" through decarbonization efforts.

In principle, the life cycle levelized cost and CI of a product includes contributions from the construction and decommissioning of facilities and equipment used in its production, delivery, and end use. While full construction costs were always included, the study did not account for decommissioning costs at any stage of the hydrogen supply chain, as these are typically much smaller than construction costs. The study also did not account for emissions due to construction of facilities and equipment ("embodied manufacturing" emissions; see Inset: Embodied Manufacturing Emissions), nor emissions resulting from decommissioning facilities and equipment.

This section focuses on the levelized cost and CI of hydrogen production, i.e., $LCOH_p$ and CI_p. Calculations utilized the MIT SESAME platform,[31] parameterized with the inputs for capex, opex, and emissions factors cataloged in Appendix X. The results were used as inputs to the MIT USREP Model to project regional and nationwide hydrogen supply and demand under the two study scenarios.

INSET

Embodied Manufacturing Emissions

Embodied manufacturing emissions are GHG emissions that arise from the extraction and processing of raw materials, conversion of raw materials to construction materials, and fabrication of the equipment. Examples include solar panels, wind turbines, electrolyzers, natural gas processing units, pipeline infrastructure, etc. These differ from operating emissions, which result during the conversion of feed (such as natural gas, water, or electricity) into hydrogen. It is important to consider embodied manufacturing emissions when comparing the environmental impacts of different hydrogen production pathways, as they can comprise a material fraction of total life cycle emissions depending on the process,

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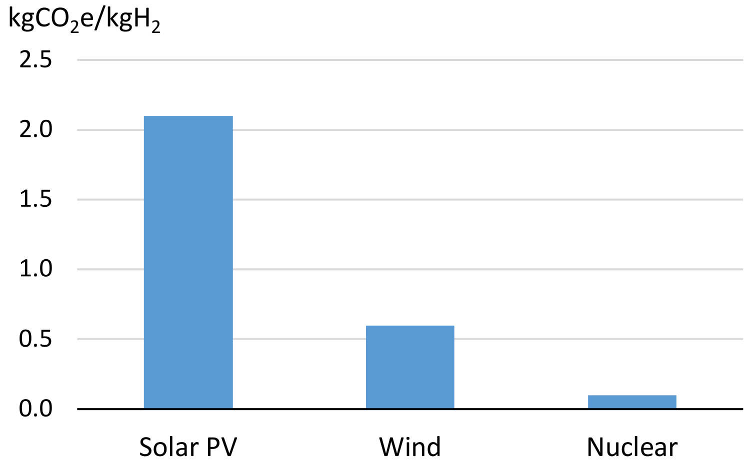
[30] The Intergovernmental Panel on Climate Change (IPCC) estimates the GWP100 for methane is about 30 (Table 7.15 in www.ipcc.ch/report/ar6/wg1/chapter/chapter-7/). GWP100 is the most common metric for comparing the climate impact of other GHG to CO_2. However, because methane is a short-lived in the atmosphere, GWP100 undervalues its climate impact over the short term. The 20-year global warming potential (GWP20) is often used to address this gap. The IPCC estimates the GWP20 of fossil methane is about 83.

[31] Sustainable Energy System Analysis Modelling Environment, MIT (2023); https://sesame.mit.edu/.

fuel type, supply chain, and design of the equipment and infrastructure. Further discussion can be found in a 2023 publication by the IEA.[a]

A comprehensive assessment requires a cradle-to-gate life cycle study that can be complicated by complex supply chains and variability in process design.[b] In the case of variable renewable energy (VRE)-based electrolytic production of hydrogen, the primary sources of embodied emissions are the solar or wind generators and the electrolyzer. The manufacturing process for crystalline silicon for solar photovoltaics (PV) is highly energy intensive, as it involves reducing quartz with an electric furnace operating above 1,000°C. The CI of this process depends on the electricity source. Today, most solar PV production is in China, where ~60% of the electricity is produced from unabated coal,[c] resulting in a CI of 0.9–2.5 $kgCO_2e/kgH_2$ for solar PV-based electrolysis; wind-based electrolysis is notably better at 0.4–0.8 $kgCO_2e/kgH_2$ due to less energy-intensive production.[d] This CI will improve as the electrical grid becomes decarbonized. The embodied manufacturing emissions for electrolyzers are smaller, contributing ~0.13 $kgCO_2e/kgH_2$.[e] Figure 2-16 compares embodied manufacturing emissions for electrolytic hydrogen production as estimated by Argonne National Labs.



Source: Argonne National Lab, 2023, https://greet.anl/gov

Notes: Argonne National Laboratory's Gases, Regulated Emissions, and Energy Use in Technologies (GREET) Estimate of well-to-gate emissions for electrolysis-based hydrogen production when embodied emissions associated from manufacturing of solar panels, wind turbines, and nuclear power facilities are included.

Figure 2-16. Embodied Manufacturing Emissions for Electrolytic Hydrogen Production as Estimated by Argonne National Labs

In contrast, the embodied manufacturing emissions for natural gas-based hydrogen production are negligible, particularly when compared to the upstream emissions from natural gas production and transportation. For example, assuming ~20,000 metric tons of steel and concrete are used to construct a facility that makes 300 metric tons H_2 annually over a 25-year lifetime, the embodied manufacturing emissions amount to <0.005 $kgCO_2e/kgH_2$.[f]

This study chose to not include embodied emissions in the assessment of hydrogen CI, because the required information was not available across all value chains. Future studies should seek to include embodied manufacturing emissions in full life cycle emissions profiles (e.g., well to end use) for hydrogen and consider the carbon payback period (the period over which a wind turbine and solar panel pays back the CO_2 emissions released during its production in CO_2 emissions reductions).

Furthermore, estimates of embodied emissions look at a single moment in time and don't consider changing supply chains where the CI of grid electricity may become progressively lower over time.[g]

Notes:

a. IEA (April 2023) "Toward hydrogen definitions based on their emissions intensity."
b. Cetinkaya et al., "Life cycle assessment of various hydrogen production methods," *Int. J. Hydrogen Energy*, 37 (3), 2012.
c. IEA World Energy Outlook (2022) Extended Dataset.
d. IEA (April 2023) "Toward hydrogen definitions based on their emissions intensity."
e. The embodied emissions for electrolyzers will vary somewhat based on the type of electrolyzer and the electricity source used during manufacturing.
f. Argonne National Lab, R&D GREET 2023 (https://greet.anl/gov)
g. https://iopscience.iop.org/article/10.1088/1748-9326/acf50d/pdf

END INSET

A. Natural Gas-Based Hydrogen

For fossil-based hydrogen production, the study focused on natural gas reforming with high levels of CO_2 capture, constructed as stand-alone plants (i.e., not integrated into a larger chemical or refining complex). Unabated reforming is included as a comparison. Natural gas is assumed to be readily available, with a cost and CI corresponding to natural gas supplied to the industrial sector. CO_2 sequestration is treated as an operating expense paid to a third party. Technoeconomic inputs are documented in Appendix X.

Figure 2-17 compares $LCOH_p$ results for different natural gas-based H_2 production routes. While these results specifically reflect the natural gas, grid electricity,[32] and CO_2 sequestration costs in the Gulf Coast region under the NZ2050 scenario, the relative costs for the different routes are similar in other regions and the Stated Policies scenario. Adding CO_2 capture significantly increases the capex for a new-build plant. Opex is also increased, due to the additional natural gas and electricity demanded by the CO_2 capture plant, plus the addition of CO_2 sequestration expenses. Costs increase over time for all production routes because natural gas and grid electricity are projected to become more expensive with increasingly stringent climate goals.

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[32] The study assumed natural gas-based H_2 production facilities will import grid electricity, given the need for a constant supply to support a 90%+ plant capacity factor.

Notably, $LCOH_p$ is nearly the same for SMR and ATR production with high levels of CO_2 capture. This is due to the lower capex and nonenergy operational costs for ATR being offset by a higher electricity demand to run the air separation unit an ATR requires. Low regional grid electricity prices can tip the $LCOH_p$ comparison slightly in favor of ATR—or slightly in favor of SMR if the prices are high—but material differences are never observed under the scenarios modeled in the study. It is expected that ATR production will be the technology of choice due to the capacity limitations of SMRs as we imagine scaling up our hydrogen production for large industrial uses.

Being able to retrofit an existing facility avoids the initial capex of the reforming plant, resulting in a lower $LCOH_p$ for natural gas-based LCI H_2. But the advantage is modest since all the other capex and opex contributions to $LCOH_p$ remain. Moreover, the potential for retrofits is limited to the existing SMR fleet, and factors such as plant age and local restrictions (e.g., plot space) mean only a fraction of that fleet are legitimate candidates for adding new equipment capable of high CO_2 capture rates.

The corresponding CI_p for natural gas-based H_2 production routes are compared in Figure 2-18. As expected, the CI_p is substantially reduced by capturing most of the CO_2 produced in the reforming process. A further decrease occurs over time due to use of cleaner natural gas and grid electricity inputs.[33] The importance of the natural gas supply chain to CI_p is apparent. In the NZ2050 scenario, where the grid is fully decarbonized by 2035, natural gas supply chain emissions account for roughly half of the remaining CI_p for natural gas-based LCI H_2.[34] Methane, even at the relatively low leak rates of less than 1 wt% modeled in the study, accounts for a quarter to half of all natural gas supply chain emissions, depending on the region and year; see Inset: Carbon Intensity of Natural Gas Used for Hydrogen Production.

As was the case for $LCOH_p$, the CI_p for hydrogen produced by SMR and ATR with high CO_2 capture rates are predicted to be not materially different. Given these similarities, the study narrowed its focus to just the ATR + CO_2 capture production pathway for subsequent analyses.

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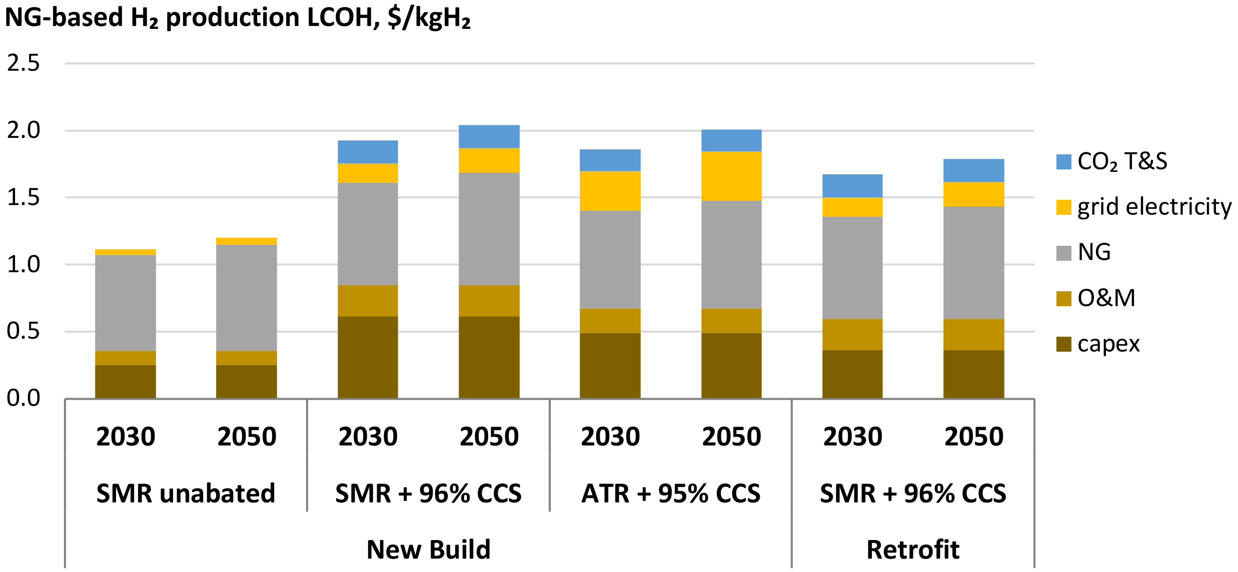
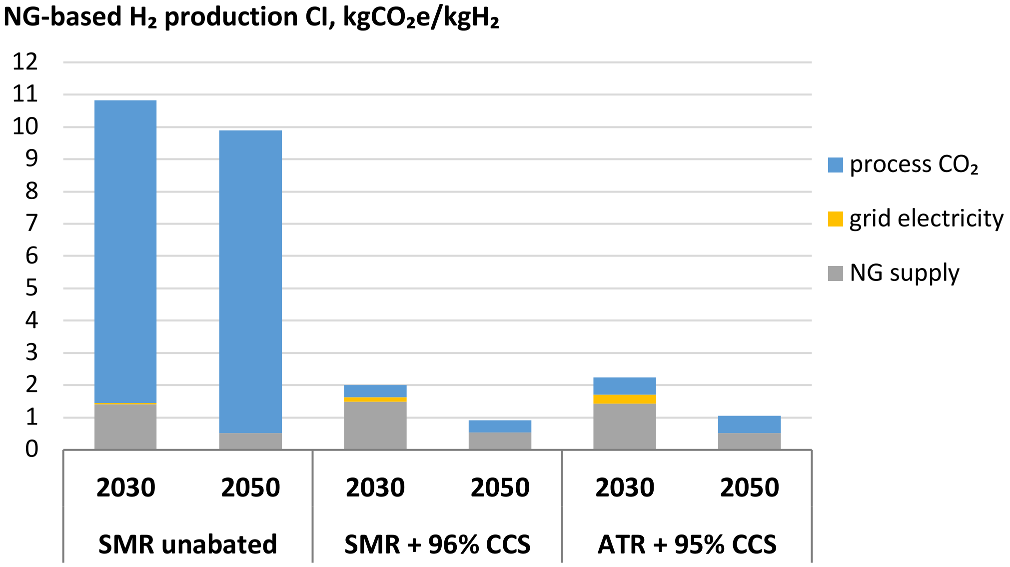
[33] Improvements in plant efficiency and higher CO_2 capture rates would further reduce CI_p, but these were not included in the study.

[34] Natural gas supply chain emissions make up an even higher fraction of total CI_p in earlier years, due to higher CH_4 and CO_2 emissions rates. This fraction is somewhat lower for the Stated Policies scenario where the contribution from grid electricity is higher.



Note: Unsubsidized production in the Gulf Coast region under the NZ2050 scenario. O&M = operation and maintenance, CO_2 T&S = CO_2 transport and storage (i.e., sequestration).

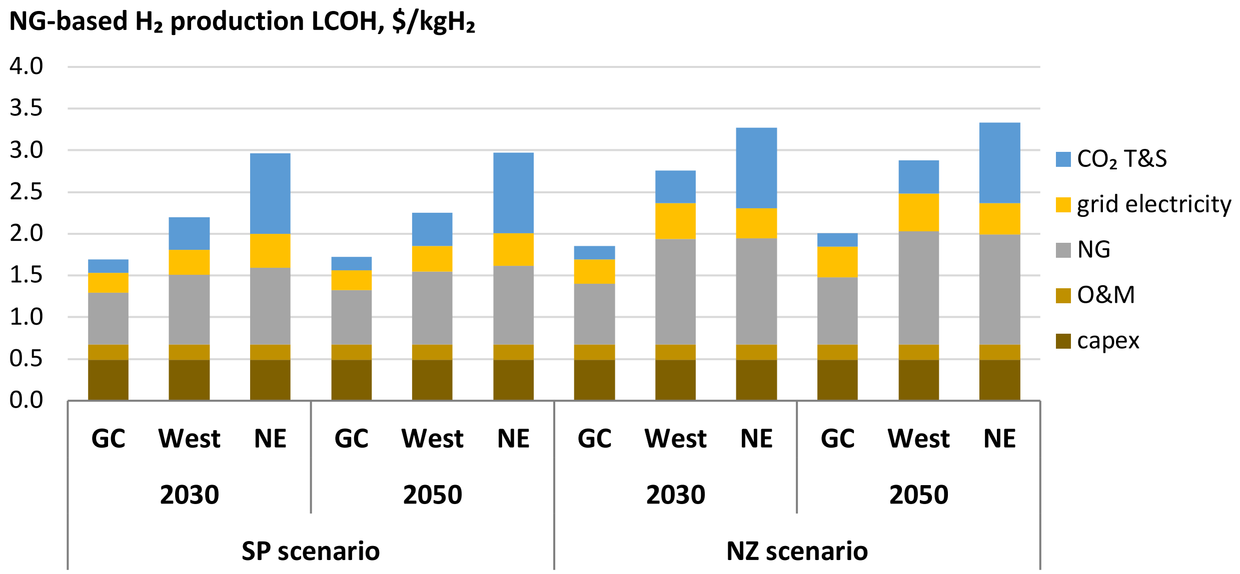
Figure 2-17. Comparison of $LCOH_p$ for Different Natural Gas-Based H_2 Production Routes



Note: Production in the Gulf Coast region under the NZ2050 scenario. CI_p for a steam methane reformer retrofitted with CO_2 capture is assumed to be the same as a new-build plant with the same CO_2 capture rate. See Appendix X for plant efficiency and CO_2 capture rates (based on National Energy Technology Laboratory analysis) and time dependence of natural gas and grid electricity carbon intensities (additional information about assumed methane leak rates described in Inset: Carbon Intensity of Natural Gas Used for Hydrogen Production). Assumed stand-alone plants, with no steam exports and embodied emissions not included.

Figure 2-18. Comparison of CI_p for Different Natural Gas-Based H_2 Production Routes

Figure 2-19 compares LCOH$_p$ for natural gas-based LCI H_2 produced in different regions. It highlights regional variability in the key cost drivers: natural gas, grid electricity, and CO_2 sequestration. In regions where these operational expenses are low, such as the Gulf Coast, LCOH$_p$ falls in the \$1.5-2.0/kgH_2 range (with higher values in the NZ2050 scenario due to more expensive natural gas and electricity). Higher natural gas and CO_2 sequestration costs in the West raise LCOH$_p$ to \$2.0-2.5/kgH_2 in the Stated Policies scenario and \$2.5-3.0/kgH_2 in the NZ2050 scenario. The Northeast region is like the West, except CO_2 sequestration is even more expensive, adding ~\$1/kgH_2 to LCOH$_p$ (about \$0.6-0.8/kgH_2 more than in other regions).



Note: Unsubsidized production via ATR + 95% CO_2 capture. GC = Gulf Coast, NE = Northeast, SP = Stated Policies scenario, NZ = Net Zero scenario. Does not include costs due to California cap and trade regulation.

Figure 2-19. Cost of Producing Natural Gas-Based LCI H_2 in Example Regions Under Both Study Scenarios

The cost of natural gas is the largest contributor to LCOH$_p$. For the Stated Policies scenario, the range is \$3.3-5.4/mmbtu reflecting the difference between low-cost regions (like the Gulf Cost) and high-cost regions (like the Northeast, Mid-Atlantic, and West).[35] This range translates to \$0.6-1.0/kgH_2 in feedstock costs for the ATR + CO_2 capture pathway. Under the NZ2050 scenario, natural gas costs of \$3.9-7.9/mmbtu are projected, which equates to \$0.7-1.4/kgH_2. Thus, the study finds a swing of at most \$0.4/kgH_2 in LCOH$_p$ due to differences in the cost of natural gas under the Stated Policies scenario, and a larger \$0.7/kgH_2 of variability under the NZ2050 scenario. Some regions see larger differences in projected natural gas prices between the two scenarios than others, but the average difference (\$1.9/mmbtu or \$0.3/kgH_2) is on par with the difference between regions under the Stated Policies scenario.

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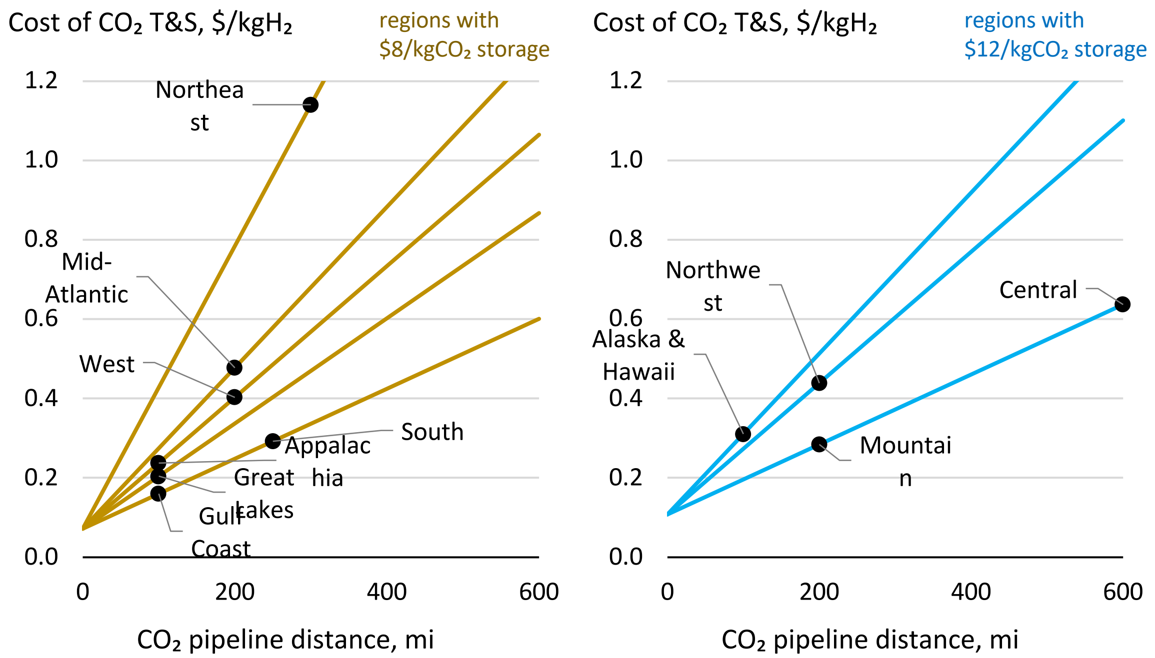
[35] The cost of natural gas cited here is the average value over the lifetime of a natural gas-based LCI plant. It varies by scenario, region, and, to a lesser extent, plant startup year. MBTU = million Btu, on HHV basis.

Differences in the cost of CO_2 sequestration represent a larger sensitivity for $LCOH_p$.[36] As described in Chapter 3: Infrastructure, the study adopted cost structures for CO_2 transport and storage that vary by region.[37] A characteristic CO_2 pipeline distance was assigned for each region based on an assessment of how far industrial centers are from probable storage sites, which ranges from 100 miles in advantaged regions (e.g., Gulf Coast and Great Lakes) to 600 miles for the most disadvantaged region (Central). Figure 2-20 shows how the study modeled CO_2 sequestration cost as a function of CO_2 transport distance for different regions, translated into $\$/kgH_2$ for the ATR + CO_2 capture pathway. The values used in the $LCOH_p$ calculations are identified. For most regions, the estimated cost of CO_2 sequestration falls in a narrow range of $\$0.15\text{-}0.30/kgH_2$. Some regions are notably more expensive due to long pipeline distances and/or high pipeline costs. Unless the CO_2 pipeline distance is less than 100 miles, the total cost is dominated by CO_2 transport, making this an important metric. For actual (vs. average) projects, $LCOH_p$ may be materially different based on CO_2 pipeline distances. Every additional 100 miles of transport increases the cost of CO_2 sequestration by $\$0.1\text{-}0.2/kgH_2$ (~$\$0.35/kgH_2$ in the Northeast).



Note: Assumes ATR + CO_2 capture production pathway. T&S = transport and storage. Inputs discussed in Chapter 3: Infrastructure.

Figure 2-20. CO_2 Sequestration Opex for Natural Gas-Based LCI H_2 Production in Different Regions

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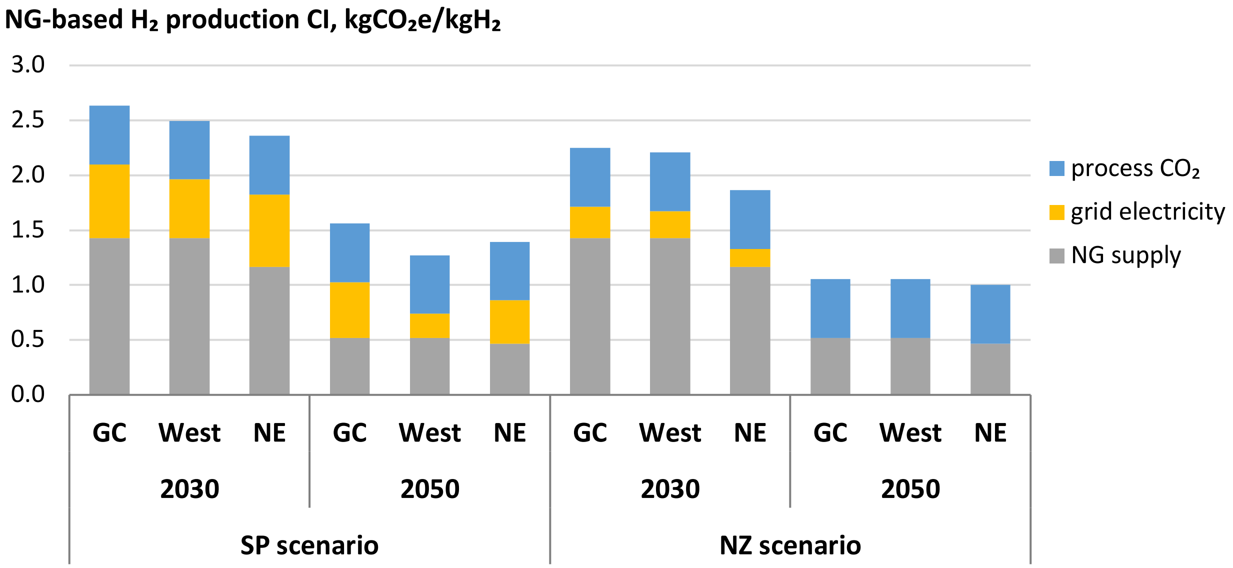
[36] For clarity, the cost of CO_2 sequestration includes only transport and storage after capture. The cost of CO_2 capture is included in the capex and opex of the LCI H_2 plant.

[37] Each region is assigned to one of five tiers of CO_2 pipeline cost (ranging between 0.1 and 0.4 $\$/tCO_2$-mi) and to one of two tiers of CO_2 storage cost (either 8 or 12 $\$/tCO_2$).

The contribution of capex to $LCOH_p$ is relatively modest at about \$0.5/kgH_2.[38] This is based on a capacity factor of 90%, typical for the chemical industry.[39] Even if the plant's output is lowered during periods of reduced customer demand, which is not an uncommon strategy for hydrogen producers, or due to temporary interruptions in CO_2 storage availability, the impact on the lifetime-average capacity factor is expected to be small, which means the change in levelized capex is also small. Moving from 90% to 70% average annual capacity factor increases $LCOH_p$ by less than \$0.2/kgH_2.

The corresponding CI assessments for the same regions are compared in Figure 2-21. Inter-regional differences are relatively modest (less than 0.5 kgCO_2e/kgH_2 in all regions and scenarios). In the early years of the study period, the natural gas supply chain is the biggest contributor to CI_p, and even in 2050 this factor accounts for at least a third of CI_p. Due to residual natural gas supply chain emissions and uncaptured process CO_2, the lowest projected CI_p for natural gas-based LCI H_2 is ~1.0 kgCO_2e/kgH_2 (in the NZ2050 scenario with a zero-carbon grid).



Note: Production via ATR + 95% CO_2 capture. GC = Gulf Coast, NE = Northeast.

Figure 2-21. Carbon Intensity of Natural Gas-Based LCI H_2 Made in Example Regions Under Both Study Scenarios

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Carbon Intensity of Natural Gas Used for Hydrogen Production

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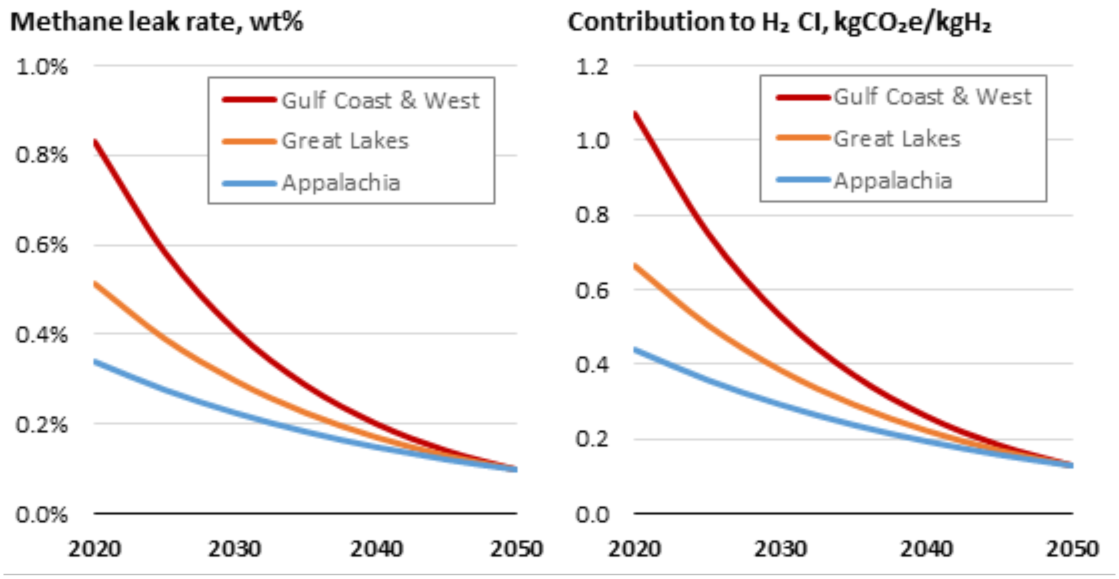
[38] While the capital cost of a new plant varies across the U.S., the study made the simplifying assumption that the differences will be small so the levelized capex contribution to $LCOH_p$ is the same in all regions.

[39] Represents the average capacity factor over the assumed 30-year capital recovery period.

Carbon intensity of the natural gas supply chain is mainly a combination of methane and carbon dioxide. Both, as GHGs, are key inputs to this study. Carbon dioxide is emitted along the natural gas supply chain from flares, gas-fired compressors, and other sources. Methane, the predominant component of natural gas, is emitted from sources that can include natural gas-powered pneumatic controllers, incomplete flare combustion, fugitive emissions, and other continuous or intermittent sources. Methane is a potent greenhouse gas. Its emissions are estimated to be responsible for at least 25% of the rise in global temperature since industrialization began,[a] and one recent modeling study suggests methane from natural gas production has the potential to contribute to around 30% of the warming the world may experience over the next two decades.[b]

Methane emissions from natural gas systems can be difficult to detect, measure, and mitigate. Leaks can occur along the entire supply chain and may be intermittent or vary based on operation dynamics. Such upstream and midstream methane emissions can account for a substantial portion of the carbon intensity (CI) of hydrogen produced from natural gas. Therefore, to achieve a low CI, the natural gas supply chain must be properly managed, which includes continued progress on measuring and minimizing methane emissions.

For the purposes of estimating the CI of natural gas-based hydrogen, this study assumed methane emissions rates for U.S. natural gas supply chains that would be leveraged for LCI H_2 production will decrease over time, reaching 0.1% by 2050 in all regions.[c] Figure 2-22 gives examples of the projected methane emissions trajectories used in the Modeling and shows how these emissions contribute to the CI of natural gas-based hydrogen. Details of the study's approach to Modeling the CI of natural gas, which includes contributions from both methane and direct carbon dioxide emissions, are provided in Appendix X. To understand more about the sources and solutions for natural gas GHG emissions, see the NPC study *Charting the Course: Reducing Greenhouse Gas Emissions from the Natural Gas Supply Chain.*



Notes: CI calculation based on methane GWP100 = 36 (IPCC AR5 with methane oxidation and climate feedback included) and natural gas-to-H_2 efficiency of 71% LHV (corresponding to ATR + 95% CO_2 capture). The examples shown here span the range modeled in the study. CO_2 emissions along the natural gas supply chain, which also contribute to the CI of natural gas-based H_2, are not shown here but are included in the Modeling.

Figure 2-22: Methane Leak Rate Trajectories Assumed for Several Regional Natural Gas Supply Chains, and Corresponding Contributions to the CI of Natural Gas-Based H_2

Across various studies, there is variability in methane emissions rates for U.S. natural gas supply chain, particularly when considering leak rates across oil and gas-producing basins. A direct measurement study has suggested that U.S. methane emissions from the oil and gas sector are 60% higher than estimates from U.S. Environmental Protection Agency (EPA), with a nationwide average leak rate nearing 2.0% of natural gas produced.[d] Emissions and leak rates can also vary across basins and global regions, with some studies estimating a weighted average of 2.95% across several basins (ranging from less than 1% in high-productivity, gas-rich regions to 9.6% in rapidly expanding, oil-rich regions)[e] and others directly measuring leak rates in specific basins: 1.1% in Appalachia, 1.9% in Gulf Coast, 3.5% in the Permian, and 5.2% in the Uinta.[f] The range of leak rates seen across studies illustrates the complexity and difficulty of detecting and measuring methane emissions from the natural gas supply chain. Life cycle analysis/assessment is needed to evaluate the source of natural gas supply, determine coproduct allocation, and calculate the specific natural gas carbon intensity. These concepts and considerations for practical applications are thoroughly examined in the NPC's *Charting the Course* study.[g]

Both the EPA and industry have taken steps to mitigate methane emissions from natural gas supply chains in the United States. The EPA recently finalized regulations that are intended to reduce future methane emissions by 80% for sources covered by the regulation.[h] Some industry leaders have taken voluntary steps to measure and reduce methane emissions including through participation in the Oil and Gas Climate Initiative (OGCI) and the Oil and Gas Methane Partnership 2.0 (OGMP). However, these regulations and initiatives do not mandate a specific level of overall supply chain reductions and participating in voluntarily initiatives do not always require measurement or third-party qualification. Ensuring that hydrogen has its intended effect of reducing energy sector emissions requires durable policy in addition to sustained industry commitment to voluntary initiatives like OGCI and OGMP.

Notes:

a. Calculated from IPCC AR5 WGI Chapter 8 SM (2013).
b. Cohen-Shields, N.; Sun, T.; Hamburg, S. P.; Ocko, I. B. Distortion of Sectoral Roles in Climate Change Threatens Climate Goals. Front. Clim. 2023, 5, 1163557. https://doi.org/10.3389/fclim.2023.1163557
c. The NPC Hydrogen study did not focus its evaluation on U.S. average natural gas value chain CI and, while reductions in methane emissions rates are anticipated across U.S. value chains, this study does not assume that all U.S. natural gas production achieves a 0.1% emissions rate by 2050. Rather, the study focuses on value chains for LCI H_2 production where CI reductions are presumed to be further encouraged.
d. Alvarez, et al., Science (2018); https://doi.org/10.1126/science.aar7204. This study reported a nationwide average methane leak rate of 2.3%, which was normalized by methane produced. The value reported has been adjusted by subtracting contributions from oil operations and natural gas distribution.
e. Sherwin, et al. Nature (2023); https://www.nature.com/articles/s41586-024-07117-5
f. Ren, et al., JGR (2019); Zhang, et al., Sci Adv (2020); Shen, et al., RSE (2022); Schneising, et al., ACP (2020); Liu, et al. GRL (2021); Cusworth, et al., PNAS (2022); Varon, et al., ACPD (2022).
g. National Petroleum Council, Charting the Course: Reducing Greenhouse Gas Emissions from the Natural Gas Supply Chain (2024).
h. U.S. EPA. “The rule would achieve a nearly 80% reduction below the future methane emissions expected without the rule.”

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B. Electrolysis-Based Hydrogen

For hydrogen production by electrolysis, the study focused on facilities powered by variable renewable energy (VRE) generated from solar and wind resources.[40] The main motivation is that the CI of such electricity is zero so the CI_p of the resulting hydrogen is also zero[41]. The VRE is assumed to be from “behind-the-meter” (i.e., not grid connected) facilities that are constructed to provide dedicated renewable electricity to the electrolysis plant. The lack of grid connectivity ensures hydrogen production is both time-matched to VRE generation and

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[40] ‘Solar’ assumes utility-scale photovoltaic (PV) plants. ‘Wind’ includes onshore wind for all regions, and offshore wind for regions with a coastline along the Atlantic or Pacific Oceans, Gulf of Mexico, or Great Lakes.

[41] assuming embodied manufacturing emissions are neglected

uses only electricity from new facilities.[42] The study also assumes production relies only on VRE from within a given region. Other sources of low-carbon electricity such as nuclear or hydro, while certainly viable for H_2 production, were not modeled based on an expectation that the H_2 volumes produced would be small compared to VRE-based production. Fully grid-powered electrolysis is explored briefly in this section, but not considered in the USREP Modeling.

The levelized cost of electrolysis-based hydrogen production depends on:

- Electrolysis plant costs: The capex and opex depend on the underlying electrolyzer technology. Carrying multiple electrolyzer technologies in the USREP Modeling was not practical. Therefore, to avoid the perception of picking a winning technology, the study opted to define a single hypothetical electrolyzer technology for use in the main Modeling efforts. This hypothetical technology represents a "market mix" of real technologies that are likely to be deployed at scale, including alkaline, PEM, and SOEC. The capex, opex, and electricity consumption are assumed to decrease over time. The values used to describe the hypothetical technology are provided in Appendix X. Subsequent calculations for electrolysis-based hydrogen production use these assumptions.
- Electrolysis plant efficiency: The efficiency, which is convenient to express in terms of how much electricity is needed to generate hydrogen (e.g., kWh_e/kgH_2)[43] depends on the underlying electrolyzer technology and is assumed to improve over time. The study's assumptions for the hypothetical market mix electrolyzer technology are summarized in Source: FuelCell Energy
- Figure 2-Source: FuelCell Energy
- Figure 2-23 and documented in Appendix X.
- Electricity cost: This was represented by the levelized cost of electricity (LCOE).[44] The LCOE depends on the capex, opex, and capacity factor of the plant generating the electricity. The study focused on VRE sources.

Capex and opex inputs were adopted from the NREL Annual Technology Baseline dataset,[45] assuming the moderate innovation case for utility PV solar, Class 5 onshore wind, and Class 5 offshore wind (see Appendix X). NREL projects substantial reductions in the capex and

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[42] Modeling grid-connected facilities (or hybrid facilities that take both VRE and grid electricity) would require a detailed power sector model to describe the interaction between electrolysis demand and the grid fleet (e.g., generation mix and dispatch) to obtain annual average pricing and CI for each region over 2025-2050. Such a model was out of scope for the study. This practical limitation also means nuclear- and hydro-powered electrolysis were not considered, as the study judged there to be a low likelihood of nuclear and hydro facilities dedicated to H_2 production by 2050.

[43] The subscript 'e' is used to distinguish electrical energy from thermal energy.

[44] LCOE is the calculated levelized cost of production, not the price of VRE in a power market. As such, it should not be directly compared to power purchase agreement (PPA) prices, which reflect supply/demand dynamics and may include grid transmission fees and subsidies, The study assumed the same 10% real return on investment for LCOE as for hydrogen production. The impact of subsidies on LCOE are considered separately in this section.

[45] NREL Annual Technology Baseline (https://atb.nrel.gov), July 2023 version. Values were converted from 2022$ to 2020$ using the U.S. Consumer Price Index (CPI).

opex for solar and wind installations over the study Modeling period (e.g., -49% for solar capex, -27% for onshore wind capex).

The capacity factor for each VRE pathway depends on the quality of the local solar and wind resources, and the technology set deployed by the VRE plant. Hourly and annual capacity factors for wind and solar generation were calculated as follows:

- VRE supply profiles for solar and onshore wind were obtained from the MIT Zephyr model.[46] Zephyr leverages NREL assessments of hourly solar irradiation and wind speed over a one-year timeframe at high geographic resolution for the continental U.S., and accounts for solar and wind capacity installation potential based on available land considerations[47]. It assumes single-axis tracking PV for solar and the power curve for a commercial 2.5 MW wind turbine. The final VRE supply profile for a given region is the weighted average of the Zephyr data for the states included in that region.[48] A significant consequence of this approach is that the VRE capacity factors and calculated LCOE reflect a regional average. While weighted toward the high-quality VRE resources in the region, the results under-represent the best possible opportunities that might be chosen first.
- VRE supply profiles for offshore wind were estimated using average wind speeds at a ~300-foot height within 50 nautical miles of the shoreline, sourced from the NREL Wind Integration National Dataset (WIND) Toolkit,[49] and assuming the power curve of a commercial 6 MW wind turbine.[50] The offshore installation potential within 50 nautical miles of the shoreline was estimated using the NREL Offshore Wind Energy Resource Assessment.[51]
- Example LCOE trajectories calculated using this approach are shown in Figure 2-24. Based on differences in regional capacity factors, there can be regional LCOE differences of up to $25 per megawatt-hour (MWh) for the same technology. On average, the solar LCOE is higher than the wind LCOE in the near term, but decreases faster to be competitive later in the period; however, each region is somewhat different.[52]
- Electrolysis plant capacity factor, which is determined by the temporal availability of electricity delivered to the plant: For VRE-powered electrolysis, it depends on the capacity and capacity factor of the VRE generators being used. If the capacity of the VRE plant feeding electricity to the electrolysis plant is the same as the capacity of the

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[46] P.R. Brown, A. Botterud: *Joule* **5**, 115-134 (2021).

[47] Other models use different time periods to estimate hourly renewable energy production. The modeling team feels as though such further granularity would have a minimal impact on the study results.

[48] Zephyr does not have data for Alaska or Hawaii, so solar and onshore wind supply profiles for the Alaska & Hawaii region were estimated as a weighted average of the other 10 regions; i.e., is set equal to the average for the continental U.S.

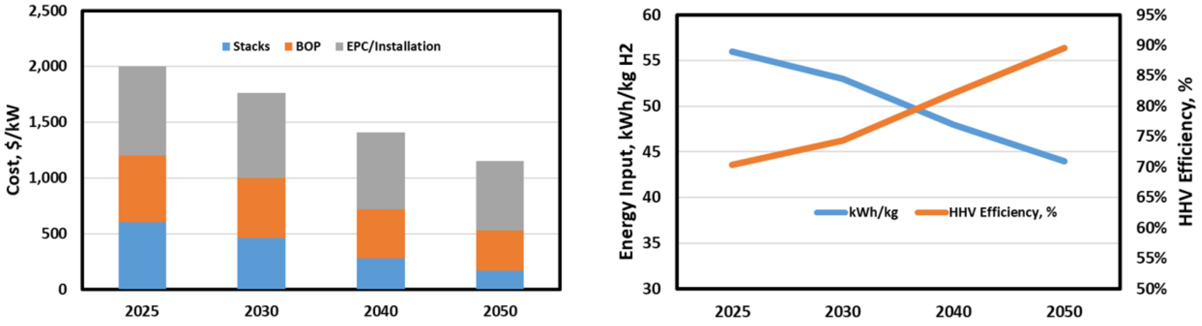
[49] N. Bondi, et al.: "2023 National Offshore Wind data set" https://www.osti.gov/biblio/1821404. Part of WIND Toolkit: https://www.nrel.gov/grid/wind-toolkit.html.

[50] T. Stehly, et al.: "2019 Cost of Wind Energy Review" (2020). https://www.osti.gov/biblio/1756710.

[51] W. Musial, et al.: "2016 Offshore Wind Energy Resource Assessment for the United States" (2016) https://www.osti.gov/biblio/1324533.

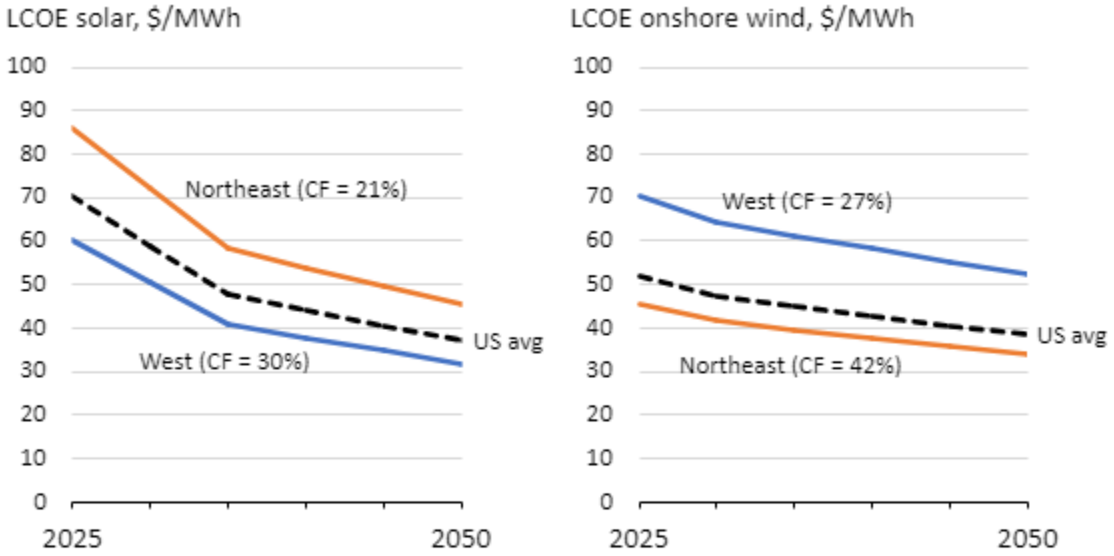
[52] The West region is unique in that the regional average capacity factor for solar is higher than for wind.

electrolysis plant (e.g., both 500 $\text{MW}_{\text{electrical}}$) then the electrolysis plant capacity factor is the same as the VRE plant capacity factor.



Source: FuelCell Energy

Figure 2-23. Electrolysis Plant Capex and Efficiency for the Market Mix of Electrolyzer Technologies Used as Modeling Input in the Study

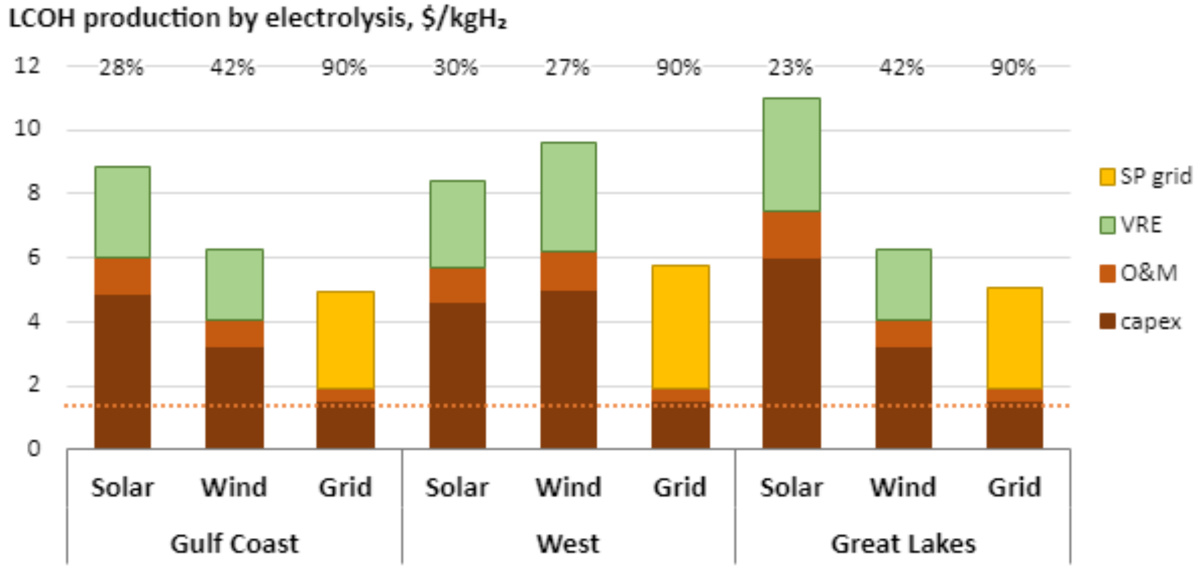


Note: Unsubsidized LCOE at the point of VRE production. LCOE decreases over time due to decreasing VRE plant capex and opex, while capacity factor (CF) is assumed to be fixed within a region. West and Northeast regions represent the extremes of solar and wind CF calculated for the study.

Figure 2-24. Example Solar and Wind LCOE Trajectories Used to Calculate LCOH_p for Hydrogen Production by VRE-Based Electrolysis

1. Simple VRE-Electrolyzer Systems

Figure 2-25 gives a sense of the range in LCOH_p for hydrogen made when the “market mix” electrolysis technology is powered by solar or wind. (Results for all regions can be found in Appendix Y.) Capex and electricity are key cost drivers. The cost of production is also strongly influenced by the electrolysis capacity factor, listed at the top of the graph, which here is equal to the capacity factor of the VRE source since it is sized to match the electrolysis capacity[53]. Typically, wind gives a lower $LCOH_p$ than solar, despite a higher LCOE, because capacity utilization of the electrolyzer is much higher. The exception is the West region, where the solar/wind ranking is reversed. The main impact comes through the capex contribution to $LCOH_p$, which varies inversely with electrolyzer capacity factor so would be much smaller if the plant operated at nameplate capacity. The electricity contribution depends only on the cost of electricity and the efficiency of the plant; even under the most favorable conditions ($30/$MWh_{electrical}$, 37 $kWh_{electrical}/kgH_2$) it is above $1/$kgH_2$, while at the other end of the spectrum ($85/$MWh_{electrical}$, 58 $kWh_{electrical}/kgH_2$) it approaches $5/$kgH_2$.



Note: Unsubsidized production in 2030 when the VRE capacity matches the electrolyzer capacity (no VRE overbuild) for solar and wind cases. The cost of grid electricity from the Stated Policies scenario. The dashed line shows the capex contribution to $LCOH_p$ if the electrolysis plant operated at nameplate capacity (100% CF).

Figure 2-25. Contributions to the Cost of Electrolysis H_2 Production in Three Example Regions

Estimates for the cost of VRE-driven electrolysis are sensitive to electrolyzer cost and performance, neither of which is well-established on a commercial basis. Figure 2-26 gives a feel for how $LCOH_p$ responds to the study's assumptions for improvements in electrolysis plant capex and efficiency over time. It also shows the range in $LCOH_p$ expected if the assumed plant capex is off by ±$500/$kW_e$ and electricity consumption is off by ±2 kWh_e/kgH_2. While such uncertainties can change $LCOH_p$ by ±1-2 $/$kgH_2$, the expected decrease in $LCOH_p$ from 2030 to 2050 is larger.

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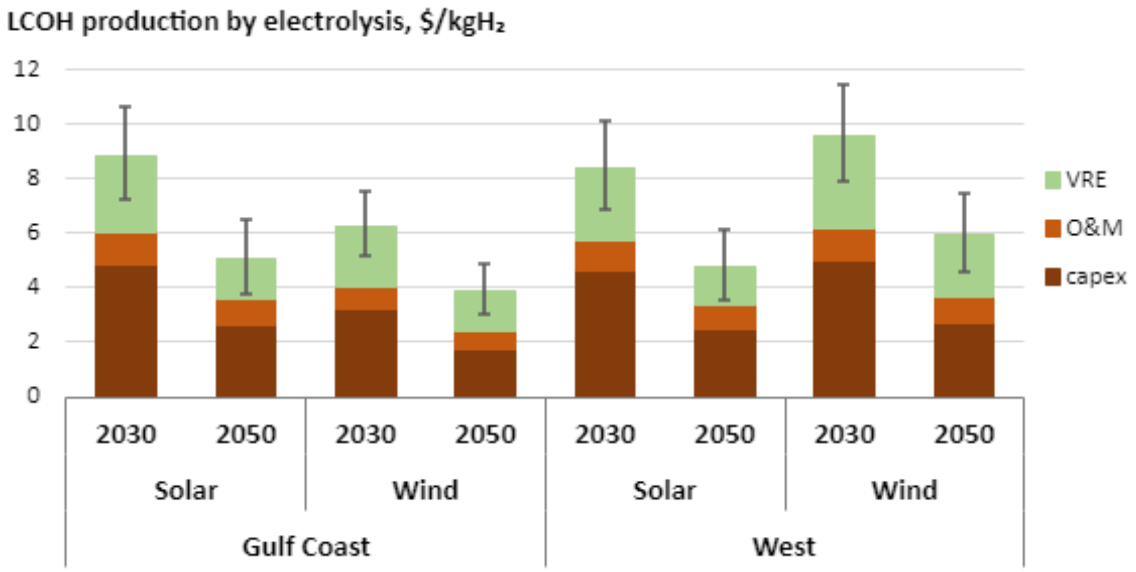
[53] Some projects will not be built with equal VRE and electrolyzer capacity. See subsequent section on overbuild of VRE to improve the capacity factor of the electrolyzer.



Note: Unsubsidized production when VRE capacity matches the electrolyzer capacity (no VRE overbuild). Error bars indicate the range of LCOH$_p$ for a low case (capex $-\$500/\text{kW}_e$, power consumption -2 kWh$_e$/kgH$_2$ vs. base case) and high case (capex $+\$500/\text{kW}_e$, power consumption +2 kWh$_e$/kgH$_2$ vs. base case).

Figure 2-26 Cost of VRE-Based Electrolysis H$_2$ Production Over Time in Two Example Regions,55 Estimates of Sensitivity to Uncertainty in Electrolysis Plant Cost and Performance

Also included in Figure 2-Figure 2-25 are estimates for the cost of grid-based electrolysis, to provide a "bookend" pathway to compare with electrolysis powered by dedicated VRE. Enabled by a firm grid, the plant operates at close to nameplate capacity (some downtime is assumed for maintenance). The cost of grid electricity, taken from the Modeling, depends on the region, year, and scenario.[54] Under Stated Policies, grid electrolysis consistently yields a lower LCOH$_p$ than either solar or wind electrolysis. Again, this is driven by the high electrolysis capacity factor, which is sufficient to overcome the higher cost of grid electricity.

The downside for grid-based H$_2$ is that, unlike VRE-based H$_2$, its CI is not automatically treated as zero. Instead, it follows the CI of the grid, so the resulting H$_2$ may not be low carbon.[55] This is demonstrated in Figure 2-27, which compares LCOH$_p$ and CI$_p$ for VRE- and grid-based H$_2$ produced in the same regions as in F, now under both study scenarios over the full Modeling period. For the Stated Policies scenario, grid-based H$_2$ is always simultaneously cheaper and higher CI than VRE-based H$_2$, although the difference varies by region because of differences in VRE quality and grid mix. Under the NZ2050 scenario, the cost of grid-based H$_2$ relative to VRE-based H$_2$ is more nuanced, but in all cases H$_2$ from either solar or wind is favored no later

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[54] USREP modeled the grid in the absence of connected electrolysis plants. So the cost and CI of grid electricity used in this analysis do not reflect the implications of large-scale grid electrolysis.

[55] To achieve a CI$_p$ of 1 kgCO$_2$/kWh by grid-powered electrolysis, the grid emissions factor must be below 20 kgCO$_2$/MWh. No region is projected to achieve this by 2050 under the Stated Policies scenario, while all regions are net zero by 2035 under the NZ2050 scenario.

than 2035. This is also when the CI of the grid is projected to reach net zero, at which point there is no longer an emissions disadvantage to using the grid to power electrolysis.[56]

Exploring the consequences of this transition for electrolysis-based hydrogen production was not feasible under the scope of the study (which did not include a detailed power sector model). Nevertheless, it is apparent that achieving a very low carbon intensity grid will reduce the reliance on dedicated renewables to produce electrolysis-based hydrogen. Using the grid also offers the advantage of firm H_2 production, which should lead to system-level benefits despite a disadvantage in production cost. A headwind is that electrolysis will compete for grid resources at the same time other sectors ramp up demand for grid electricity. Exploring how this could play out requires integrated energy system modeling capable of robustly representing both the hydrogen and the power sectors and their interactions.

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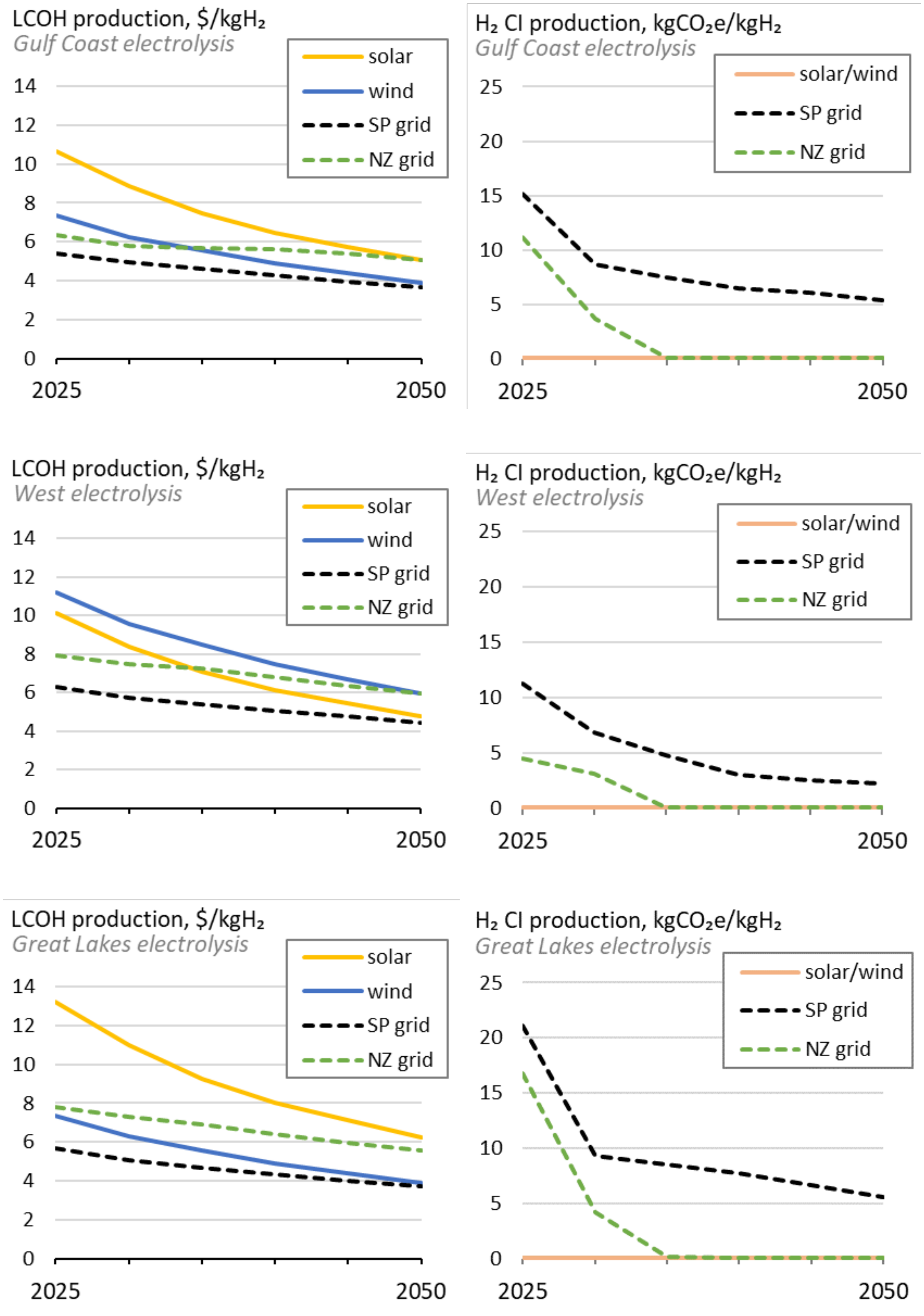
[56] Today RECs are used as a means to offset carbon emissions when using grid electricity.

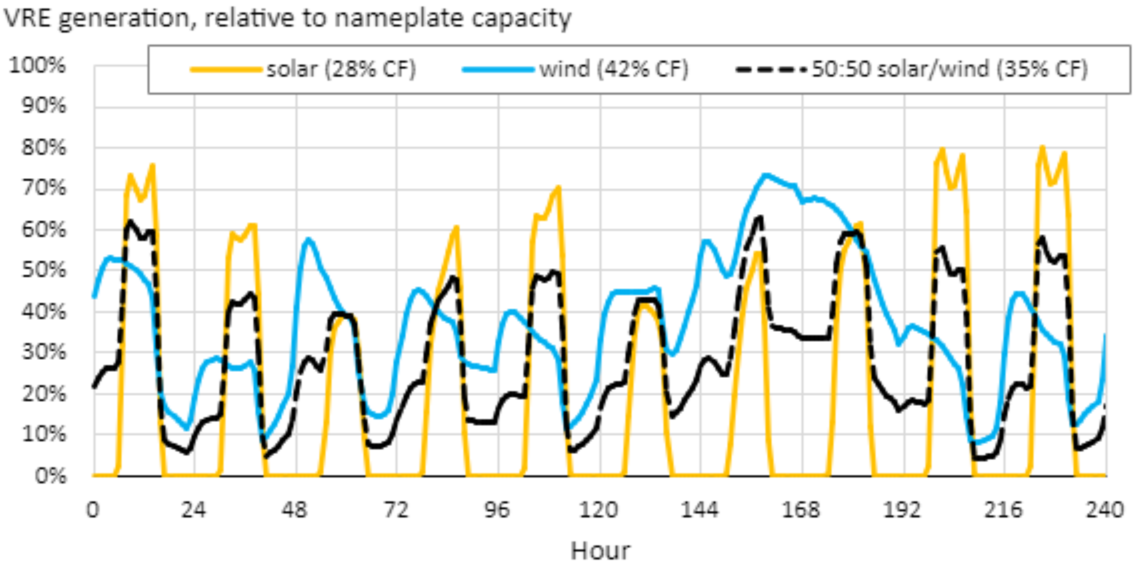


Note: Unsubsidized production.

Figure 2-27. Comparison of LCOH$_p$ and CI$_p$ for H_2 Made by Electrolysis Using Electricity f57rom Dedicated VRE or the Grid in Three Example Regions

2. Mixed VRE and VRE Overbuild

The preceding results demonstrate the importance of electrolysis plant capacity factor on the cost of producing hydrogen by electrolysis. Underutilization of the electrolysis plant means the capital investment is recovered over less hydrogen, leading to a high contribution to $\mathrm{LCOH_P}$. This is particularly acute for solar, which has an unavoidably low VRE capacity factor. One way to increase the electrolysis capacity factor in that case is to leverage wind, since solar and wind resources tend to be out of phase (wind often picks up at night). Figure 2-28 demonstrates the impact of moving from pure solar to a blend of solar and wind on the electricity generation profile, using the first 10 days of the representative annual data set calculated by MIT for the Gulf Coast region. Here the electrolysis capacity factor increases steadily as more wind is added to the mix. This holds for all other regions as well, except for the West.[57]



Note: The profile reflects the average VRE resource capture for the region. While the plot shows the first 10 days of the year, the CF in the legend is the annual value calculated from the full year data set.

Figure 2-28. Example of VRE Output from Pure Solar, Pure Wind, or a 50:50 Mix of Solar and Wind in the Gulf Coast Region

The availability of VRE to the electrolysis plant is not the only factor to consider for hydrogen production; the associated LCOE is important, too. The impact of using a solar/wind mix on LCOE, electrolysis capacity factor, and final $\mathrm{LCOH_P}$ are shown in Figure 2-29 for the Gulf Coast and West regions. Most regions behave like the Gulf Coast, where using wind as the sole VRE resource achieves the minimum $\mathrm{LCOH_P}$—except in the West, where using just solar is advantaged. This observation is robust to 2050.

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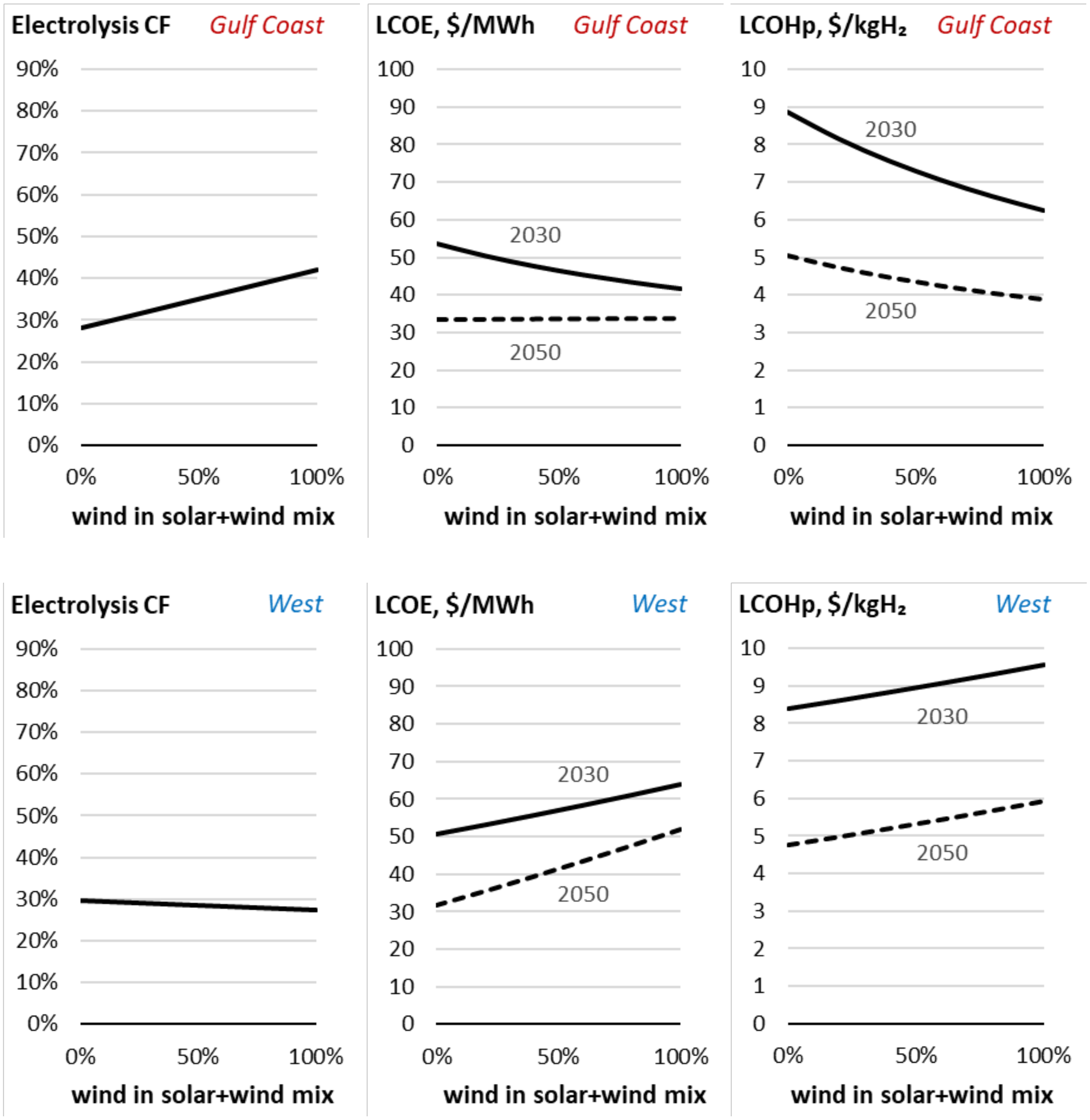
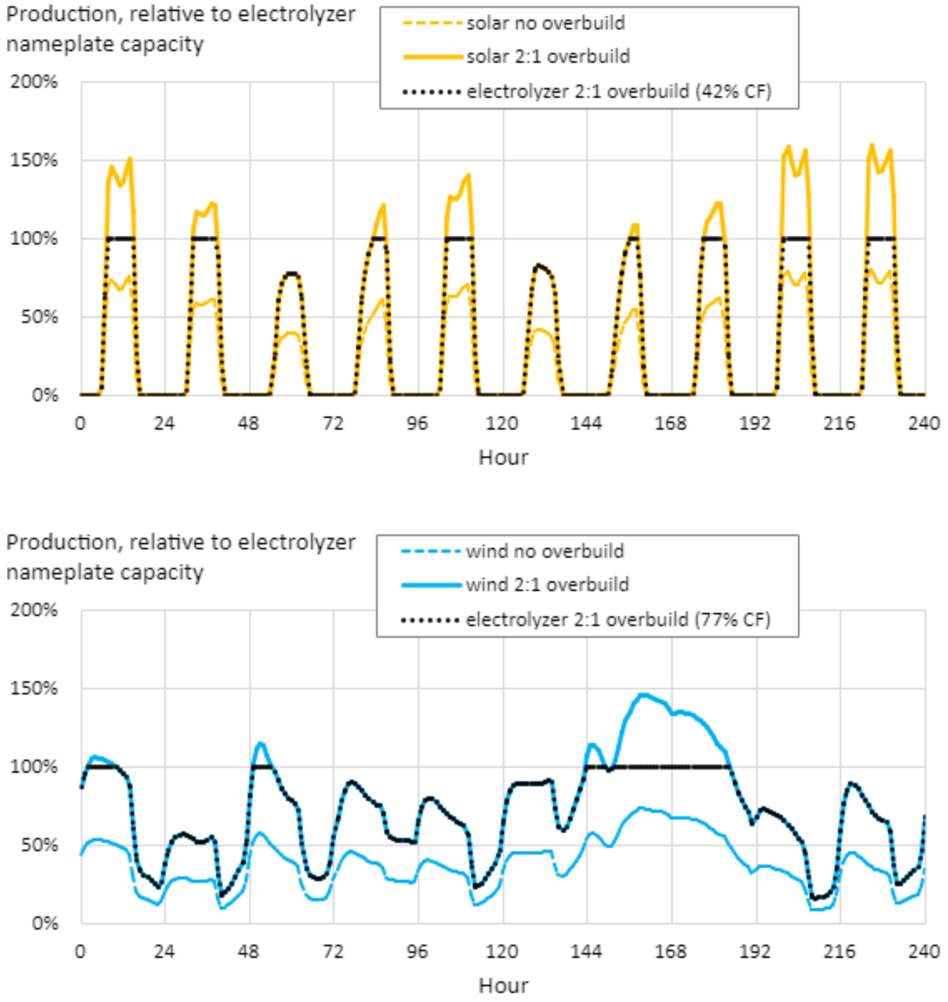
[57] The West region has the lowest average wind capacity factor of all regions (27%) but the highest average solar capacity factor (30%). As a result, adding wind to solar in that region is detrimental to the electrolysis capacity factor.



Note: Total VRE capacity matched to electrolysis capacity (i.e., no overbuild).

Figure 2-29. Impact of Solar/Wind Mix on Electrolysis Production of H_2 in the Gulf Coast and West Regions

A stronger lever for increasing the electrolysis plant capacity factor is “overbuilding” the VRE output capacity relative to the electrolyzer input capacity. When these capacities are matched, the electrolyzer capacity factor is equal to the VRE capacity factor. Overbuilding the VRE increases the amount of electricity to the electrolyzer, thereby allowing it to run at closer to its full capacity during times of weak solar or wind resources. Directionally, higher electrolyzer utilization drives lower $LCOH_p$, although the benefit saturates at high overbuild. Figure 2-30 demonstrates the impact of VRE overbuild on electrolyzer capacity utilization using data for the Gulf Coast region.



Note: Snapshot over first 10 days of average VRE resource for Gulf Coast Region. Ratio is legend is VRE:electrolyzer capacity overbuild. Resulting electrolyzer capacity factor is the annualized value.

Figure 2-30. Example Impact of Using Excess VRE Resources to Power Electrolyzer

However, there is also a downside to VRE overbuild: The electricity used to make H_2 becomes more expensive. The cost of larger VRE facilities must be recovered by the project, and some electricity is wasted (curtailed) once the amount generated exceeds the electrolyzer capacity.[58] Both drive LCOE higher, which directionally increases $LCOH_P$. Consequently, there is an optimum overbuild ratio that yields a minimum $LCOH_P$. At this optimum, the capacity factor of the electrolysis plant is greater than the capacity factor of the VRE supply. This is demonstrated in Figure 2-31, which documents the impact of solar and wind overbuild on LCOE, electrolysis capacity factor, and $LCOH_P$ for the Gulf Coast and West regions.

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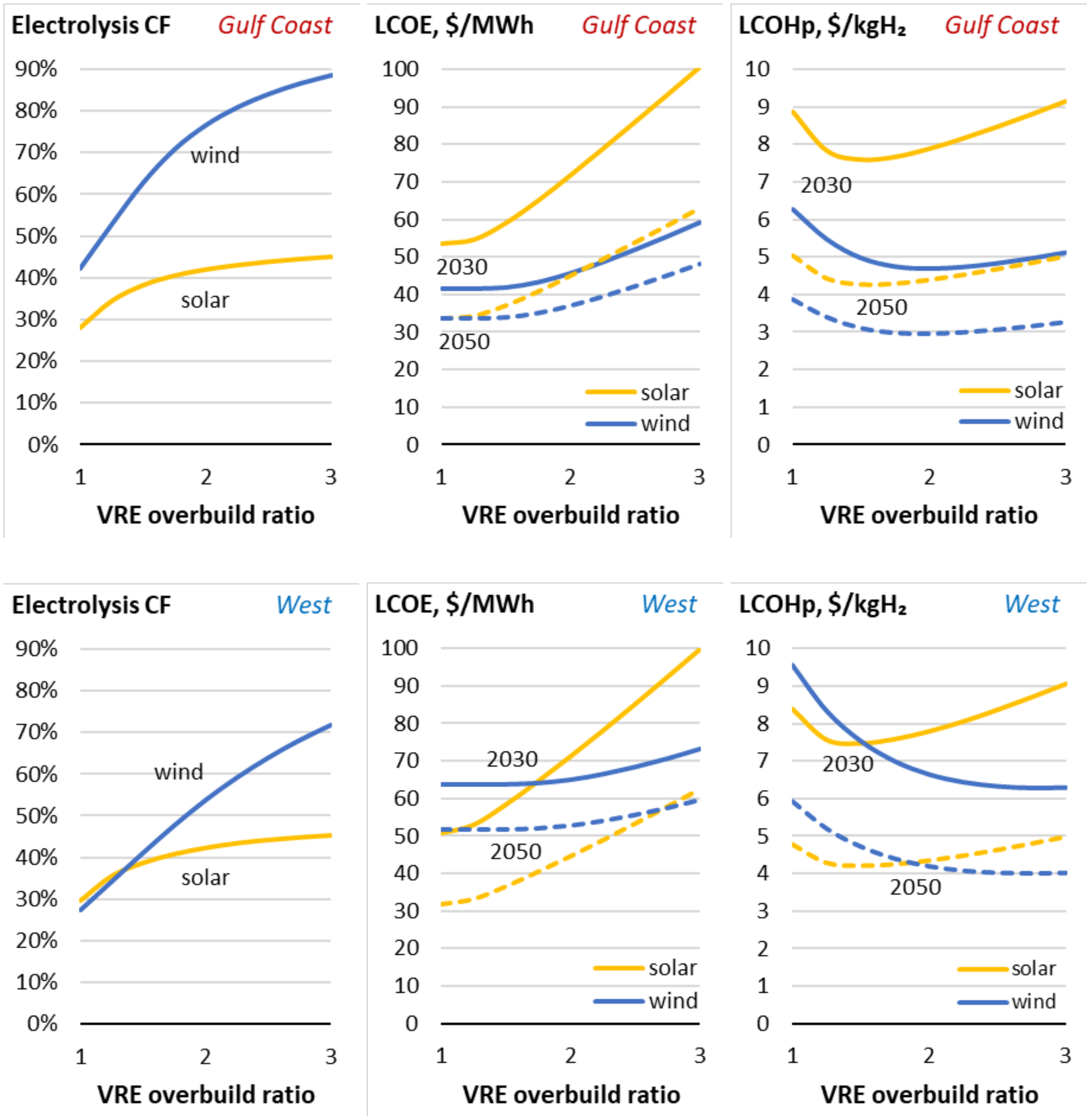
[58] The study's "behind the meter" assumption for VRE plants precludes selling this excess electricity to the grid. It is assumed to have zero value. Actual projects may be structured in a way that allows selling the excess electricity back to the grid.

The minimum in LCOH_p occurs at a lower overbuild ratio for solar (~1.5) than for wind (~2-3 depending on the region). The VRE capacity factor saturates earlier for solar—because no amount of additional capacity can overcome zero generation at night—which causes a commensurate saturation in the electrolyzer capacity factor and a rapid rise in the solar LCOE. As a result, the opportunity space for overbuilding solar is small. In contrast, a large overbuild of wind can substantially reduce the cost to produce H_2, with electrolyzer capacity factors near 90% feasible in regions with good wind resources (e.g., Gulf Coast and Great Lakes). Consistent with previous results, a lower LCOH_p can be achieved with wind, although the unique aspects of the West region cause solar to be a better option at low overbuild ratios. These observations are robust to 2050.



Note: Curves reflect VRE that is either pure solar (yellow) or pure wind (blue). For LCOE and LCOH_p, solid lines are for 2030, dashed lines are for 2050.

Figure 2-31. Impact of VRE Capacity Overbuild on Electrolysis Production of H_2 in the Gulf Coast and West Regions

C. Impact of Subsidies

The analysis thus far has only examined levelized production costs on an unsubsidized basis. Figure 2-32 demonstrates the impact of U.S. tax credits associated with LCI H_2 on $LCOH_p$. These credits considered are:

- IRA 45Q Carbon Sequestration Tax Credit: The value depends on criteria related to the capture facility. It is granted over the first 12 years of sequestration. The study assumed a tax credit of \$85/tCO_2 for projects modeled with a startup before 2035. The ATR + 95% CO_2 capture production pathway sequesters 9 kgCO_2/kgH_2, which translates to a tax credit of \$0.77/kgH_2.

- IRA 45V Clean Hydrogen Production Tax Credit: The value depends on the CI of the production route, the project startup year, and whether criteria related to the production facility are met.[59] It is granted over the first 10 years of production for projects modeled with a startup before 2035. Table 2-3 below summarizes the incentive structure assumed in the study:

1.

Table 2-3. IRA 45V Clean Hydrogen Production Tax Credit

Tier	CI_p (kgCO_2e/kgH_2)	Tax Credit (\$/kgH_2)
I	4 – 2.5	0.60
II	2.5 – 1.5	0.75
III	1.5 – 0.45	1.00
IV	<0.45	3.00

:

- IRA 45Y Clean Electricity Production Tax Credit: The value depends on the project startup year and whether criteria related to the production facility are met. It is granted over the first 10 years of production. The study assumed \$27.5/MWhe (2022\$) tax credit for projects that start in 2025,[60] corresponding to \$1.36/kgH2 (2020\$) for a "market mix"

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[59] https://www.federalregister.gov/documents/2023/12/26/2023-28359/section-45v-credit-for-production-of-clean-hydrogen-section-48a15-election-to-treat-clean-hydrogen

[60] U.S. EPA (2023) https://www.epa.gov/green-power-markets/summary-inflation-reduction-act-provisions-related-renewable-energy#ITCPTC

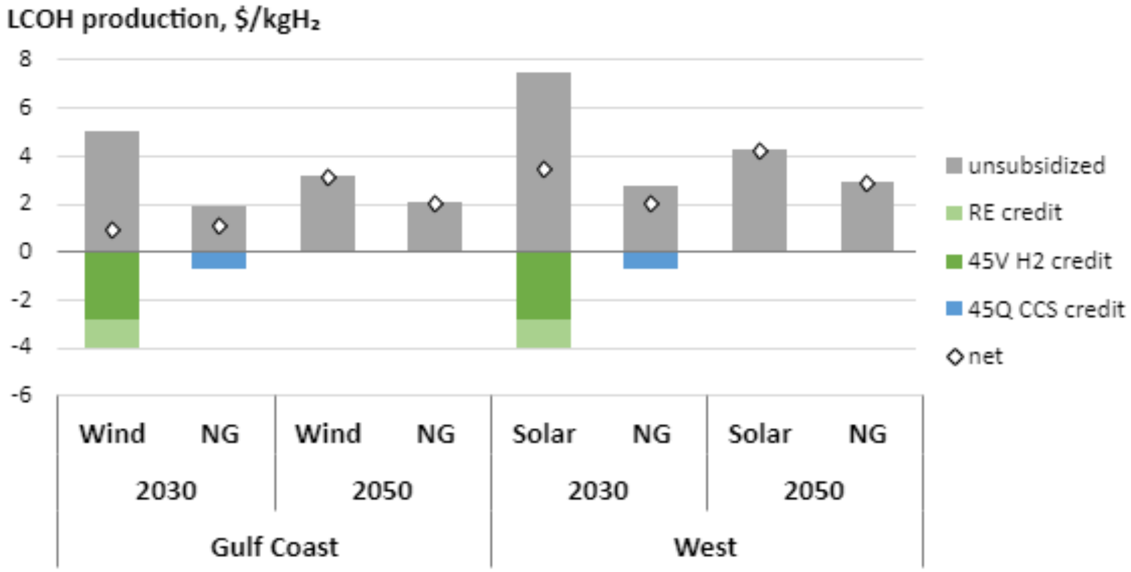
electrolysis plant of that vintage. Projects modeled to startup in 2035 or later receive no credit.[61]

Production using dedicated VRE to drive electrolysis is assumed to receive the maximum 45Y credit of \$3/kgH_2. This production route is also eligible to receive the 45Y credit for the RE generated to make H_2, since the IRA allows these credits to be stacked.[62] Natural gas-based LCI H_2 projects are assumed to take the 45Q credit instead of the 45Y credit (the IRA does not allow these to be stacked) because CI_p is projected to be greater than 1.5 kgCO_2e/kgH_2 (see Figure 2-18) so only the lowest tier 45V credits are available.

As the results in Figure 2-32 show, unsubsidized VRE-based LCI H_2 is projected to remain higher cost than natural gas-based LCI H_2 over the Modeling period. This is true even under the NZ2050 scenario (shown) in 2050 after assumed reductions in electrolytic hydrogen plant and renewable power costs. However, the ~\$4/kgH2 subsidy currently available to VRE-based LCI LCI H_2 is quite significant.

On a subsidized basis, and assuming a 1.5:1 VRE:electrolyzer overbuild, VRE-based LCI H_2 production becomes marginally lower cost in many regions, like the Gulf Coast, by 2030.

After this policy expires, the pathways will again compete on an unsubsidized basis. The study's Modeling indicates that the cost of VRE-based LCI H_2 production will not have fallen enough, even by 2050, to match LCI H_2 production by natural gas reforming.



Note: Wind and solar data represent the best VRE resource for each region, calculated assuming a VRE:electrolyzer overbuild of 1.5:1. Natural gas data based on the ATR+95% CO_2 capture pathway under theNZ2050 scenario. The credits shown reflect levelized tax credits as explained in Appendix Z.

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[61] Note that, on a hydrogen basis, the RE tax credit is smaller when the electrolysis plant is more efficient.

[62] The RE PTC is assumed for electricity used to generate hydrogen. In cases where VRE overbuild results in curtailed electricity, the excess is not credited.

Figure 2-32. Comparison of Production Cost for LCI H_2 Made by VRE-Electrolysis and Natural Gas Reforming in Gulf Coast and West Regions

Production costs only tell part of the story. The full cost of hydrogen delivered to the customer, which includes both production and infrastructure costs associated with transporting and storing hydrogen, is explored in Chapter 4: Integrated Supply Chain. The contributions are incorporated into an optimization algorithm to determine the production and infrastructure pathways that yield the lowest cost of delivered hydrogen. Those optimized results, not the ones presented in this chapter, were used as inputs to the Model.

VI. FACTORS IMPACTING SUPPLY BUILDOUT

All LCI H_2 production facilities have buildout challenges. In this section those challenges will be called out and summarized. More details relating to infrastructure, policy and social issues are found in later chapters.

A. Policy

This study underscores the need for a total of ~75 million tons of LCI H_2 to meet U.S.-stated policy goals of achieving net zero emissions. However, in the short-term, there's a notable reliance on fossil fuel-produced hydrogen with carbon capture, comprising more than 70% of the announced capacity in the United States.

To align to achieve the U.S. goal of net zero emissions by 2050, there is a call for policies to focus on creating and utilizing LCI H_2. This strategic emphasis aims to transition from higher carbon-intensive production methods to more sustainable alternatives. Specifically, the policy suggests supporting hydrogen production units with a CI of less than or equal to 4 kg CO_2 equivalent per kilogram of hydrogen ($\leq$4 kg CO_2eq/kg H_2).

Furthermore, there's a tiered approach proposed, advocating support for hydrogen production methods with CI levels of $\leq$2.5 kg CO_2eq/kg H_2, $\leq$1.5 kg CO_2eq/kg H_2 and even $\leq$0.45 kg CO_2eq/kg H_2. This approach reflects a commitment to fostering hydrogen production with increasingly lower carbon footprints.

Integrating renewable energy sources and low-cost NG+CCS into hydrogen production processes is crucial for achieving these ambitious targets. The benefits extend beyond environmental advantages, potentially encompassing economic growth, job creation, and energy independence, rendering them attractive on a global scale.

The DOE's innovative approach entails tax credits to LCI H_2 producers, with the credit amount tied to the carbon emissions generated during hydrogen production. This incentivizes producers with a credit potential of up to \$3/kg H_2, creating a compelling economic landscape for electrolyzer hydrogen produced using renewable energy. The anticipated result is a promising cost reduction.

Simultaneously, the IRA introduces a nuanced provision to stimulate the energy storage technology sector. This provision establishes a 30% credit tailored specifically for hydrogen-related storage projects and applies to those constructed before January 2025. The strategic intent behind this provision is to encourage the development of hydrogen storage infrastructure, thereby providing critical support for the overall growth of the hydrogen industry.

The broader context of the IRA's tax credits and incentives provisions aims to expedite the transition to a cleaner, more sustainable energy future. By providing financial support and enabling NG + CCS and renewable electricity based LCI H_2 economically viable, the IRA seeks to jumpstart the development of LCI H_2 production in the United States.

The IRA takes center stage by introducing the hydrogen production tax credit, a mechanism offering production tax credits (PTCs) to stimulate the development of LCI H_2 production. While the PTCs play a critical role in expanding LCI H_2 production, it is acknowledged that creating a sustainable market demands not just incentives, but also a corresponding demand for hydrogen. This necessitates new or modified policies, investments in research and development, the establishment of infrastructure, the decarbonization of the electric grid, significant capital investments in renewable energy, and public education about the benefits of hydrogen.

The U.S. Treasury and IRS proposed guidance for claiming the 45V Clean Hydrogen Production Tax Credit was issued for comment on December 22, 2023. The move is part of the administration’s broader efforts to support hydrogen and other technologies that will enable the United States to cut emissions from so-called hardest-to-abate sectors of the economy, including heavy industry and long-haul transportation. However, there are acknowledged challenges related to the tax credit’s structure and implementation, with potential impacts on hydrogen production in the short, medium, and long term.

Noteworthy research and think tank studies are underway, delving into the potential effects and implications of the LCI H_2 production tax credit on various facets of the hydrogen industry. These studies encompass production costs, market competitiveness, technology deployment, and overall decarbonization efforts. The findings from these studies are anticipated to provide valuable insights, informing the final design and implementation of the tax credit.

The H_2 production tax credit is positioned as a pivotal driver for the growth of the hydrogen sector. It encourages investment in low-carbon technologies and expedites the transition to lower emissions and energy alternatives. The enactment of the IIJA in November 2021, and the IRA in August 2022, solidifies the commitment with a substantial allocation of $9.5 billion for clean hydrogen and significant tax credits for hydrogen production. Both acts include short-term hydrogen-specific programs, underlining the government’s focus on fostering hydrogen-related initiatives.

The Clean Hydrogen Production Tax Credit further strengthens the commitment to environmentally conscious choices in hydrogen production. This credit introduces a dynamic incentive structure that adjusts based on the CI of the chosen hydrogen production method. The credit utilizes the Argonne National Laboratory’s Gases, Regulated Emissions, and Energy Use in Technologies (GREET) model to evaluate the CI of hydrogen production methods. Integrating the GREET model into the credit enhances its effectiveness and transparency, aligning policy incentives with data-driven environmental impact assessments.

The IIJA and IRA provide a platform for advancing CCS for fossil fuel-generated hydrogen production. The IRA and IIJA also offer funding and incentives for hydrogen infrastructure projects, encompassing pipelines, refueling stations, and power-to-gas facilities. These projects aim to enhance the accessibility and affordability of hydrogen for various end-use applications, including transportation, power generation, and industrial processes. By bolstering hydrogen infrastructure, the IRA and IIJA facilitate the integration of hydrogen into the broader energy system, creating new markets and opportunities for hydrogen utilization.

In summary, these federal programs illustrate a comprehensive landscape of governmental initiatives, tax credits, and strategic policies to foster the growth of the hydrogen sector. The multifaceted approach encompasses incentivizing LCI H_2 production, supporting storage infrastructure, and addressing challenges associated with tax credits. These concerted efforts are underpinned by a commitment to environmental sustainability, economic growth, and establishing hydrogen as a crucial player in the evolving energy landscape but will require additional policy to drive end-use applications.

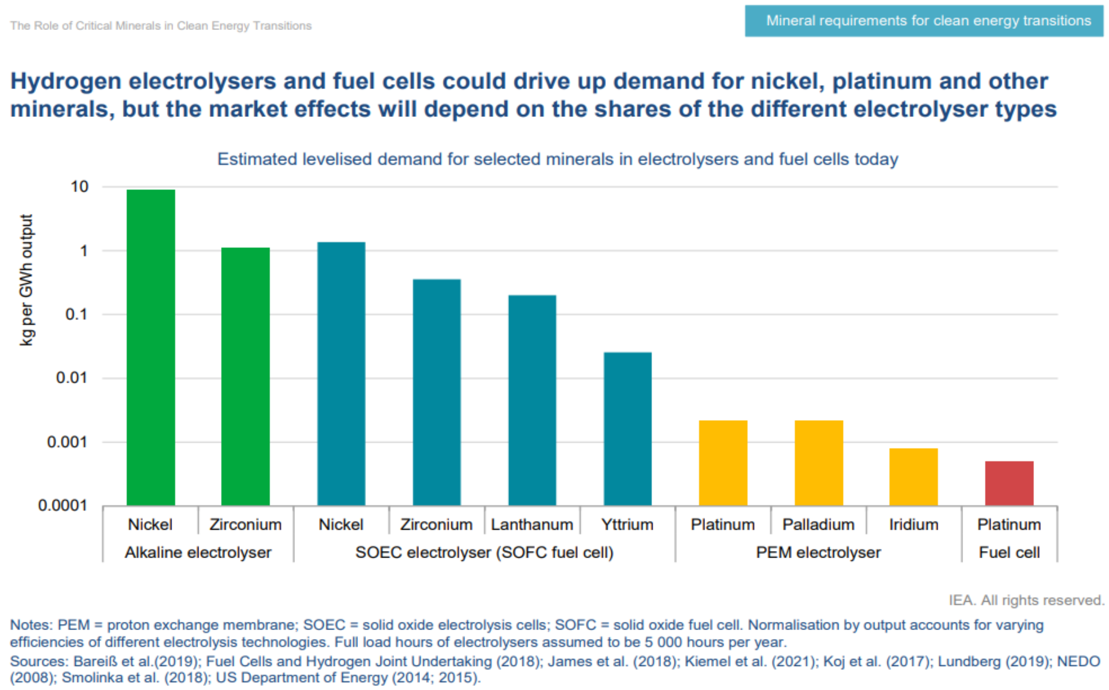
B. Electrolyzer Manufacturing

Electrolyzer manufacturing involves various aspects, such as costs, scale-up, mass production, durability, lifespan, efficiency, performance, materials selection, and critical mineral shortages. These aspects pose different technical, economic, and environmental issues that require further research, development, and innovation.

One of the primary challenges of electrolyzer manufacturing is reducing the costs of all electrolyzer technologies and sourcing critical elements needed for electrolyzer units as depicted in Figure 2-33. Currently, the materials and components used in electrolyzer manufacturing can be expensive, such as the electrodes, the electrolytes, the membranes, the catalysts, and the power electronics. Finding cost-effective alternatives and optimizing manufacturing processes are essential to making electrolyzers more affordable and competitive with other hydrogen production methods. For example, research into new catalyst materials, such as nonprecious metals or nanomaterials, can reduce the reliance on expensive and rare metals, such as platinum and iridium. Similarly, research into new membrane materials, such as polymer composites or ceramic materials, can improve the durability and performance of electrolyzers while lowering the costs.

Another challenge of electrolyzer manufacturing is scaling up and mass producing them to meet the growing demand for renewable hydrogen. However, there exists a “chicken and egg” dilemma: manufacturers need committed large orders to justify the investment of scaled electrolyzer production facilities while the customers need the lower costs enabled by scale to justify the investment. Unless manufactures and customers can make large investment commitments, the scaling process will slow. If the “chicken and egg” problem can be solved, manufacturers must develop streamlined production processes and supply chains to increase output and reduce unit costs. This may involve adopting advanced manufacturing techniques, such as additive manufacturing, automated assembly, or modular design, to enhance the efficiency and flexibility of electrolyzer production. Moreover, manufacturers must also coordinate with other stakeholders, such as power utilities, hydrogen distributors, and end users, to ensure the integration and compatibility of electrolyzers with the existing and planned energy infrastructure. A February 2023 Ernst and Young report on a shortage of electrolyzers with the current global manufacturing output of all types is 5,600 MW, with a 6x growth ambition to 37,000 MW by 2025 and a 10x growth ambition to 60,000 MW by 2050.[63]

To meet the electrolytic hydrogen production rates estimated in the Model (7 MMTpa in 2030 increasing to 52 MMTpa in 2050), installed electrolysis capacity must grow from 65 GW in 2030 to 409 GW by 2050, with annual capacity additions of 13 to 19 GW per year over that period.



The Role of Critical Minerals in Clean Energy Transitions

Mineral requirements for clean energy transitions

Hydrogen electrolysers and fuel cells could drive up demand for nickel, platinum and other minerals, but the market effects will depend on the shares of the different electrolyser types

Notes: PEM = proton exchange membrane; SOEC = solid oxide electrolysis cells; SOFC = solid oxide fuel cell. Normalisation by output accounts for varying efficiencies of different electrolysis technologies. Full load hours of electrolysers assumed to be 5 000 hours per year.
Sources: Bareiß et al.(2019); Fuel Cells and Hydrogen Joint Undertaking (2018); James et al. (2018); Kiemel et al. (2021); Koj et al. (2017); Lundberg (2019); NEDO (2008); Smolinka et al. (2018); US Department of Energy (2014; 2015).

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Source: Bareiß et al., (2019); Fuel Cells and Hydrogen Joint Undertaking (2018); James et al., (2018); Kiemel et al. (2021); Koj et al., (2017); Lundberg (2019); NEDO (2008); Smolinka et al., (2018); U.S. DOE (2014; 2015)

Figure 2-33. Critical Elements by Electrolyzer Manufacturing Type

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[63] Shortage of electrolyzers for green hydrogen, Ernst & Young, February 2023

Electrolyzers must have a long operational life to justify their investment and contribute to sustainable hydrogen production. Therefore, enhancing the durability and reliability of electrolyzer components, such as the electrodes, membranes, catalysts, and seals, is crucial to extending their lifespan and reducing maintenance costs. This may involve developing and testing new materials, coatings, or designs that can withstand the operating conditions and prevent corrosion, fouling, or degradation. Enhancing the durability and lifespan of electrolyzers will require further research.

Electrolyzer manufacturing is improving their efficiency and performance but more is needed. Efficiency is a measure of how much electricity is converted to hydrogen during the electrolysis process. Higher efficiency translates to more cost-effective and energy-efficient hydrogen production. However, electrolyzers are subject to various losses, such as ohmic losses, activation losses, and concentration losses, which reduces their efficiency and performance. Improving this is essential to minimize energy losses and maximize hydrogen output. This may involve optimizing the operating parameters, such as the temperature, the pressure, the current density, and the water flow rate, as well as improving the design and configuration of electrolyzer components, such as the electrodes, the membranes, the catalysts, and the interconnectors.

Electrolyzer manufacturing is a key challenge and opportunity for the development and deployment of electrolysis technology and renewable hydrogen production. Electrolyzer manufacturing involves various aspects, such as costs, scale-up, mass production, durability, lifespan, efficiency, performance, materials selection, and critical mineral shortages, which pose different technical, economic, and environmental issues that require further research, development, and innovation. By addressing these issues and adopting supportive measures, electrolyzer manufacturing can enable the production of renewable hydrogen and contribute to the decarbonization and diversification of the energy system.

C. Renewables Availability

Given the large contribution of renewable power required for electrolysis H_2 production, having low-cost renewable energy and enough renewable energy available is a hurdle for electrolysis. As noted above, installed electrolysis capacity increases to over 400 GW by 2050 under the NZ2050 scenario. To supply these electrolyzers at low to mid-60s% capacity factor with renewable energy, a renewable overbuild ratio of 1.5 to 2 is needed, so the required renewable resource capacity is on the order of 600 to 800 GW.

As the United States transitions toward electrification and increases the integration of renewable energy sources, the electricity grids face significant challenges to keep up with this transition. Some of the key challenges include:

1. The variable and intermittent nature of renewable energy sources like solar and wind can cause fluctuations in electricity generation, challenging grid stability and requiring advanced grid management techniques and energy storage systems to ensure a reliable power supply. As more electric vehicles, and other electrified technologies are adopted, the demand for electricity increases. Grid capacity will need to be expanded or reinforced to handle the higher loads, especially in areas

with rapid urbanization and population growth.[64] The rise of small-scale renewable energy installations, energy storage systems, and smart devices at the consumer level adds complexity to grid management. Integrating these distributed energy resources into the grid effectively requires advanced grid management and communication technologies. Upgrading and expanding the electricity grid to accommodate rapid electrification requires significant investments. Ensuring adequate funding for grid modernization projects is crucial to keep up with the pace of electrification.

2. Clear and supportive regulatory and policy frameworks are essential for incentivizing grid operators and energy companies to invest in grid modernization and upgrade. To facilitate the integration of renewable energy sources across regions, interconnecting different grids becomes necessary. Additionally, maintaining a stable power supply is vital to ensuring grid resilience against extreme weather events and cyber threats. Encouraging demand-response programs and flexible electricity pricing can help manage peak loads and balance supply and demand, especially during high renewable energy production. Addressing these challenges requires a collaborative effort among governments, grid operators, energy companies, technology providers, and consumers. Innovative grid solutions, energy storage technologies, advanced grid management systems, and demand-side management strategies are essential to ensure the grid can cope with rapid electrification and integrate renewable energy sources effectively. Moreover, fostering innovation and research in grid technologies can lead to more efficient and resilient grid infrastructure. An increase in available renewable energy is required for producing hydrogen through electrolysis. The DOE must incentivize and promote deploying renewable energy sources, as these measures are essential for ensuring the sustainable growth of LCI H_2 production. Besides the current tax credits, a market for feed-in tariffs, renewable energy certificates, or direct subsidies for renewable energy producers must be encouraged. Facilitating long-term Power Purchase Agreement (PPAs) between renewable energy producers and hydrogen producers should be encouraged. PPAs provide stable revenue streams for renewable energy projects, making them more attractive to investors and ensuring a reliable supply of clean energy for hydrogen production. Massive grid infrastructure investment is needed by upgrading transmission lines, expanding storage capacity, and improving demand-response capabilities to manage fluctuations in renewable energy generation to accommodate the increased renewable energy capacity required.

D. Hydrogen Storage

Hydrogen storage is a key component of the hydrogen supply chain, as it can balance the supply and demand of hydrogen and provide flexibility and security for the hydrogen market. However, hydrogen storage, in general and especially at scale, is more expensive with fewer

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[64] https://www.mckinsey.com/industries/electric-power-and-natural-gas/our-insights/how-grid-operators-can-integrate-the-coming-wave-of-renewable-energy

options than liquid fuels or natural gas. It can be stored in gaseous or liquid form in above ground pressure vessels or underground in geological storage. The comparatively low volumetric energy density of gaseous hydrogen and facilities needed to keep liquid hydrogen in its liquid phase are key contributors to the above ground storage costs.

Geologic hydrogen storage has several advantages over other storage methods, such as high storage capacity, low leakage rate, and low environmental impact. However, geologic hydrogen storage also has some challenges, such as site selection, injection and extraction methods, safety and monitoring systems, and legal and regulatory frameworks. This is further discussed in Chapter 3: Infrastructure.

E. Carbon Capture and Storage Infrastructure Availability

As noted in this study, natural gas-based hydrogen production with carbon capture and sequestration is a key LCI H_2 pathway if we are to achieve our NZ2050 ambition. While there are many attractive regions with suitable subsurface conditions to accommodate CO_2 sequestration, and large-scale CO_2 capture technology exists today and is well referenced,[65] CCS faces several challenges, such as high costs, public acceptance, and regulatory barriers that need to be overcome to enable its widespread deployment.

To understand the additional challenges to be overcome and enable at-scale production of LCI H_2 via natural gas-based pathway, we recommend the reader refer to the 2019 NPC Report: *Meeting the Dual Challenge, A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage*, *Volume III, Chapter 5 – Carbon Capture*.

F. Potential Resource Limitations

Hydrogen production depends on several factors, such as the availability of resources, the production method, and the region. Water and land availability affect hydrogen production. Different regions may face different challenges and opportunities for sustainable hydrogen production.

Hydrogen production is a complex and diverse process that depends on various factors, such as the availability of resources, the production method, and the region. Water and land are two important resources that affect hydrogen production and pose different challenges and opportunities for sustainable development. Moreover, infrastructure is another key factor that influences hydrogen production and distribution and requires coordination and collaboration among various actors. By addressing these factors and adopting a holistic and integrated approach, hydrogen production can be a viable and beneficial option for achieving a lower emissions and resilient energy system.

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[65] https://www.energy.gov/sites/default/files/2021-09/h2-shot-summit-panel2-methane-pyrolysis.pdf.

1. Water

While hydrogen is a clean energy carrier, almost all hydrogen production pathways require sustainable, long-term access to significant quantities of water, which can have implications for water availability, and disposal options in different regions.

In a steam methane reformer, water is used as a reactant in both the SMR reaction and the water-gas shift reaction, where it is introduced in the form of pressurized steam. The stoichiometry of the process dictates that approximately 4.5 kg (~1.2 gallons) of deionized water is required to produce 1 kg of hydrogen. However, the actual water consumption for hydrogen production can vary significantly, ranging from 5.7 to 19 kg (or 1.5 to 5 gallons) per kg of hydrogen.[66] This variation is influenced by several factors, including whether the production is centralized or distributed, whether there is recycling of steam condensate, and the type of cooling technology employed. Furthermore, when CCS is integrated into the process, the water demand for natural gas-reformed hydrogen is expected to increase. This is due to the introduction of additional unit operations such as amine-based carbon capture and CO_2 compression.[67] In the context of meeting the supply projections for the NZ2050 case, a minimum of 125 million gallons per day (MGD) of deionized water would be required to supply ~30 MMTpa of natural gas-reformed H_2, based on a ratio of 1.5 gallons per kg of H_2. If we consider a higher ratio of 5 gallons per kg of H_2, the source water requirement could potentially exceed 500 MGD.

In electrolysis, high purity water is required as a feedstock to produce hydrogen. Theoretically, the water demand for this process is 8.9 kg (~2.4 gallons) for every kg of hydrogen produced. However, in practice, the actual water demand can be higher due to water treatment reject rates or cooling. In published specifications from electrolysis equipment providers water consumption ranges in liters per kg of hydrogen are 9.5 to 17 for alkaline, 10 to 13 for PEM, and 9.1 to 11 for solid oxide. For large-scale systems developers may choose to use water cooling towers for PEM or alkaline systems, which could triple water consumption over the theoretical value.[68]

Using the high end of the published water consumption values of 17 liters per kg of hydrogen, the ~52 million annual metric tons production modeled in the NZ2050 scenario will require 2,400 million liters (640 million gallons) of water per day. This is a relatively small number when compared to water use for the power industry and irrigation sector, which was at 151 billion gallons per day based on U.S. Geological Survey (USGS) data for 2015.[69] However, on a regional level, water use for hydrogen production can be significant as water is increasingly becoming a challenging resource in certain geographies (see Figure 2-34 below). Some of the states that are considered high water stress are identified as darker red areas. In these areas, hydrogen projects would have to compete with local demand for ranching, farming, and domestic use. One alternative might be the use of brackish groundwater to meet supply challenges in such regions. While technically feasible, this option also has challenges on the effluent discharge of salty brine or reject stream from the process. These locations being many

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[66] Reference Life Cycle Analysis of Water Consumption for Hydrogen Production (energy.gov)

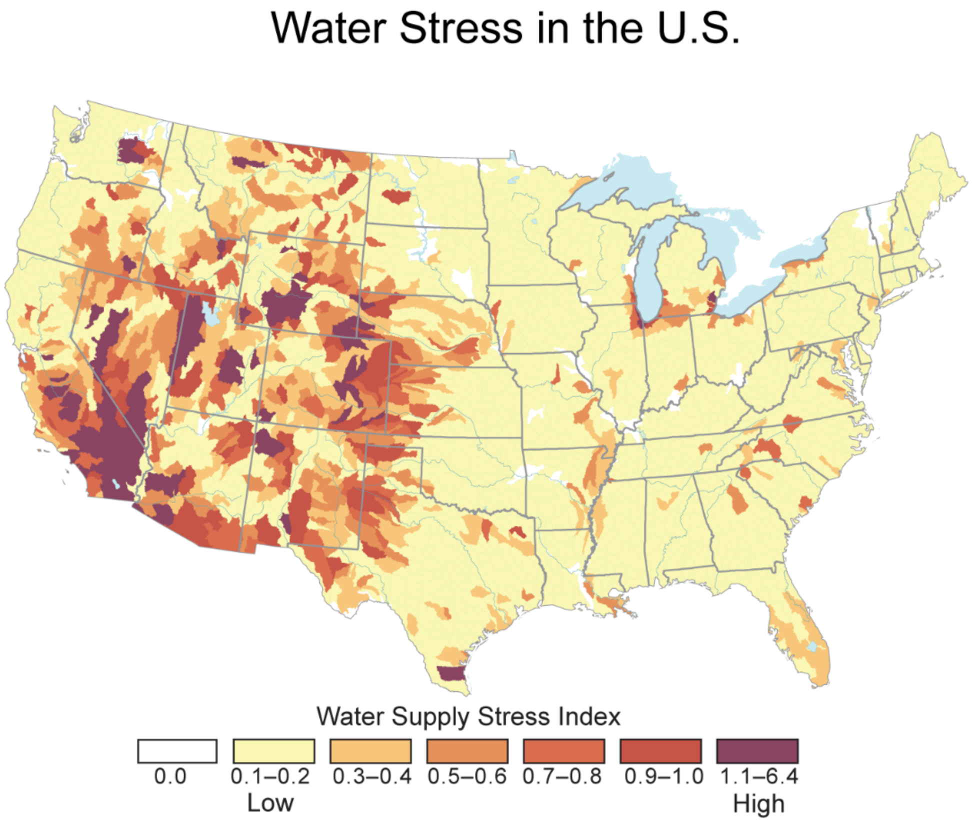
[67] Water Considerations for the Energy Transformation (epri.com)

[68] https://publicdownload.epri.com/PublicAttachmentDownload.svc/AttachmentId=85268

[69] Total Water Use in the United States | U.S. Geological Survey (usgs.gov)

miles away from the coast, project developers would have to often consider installing expensive evaporation ponds or crystallization technologies, both of which can increase land use and opex significantly. Additional approaches to address high water stressed areas feedstock supply are being studied and demonstrated, including the use of undervalued water resources.

If areas of abundant solar and wind power were overlayed on Figure 2-34, we would see a high correlation of these two factors within regions. This would put even more stress on the limited power transmission capability and highlight the electric grid as a potential resource limitation.



Source: Averyt et al., 2011, https://data.globalchange.gov/report/nca3/chapter/water-energy-land-use/figure/water-stress-in-the-us

Figure 2-34. Water Supply Stress Index

2. Land

Land is another resource that may affect hydrogen production through renewable energy-based methods like electrolysis and biomass gasification. These methods may require land for installing solar panels, wind turbines, or biomass facilities. The amount of land needed depends on the scale of production and the energy source used. This land can often be co-located with existing renewable energy installations, optimizing land usage but expanding the production footprint.

Hydrogen production through renewable energy-based methods, such as electrolysis and biomass gasification, is a promising way to produce clean and LCI H_2 for various applications. However, these methods may also require land for installing renewable energy facilities, such as solar panels, wind turbines, or biomass plants. The use of land for hydrogen production, renewable energy, has several implications for the environment, the economy, and the society.

The amount of land needed for hydrogen production and its renewable energy depends on the scale of production and the energy source used. For example, a study by IRENA[70] estimated that producing 1 kg of hydrogen from solar PV electrolysis would require 0.12 acres of land, while producing the same amount from wind electrolysis would require 0.02 acres of land. These land requirements are comparable to those of other renewable energy technologies, such as biofuels or geothermal power. However, they are higher than those of fossil fuel-based hydrogen production methods, such as natural gas reforming or coal gasification, which typically require less than 0.0002 acres of land per kg of hydrogen.[71]

The use of land for hydrogen production, renewable energy, can have both positive and negative impacts on the environment. On the one hand, it can reduce GHG emissions and air pollution as an alternative to fossil fuels and enhancing carbon sequestration. On the other hand, it can affect land use change, biodiversity, soil quality, and water resources by altering the natural ecosystems and competing with other land uses, such as agriculture, forestry, or urban development. Therefore, the environmental impacts of land use for hydrogen production, renewable energy, should be assessed and mitigated through careful site selection, planning, and management. For example, renewable energy facilities can be co-located with existing infrastructure, such as roads, power lines, or pipelines, to minimize land disturbance and fragmentation. They can also be integrated with other land uses, such as grazing, farming, or recreation, to create synergies and benefits for the local communities.[72]

The use of land for hydrogen production, renewable energy, can also have economic and social implications. It can create new opportunities for income generation, employment, and innovation by stimulating the development of the renewable energy and hydrogen sectors. It can also increase the energy security and resilience of the regions by diversifying the energy sources and reducing the dependence on imported fuels. However, it can also pose challenges for the landowners, the developers, and the regulators by involving complex and uncertain legal, regulatory, and financial issues. For example, land tenure reforms may be needed to clarify the rights and responsibilities of the different stakeholders and to facilitate the access and acquisition of land for renewable energy and hydrogen projects. Moreover, public acceptance and participation may be essential to ensure the social and environmental sustainability of the land use for hydrogen production, renewable energy. Therefore, the economic and social impacts of

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[70] https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2020/Dec/IRENA_Green_hydrogen_cost_2020.pdf

[71] https://www.irena.org/publications/2022/May/Global-hydrogen-trade-Cost

[72] https://www.gtlaw.com.au/knowledge/greener-pastures-land-tenure-other-legal-reforms-flagged-was-renewable-or-green-hydrogen; https://www.bloomberg.com/graphics/2021-energy-land-use-economy/

land use for hydrogen production, renewable energy, should be evaluated and enhanced through stakeholder engagement, consultation, and collaboration.[73]

Land use for hydrogen production and renewable energy is a complex and multifaceted issue that requires a holistic and integrated approach. It can potentially contribute to the decarbonization and diversification of the energy system, but it also entails environmental, economic, and social trade-offs and challenges. By addressing these aspects and adopting best practices and policies, the use of land for hydrogen production, and renewable energy can be a viable and beneficial option for achieving a clean and resilient energy future.

3. Renewable Natural Gas

Renewable natural gas (RNG) is a potential feedstock for hydrogen production, especially in regions with established biogas or biomethane production from organic waste. This source is renewable and can provide a sustainable pathway for producing limited amounts of hydrogen. However, RNG production may also require land for collecting and processing organic waste, such as agricultural residues, municipal solid waste, or wastewater. The availability and quality of these waste streams may vary depending on the region and the season. Moreover, RNG production may compete with other uses of organic waste, such as composting, animal feed, or biofuels. Therefore, policymakers and industries should evaluate the potential benefits and trade-offs of using RNG for hydrogen production in different regions and scenarios.

4. Associated Infrastructure

Infrastructure is another key factor that influences hydrogen production and distribution. Hydrogen production facilities require access to electricity, water, and gas networks, as well as transportation and storage infrastructure. The availability and reliability of these infrastructure elements may vary depending on the region and the production method. For example, regions with high renewable energy penetration may have intermittent and variable electricity supply, which could affect the efficiency and stability of electrolysis. Similarly, regions with limited gas pipeline networks may face challenges in transporting and distributing hydrogen produced from natural gas or RNG. Therefore, hydrogen production projects should consider the existing and planned infrastructure development in the region and coordinate with relevant stakeholders to ensure smooth and safe operation.

G. Permitting

1. Direct Emissions

Hydrogen production is also subject to the CAA, a federal law that regulates air emissions from stationery and mobile sources to protect public health and the environment from air pollution. The CAA authorizes hydrogen production plants in several ways, but it also imposes certain requirements and standards for reducing emissions and ensuring environmental

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[73] https://www.gtlaw.com.au/knowledge/greener-pastures-land-tenure-other-legal-reforms-flagged-was-renewable-or-green-hydrogen; https://www.energy.gov/eere/fuelcells/hydrogen-production; https://www.bloomberg.com/graphics/2021-energy-land-use-economy/

sustainability. Electrolyzers do not have air emissions, but emissions permitting will apply to NG+CCS.

One of the ways that the CAA authorizes hydrogen production plants under the New Source Review (NSR) permitting program, which requires new or modified major stationary sources of air pollution, such as hydrogen production plants, to obtain permits before construction or modification. The NSR permits ensure that the hydrogen production plants meet the best available control technology (BACT) or the lowest achievable emissions rate (LAER) standards for reducing emissions of criteria pollutants and greenhouse gases. The NSR permitting program consists of two types of permits: Prevention of Significant Deterioration (PSD) permits and Nonattainment New Source Review (NNSR) permits. PSD permits apply to sources located in areas that meet the National Ambient Air Quality Standards (NAAQS), while NNSR permits apply to sources located in areas that do not meet the NAAQS.[74]

The NSR permitting program aims to protect air quality and public health by ensuring that new or modified sources of air pollution are as clean as possible and that advances in pollution control occur concurrently with industrial expansion.[75]

To obtain an NSR permit, the owner or operator of a steam methane reformer must determine whether the new source will emit, or the modification will increase air emissions above certain thresholds, known as significant emissions rates or major modification thresholds. These thresholds vary depending on the pollutant and the type of permit. If the thresholds are exceeded, the owner or operator must conduct a BACT analysis for PSD permits or a LAER analysis for NNSR permits. These analyses require the owner or operator to identify and implement the most effective and feasible emissions control technologies for the steam methane reformer.[76]

The CAA establishes the National Emission Standards for Hazardous Air Pollutants (NESHAPs), which set limits on the emissions of hazardous air pollutants. The NESHAPs require the hydrogen production plants to meet the maximum achievable control technology standards or the generally available control technology standards for reducing emissions of hazardous air pollutants.

The CAA provides incentives and support for the development and deployment of clean hydrogen production technologies, such as CCS, low-GHG hydrogen co-firing, and renewable energy-based electrolysis. The CAA authorizes the EPA to conduct RD&D projects on clean hydrogen production technologies and to provide grants, loans, and tax credits for their implementation. It also allows the EPA to issue regulations and guidance for the safe and effective operation of clean hydrogen production technologies and to coordinate with other federal agencies and stakeholders on their integration into the energy system.

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[74] https://www.epa.gov/nsr

[75] https://19january2021snapshot.epa.gov/nsr_.html

[76] https://www.epa.gov/newsreleases/epa-continues-improve-and-clarify-clean-air-permitting-process; https://19january2021snapshot.epa.gov/nsr_.html

Additionally, the owner or operator of a steam methane reformer must comply with the National Environmental Policy Act (NEPA), which requires federal agencies to evaluate the environmental impacts of their actions and to involve the public in the decision-making process. NEPA applies to steam methane reformers that receive federal funding, permits, or approvals, such as NSR permits. Under NEPA, the federal agency responsible for issuing the NSR permit must prepare an Environmental Assessment (EA) or an Environmental Impact Statement (EIS) to assess the potential environmental effects of the proposed steam methane reformer project and to consider alternatives and mitigation measures. The EA or EIS must be made available for public review and comment before the final decision is made.

Air permitting of steam methane reformers under the new source permit review and NEPA is a complex and rigorous process that requires the owner or operator of the steam methane reformer to obtain an NSR permit and to comply with NEPA. The process involves determining the applicability of the NSR program, conducting emissions control analyses, and evaluating the environmental impacts of the steam methane reformer project. The process also involves public participation and consultation with relevant stakeholders. By following this process, the owner or operator of the steam methane reformer can ensure that the project meets the legal and environmental requirements and standards.

2. Carbon Capture and Storage

In addition to the permit requirements for a natural gas reformer, there are permit requirements for CCS. The 2019 NPC Report: *Meeting the Dual Challenge, A Roadmap to At-Scale Deployment of Carbon Capture, Use and Storage*, *Volume III, Chapter 5 – Carbon Capture* provided an in-depth discussion on permitting considerations.

Carbon capture units are required to ensure that amine scrubbing units comply with local and federal air quality standards. Typically, the vent gases from the capture system should not increase or appear to increase particulate matter-2.5 from ammonia/amine emissions.

According to the U.S. EPA, Class VI wells are used for injecting CO_2 into deep rock formations for long-term storage to reduce emissions to the atmosphere. The EPA's Underground Injection Control (UIC) program regulates the injection of fluids into the subsurface for storage or disposal, including CO_2. The Class VI well requirements are designed to protect public health and underground sources of drinking water (USDWs) from the unique nature of CO_2 injection for geologic sequestration, including the relative buoyancy of CO_2, subsurface mobility, and corrosivity in the presence of water. The permit application for a Class VI well must include substantial information that includes a map of the "area of review," showing "all injection wells, producing wells, abandoned wells, plugged wells or dry holes, deep stratigraphic boreholes," and "faults, if known or suspected." The EPA has developed requirements and provisions for the UIC Program to protect USDWs, which are aquifers or parts of aquifers that supply a public water system or contain enough groundwater to supply a public water system now or in the future.

As of late 2023, the EPA has issued only two Class VI well permits. With a typical processing time of six years, there are more than 170 Class VI injection wells awaiting approval by the EPA. Expedited timeframes for review and approval of these Class VI injection-well applications will enable the planning and commercial development of new pipelines and sequestration infrastructure that are needed to capture, transport, and sequester CO_2 and meet decarbonization objectives.

3. Water

The type and number of water permits needed for electrolyzers and natural gas reformers may vary depending on the location, scale, and technology of the hydrogen production facility. However, some common water permits that may be applicable are:

Water withdrawal or abstraction permit: This permit allows the hydrogen production facility to withdraw or abstract water from a surface or groundwater source, such as a river, lake, well, or aquifer. The permit may specify the amount, rate, and timing of water withdrawal or abstraction, as well as the conditions and restrictions to protect the water source and the environment.

Water discharge or effluent permit: This permit allows the hydrogen production facility to discharge or release wastewater or effluent to a surface water body, such as a stream, pond, or ocean. The permit may specify the quality, quantity, and frequency of water discharge or effluent, as well as the monitoring and reporting requirements to ensure compliance with the water quality standards and regulations.

Water reuse or recycling permit: This permit allows the hydrogen production facility to reuse or recycle water within the facility or for other purposes, such as irrigation, cooling, or industrial processes. The permit may specify the quality, quantity, and treatment of water reuse or recycling, as well as the health and safety measures to prevent contamination and exposure.[77]

In addition to these water permits, the hydrogen production facility may also need to obtain other environmental permits, such as land use permits and waste management permits, depending on the production method and the environmental impacts of the facility. For example, steam methane reformers may need to obtain land use permits for their location and footprint. Electrolyzers may need to obtain waste management permits for their disposal or recycling of spent electrodes and electrolytes.

The process of obtaining construction and operating permits is similar and follows this general flow of events:

- Preapplication consultation begins the permit process and involves contacting and consulting with the relevant authorities and stakeholders, such as the local regulatory agency, environmental agency, local government, and the public, to identify the applicable permits, the requirements and criteria, and the potential issues and concerns for the hydrogen production facility.
- Application submission involves preparing and submitting the application forms and supporting documents, such as the facility design, the water balance, heat and material balance, the EA, and the mitigation plans, to the relevant authorities for review and approval.

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[77] https://www.slrconsulting.com/insights/environmental-permitting-of-hydrogen-production/

- Application review involves the evaluation and verification of the application by the relevant authorities, which may include site visits, technical analysis, public hearings, and inter-agency coordination, to determine the suitability and compliance of the hydrogen production facility.
- Permit issuance by the relevant authorities, which may include the permit conditions, limitations, and obligations, as well as the fees and charges, for the hydrogen production facility.
- Permit compliance involves the implementation and monitoring of the permit by the hydrogen production facility, which may include the installation and operation of the water and environmental control systems, the measurement and reporting of the environmental performance, and the inspection and auditing by the relevant authorities.

The process of obtaining water permits and other environmental permits for electrolyzers and steam methane reformers may take several months or years, depending on the complexity and scale of the hydrogen production facility, the availability and capacity of the relevant authorities, and the level of public involvement and participation. Typically, ground cannot be disturbed before permits are issued, therefore, the hydrogen production facility should plan ahead and allocate sufficient time and resources for the permitting process.

VII. ENVIRONMENTAL, SAFETY, AND SOCIETAL CONSIDERATIONS AND IMPACTS

A. Climate Concerns

Renewable hydrogen is a clean energy source that can help reduce GHG emissions by serving as an alternative to fossil fuels. However, renewable hydrogen also has challenges, such as the potential indirect global warming impact of hydrogen emissions and embedded emissions in renewables production. The global warming potential of hydrogen is discussed in Chapter 1: Role of LCI Hydrogen.

Embedded emissions are those that occur during renewables production, such as solar panel manufacturing or wind turbines. These emissions can reduce the net benefit of using renewables for hydrogen production.

To reduce the climate impact of a hydrogen economy, we need to minimize, prevent, and monitor hydrogen emissions and embedded emissions. We need to set industry standards, use better sensor technology and mitigation measures, and support research and development to improve the efficiency and safety of hydrogen production, storage, and use processes. We also need to consider the life cycle emissions of renewables and choose the most sustainable sources for hydrogen production. Hydrogen is a key technology and pathway for reaching U.S. net zero goals. Through thoughtful planning and research, we can safely secure a lower emissions hydrogen future.[78]

B. Safety and Societal Considerations and Impacts

As discussed in Chapter 7: Safety, Societal Considerations and Impacts, multiple federal agencies and their subsidiaries in the United States regulate, influence, or advance the safe and efficient production, transportation, storage, distribution, and use of hydrogen. This includes: the EPA, the Department of Transportation (DOT), the Pipeline and Hazardous Materials Safety Administration as part of DOT, the Surface Transportation Board, the Occupational Safety and Health Administration, the Federal Motor Carrier Safety Administration, the Federal Aviation Administration, and the Bureau of Safety and Environmental Enforcement are among those involved. The DOE's Hydrogen and Fuel Cell Technologies Office oversees conducting RD&D efforts to advance diverse technologies and infrastructure for hydrogen production, transportation, delivery, storage, and utilization. The RD&D efforts are focused on the materials, component, and system levels to address the cost, performance, durability, and safety requirements for widespread hydrogen adoption across multiple end-use sectors.

C. Addressing Concerns

Risk Identification and mitigation: In general, hydrogen producers and the hydrogen industry have been making significant efforts to minimize the risks associated with hydrogen handling and operating systems safely for nearly a century.[79] However, it's essential to remember that safety practices and technologies are evolving with research in private and government.

Some of the measures and advancements implemented by hydrogen producers to mitigate risks include:

- **Stringent Safety Standards:** Hydrogen producers adhere to strict safety standards set by regulatory authorities and industry organizations to ensure hydrogen production, storage, and transportation.
- **Risk Assessments:** Producers conduct thorough risk assessments at all stages of the hydrogen supply chain to identify potential hazards and implement appropriate safety measures.
- **Safe Storage and Handling:** Hydrogen producers use specialized storage methods and containers to safely handle hydrogen, including high-pressure tanks or cryogenic storage systems.
- **Safety Training and Procedures:** Employees involved in hydrogen production undergo comprehensive safety training to ensure they are knowledgeable about proper handling procedures and emergency protocols.

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[78] EDF website https://www.edf.org/hydrogen-climate-friendly-energy-solution-we-need

[79] https://safehydrogenproject.org/hydrogen-safety/#:~:text=Hydrogen%20has%20been%20safely%20produced,or%20environmental%20health%20if%20released.

- **Leak Detection Systems:** Advanced leak detection systems are employed to promptly identify and address any hydrogen leaks.
- **Hydrogen Purity Monitoring:** Regular monitoring of hydrogen purity helps ensure its quality and prevent contamination, which could increase safety risks.
- **Hydrogen Sensors and Alarms:** Hydrogen producers install sensors and alarms to detect potentially hazardous concentrations of hydrogen in the air.
- **Hydrogen Infrastructure Development:** Investments in infrastructure development aim to enhance the safety of hydrogen transportation and distribution.
- **Collaboration and Knowledge Sharing:** Hydrogen producers often collaborate with research institutions, government agencies, and industry partners to share best practices and promote safety advancements.

Despite these efforts, it is important to acknowledge that hydrogen handling still carries some inherent risks due to its flammability and potential for embrittlement in certain materials. Therefore, safety measures and continuous improvement remain crucial in ensuring the safe and sustainable growth of the hydrogen industry.

Hydrogen producers have a demonstrated record of minimizing risks associated with hydrogen handling. These activities include designing risk assessments, deploying training and education for operations personnel, developing emergency response planning, and enforcing proper handling and storage.

In addition to the environmental, safety, and societal impacts discussed above, the following considerations also need to be addressed:

- **Skepticisms toward H_2:** Industry could help inform the public amid growing interest and discourse around hydrogen as an abatement tool.
- **Societal awareness:** Government initiatives coupled with industry sponsored campaigns can facilitate hydrogen adaptation.
- **Cost concerns:** As industry continues to invest in LCI hydrogen scaling and deployment, costs are expected to decrease.
- **Feasibility:** Industry will continue to support demonstration of hydrogen technologies, such as fuel cell vehicles and hydrogen refueling stations, to provide tangible examples of hydrogen being leveraged in everyday life.
- **Emissions certification:** Potential H_2 suppliers are evaluating use of mass-based emissions (lbs/mmbtu or nanograms/joule and concentration-based emissions (ppm dry corrected for 15% O_2)) for measuring production-associated GHG, depending on stakeholder preference and concerns about immediate impact of emissions on air quality versus total amount of GHG emissions.