

GREEN HYDROGEN IN A CIRCULAR CARBON ECONOMY: OPPORTUNITIES AND LIMITS

BY ZHIYUAN FAN, EMEKA OCHU, SARAH BRAVERMAN,
YUSHAN LOU, GRIFFIN SMITH, AMAR BHARDWAJ, DR. JACK
BROUWER, DR. COLIN MCCORMICK, DR. JULIO FRIEDMANN
AUGUST 2021

ER

NATU

ABOUT THE CENTER ON GLOBAL ENERGY POLICY

The Center on Global Energy Policy at Columbia University SIPA advances smart, actionable and evidence-based energy and climate solutions through research, education and dialogue. Based at one of the world's top research universities, what sets CGEP apart is our ability to communicate academic research, scholarship and insights in formats and on timescales that are useful to decision makers. We bridge the gap between academic research and policy — complementing and strengthening the world-class research already underway at Columbia University, while providing support, expertise, and policy recommendations to foster stronger, evidence-based policy. Recently, Columbia University President Lee Bollinger announced the creation of a new Climate School — the first in the nation — to tackle the most urgent environmental and public health challenges facing humanity.

Visit us at www.energypolicy.columbia.edu

   @ColumbiaUEnergy

ABOUT THE CARBON MANAGEMENT RESEARCH INITIATIVE

The Carbon Management Research Initiative (CaMRI) at the Center on Global Energy Policy provides independent insight and data-driven analysis for private and public sector leaders navigating this new and complex landscape, leveraging the multidisciplinary scholars and the extensive technical expertise at Columbia University, including in law, business, science, engineering, finance, public policy and social science.

CaMRI is grateful for the time and perspectives of the Circular Carbon Economy project advisory committee, which includes individuals from across government, academia, civil society and industry with deep expertise across technology, policy, economics and finance relevant to enabling solutions to climate change. Current participants include:

- Mr. Brad Page, CEO, Global Carbon Capture & Storage Institute (Co-Chair)
- Mr. Ahmad Al-Khowaiter, CTO, Saudi Aramco (Co-Chair)
- Dr. Stephen Bohlen, Acting State Geologist, California Department of Conservation
- Ms. Heidi Heitkamp, Former Senator from North Dakota, U.S. Senate, United States of America
- Mr. Richard Kaufmann, Chairman, New York State Energy Research and Development Authority (NYSERDA)
- Ms. Maria Jelescu Dreyfus, CEO, Ardinall Investment Management
- Dr. Arun Majumdar, Director, Precourt Institute for Energy at Stanford University
- Dr. Nebojsa Nakicenovic, Former Deputy Director General/CEO, International Institute for Applied Systems Analysis (IIASA)
- Mr. Adam Sieminski, President, King Abdullah Petroleum Studies and Research Center (KAPSARC)
- Prof. Nobuo Tanaka, Former Executive Director, International Energy Agency (IEA) and Distinguished Fellow, Institute of Energy Economics Japan

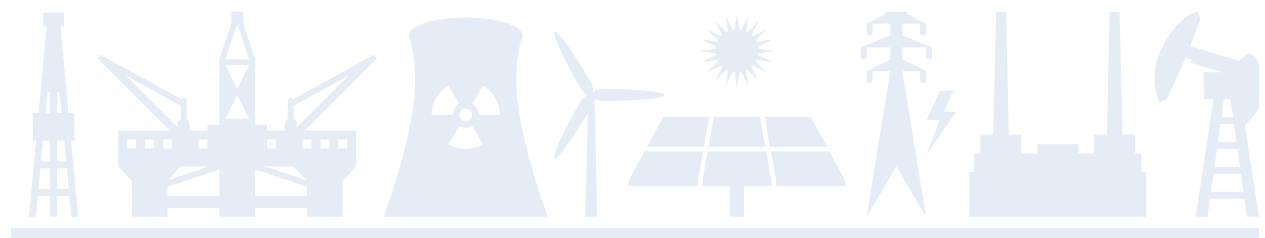
ABOUT THE SCHOOL OF INTERNATIONAL AND PUBLIC AFFAIRS

SIPA's mission is to empower people to serve the global public interest. Our goal is to foster economic growth, sustainable development, social progress, and democratic governance by educating public policy professionals, producing policy-related research, and conveying the results to the world. Based in New York City, with a student body that is 50 percent international and educational partners in cities around the world, SIPA is the most global of public policy schools.

For more information, please visit www.sipa.columbia.edu

GREEN HYDROGEN IN A CIRCULAR CARBON ECONOMY: OPPORTUNITIES AND LIMITS

BY ZHIYUAN FAN, EMEKA OCHU, SARAH BRAVERMAN,
YUSHAN LOU, GRIFFIN SMITH, AMAR BHARDWAJ, DR. JACK
BROUWER, DR. COLIN MCCORMICK, DR. JULIO FRIEDMANN
AUGUST 2021



Columbia University CGEP
1255 Amsterdam Ave.
New York, NY 10027
energypolicy.columbia.edu

   @ColumbiaUenergy

ABOUT THE AUTHORS

Zhiyuan Fan is a research associate at the Center on Global Energy Policy (CGEP) at Columbia University's School of International and Public Affairs. He supports CGEP's Carbon Management Research Initiative, focusing on low-carbon industrial systems, including low-carbon fuels and processes, carbon capture and storage, and CO₂ use/recycling. Prior to joining CGEP, he worked as a graduate student researcher at the Sustainable Engineering Lab in Columbia University's Mechanical Engineering Department, focusing on energy system modeling and optimization under deep renewable penetration, and electrification of heavy road transportation.

Emeka Richard Ochu is a research associate at the Center on Global Energy Policy (CGEP) at Columbia University's School of International and Public Affairs (SIPA). He supports CGEP's Carbon Management Research Initiative, focusing on financial and policy analyses for application of carbon capture, use, and storage to power and industrial facilities. Prior to joining CGEP, Ochu was an energy research economist at the Central Bank of Nigeria, where he published research on the electricity and gas subsector of the economy and served on various national energy projects. Previously, he worked in consulting and banking as an energy finance and investment lead, analyzing energy investment opportunities and providing finance for viable renewable energy projects in energy poor communities in Sub-Saharan Africa. Ochu holds a master of public affairs from Columbia University's SIPA and a master of science in energy economics from the University of Aberdeen, United Kingdom, as well as a bachelor of science with honors in economics from Abia State University, Nigeria.

Sarah Braverman was a student research officer for the Carbon Management Research Initiative at the Center on Global Energy Policy at Columbia University's School of International and Public Affairs (SIPA) while completing a master of public administration with a concentration in environmental science and policy from SIPA. For her capstone with the Natural Resources Defense Council, she managed a team of graduate consultants in their endeavor to develop policy recommendations for managing hydrofluorocarbon emissions. Braverman has worked for several years in the environmental nonprofit sector, both domestically and internationally, in a variety of capacities, including project management and external partnership development. She is currently a client project manager at Carbon Direct.

Yushan Laria Lou worked as a research assistant for the Carbon Management Research Initiative at the Center on Global Energy Policy at Columbia University's School of International and Public Affairs (SIPA), with a focus on green hydrogen, bio-hydrogen, and other low-carbon fuels. She recently completed a master of public administration with a concentration in energy and environment from SIPA.

Griffin Marie Smith was a student research officer for the Carbon Management Research Initiative at the Center on Global Energy Policy at Columbia University's School of International and Public Affairs (SIPA). She recently graduated from SIPA with a master of public administration, with a concentration in environmental science and policy, and holds



an MS in applied economics and a BS in finance and business economics from Marquette University. Smith is currently a climate policy analyst for General Motors.

Amar Bhardwaj is a current Marshall Scholar and a former research assistant at the Center on Global Energy Policy at Columbia University's School of International and Public Affairs. He is focused on policy and economic analysis as well as technology development within renewable energy, clean fuels, and CO₂ utilization. Bhardwaj is also an incoming energy industry analyst in the Office of Energy Policy and Innovation at the Federal Energy Regulatory Commission. Previously, he was a lead researcher in Columbia's Solar Fuels Engineering Lab, the editor in chief of *Consilience: The Journal of Sustainable Development*, and an expert reviewer for the Intergovernmental Panel on Climate Change's Sixth Assessment Report. Bhardwaj has authored numerous publications in energy policy and technology and has presented his work globally, including at the United Nations. He holds a BS in chemical engineering, summa cum laude, from Columbia University, and will shortly begin a PhD in chemical engineering at Stanford University.

Dr. Jack Brouwer is a professor of mechanical and aerospace engineering, civil and environmental engineering at the University of California, Irvine (UCI), and is director of its National Fuel Cell Research Center & Advanced Power and Energy Program. He is an energy system dynamics expert with research interests in renewable energy systems development; dynamic simulation and control; energy system thermodynamics, design, and integration; electrochemical conversion devices and systems such as fuel cells, electrolyzers and batteries; hydrogen production, storage and conversion systems; and electrochemical reactions with concurrent heat, mass and momentum transfer. Dr. Brouwer obtained his MS and BS in mechanical engineering from UCI and his PhD in mechanical engineering from MIT.

Dr. Colin McCormick is an expert on low-carbon and negative-emissions technologies, including pathways for carbon dioxide removal and research needs for clean energy systems. He is currently the chief innovation officer for Carbon Direct, and previously served as the senior advisor for R&D at the US Department of Energy. He holds a PhD in physics from UC Berkeley and is an adjunct associate professor at the Georgetown University Walsh School of Foreign Service.

Dr. Julio Friedmann is a senior research scholar at the Center on Global Energy Policy at Columbia University's School of International and Public Affairs. He is one of the most widely known and authoritative experts in the United States on carbon removal (CO₂ drawdown from the air and oceans), CO₂ conversion and use (carbon-to-value), and carbon capture and sequestration. Dr. Friedmann recently served as principal deputy assistant secretary for the Office of Fossil Energy at the Department of Energy, where he was responsible for DOE's R&D program in advanced fossil energy systems, carbon capture and storage (CCS), CO₂ utilization, and clean coal deployment. He has also held positions at Lawrence Livermore National Laboratory, including senior advisor for energy innovation and chief energy technologist. He is also the CEO of Carbon Wrangler, LLC, is a distinguished associate at the Energy Futures Initiative, and serves as a special advisor to the Global CCS Institute. Dr. Friedmann received his bachelor of science and master of science degrees from the Massachusetts Institute of Technology, followed by a PhD in geology at the University of Southern California.



ACKNOWLEDGMENTS

This report benefitted from a multi-round peer review process involving three anonymous external expert reviewers and two anonymous Columbia University reviewers. The authors deeply thank these reviewers for their thoughtful and detailed comments, which contributed materially to the work. The authors are also grateful to their fellow colleagues in the Carbon Management Research Initiative at the Center on Global Energy Policy, who provided helpful feedback, resources, and support throughout the development of the report. Last but not least, the authors thank all their colleagues at the Center on Global Energy Policy for helping with the design, publication, launch, and promotion of the work.

This report represents the research and views of the authors. It does not necessarily represent the views of the Center on Global Energy Policy. The paper may be subject to further revision.

This report is part of The Circular Carbon Economy: Keystone to Global Sustainability series, which assesses the opportunities and limits associated with the transition toward more resilient, sustainable energy systems that address climate change, increase access to energy, and spark innovation for a thriving global economy.

This work was made possible by support from the Center on Global Energy Policy and grant funding from the Global Carbon Capture & Storage Institute. More information is available at <https://energypolicy.columbia.edu/about/partners>.



TABLE OF CONTENTS

| | |
|---|-----------|
| Executive Summary | 09 |
| Introduction | 12 |
| Background | 14 |
| Hydrogen Energy Basics | 14 |
| 2002–2009 Hype Cycle | 15 |
| Green Hydrogen Production | 17 |
| Technology | 18 |
| Associated GHG Emissions | 20 |
| Cost Estimates Today | 25 |
| Hydrogen-Favoring Policy Case | 31 |
| Forecast Price Estimates | 32 |
| Green Hydrogen Applications: Fuel, Heat, Feedstock | 35 |
| Industry | 36 |
| Transportation | 36 |
| Power | 40 |
| Green Hydrogen Scale | 44 |
| Scale Today | 44 |
| Future Scale | 45 |
| Infrastructure Needs | 47 |
| Opportunities | 49 |
| Near-Term Market Opportunities | 50 |
| Near-Term Limits | 54 |
| Policies to Meet Infrastructure Needs | 56 |
| Findings and Recommendations | 57 |
| Finding 1 | 57 |
| Finding 2 | 57 |
| Finding 3 | 57 |
| Finding 4 | 58 |



| | |
|-------------------------------------|-----------|
| Finding 5 | 58 |
| Reccomendation 1 | 58 |
| Reccomendation 2 | 59 |
| Reccomendation 3 | 59 |
| Reccomendation 4 | 59 |
| Reccomendation 5 | 60 |
| Appendix | 61 |
| Monte Carlo Simulation Methodology | 61 |
| Glossary of Abbreviations and Terms | 65 |
| References | 66 |
| Notes | 81 |



EXECUTIVE SUMMARY

As global warming mitigation and carbon dioxide (CO₂) emissions reduction become increasingly urgent to counter climate change, many nations have announced net-zero emission targets as a commitment to rapidly reduce greenhouse gas emissions. Low-carbon hydrogen has received renewed attention under these decarbonization frameworks as a potential low-carbon fuel and feedstock, especially for hard-to-abate sectors such as heavy-duty transportation (trucks, shipping) and heavy industries (e.g., steel, chemicals). Green hydrogen in particular, **defined as hydrogen produced from water electrolysis with zero-carbon electricity**, could have significant potential in helping countries transition their economies to meet climate goals. Today, green hydrogen production faces enormous challenges, including its cost and economics, infrastructure limitations, and potential increases in CO₂ emissions (e.g., if produced with uncontrolled fossil power generation, which would be hydrogen but would not be green).

This report, part of the Carbon Management Research Initiative at Columbia University's Center on Global Energy Policy, examines green hydrogen production and applications to understand the core challenges to its expansion at scale and the near-term opportunity to enable deployment. An analysis using Monte Carlo simulations with a varying range of assumptions, including both temporal (i.e., today versus the future) and geographical (e.g., the US, the EU, China, India, Japan) factors, anticipates emissions intensity and costs of producing green hydrogen. The authors evaluate these production costs for different scenarios as well as associated infrastructure requirements and highlight near-term market opportunities and policies to motivate development of the green hydrogen industry.

Key findings include:

- **Green hydrogen could play a major role in a decarbonized economy.** Green hydrogen and fuels derived from it (e.g., ammonia, methanol, aviation fuels) can replace higher-carbon fuels in some areas of the transportation sector, industrial sector, and power sector. They can provide low-carbon heat, serve as low-carbon feedstock and reducing gas for chemical processes, and act as an anchor for recycling CO₂.
- **The primary challenge to green hydrogen adoption and use is its cost.** The cost of green hydrogen is high today, between \$6–12/kilogram (kg) on average in most markets, and may remain high without subsidies and other policy supports. Zero-carbon electricity is the primary cost element of production (50–70 percent) even in geographies with significant renewable resources, with electrolyzers and the balance of system as secondary costs.
- **Green hydrogen commercialization is also limited by existing infrastructure.** Growing demand of green hydrogen will require enormous investment and construction of electricity transmission, distribution and storage networks, and much larger volumes of zero-carbon power generation, as well as electrolyzer production systems, some hydrogen pipelines, and hydrogen fueling systems. An 88 million tons



per annum (Mtpa) green hydrogen production by 2030, corresponding to the Stated Policies Scenario from the International Energy Agency (IEA) for that year, could cost \$2.4 trillion and require 1,238 gigawatts (GW) of additional zero-carbon power generation capacity.

- **Some nations have developed hydrogen road maps with large green hydrogen components.** The governments of Japan, Canada, and the EU (including some member nations, notably Germany) have published formal road maps for hydrogen production, use, and growth. These plans include industrial policy (e.g., subsidies for manufacturing electrolyzer and fuel cells), port infrastructure (e.g., industrial hubs), and market aligning policies. These plans may provide these nations a competitive advantage in scaling, using, and adopting green hydrogen.
- **Additional factors could support or limit rapid scale-up of hydrogen production.** Use of green hydrogen and hydrogen fuels could provide substantial additional benefits to local economies and environments, including reduction of particulate and sulfur pollution, maintenance or growth of high-wage jobs, and new export opportunities (fuels, commodities, and technologies). Public concerns around safety, ammonia toxicity, and nitrogen oxide (NO_x) emissions, however, might present additional challenges to ramping up deployment of hydrogen systems.

Based on these findings, the authors recommend the following set of policy actions:

- **Nations and regions that wish to pursue green hydrogen production and use should prioritize detailed analysis and planning today.** Location and scale of infrastructure bottlenecks, limits to electrolyzer and fuel cell production, potential trade-offs in cost and speed with competition, resource availability, public risks, and financial gaps in specific markets and applications must be studied and considered in planning.
- **To reduce emissions rapidly through green hydrogen deployment, nations and regions should adopt market-aligning policies and production standards.** The substantial price gap between green hydrogen and “gray” hydrogen (produced with fossil fuels without carbon capture) calls for active policy intervention to bring production online to serve existing and future markets. This could include measures to reduce or subsidize the cost of zero-carbon electricity or measures to incentivize the value and use of low-carbon hydrogen.
- **Local, regional, and national governments interested in green hydrogen development should prioritize the construction of necessary infrastructure.** Major new infrastructure and infrastructure transformation (e.g., gas grid transformation for transporting and storing green hydrogen) is required for electricity transmission, hydrogen production, hydrogen storage, hydrogen transmission, fueling for transportation (both hydrogen and ammonia), and international trade ports.
- **Governments pursuing green hydrogen should increase investments in innovation, including research, development, and demonstration (RD&D).** Investments could be focused on the early-stage research on low technology readiness level approaches,



improving manufacturing for commercialized technology, and novel ways of producing low-cost, zero-carbon electricity.

- **Policymakers should appreciate and account for green hydrogen benefits outside of carbon abatement when crafting policies.** Additional benefits can include reduction of criteria pollutants (e.g., sulfur, particulates, and nitrogen oxides) and grid reliability and resilience.



INTRODUCTION

Since ratification of the Paris Accord in 2016, governments around the world have made increasingly strong commitments to profoundly reduce their greenhouse gas emissions. Many nations have selected economy-wide net-zero greenhouse gas emissions targets in their planning (by 2040–2060) and in many cases have made commitments to rapidly reduce greenhouse gas emissions much sooner. They have matched these commitments with ambitious investments in clean energy production and use as part of a decarbonization strategy. In concert, many large and significant companies have committed themselves to net-zero goals between 2030 and 2050, including leading energy, chemical, shipping, and aviation companies.

Against this backdrop, low-carbon hydrogen has emerged as an important option to provide net-zero emissions energy services (Renssen 2020). This reflects the versatility of hydrogen as a fuel and feedstock, as well as its high energy content (especially on a weight basis) and immense storage potential. In a circular carbon economy framework (Mansouri et al. 2020), defined as economy-wide human-earth balance and harmonized carbon cycle, hydrogen can play four important roles in decarbonization:

- **Reducing** emissions by substituting for carbonaceous fuels like oil, gas, coal, and biomass (Blank and Molly 2020)
- **Recycling** emissions by adding hydrogen to CO₂ to make fuels (Keith et al. 2018), building materials, and other products (Bhardwaj et al. 2021)
- **Removing** emissions by separating and storing carbon from fossil or biomass sources (Larson et al. 2020; Baker et al. 2020)
- **Retaining** important features necessary for electric grid resilience and operation, and industrial decarbonization (Davis et al. 2019; Ostadi et al. 2020; Bhaskar et al. 2020)

Although an attractive option in the energy transition to a net-zero economy, deployment of low-carbon hydrogen faces substantial challenges, including technical concerns, cost and economics, infrastructure needs, absence of manufacturing capability for key equipment, and insufficient market aligning policies. While low-emissions hydrogen can be produced via fossil fuel feedstock with carbon capture (“blue” hydrogen), this report focuses chiefly on “green” hydrogen (produced with zero-carbon electricity rather than with fossil energy) and biohydrogen (produced using biogenic sources), including technical pathways, key value propositions, and core challenges to widespread adoption. Here, “zero-carbon electricity” refers to energy produced by renewable or nuclear energy technologies. Blue hydrogen and biohydrogen are treated separately in related reports (e.g., Zapantis 2021). After explaining the basics of hydrogen and the industry’s growth, this report will begin in section 1 by discussing the production of green hydrogen, followed in section 2 with its potential applications. Section 3 examines production scaling and infrastructure requirements, and section 4 covers other short-term opportunities. Finally, section 5 provides findings and recommendations.



Zero-Carbon Electricity in This Report

The term “zero-carbon electricity” in this paper represents power supplies with zero or minimal scope 1 emissions but which may have nonzero life-cycle emissions. Many electricity supplies emit zero greenhouse gases during operation (e.g., renewables, nuclear), although they have some carbon emissions associated with upstream material extraction and mining, manufacturing, installation, maintenance, and end of life. Some generation emits some greenhouse gas (e.g., fossil + carbon capture) with varying intensities, which must be minimized to reach net zero. However, in the net-zero climate framework, there is value in using either near-zero or net-zero power for green hydrogen production. In this report, “zero-carbon electricity” is defined as having less than 100 kg carbon dioxide equivalent (CO₂e) per megawatt hour (MWh) of life-cycle emissions.



BACKGROUND

To understand the growing interest in green hydrogen as an anchor of a net-zero economy, it's helpful to understand what hydrogen is, how it can be made and used, and its relevance to climate change and global commerce. It's also helpful to understand the political backdrop against which hydrogen has reemerged after two decades of exploration and investment (with mixed results).

Hydrogen Energy Basics

Hydrogen is the most abundant element in the universe. The molecular form of hydrogen, which is of interest as an energy carrier, is the diatomic molecule composed of two protons and two electrons. On Earth, hydrogen is naturally present in molecular forms bound to oxygen or carbon (such as water and hydrocarbons) rather than pure hydrogen molecules, and therefore cannot be directly mined as a resource. The industrial production of hydrogen today is usually based on converting fossil fuels, although conversion of biogenic sources or water is also being accomplished to a lesser extent. On its own, hydrogen gas can be an excellent fuel, burning at a high temperature or readily converted electrochemically in fuel cells and possessing physical properties that make it relatively easy to handle (although it is more complicated to store compared to current infrastructure fuels, such as high-pressure, low-temperature storage tanks, compression and expansion units, etc.). Hydrogen can also be a feedstock for other fuels and chemicals, including ammonia (NH_3), methanol (CH_3OH) and gasoline. Roughly half of today's hydrogen production goes into fertilizers like ammonia and urea, with the balance largely going into fuel production and petrochemicals.

Because it is such a small molecule, hydrogen can be challenging to store and transport. It must generally be compressed to high pressures, liquified at very low temperatures, or stored within a porous material. It may leak more readily than current gaseous infrastructure fuels like natural gas or propane. It can also embrittle some current infrastructure materials such as pipeline steels, posing challenges for their immediate use for hydrogen without investment (Bartlett and Krupnick 2020).

To generate useful energy (heat or power), hydrogen can be burned in a furnace, boiler, or turbine or converted directly to electricity and lower-grade heat in a fuel cell. Hydrogen can produce heat at high temperatures sufficient for steelmaking and other high temperature industrial processes, while establishing reducing (low-oxygen) conditions for applications such as cement, glass, and computer chip manufacturing. Hydrogen can also drive an engine, power a zero-emission fuel cell car, back up a power generator, or warm a house. The electricity produced from hydrogen can provide grid services or run an electric drivetrain in a truck or bus. Hydrogen can also be a key feedstock for conventional fuels and chemicals (like ammonia or methanol) or novel synthetic fuels and materials made of recycled CO_2 (e.g., e-fuels). Combusting hydrogen with pure oxygen or consuming it in a fuel cell emits no direct carbon emissions. NO_x emission is possible for hydrogen combustion in air while many other pollutants are avoided, including CO, soot, partial-burned hydrocarbons, etc. (Frassoldati et



al. 2006). In a carbon-constrained economy, therefore, hydrogen can be a potentially valuable and useful fuel and feedstock—and it has been a focus of energy planning and analysis for many years.

2002–2009 Hype Cycle

Hydrogen interest was pronounced during 2002–2009, in part driven by policies of the George W. Bush administration (Office of the Press Secretary 2003), which helped stimulate commercial interest as well. During the early days of the Obama administration, interest was partially sustained by potential legislation limiting carbon emissions, notably the Waxman-Markey bill (US Congress 2010).

During this decade, there was widespread assumption by many energy experts that renewables and batteries would remain expensive, natural gas and oil supplies were in decline (Deffeyes 2001), and there was abundant time to develop strategies for global warming abatement (Abraham 2004). Cost and performance limits of batteries over 15 years ago led to failures in deployment of electric cars, underscoring the potential value of hydrogen as a transportation fuel. Many nations (including Australia, China, and the US) pushed technologies that would convert coal to hydrogen with carbon capture and storage (CCS) for power generation (integrated gasification combined cycle plants) such as FutureGen (DOE 2005), ZeroGen (Zero Emission Resource Organisation 2016b), and GreenGen (Zero Emission Resource Organisation 2016a). These projects received many hundreds of millions of dollars in government funding in anticipation of a major boom in gasifier technology and abundant low-cost hydrogen from coal.

All these assumptions proved wrong. Oil and gas production exploded due to innovations in unconventional oil and gas recovery, with the US emerging as the world’s largest producer and a major liquefied natural gas exporter (IEA 2019b). This abundance displaced coal in North America (Gruenspecht 2019) and led to rapid oil and gas commodity price drops (EIA 2020a). Technology innovation, industrial policy, and climate policy commitments led to swift and profound reductions in renewable power costs, with wind and solar emerging as the cheapest source of electricity in many markets (IRENA 2020ab). This further displaced coal and has begun to displace natural gas, leading to further price drops for fossil energy (BNEF 2021). Finally, China’s emissions grew extremely quickly between 2005 and 2015, consuming part of the global carbon budget to ensure climate stabilization within a 1.5°C or 2°C rise—and limiting the time available to counter climate change (IEA 2019c).

Against this backdrop, hydrogen skepticism was widespread, in part because the original narrative was misplaced. Doubts were well summarized in the book *The Hype About Hydrogen* (Romm 2004), which detailed concerns about hydrogen use, mostly for automobiles. Challenges in 2005 included production, storage, transportation, conversion, infrastructure limits, market readiness, and others. On this basis, some investors, policymakers, and environmental nongovernmental organizations remain skeptical today about the value of hydrogen in providing energy services.

Nonetheless, the urgency of climate change action (UN 2021), the increased awareness of the utility of hydrogen in “harder to abate sectors” (IEA 2019a; ETC 2020), and the abundance



of low-cost natural gas and renewable electricity (IEA 2019a) have made hydrogen a primary focus of decarbonization efforts and related policies around the world. Moreover, dramatic technical improvements in key technologies (e.g., fuel cells and hydrogen tanks) have stimulated many recent analyses (ETC 2020; IEA World Energy Outlook 2021; Friedmann et al. 2019) to see hydrogen as an essential component of the energy transition, provided its upstream production and use emit very few greenhouse gases and pollutants.



GREEN HYDROGEN PRODUCTION

Because of economics and technical maturity, most hydrogen production today involves fossil fuel conversion and separation. In the Organisation for Economic Co-operation and Development (OECD) and most nations in the Organization of the Petroleum Exporting Countries (OPEC), steam methane reformation (SMR) of natural gas followed by water-gas shift (WGS) reactions and pressure swing absorption (PSA) purification is the preferred approach. Hydrogen produced this way is known as “gray” hydrogen. In China and most developing nations, coal gasification is combined with WGS reactions and PSA purification to produce “brown” or “black” hydrogen, depending on the type of coal used. Both approaches create by-product streams of CO₂, which are typically vented into the atmosphere or combined with produced ammonia to make urea. If the by-product CO₂ is captured and stored, then the hydrogen has low net CO₂ emissions and is called “blue” hydrogen.

Green hydrogen is produced by water electrolysis with various types of electrolyzers, in which zero-carbon electricity is used to split water molecules into hydrogen and oxygen molecules. All these green hydrogen production methods are not commonly deployed today. But because of the increasingly widespread availability and lower cost of solar and wind power, green electrolytic hydrogen is expected to become the most common means of producing hydrogen in the future. Hydrogen produced via electrolysis using electricity from power grids with high average CO₂ emissions (due to fossil-fired generation) is not considered low-carbon because of the associated upstream greenhouse gas emissions (GHG) emissions and is generally not considered “green.” That term is reserved for hydrogen produced from biogenic sources or by electrolysis powered by low-carbon power systems, such as nuclear or renewable electricity.

Biohydrogen

Biohydrogen is here defined as hydrogen produced either biologically or thermochemically from biomass or biogas feedstocks (Manish and Banerjee 2008). Biomass and biogas feedstocks can be sustainable and low carbon so that the hydrogen (H₂) produced can have a low-carbon footprint (Kalinci et al. 2012). In addition, when biohydrogen production is combined with carbon capture and storage, it can be strongly carbon negative, removing CO₂ from the air and oceans by photosynthesis and carbon capture and storage (Baker et al. 2020; Larson et al. 2020; Sandalow et al. 2021). Many of these biogenic sources come from waste streams that society must continually manage, such as municipal solid wastes, animal manure, etc., so that production of a useful resource, such as hydrogen, is desired for a zero emissions future.



Technology

The present and near-term cost of green hydrogen production is significantly higher than conventional hydrogen production using SMR (IEA 2019a). One of the most mature green hydrogen pathways is based on water electrolysis, using either alkaline electrolyzers (the current market leading technology) or polymer electrolyte membrane (PEM) electrolyzers (an emerging competitor). The market for electrolyzers is relatively small and growing slowly, with growth rates far lower than technologies such as solar photovoltaic (PV) (Grimm et al. 2020). While other electrolytic hydrogen production technologies are being developed, they remain significantly less mature (see Table 1). Specifically, the “stack electrical efficiency” measures electricity energy consumption for electrolyzer stack per unit of hydrogen production. The “system energy efficiency” measures total energy consumption per unit of hydrogen production, including both electricity (e.g., from electrolyzer stack and other equipments) and heat (e.g., to warm up the electrolyzer, produce steam, etc.). The stack electrical efficiency is used to calculate electricity consumption for the electrolyzer stack and is simply referred to as “efficiency” later.

Table 1: Selected electrolytic hydrogen production technology options with high TRL

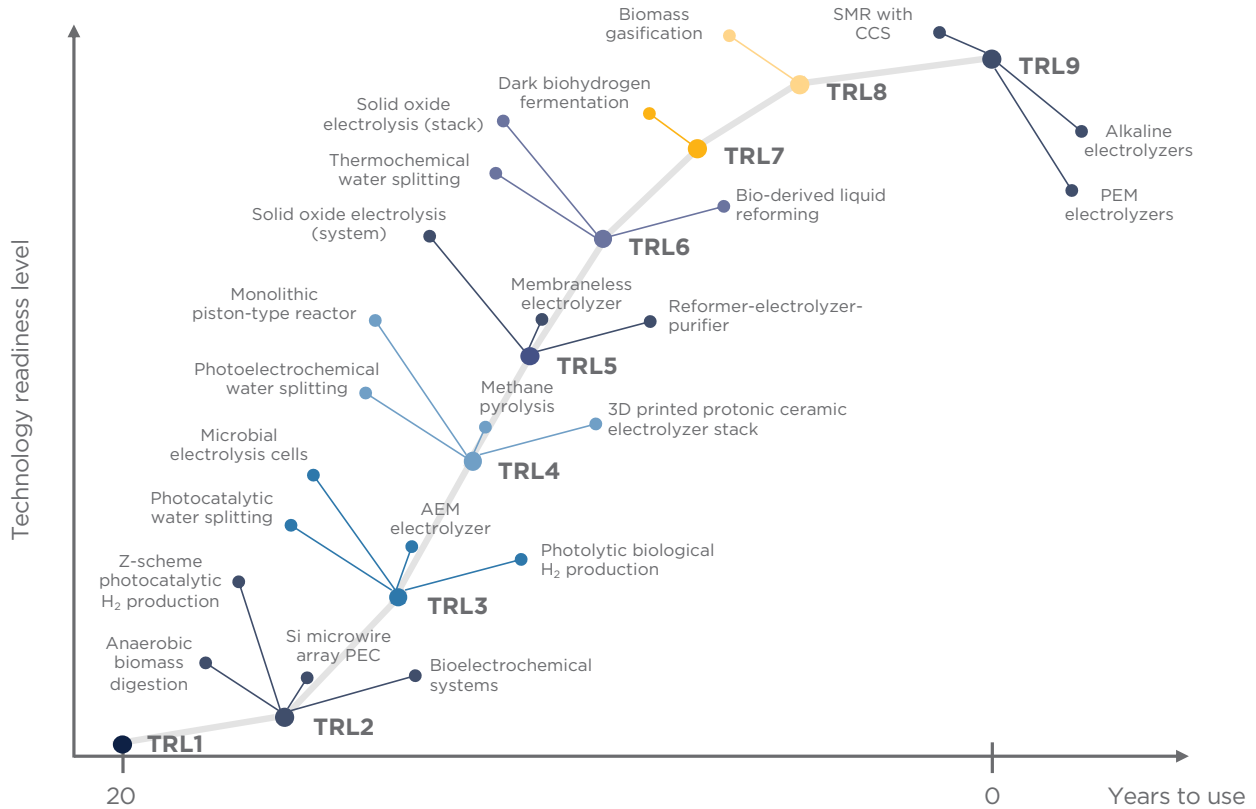
| Technology name | Technology readiness level (Figure 1 below) | Cost (\$/kW) | Stack electrical efficiency | System energy efficiency |
|--------------------------------------|---|--------------------|----------------------------------|--------------------------|
| Alkaline electrolyzers | TRL 9 (full maturity) | \$860-\$1,240/kW | 70%-80% | 59%-70% |
| PEM electrolyzers | TRL 9 (limited production) | \$1,350-\$2,200/kW | 80%-90% | 65%-82% |
| Solid oxide electrolysis cell (SOEC) | TRL 5-6 | \$1,045/kW | 70%-93% (high temperature water) | 65%-82% |

Note: SOEC or more generally solid oxide electrolysis technology is quickly evolving, and because of a lack of existing project data, actual efficiency may be different from today’s research and estimation.

Source: Source: TRL data compiled from Nadeem et al. (2021), Grimm et al. (2020), DOE (2020), Calise et al. (2019), Hallenbeck and Benemann (2018), and Miller et al. (2020); efficiency data compiled from Kumar et al. (2019), Zeng et al. (2009), AlZahrani et al. (2018), and Wang et al. (2019); cost data from Grimm et al. (2020).



Figure 1: Technology readiness level for hydrogen production



Note: TRL1 refers the lowest readiness (laboratory benchtop only), and TRL 9 refers to the highest readiness (commercially available)

Source: Authors' analysis based on Nadeem et al. (2021), Grimm et al. (2020), DOE (2020), Calise et al. (2019), Hallenbeck and Benemann (2018), and Miller et al. (2020).

Alkaline systems have operated for over 100 years (Zayat et al. 2020), and alkaline electrolyzers have operated for decades (Mayyas et al. 2019). They consist of an anode and cathode separated by a porous separator (such as Zirfon) immersed in an aqueous alkali hydroxide electrolyte (typically potassium hydroxide, KOH, or sodium hydroxide, NaOH)¹. They exhibit 59–70 percent conversion efficiency, and their relatively low cost (\$860–\$1,240/kW) has led most industrial producers to favor them over other approaches. Alkaline electrolyzers perform poorly with intermittent and fluctuating power sources because of slow start-up and cross-diffusion of hydrogen and oxygen molecules under low system loads (Krishnan et al. 2020).

PEM electrolyzers perform better with fluctuating input currents and integrate better with intermittent power generation (e.g., wind and solar). In addition, they have the potential to produce hydrogen at higher pressures by electrochemical compression. PEM electrolyzers'



capability to operate highly dynamically with intermittent load and at higher pressure balances their higher capital cost (\$1,350–\$2,200/kW). These costs are expected to drop through innovation and deployment (Böhm et al. 2018), which may lead to greater adoption of PEM systems. The technology is available commercially but manufactured in low quantities. An important advantage of PEM electrolyzers is that they are safer than alkaline electrolyzers because they do not require caustic or corrosive electrolytes.

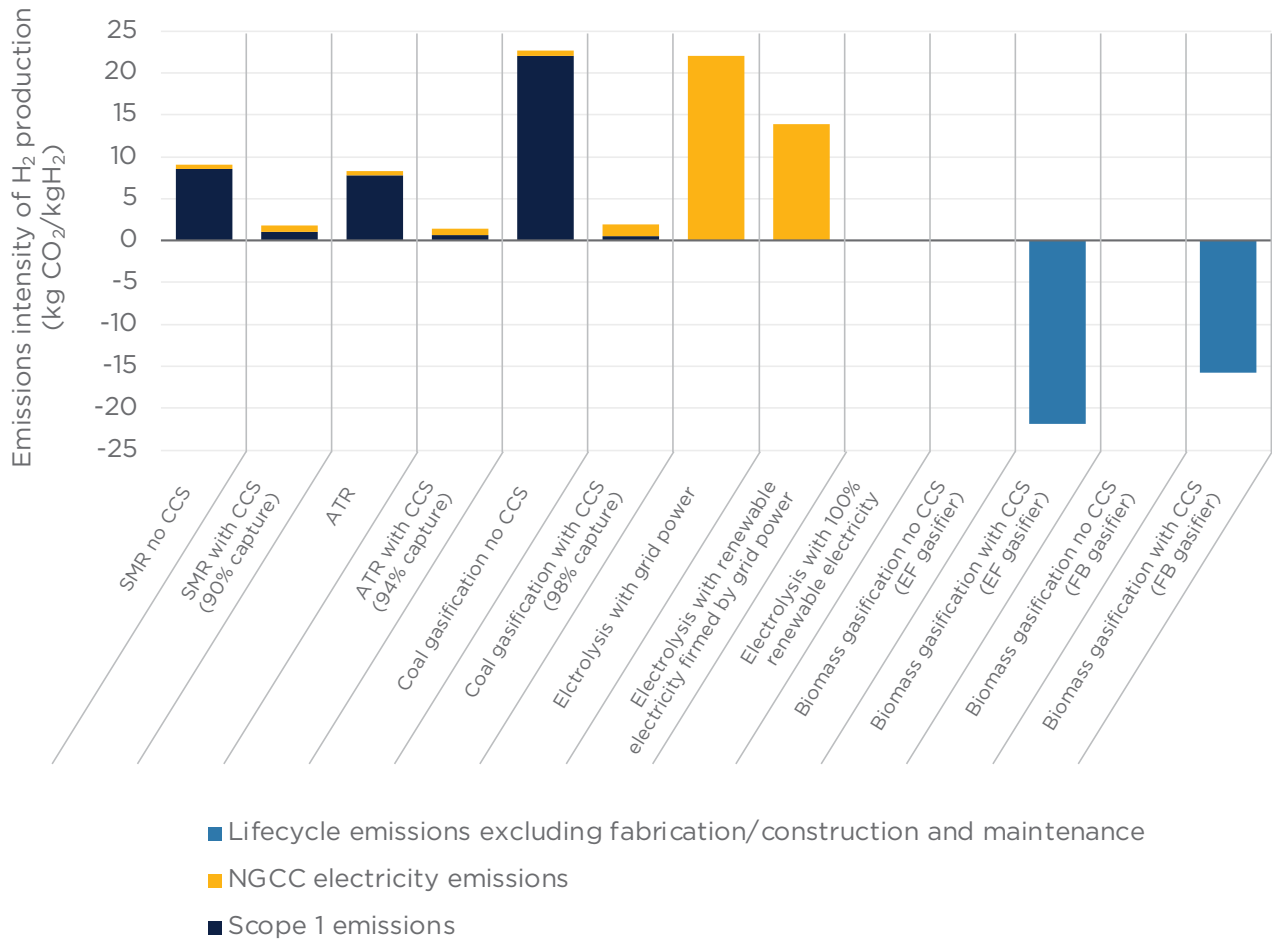
Green hydrogen can also be produced using solid oxide electrolysis cells (SOEC) (Hauch et al. 2020) or anion exchange membrane (AEM) electrolysis (Miller et al. 2020). SOEC are typically operated for high temperature water electrolysis or steam electrolysis, where a larger portion of the energy for splitting water molecules is provided in the form of heat. These processes reduce electricity consumption, resulting in a higher stack electrical efficiency but not necessarily a higher overall energy efficiency (see Table 1). While both SOEC and AEM technologies have made significant progress in recent years and offer some advantageous characteristics, they require primary systems integration and durability proofs before they can achieve widespread commercial deployment. Although alkaline and PEM electrolyzers are commercially available at scale, SOEC and AEM are considered out of scope for analysis in this report.

Associated GHG Emissions

Emissions related to electrolysis-based hydrogen production depend on the CO₂ intensity of the electricity input. The typical unit of measuring the CO₂ footprint is the emissions intensity of hydrogen production (kgCO₂/kgH₂). A conventional SMR gray hydrogen system will emit between 12–15 kgCO₂/kgH₂, and a coal-based process as much as 20 kgCO₂/kgH₂. Water electrolysis is only as “clean” as its electricity source. In regions with moderately high grid average carbon intensities, using grid electricity for water electrolysis can often exceed the emissions of conventional steam methane reforming to produce hydrogen (Figure 2). As a result, the source of electricity used for water electrolysis dictates whether or how much carbon abatement is possible.



Figure 2: Emissions intensity of hydrogen production technologies



Note: Assumes emissions intensity of natural gas combined cycle (NGCC) of 400kgCO₂/MWh, 55kWh/kgH₂ for electrolysis, 37 percent of production from grid firming electrolysis utilizes zero emissions renewable electricity. EF = entrained flow. FB = fluidized bed. Electricity required for methane and coal production pathways are full-lifecycle including power used in methane and coal production from Mehmeti et al. (2018). Emissions from biomass gasification are from Salkuyeh, Saville and MacLean (2018). Fugitive emissions from natural gas and coal production are not explicitly considered and will add to total lifecycle emissions from fossil pathways. Lifecycle emissions from construction and maintenance of renewable generation facilities and biomass production are also not fully considered and will add to the emission intensity of those production pathways. ATR refers to autothermal reforming.

Source: Data courtesy of Alex Zapantis, originally reported in Zapantis et al., “Blue Hydrogen,” Global CCS Institute (2021), <https://www.globalccsinstitute.com/wp-content/uploads/2021/04/CCE-Blue-Hydrogen.pdf>

To understand the emissions intensity of hydrogen production by water electrolysis, we undertook a Monte Carlo simulation to forecast the emissions intensity of electrolytic hydrogen production in 2030 across different geographies and learning rates (see Appendix). The resulting distribution of emissions intensity output values is plotted in Figure 3. The mean



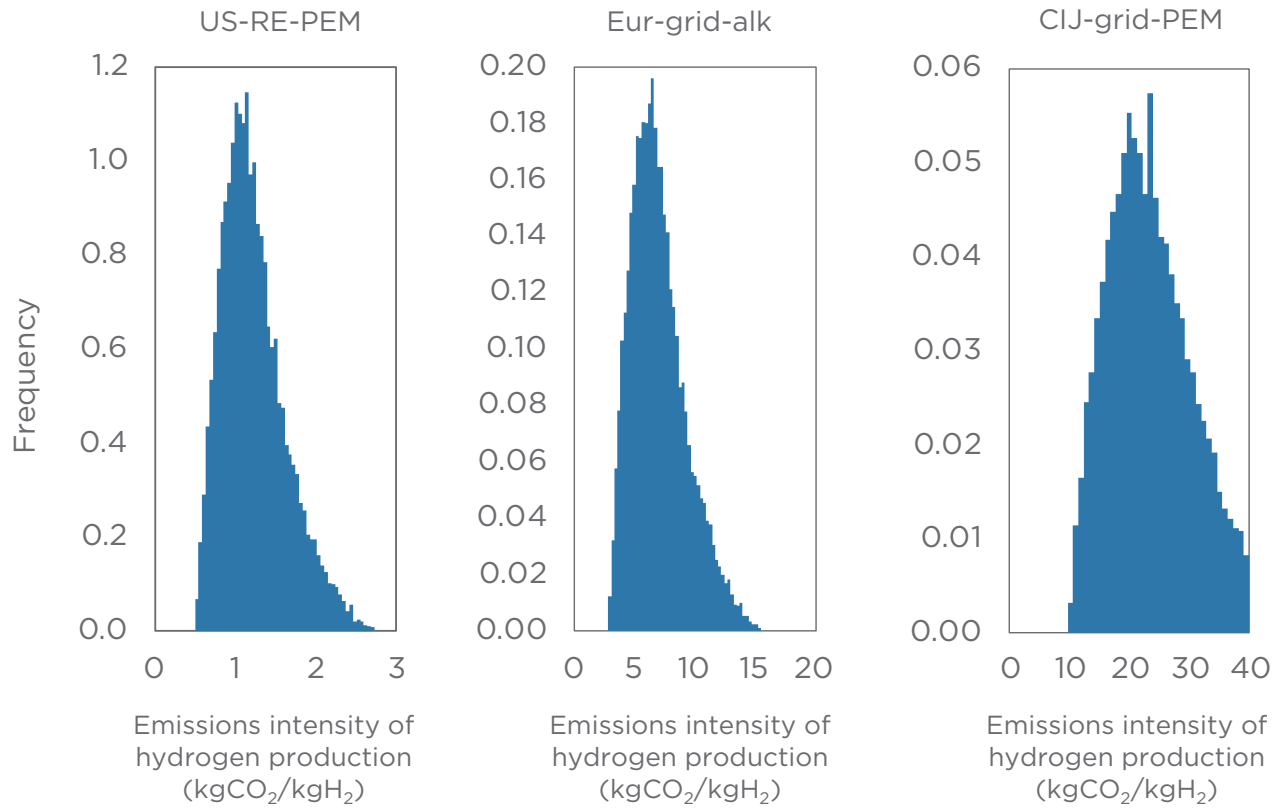
values and 5th and 95th percentiles from these distributions are shown in Figure 4.

The results reveal a stark distinction in emissions intensity forecasts for the scenarios that use grid electricity compared to solely zero-carbon electricity. Despite projected improvements in the emissions intensity of grid electricity in all regions by 2030 (see Appendix), electrolytic hydrogen production using grid electricity has roughly similar emissions intensity as conventional hydrogen generation methods. In the US in 2030, using much cleaner grid electricity for water electrolysis will result in comparable emissions to steam methane reforming, meaning the use of grid-supplied hydrogen would not provide meaningful CO₂ emissions abatement. In the China-India-Japan cases, grid-powered electrolytic hydrogen could prove more carbon intensive than unabated coal-based hydrogen production. Europe is the only region that is projected to have lower emissions intensity of electrolytic hydrogen production using grid electricity than SMR, due to the expected progress toward decarbonization of electricity supply, although if production increases substantially, the attendant emissions would remain large.

Figure 4 shows that only electrolysis powered by zero-carbon electricity might significantly abate the emissions of hydrogen production in 2030. In all regions, electrolytic hydrogen production with zero-carbon power has an emissions intensity of $\approx 1.3 \text{ kgCO}_2/\text{kgH}_2$. Though the small embodied emissions of renewable and nuclear electricity do result in a nonnegligible emissions intensity of hydrogen generation, this value is significantly lower than current emissions intensities. Renewable electricity has life-cycle emissions of approximately $25 \text{ gCO}_2/\text{kWh}$ (Nugent and Sovacool 2014), compared to $490 \text{ gCO}_2/\text{kWh}$ for natural gas combined cycle power (Schlömer et al. 2014).



Figure 3: Histograms of 2030 emissions intensity forecast distributions from Monte Carlo simulations for three representative scenarios

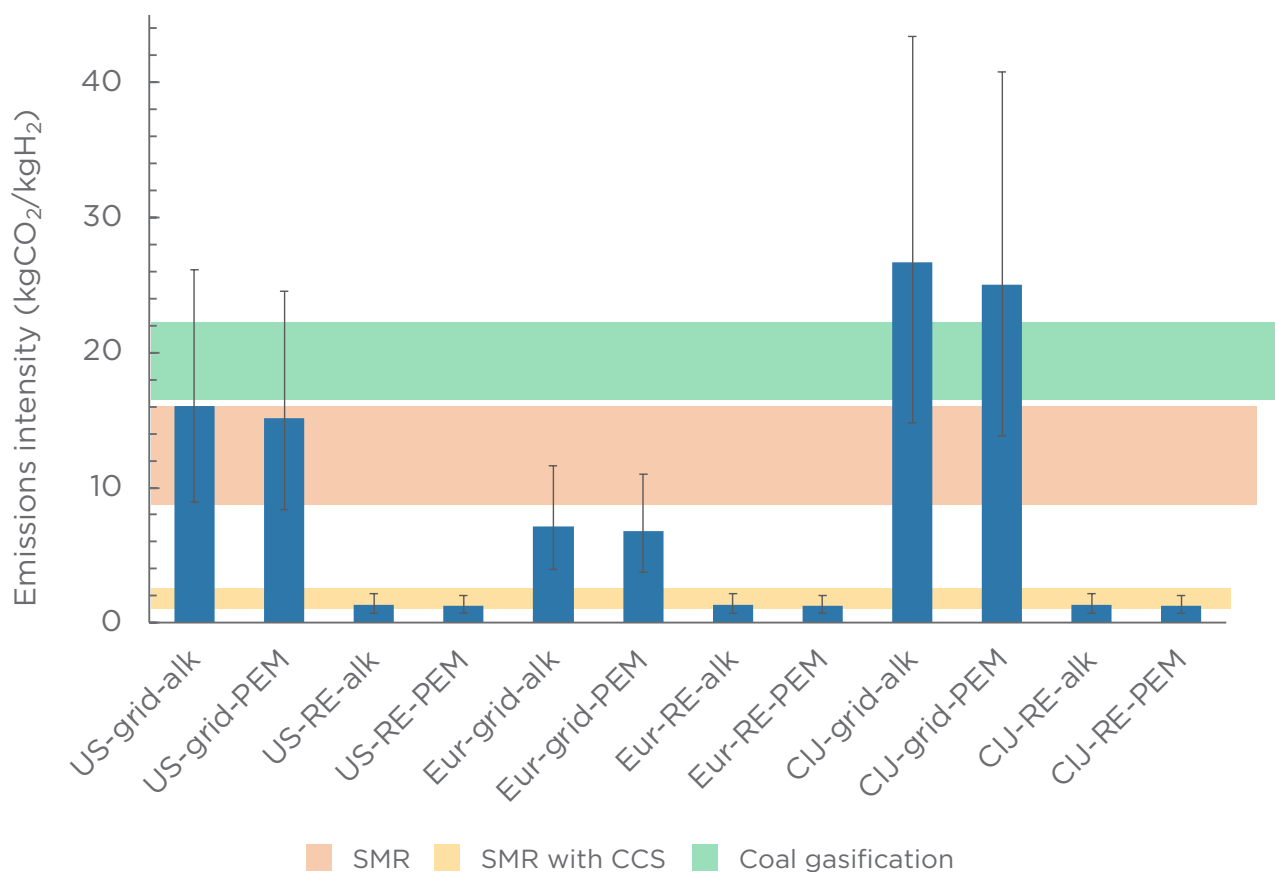


Note: All scenarios are illustrated in Figure A1 in the appendix.

Source: Authors' analysis.



Figure 4: Mean 2030 emissions intensity forecasts from Monte Carlo simulations



Note: Error bars represent 5th and 95th percentiles.

Source: Authors' analysis.

These findings highlight that, depending on the source of electricity, hydrogen from water splitting may be highly emissions intensive unless zero-carbon electricity is used. Due to the emissions intensities of grid electricity, using grid electricity for water electrolysis through 2030 would not provide carbon abatement compared to SMR in many locations and contexts (Bartlett and Krupnick 2020). This indicates the relatively low-carbon intensity of SMR-produced hydrogen, which may be useful in the short term to enable hydrogen infrastructure to develop and flourish, providing carbon and pollutant emissions reductions in the short term (when used in transportation applications that displace diesel or gasoline) while phasing out the use of fossil fuel SMR in the long term to lower hydrogen carbon intensity.

It is important to understand that given the carbon intensity of hydrogen produced as indicated in the scenarios of the Monte Carlo analyses, the most valuable end use in all the jurisdictions considered is in displacing gasoline and diesel. If one considers the carbon



reductions of such use in this analysis, then all the scenarios produce reductions in both carbon and criteria pollutant emissions in 2030. And investments that deliver carbon and criteria pollutant emissions reductions in the short term (2030 case considered here) also invest in hydrogen infrastructure that prepares the utility grid network for higher levels of renewable power use by increasingly engendering the required seasonal and long-duration storage as well as transmission, distribution, and resilience features of a zero emissions electric grid.

Water Consumption for Green Hydrogen

The water footprint of electrolytic hydrogen is very small. This water footprint arises from both direct consumption of fresh water in the electrolysis reaction and the freshwater consumption associated with the required electricity generation. The water consumed directly in an electrolyzer must be purified beforehand, but this purification process accounts for ~0.4 percent of the energy consumption of green hydrogen production (Webber 2007). The water consumption of electricity generation is significantly larger for fossil electricity compared to solar and wind power due to the evaporation of water that is most often used in thermoelectric power plants for the required cooling step. Using thermoelectric power, electrolytic hydrogen has an overall water consumption of ~130 L water/kgH₂. By contrast, green hydrogen production powered by solar or wind has a water footprint of ~30 L water/kgH₂ (Shi et al. 2020). With a 30 L/kgH₂ water consumption, supplying the world's current 70 Mt/yr demand for hydrogen using green H₂ would consume 2.1 billion m³ fresh water/yr, which is three orders of magnitude less than global freshwater consumption of ~1,500 billion m³/yr for nonagricultural activities (UNESCO 2019). In specific locations and applications, such as arid coastal environments, the water footprint of green hydrogen may stress limited freshwater resources, in which case technologies are being developed to directly electrolyze seawater instead of fresh water to produce hydrogen (Bhardwaj et al. 2021; Dresch et al. 2019).

Cost Estimates Today

The cost of hydrogen can be quantified using the metric levelized cost of hydrogen (LCOH), similar to the levelized cost of electricity. For example, conventional (gray) hydrogen production from fossil feedstocks has an estimated LCOH of \$1–\$2/kg until at least 2030 and probably beyond, depending on local fuel prices (Zapantis 2021). The LCOH of producing green hydrogen is influenced mainly by the cost of producing reliable zero-carbon power, electrolyzer capital costs, financing and fixed operating costs (e.g., plant upkeep and maintenance). Of these costs, the cost of zero-carbon electricity is the most significant, representing approximately 50 to 55 percent of the LCOH on average. In this analysis, renewable power options were studied but did not formally include nuclear power options. Nuclear electricity prices that equal the renewable prices and capacity factors would be equivalent in cost.



The cost of renewable energy varies in different geographies, depending largely on the local renewables potential. In the US, for example, solar PV costs are cheaper in California than in most states, and broader renewable energy costs (mostly wind and solar) are cheaper in states such as Texas and California (Friedmann et al. 2020) because they have a higher capacity factor. As the cost of renewable power generation continues to fall, some countries with significant renewable energy potential such as Australia, China, Chile, Germany, Morocco, Saudi Arabia, and the UK will have a cost advantage in producing green hydrogen. Electrolyzer capital expenditure (CAPEX) is also expected to fall over time as a result of economies of scale, bringing down green hydrogen costs in all geographies (IRENA 2020c).

To demonstrate how various factors affect LCOH in specific geographies, the authors developed a model to compare today's LCOH in the US with the European Union, Australia, and Asia. For the Asia scenario, renewable prices reflect a weighted average cost of renewables in China, India, and Japan (CIJ). The model calculated the capital cost of the LCOH using electrolyzer CAPEX (PEM and alkaline), its efficiency, stack lifetime, and weighted average cost of capital (WACC) for an average 10-megawatt (MW) facility. Zero-carbon electricity costs analyzed both utility solar and onshore wind as well as operating and maintenance to determine the LCOH in dollars per kilogram for the various scenarios.

Renewable Electricity Prices

Although LCOH studies often assume renewable electricity prices based on the levelized cost of energy (LCOE) for renewable generators or average power purchase agreement (PPA) prices for renewables, these methods do not reflect the contributions of network costs (cost of transmission and distribution) and electricity taxes to the end use industrial electricity price paid by green hydrogen producers. Though producers may have access to PPA-range renewable electricity prices at certain times, in limited contexts, and with low capacity factors, these low prices will not be available on average for the large production scale evaluated in this study. Therefore, for this paper's estimate of regional average LCOH values at high production volumes, the authors incorporate the contributions of network costs and taxes to industrial prices for renewable power beyond the PPA price.

To estimate the renewable electricity price used in this study, the authors take renewable power PPA prices in a region to be equivalent to the wholesale price of renewable electricity and calculate the corresponding industrial price of renewable electricity by increasing the PPA price to reflect the additional contributions of network costs and taxes to industrial prices. Wholesale electricity prices account for 10–70 percent of industrial electricity prices in different countries. The authors assume that renewable PPA prices account for the same percentage of the final renewable electricity industrial price in a particular region. It is also assumed that green hydrogen producers have access to industrial electricity markets for medium-size industrial electricity consumers. For each region evaluated, the authors found data for wholesale electricity prices as a percentage of industrial electricity prices. For instance, wholesale prices in the EU on average represent 42 percent of the value of industrial electricity prices (Eurostat 2019). The authors then found average renewable electricity PPA prices for the region. To find the corresponding industrial electricity price of renewable power, the average PPA price was divided by the aforementioned wholesale price percentage.



For the EU, an average PPA price of 5.8 ¢/kWh (LevelTen 2020) was divided by 42 percent to obtain a renewable industrial electricity price of 13.81 ¢/kWh. The renewable industrial electricity price estimates using this method range from 8 ¢/kWh to 16 ¢/kWh for different regions and sources in 2020. The same method is used to estimate prices for 2030 using PPA price forecasts.

To be clear, the costs that are estimated here assume retail prices for industrial electricity generation. Given these costs, there may be many ways to provide additional revenue or benefits to electric power systems that could reduce the electricity price for electrolyzers. For example, some electrolyzers (e.g., PEM) can ramp quickly, providing an opportunity to provide ancillary grid services (similar to demand response or battery systems). Similarly, policies could provide revenues or cost abatement, either through legislated incentives, higher valuation of ancillary services, or access to wholesale or subsidized power prices.

Economies of Scale

The authors assume that a 10 MW electrolyzer facility benefits from economies of scale (i.e., reducing CAPEX per unit of output). The authors find that the true dollar per kWh price of renewable power for industrial production is significantly higher than the LCOE value generally used for the calculation of LCOH and represents the wholesale PPA price plus a markup of taxes and network costs. Thus, even in the case of countries with significant renewables potential, industrial renewables prices must be cheaper than they are currently to scale green hydrogen production to have a profitable LCOH (see below). Also, the slightly lower capital cost of alkaline electrolyzers today leads to lower LCOH estimates in most scenarios, even with a higher efficiency value for PEM electrolyzers. The expectation is that this trend would reverse if PEM CAPEX reduces to mirror that of alkaline electrolyzers (AEs) in the future.

LCOH Results

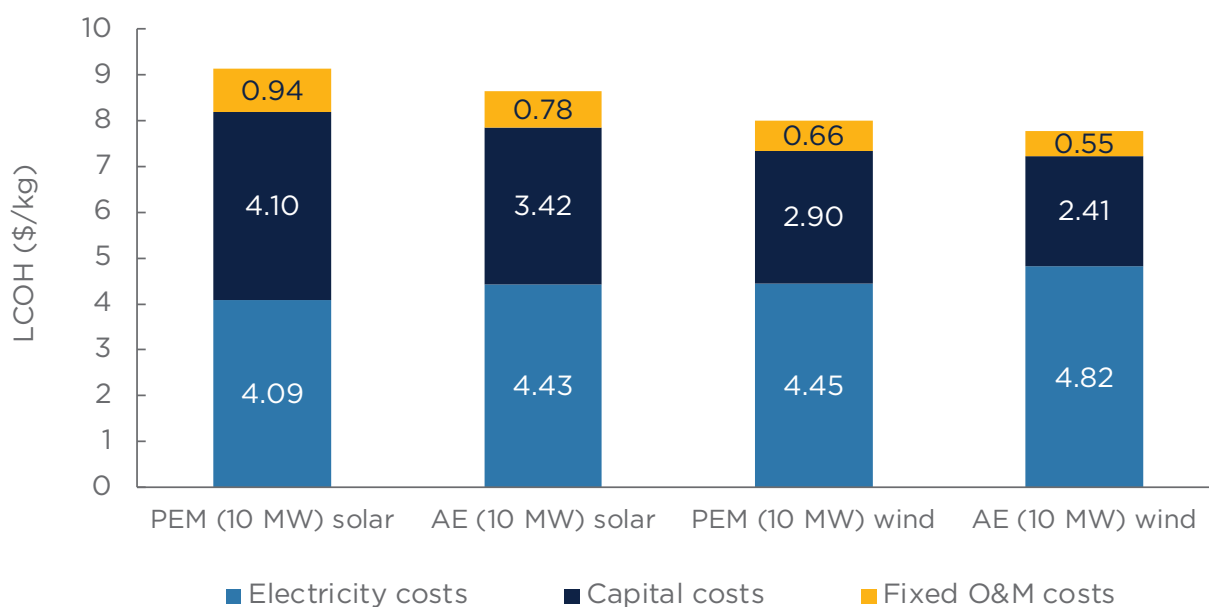
The LCOH in this paper's analysis ranges today from \$7.78-\$12.66/kg of green hydrogen for two standard deviations in these markets: the US, EU, and China India Japan (CIJ) with PEM and alkaline electrolyzers.

For a representative 10-MW PEM electrolyzer facility in the US, average LCOH are \$9.13/kg and \$8.00/kg for solar and wind scenarios, respectively; and \$8.63/kg and \$7.78/kg for solar and wind in the case of the alkaline electrolyzer of equal capacity.

The industrial price of onshore wind is higher than that of utility solar in the US today; however, the capacity factor for wind is currently higher than that of utility solar in the US, accounting for the lower LCOH for the wind scenarios.



Figure 5: US LCOH estimates for 2020 technology and industrial renewable power systems



Note: Analysis assumes 10 MW capacity electrolyzer efficiency at nominal capacity of 72 percent and 78 percent for AE and PEM respectively, with an HHV of 39.4 kilowatt hour/kilogram of hydrogen (kWh/kg H₂), a WACC of 5 percent, a stack lifetime of 70,000 hours, and an electrolyzer CapEx of \$1,300 and \$1,000/kW for PEM and AE, respectively. Calculated industrial electricity price for solar = \$0.081/kWh, wind = \$0.088/kWh; fixed O&M cost at 3 percent of electrolyzer CapEx.

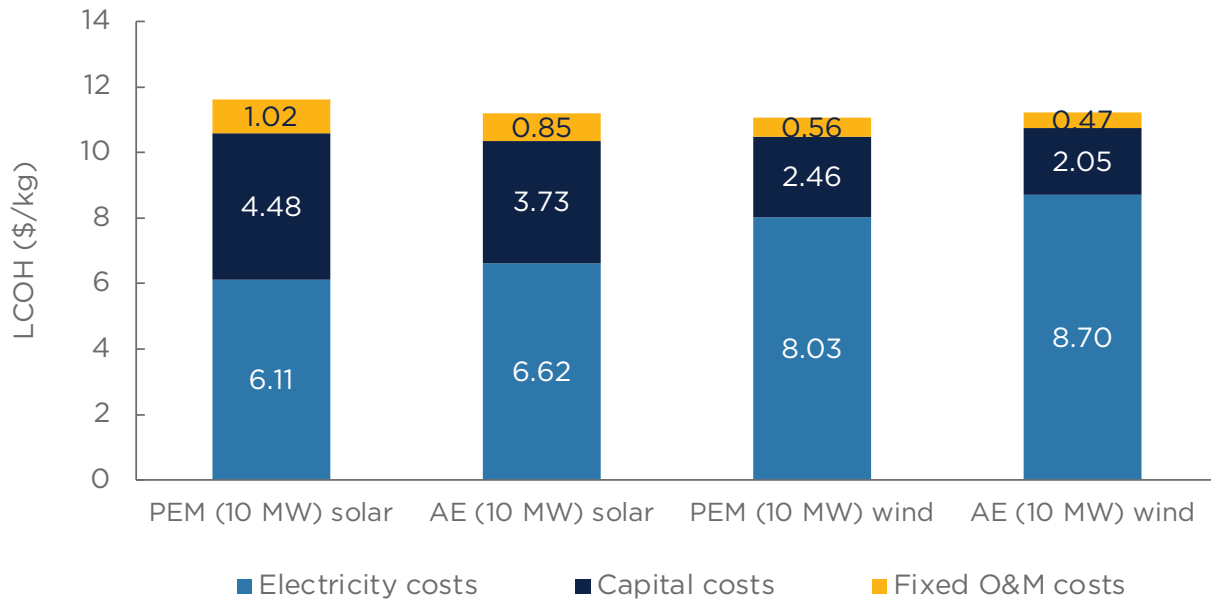
Source: Authors' analysis based on data from IEA and IRENA.

In the case of a representative 10-MW PEM electrolyzer facility in Europe, average LCOH are \$11.61/kg and \$11.06/kg for solar and wind scenarios, respectively; and \$11.20/kg and \$11.22/kg for solar and wind in the case of the alkaline electrolyzer of equal capacity.

A higher capacity factor is largely responsible for the relatively lower LCOH for the onshore wind scenario in the EU.



Figure 6: European LCOH estimates for 2020 technology and industrial renewable power systems



Note: Analysis assumes 10 MW capacity electrolyzer efficiency at nominal capacity of 72 percent and 78 percent for AE and PEM respectively, with an HHV of 39.4 kilowatt hour/kilogram of hydrogen (kWh/kg H₂), a WACC of 5 percent, a stack lifetime of 70,000 hours, and an electrolyzer CapEx of \$1,300 and \$1,000/kW for PEM and AE, respectively. Calculated industrial electricity price for solar = \$0.121/kWh, wind = \$0.159/kWh; fixed O&M cost at 3 percent of electrolyzer CapEx.

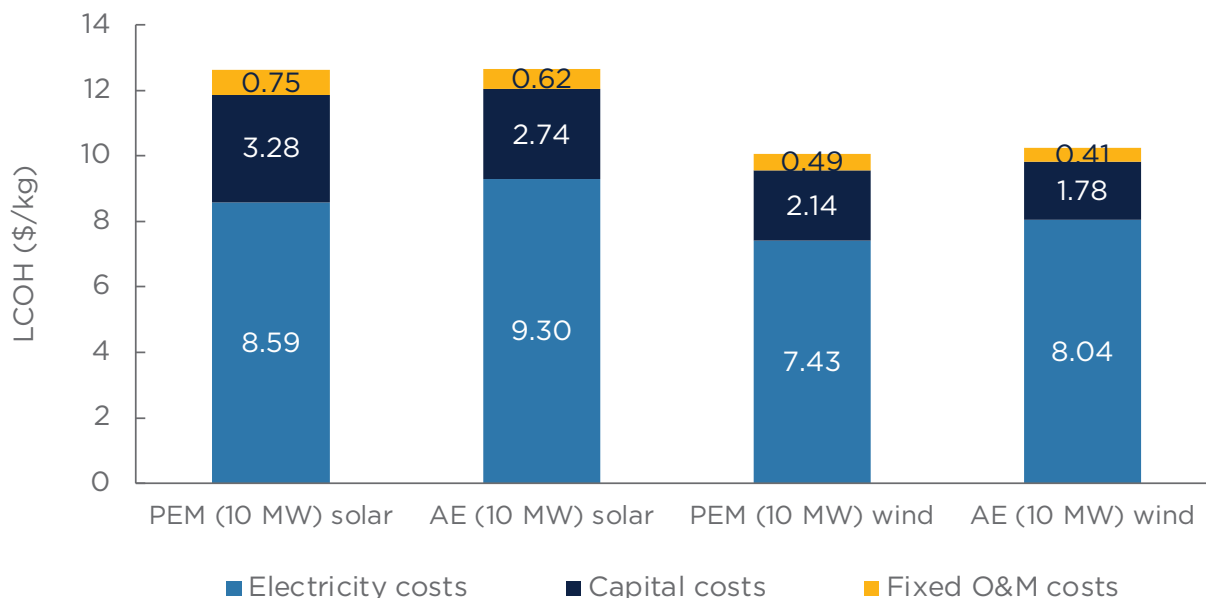
Source: Authors' analysis based on data from IEA and IRENA.

For a representative 10-MW PEM electrolyzer facility in Australia, average LCOH are \$12.62/kg and \$10.06/kg for solar and wind scenarios, respectively; and \$12.66/kg and \$10.24/kg for solar and wind in the case of the alkaline electrolyzer of equal capacity.

Onshore wind is significantly cheaper than utility solar in Australia today, on average, accounting for the lower LCOH for the solar scenarios. Additionally, onshore wind has a higher capacity factor in Australia today, compared to utility solar.



Figure 7: Australian LCOH estimates for 2020 technology and industrial renewable power systems



Note: Analysis assumes 10 MW capacity electrolyzer efficiency at nominal capacity of 72 percent and 78 percent for AE and PEM respectively, with an HHV of 39.4 kilowatt hour/kilogram of hydrogen (kWh/kg H₂), a WACC of 5 percent, a stack lifetime of 70,000 hours, and an electrolyzer CapEx of \$1,300 and \$1,000/kW for PEM and AE, respectively. Calculated industrial electricity price for solar = \$0.17/kWh, wind = \$0.147/kWh; fixed O&M cost at 3 percent of electrolyzer CapEx.

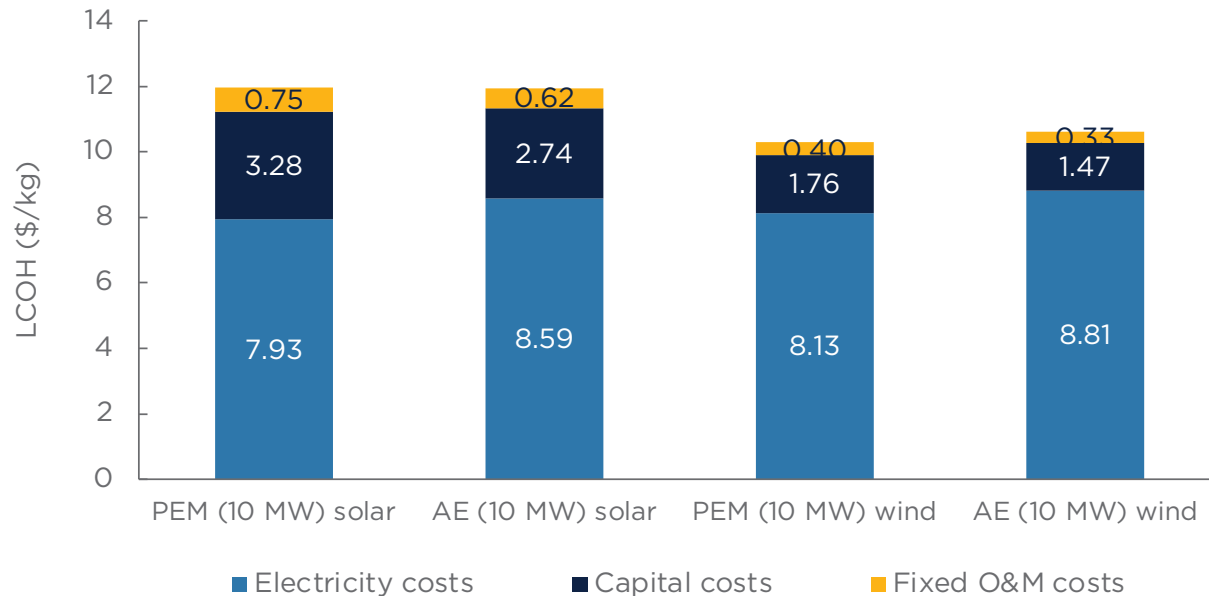
Source: Authors' analysis based on data from IEA and IRENA.

In the case of a representative 10-MW PEM electrolyzer facility in the CIJ region, average LCOH are \$11.96/kg and \$10.29/kg for solar and wind scenarios, respectively; and \$11.95/kg and \$10.61/kg for solar and wind in the case of the alkaline electrolyzer of equal capacity.

Solar power is slightly cheaper than onshore wind in the CIJ scenario, on average, and generally cheaper compared to many geographies today. However, onshore wind has a higher capacity factor, accounting for a slightly lower LCOH than the utility solar case, on average. Additionally, Solar power in CIJ has a higher capacity factor compared to most geographies today.



Figure 8: China, India, and Japan LCOH estimates for 2020 technology and industrial renewable power systems



Note: Analysis assumes 10 MW capacity electrolyzer efficiency at nominal capacity of 72 percent and 78 percent for AE and PEM respectively, with an HHV of 39.4 kilowatt hour/kilogram of hydrogen (kWh/kg H₂), a WACC of 5 percent, a stack lifetime of 70,000 hours, and an electrolyzer CapEx of \$1,300 and \$1,000/kW for PEM and AE, respectively. Calculated industrial electricity price for solar = \$0.157/kWh, wind = \$0.161/kWh; fixed O&M cost at 3 percent of electrolyzer CapEx.

Source: Authors' analysis based on data from IEA and IRENA.

Hydrogen-Favoring Policy Case

If lower electricity prices were made available to electrolyzers connected to utility grid networks because of the positive grid benefits that they provide in a manner that is similar to the positive grid benefits that an inverter-based battery energy storage system (BESS) does, the LCOH would change significantly. Note that such policies could be put in place because they value the future benefits of hydrogen and BESSs and desire to offset current costs to encourage their adoption and use.

Note that BESSs are currently being provided favorable access to utility wholesale rates because they can be dispatched to help the grid to incorporate more renewables. Similarly, hydrogen production facilities could be provided access to wholesale rates or wholesale rates plus smaller network transmission and distribution charges because the production of this hydrogen can be scheduled to support more renewable generation on the grid. Especially when very high levels of renewables are on the grid, hydrogen can provide the power supply reliability needed to balance the more variable nature of renewable generation (e.g., long-duration and massive storage, resilient transmission and distribution).



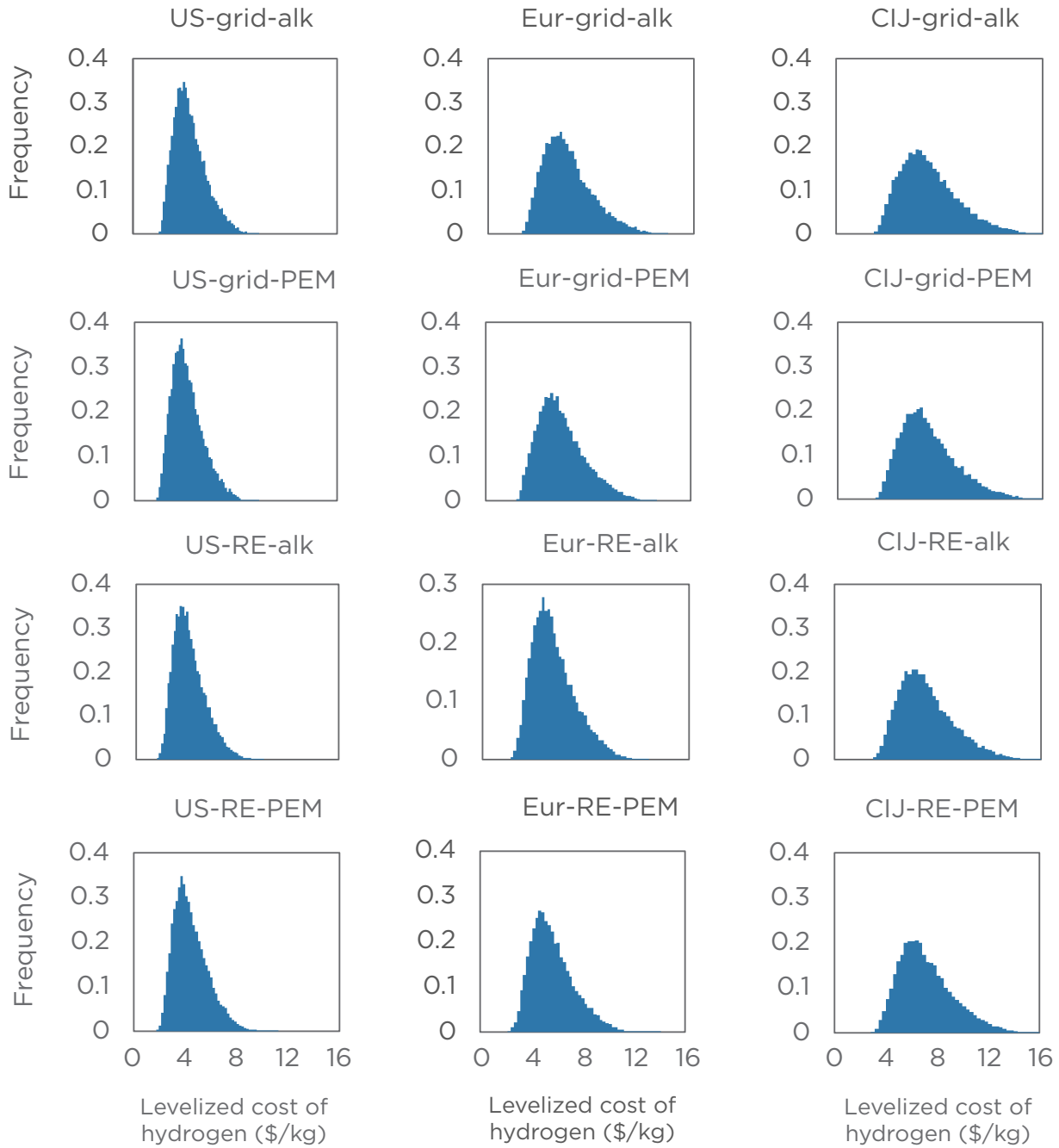
This case is mentioned to represent the other end of the spectrum of likely electricity price cases between now and 2030 in many jurisdictions.

Forecast Price Estimates

In addition to estimating current LCOH values, the authors forecasted the LCOH in 2030 for the 12 scenarios outlined. Similar to the emissions intensity forecast, a Monte Carlo simulation is used for LCOH with a probability density function based on a truncated normal distribution for electrolyzer efficiency, capital cost, electricity price, and capacity factor in 2030 (see Appendix). The simulation randomly selected a value for each parameter based on the probability density function and used these values to calculate 20,000 LCOH output values for each scenario. The distributions of the resulting LCOH values are displayed in histograms in Figure 9. The mean and 5th and 95th percentile of each LCOH distribution are plotted in Figure 10.



Figure 9: Histograms of 2030 LCOH forecast distributions from Monte Carlo simulations for 12 scenarios

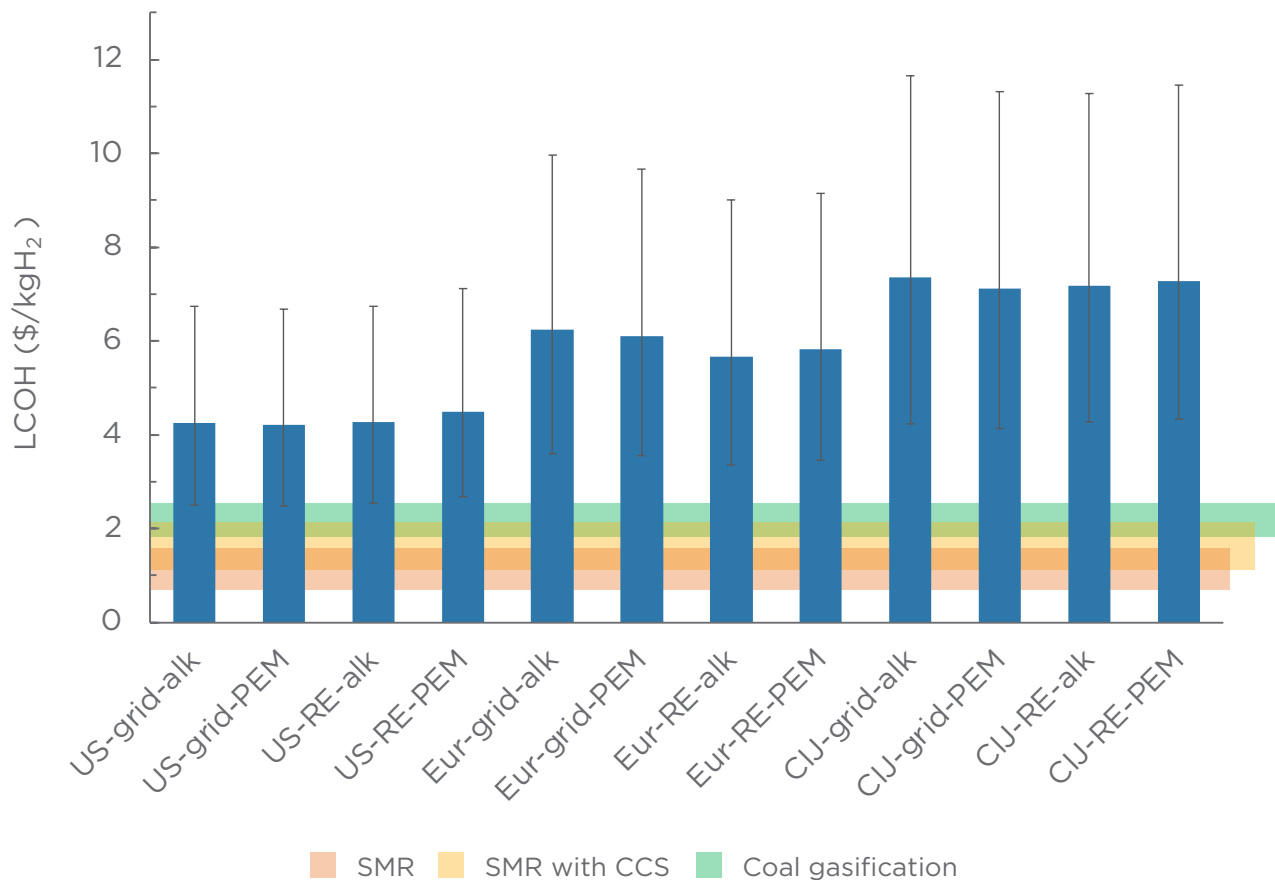


Note: All values are levelized cost of hydrogen (\$/kg_{H₂}).

Source: Authors' analysis.



Figure 10: Mean 2030 LCOH forecasts from Monte Carlo simulations



Note: Error bars represent 5th and 95th percentiles.

Source: Authors' analysis.

The mean LCOH values range from \$4-8/kgH₂ across the scenarios.

Notably, the LCOH using renewable electricity is on par with or even slightly lower than the LCOH for using grid electricity in the same region. This is largely due to the drop in zero-carbon electricity costs in many markets, notably intermittent renewable generation (solar and wind). This insight, taken with the aforementioned finding that renewable-powered electrolysis will have markedly lower emissions through 2030, makes using renewable electricity as opposed to grid electricity for electrolytic hydrogen production more viable. There are some very low LCOH results in the US and EU, on the order of \$2.3-\$3.0/kg, while cheap electricity is provided (<\$30/MWh) with high capacity factor (>80 percent). These high quality sites, wherever they occur, will likely provide early opportunities to grow green hydrogen and help develop infrastructure and commercial frameworks.



GREEN HYDROGEN APPLICATIONS: FUEL, HEAT, FEEDSTOCK

Hydrogen and hydrogen-based low-carbon fuels, such as ammonia, can be used to drive down the emissions in some of the most carbon-intensive industries. The specific viability, benefits, and potential risks of these approaches vary by sector, application, displaced fuel, and infrastructure readiness, which are discussed below.

Ammonia as a Synthetic Fuel

Ammonia has attracted attention as a hydrogen transport medium and as a fuel in its own right. This is partly because it is more easily transportable in liquid form, requiring much milder temperatures and pressures than hydrogen to liquefy (Northwestern University 2020). Ammonia has several other attractive properties including a narrow range of concentrations in air at which it is flammable, as well as its versatility either in combustion or use in an ammonia fuel cell. When burned in an engine or turbine, there's no soot or sulfur pollution, zero greenhouse gas emissions, and nitrogen oxide emissions that can be controlled or managed to be less than with other fuels. Combustion of ammonia without significant attention to novel combustor design and control, however, could lead to higher nitrogen oxide emissions. When ammonia or “cracked” ammonia (the process of splitting the hydrogen from the nitrogen in ammonia) are converted in a non-combustion fuel cell system,² there are no associated criteria pollutant or greenhouse gas emissions—only water and nitrogen gas. If made from low-carbon hydrogen, ammonia can serve as a low-carbon fuel, transportation medium, or product. Although ammonia has roughly one-third the energy density of gasoline, it has a higher energy density than natural gas and compressed liquid or gaseous hydrogen and can be blended with many fuels directly and used in existing engines (Dimitriou et al. 2020).

Ammonia is primarily produced by the Haber–Bosch process, an energy intensive process which requires 450°C–500°C heat and 200 atmospheres of pressure (Leigh 2004). The average carbon intensity of current ammonia production is 2.6 metric ton CO₂-eq/ton ammonia, but when produced by zero-carbon electricity, green ammonia has a 0.23 ton CO₂-eq/ton ammonia (Liu et al. 2020). The annual production of approximately 150 million ton of ammonia (Apodaca 2020) accounts for about 1 percent of global greenhouse gas emissions (MacFarlane et al. 2020). Approximately 72 percent of global ammonia production uses natural gas. The process of producing ammonia with natural gas accounts for 5 percent of global natural gas consumption (Markets and Markets 2020). Therefore, replacing existing ammonia production with green hydrogen feedstocks has the potential to cut carbon emissions significantly.



Industry

Industry could provide a market for green hydrogen if molecules were commercially available. Industrial production is the second largest source of GHG emissions in the US and worldwide. Most hydrogen is used today as a chemical feedstock across many industrial sectors (Brown 2019), from chemicals and refining to metallurgy, aerospace, electronics, and even food processing (Cecere et al. 2014). Currently, about 90 percent of the hydrogen produced in the world is applied as an important petrochemical raw material for the production of synthetic ammonia, urea, methanol, and hydrogenation reactions in petroleum refining processes (Hydrogen Europe 2021a). Not only is hydrogen the key starting material and feedstock for ammonia (fertilizers) and methanol (polymers), but it is also used to remove sulfur, nitrogen and other metal impurities during the refining process (Brown 2019). In the metallurgical industry, hydrogen can be used as a reducing gas to reduce metal oxides to metals (Fan and Friedmann 2021).

The drive for rapid decarbonization has highlighted a new potential use for hydrogen in industries: creating heat (Menzies 2019). Industrial heat produces roughly 10 percent of GHG emissions today, and Montean industrial processes (cement kilns, chemical reactors, blast furnaces, glass making) require large amounts of thermal energy at very high temperatures (Friedmann et al. 2019; Sandalow et al. 2019). As a gaseous fuel, hydrogen can substitute for natural gas in some industrial processes directly, for example in the chemical industry as a fuel for furnaces and boilers (IEA 2020h). As a substitute fuel for heat production, hydrogen or ammonia can also be used directly in blast furnaces. Japan and Sweden have already begun piloting projects that use green hydrogen to replace natural gas as the heating source in carbon-intensive steelmaking (Patel 2020; Kawakami 2020).

Transportation

Transportation is the largest contributor to US GHG, accounting for nearly 30 percent of total US GHG emissions in 2018 (EPA 2020) and roughly 15 percent of global GHG emissions. Currently, petroleum distillate fossil fuel supplies 96 percent of transportation energy demand globally and 92 percent in the US (EIA 2021). As discussed above, hydrogen received significant attention in the early 2000s as a fuel for automobiles but was not widely adopted due to multiple factors, including the cost of hydrogen, cost of fuel cells, storage challenges, and lack of hydrogen fueling infrastructure. However, hydrogen remains of interest as a low-carbon alternative fuel option and energy carrier in the transport sector because of hard-to-abate long haul transportation. Two types of hydrogen vehicles are commonly discussed: (1) vehicles that burn hydrogen in a conventional internal combustion engine (Hosseini and Butler 2020); and (2) hydrogen fuel cell electric vehicles, in which the fuel cell electrochemically converts hydrogen with oxygen to generate electricity (and by-product water) for an electric drivetrain (Manoharan et al. 2019). Both fuel cells and combustion engines can run on hydrogen or ammonia, which could power trucks, ferries, ships, or trains in addition to light-duty vehicles. Some have proposed hydrogen airplanes (Kramer 2020), and demonstration aircraft are being developed; however, direct hydrogen use for the majority of aviation applications is not very likely due to low volumetric energy density. Rather, it is expected that hydrogen could be combined with CO₂ to create synthetic low-carbon high volumetric and gravimetric energy density aviation fuels.



Passenger and Light-Freight Vehicles

Hydrogen as a fuel for vehicles has advantages over its gasoline-dependent counterparts on three counts: GHG emissions reductions, energy security, and reduction of local air pollution (Singh et al. 2015). However, the use of hydrogen in the transportation sector remains at its nascent stage and faces several constraints that limit its competitiveness compared to electric vehicles, the main alternative technology pathway for decarbonizing parts of the transportation sector. First, despite recent reductions in green H₂ production costs, the LCOH ranges from around \$4/kg to \$11/kg in 2020 (IEA 2020d; IRENA 2020) well above the \$2/kg benchmark (BloombergNEF 2020) for broad and viable commercial adoption. Second, the volumetric energy density of hydrogen gas is very low, so high-pressure compression and/or liquefaction is required for transportation and use; unfortunately, high-pressure compression and liquefaction of hydrogen requires substantial energy and expensive carbon fiber or cryogenic tanks (-253°C), which add cost and maintenance challenges (Connelly et al. 2019). Consequently, the costs to compress or liquefy, store, transport, and distribute hydrogen are substantial and require special equipment for safe fueling. Third, and most importantly, limited infrastructure exists to support hydrogen as fuel in the transportation sector in most countries, which greatly limits demand for vehicles, which is in contrast to ubiquitous availability of electricity for slow charging of electric vehicles and recent significant addition of purpose-built fast charging infrastructure in many jurisdictions. At the moment, a small number of hydrogen fueling stations exist and are located in only a few regions (e.g., Japan [Ikeda 2018], California [CAFCP 2021], and Germany [Bonhoff et al. 2012]). For these reasons, battery electric vehicles are currently a more competitive option for passenger and light-freight vehicles; hydrogen is unlikely to dominate the light-duty vehicle market in the near-future until these constraints are mitigated.

Despite these challenges, one advantage hydrogen offers in the light-duty vehicle application is fast refueling. With current systems, liquid hydrogen fueling stations deliver 5–7 kg of hydrogen in 3–5 minutes, comparable to conventional gasoline refueling and sufficient for a light-duty vehicle to drive 300 miles (Reddi et al. 2017). By contrast, electric vehicles generally require at least 30 minutes to charge to 80 percent capacity (approximately double this for full recharge) using the highest-power fast chargers (>100 kW) and many hours using more widely available Level 1 and Level 2 chargers (Colwell 2020). The gaps in fueling times are multiplied when considering heavy-duty vehicles (trucks and ships).

In addition, whether stored as a compressed gas or liquid, hydrogen is much lighter than batteries and can thus enable longer range and heavier payload in passenger and light-freight vehicles. Finally, there is likely to be an infrastructure cost and space (land use) advantage for hydrogen use in light-duty vehicles because several thousand vehicles can be fueled by one corner fueling station compared to the need for hundreds of individual fast chargers. This may especially be true in dense urban environments to reach very high market penetration of zero emission light-duty vehicles.



Medium- and Heavy-Duty Vehicles

In the United States, medium- and heavy-duty vehicles powered by diesel fuel represent only 4 percent of road vehicles, but they contribute around 20 percent of the transportation sector's GHG emissions, nearly half the on-road NO_x emissions, and around 60 percent of the fine particulate emissions from all vehicles on US roads (Chambers and Schmitt 2015; Quiros 2017; O'Connor 2020). Besides the global warming potential caused by truck GHG emissions, NO_x and its air quality damaging derivatives and fine particulate matter are dangerous human health hazards on a local level and can lead to respiratory and cardiovascular disease, cancer, and premature death, which often affect disadvantaged communities disproportionately (EPA 2016; Connor 2020). For these reasons, electrifying medium- and heavy-duty vehicles is a viable alternative to reduce both the carbon intensity of the transportation sector and roadside air pollution emitted by heavy-duty trucks.

Both hydrogen fuel cells and lithium batteries are potential options for decarbonizing pathways for heavy-duty vehicles. However, batteries are not practical for many heavy-duty applications for several reasons:

- Batteries have limited range, which lessens their value for long-distance transportation, and unstable performance that is easily affected by the external environment—low temperatures further reduce driving ranges (Deloitte China 2020). Hydrogen fuel cells can significantly extend trucks' zero emission range capabilities to on par with conventional vehicles (Winton 2020).
- The size and weight of lithium battery packs to power trucks are cumbersome, which reduces the allowable freight weight and space to carry and transport goods (Crooks 2020). A typical regional haul for trucks of 350 miles requires 16,000 pounds of batteries; the same distance requires 120 pounds of hydrogen and a 4,000-pound hydrogen storage tank (Park 2019).
- Batteries have long charging times, which for long-haul vehicles could be hours; by contrast, the refueling time for hydrogen fuel cell trucks is only 10 to 20 minutes (Transport and Environment 2020). This difference is meaningful for reducing downtime in a fleet's daily operations.

Furthermore, heavy-duty transport trucks have regimented duty cycles; many fleets are typically owned and operated by the same company and fueled in the same location. A concerted effort between local governments and trucking companies could enable construction of a relatively small number of hydrogen fueling stations to serve larger fleets based on the existing routes of these trucks, which would overcome the limits of current infrastructure to engender zero emissions medium- and heavy-duty transport via hydrogen.

Ships

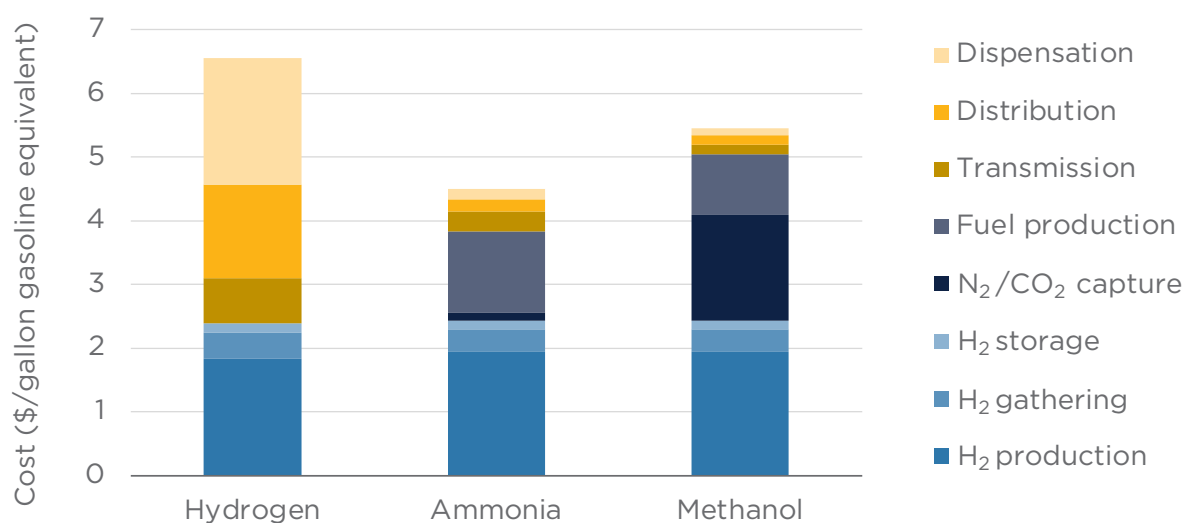
The global shipping industry currently exclusively uses heavy oil or marine diesel as fuel and is responsible for more than 3 percent of global greenhouse gas emissions (Olmer et al. 2017). Shipping fuel also has a high concentration of sulfur; when burned, sulfur emissions



produce air polluting chemicals and particles that are harmful to human health (Roberts 2018). These pollutants are also concentrated near coastlines where densely populated communities reside (Chen et al. 2019). Global shipping pollution contributes to roughly 14 million cases of childhood asthma annually and 400,000 premature deaths from lung cancer and cardiovascular disease annually (Sofiev 2018). So changing to cleaner shipping fuels will not only reduce GHG emissions but also yield significant health benefits, especially to disadvantaged communities living near ports.

Similar to medium- and heavy-duty trucks, batteries are impractical for maritime applications due to their relatively heavy weight and limited range (Timperley 2020). Hydrogen can provide a range of different marine fuel options, including liquid hydrogen or gaseous compressed hydrogen, or methanol and ammonia, which are both made from hydrogen. Of these, ammonia is seen by many as most suitable for transition to a sustainable shipping sector (Hansson et al. 2020), as liquid hydrogen cannot be blended into conventional marine fuels and must be kept at high pressures (70 megapascals [MPa]) or extremely cold temperatures (-253°C) (Office of Energy Efficiency and Renewable Energy 2021). Low-carbon ammonia (blue, bio-, and green), on the other hand, has high energy density (i.e., less on-board storage volume) compared with other fuels (Timperley 2020) and lower overall fuel-related costs (Figure 11), especially compared to hydrogen, because it can be easily stored as a liquid in inexpensive tanks at very low pressures. Additionally, ammonia can be used in internal combustion engines or fuel cells, and many ship engines can be retrofitted to adapt to use of ammonia fuel (Jacobsen 2020), making ammonia not just a low-carbon alternative but also available today and viable for rapid scaling. Methanol has also demonstrated many of these benefits (e.g., high energy density, ability to blend with existing fuels, ease of storage as a liquid); however, ammonia contains no carbon and releases no carbon dioxide in use, making it both a lower carbon and lower full-cost alternative.



Figure 11: Overall fuel-related costs of hydrogen, ammonia, and methanol

Source: Data courtesy of Yun Zhao, originally reported in Zhao et al., “An Efficient Direct Ammonia Fuel Cell for Affordable Carbon-Neutral Transportation,” *Joule* 3, no. 10 (2019): 2472–2484, <https://doi.org/10.1016/j.joule.2019.07.005>.

Ammonia has one major limitation as a low-carbon fuel: it is toxic. Leakage into the environment and potential exposure to human and aquatic life represent important safety and environmental issues. But because ammonia is made in large volumes and is shipped around the world today, specific technologies and safety regulations exist that have proven capabilities to manage these concerns. However, scale-up of a global ammonia fuel industry could lead to emissions, such as ammonia evaporation and NO_x emissions, that are dangerous and environmentally damaging (Hansson 2020), requiring attention and careful management in scale-up and deployment. Many technology options exist to manage nitrogen oxide emissions. Hydrogen combustion can in some cases increase NO_x emissions as well due to its high temperature. These considerations must be built into energy conversion involving hydrogen production. Ammonia combustion is less studied than hydrogen combustion and may face similar challenges, which would require similar consideration. Alternatively, fuel cell use provides options to generate electricity, heating, and cooling without combustion, and ammonia fuel cells could prove a useful option in many applications.

Power

The power sector is the third largest source of US greenhouse gas emissions, accounting for 27 percent of total US GHG emissions (EIA 2021) and is the third largest source of GHG emissions worldwide (IEA 2020e). Approximately 63 percent of US electricity comes from burning fossil fuels (globally 64.5 percent), mostly natural gas and coal (EIA 2020b). Zero-carbon hydrogen fuels can serve power sectors by (1) working as an energy storage system with electrolyzers and fuel cells; (2) substituting directly for fossil fuel in power generation



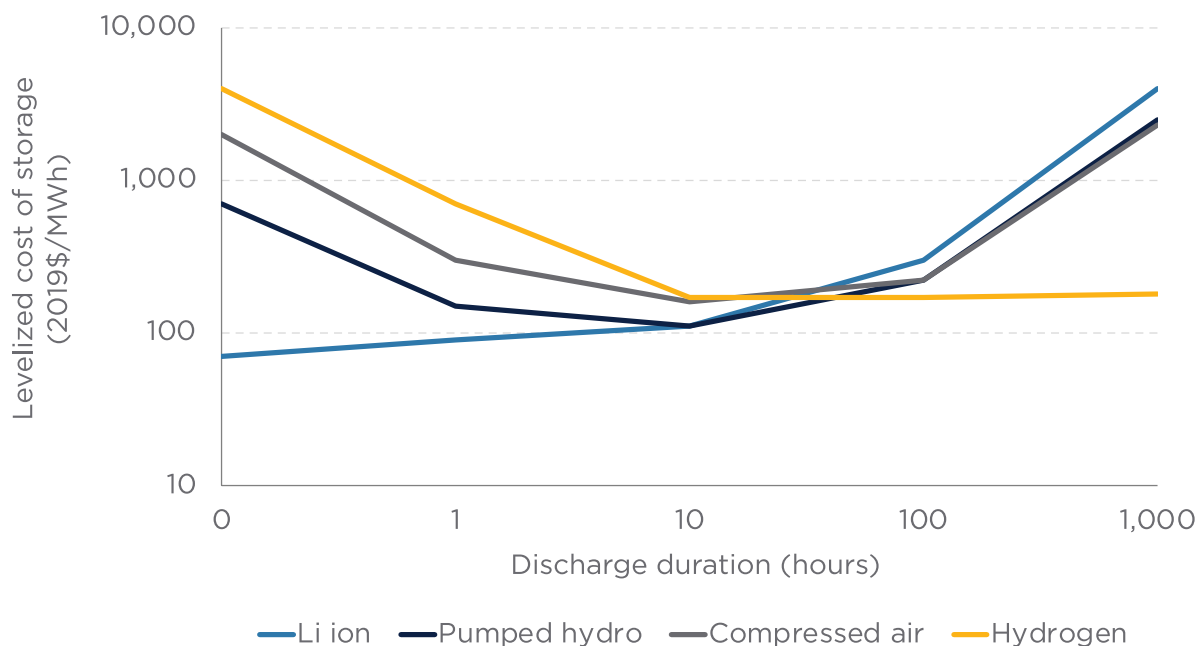
cycles; and (3) engendering reliability and resiliency to the power sector via underground pipeline delivery of renewable energy and enabling massive, long-duration energy storage.

Load Balancing and Renewable Overgeneration

The remarkable and rapid expansion of renewable electricity generation in the last 15 years, particularly solar and both onshore and offshore wind, has demonstrated opportunities to replace fossil generation and decarbonize the grid quickly, up to a certain percentage of total generation. Intermittency (power being available mostly when the wind blows or the sun shines) remains a challenge, requiring energy storage. Especially as renewable percentages greater than 50–70 percent of total generation are realized, seasonal or long-duration weather events that lead to large and long-duration production gaps make full grid decarbonization concerning. Unfortunately, large-scale energy storage systems also face hurdles. Batteries become expensive due to coupled power and energy scaling and are poorly suited due to unavoidable self-discharge to balancing long-term or seasonal electricity demands (Bartlett and Krupnick 2020). Although lithium-ion batteries continue to drop in cost and provide storage durations in the four- to six-hour range (Cohn 2017), they and other batteries still are not yet capable of economic large-scale and long-term storage (O’Neil 2019).

Another option, grid-connected green hydrogen production and storage, consists of an electrolyzer coupled with a storage system and a fuel cell or turbine that supplies power when required (Spiegel 2020). This configuration can offer a long-term storage solution to address the seasonality and intermittent availability of renewable energy (Schiavo and Nietvelt 2020). Pumped hydropower can store large-scale and long-term energy by pumping water to higher altitude and generate electricity in hydropower stations (Schiavo and Nietvelt 2020), but is constrained by limited geographical availability (Johnson et al. 2019) and environmental impacts of lake construction. Interim green H₂ production and storage also appear more cost competitive than batteries for long-term and massive energy storage applications (Figure 12). Hydrogen can be stored for long periods of time with minimal loss, and the quantities stored are only limited by the size of the storage facility (O’Neil 2019). Separate power and energy scaling associated with hydrogen energy storage (i.e., power capacity is set by the size of the electrolyzer and fuel cell, while energy capacity is set by the size of the storage tank/facility) make massive hydrogen energy storage cheaper than most other options. The storage potential of hydrogen can be immense: the green hydrogen underground storage of just one storage facility developed in Utah that uses salt caverns (FuelCellWorks 2020) can store 150 times the total US installed lithium-ion batteries capacity, and the storage can last for months, way beyond the duration of a large battery energy storage system (St. John 2020).



Figure 12: Electricity storage costs vs. discharge duration

Source: Data from IEA (2019) as used in Bartlett and Krupnick, "Decarbonized Hydrogen in the US Power and Industrial Sectors: Identifying and Incentivizing Opportunities to Lower Emissions," *Resources for the Future* (December 2020), https://media.rff.org/documents/RFF_Report_20-25_Decarbonized_Hydrogen.pdf.

Substitute Fuel (for Coal and Gas)

Traditionally, electricity can be generated via coal-fired plants by burning coal in a boiler or via natural gas with a gas turbine (Brown and Welch 2020). Conventional electricity production contributes to GHG emissions and causes sulfur dioxide emissions and NO_x production that are detrimental to air quality and human health. To lower GHG emissions from the power sector, utilities worldwide are looking to (1) inject hydrogen gas/ammonia directly into natural gas fueled turbine-based power plants to displace fossil fuel consumption and reduce emissions (McDonald 2020) and (2) use ammonia to directly replace coal at coal-fired power plants (Patel 2020). Substitution of hydrogen for fossil fuels will remove 100 percent of sulfur, particulate, volatile organic carbon, mercury, and similar emissions, yielding substantial health and environmental benefits. However, careful attention must be paid to the production of nitrogen oxides, which could be increased with combustion of hydrogen or ammonia in these applications. Careful modification and design are required to avoid NO_x production in the combustion process and remove it from the combustion products via selective catalytic reduction aftertreatment. Substitution of stationary fuel cell power plants at these same locations over time could eliminate both the GHG and criteria pollutant emissions because fuel cells electrochemically convert fuels rather than burning them.



At ambient pressures and temperatures, both hydrogen and ammonia are gases, making them candidates for blending into or replacing natural gas in existing gas turbines. Many existing units, including units manufactured by GE, Siemens, BakerHughes, Mitsubishi, and Solar Turbines, have been tested on blends of hydrogen from 5 to 100 percent (ETN Global 2020). These studies have shown that at low levels of blending, NO_x emissions are comparable to existing unit emissions but that at higher levels additional steps are needed to avoid increased pollution (e.g., using low-NO_x burners and adding selective catalytic reduction if not present). These emissions concerns are also true for blending hydrogen directly in natural gas pipelines and domestic/residential systems for appliances and heating (Leeds City Gate 2017). At high blend levels, modifications to appliances are required to maintain low NO_x performance (Zhao et al. 2019).

Natural gas fueled turbines are fuel flexible, which means they can be configured to operate on green hydrogen or other similar fuels as a new unit or be upgraded after extended service using traditional fuels (e.g., natural gas) (GE 2021). This is considered an important pathway to increase the direct end use of hydrogen while reducing the emissions from power sectors without the need to significantly transform the existing infrastructure (IEA 2019a), which will be very important to the cost-effective transformation of the power sector that contains a large number of existing assets that are not fully amortized. GE's gas turbines have been using hydrogen blends as an energy source (most typically from gasification of solid fuel streams) for the past 30 years, with concentrations ranging from 5 percent to 95 percent by volume (GE 2021). The IEA World Energy Outlook in 2019 estimated that a 5 percent (by volume) blend of green hydrogen can reduce the CO₂ emission of natural gas by 2 percent. Japan has also been exploring cofiring of green hydrogen-produced ammonia in coal-fueled boilers to reduce the GHG emissions from coal power plants. Up to 20 percent blending of ammonia with coal has been achieved with only minor adjustments to the coal power plant, without any increase in NO_x emissions and while reducing the carbon emissions in the process (Croluis 2021).



GREEN HYDROGEN SCALE

Despite the promise of green hydrogen, it represents less than 1 percent of the existing hydrogen market. To play a substantial role as fuel or feedstock in a circular carbon economy, green hydrogen production must increase roughly 1000x over the next 30 years.

Scale Today

Fukushima

As of February 2020, The Fukushima Hydrogen Energy Research Field (FH2R) is the largest green hydrogen plant in the world, producing 1,200 normal cubic meter (Nm³) of green hydrogen per hour (NEDO 2020), approximately 900 tons annually (Crolius 2017). Located on 45 acres of land in the Namie Township, FH2R harnesses energy from the 100 percent renewable-powered grid and a 20 MW solar field to power a 10 MW electrolyzer (Lee 2020). The hydrogen produced by FH2R is transported via tube trailers within the city primarily for use in manufacturing fuel cell systems for hydrogen electric vehicles and buses (Fuel Cells Bulletin 2020).

This project is an example of a public-private enterprise between the Japanese government's New Energy Industrial Technology Development Organization (NEDO) and three private project developers: Tohoku Electric (utility company), Toshiba, and Itwatani (industrial gas company) (Crolius 2017). The total cost of the project is about 20 billion yen (\$189 million) (Hiroi 2020).

A couple of drawbacks to this project are the relatively small size of the electrolyzer compared to larger green H₂ projects, such as the 40 MW electrolyzer of the Masshyla Project in France (Scully 2021), and the relatively high renewable energy prices in Japan, which threaten the cost-competitiveness of FH2R products. The capital cost of electrolyzers is about \$850 per kW of power capacity, leading to a baseline production cost of \$1.00 per kg for CAPEX only (Crolius 2017). It's worth noting that all current hydrogen projects are very small compared to typical grid-scale and refinery-scale projects, which are commonly in the gigawatt size class; that is, it is at least two orders of magnitude larger.

NEOM

Air Products and Saudi Arabia Power company, ACWA Power, are developing the world's largest green hydrogen plant as part of the NEOM industrial cluster project in Saudi Arabia. The \$5 billion project (Air Products 2020), powered by 4 GW of renewable electricity from wind and solar plants, will produce 650 tons per day of green hydrogen (238,000 tons/year), which is 3 percent of the eight million tons per annum of projected low-carbon hydrogen demand in the IEA Sustainable Development Scenario in 2030 (IEA 2020e), and export 1.2 million tons per year of green ammonia for transport. This production capacity is adequate to power about 20,000 hydrogen fuel cell buses (Parnell 2020). The project is scheduled to begin production of ammonia by 2025. The NEOM project will benefit from its



unique geography, which combines exceptional solar and wind resources to produce cheap renewable electricity.

Asian Renewable Energy Hub

The Asian Renewable Energy Hub (AREH) is an intercontinental renewable energy project under development in Western Australia with a target date to start construction in 2026, with first exports expected to commence by 2028 (AREH 2021). At full capacity, its 16 GW of wind and 10 GW of solar should produce ~1.75 million tons of green hydrogen per year for ~10 million ton of green ammonia per year. Over the 10-year construction period, AREH expects to employ up to 5,000 workers, and the hub expects to employ up to 3,000 workers for long-term operations and maintenance. This \$40 billion USD project is being developed by a consortium of developers and investors, including Intercontinental Energy (Hong Kong), CWP Renewables, Vestas, and Pathways Investments.

Fossil fuel companies have a strong hold on the central Australian legislature, complicating wide adoption of renewable energy across the country. For that reason, among others, AREH's power station is off grid, and the hub is focused on exporting its energy sources. If progress continues, it hopes to export renewable energy as liquid fuel to trading partners in the Asia-Pacific region. Given the size of AREH, construction and operation of the hub requires a large number of state and federal approvals. AREH received an initial environmental permit for the production of 15 GW of wind and solar generation in October 2020 and had to reapply for additional approval to expand to 26 GW of power generation to produce hydrogen and ammonia as well as apply to build key export infrastructure. The approval process will take approximately two years, highlighting regulatory challenges to rapid scaling of green hydrogen and its derivatives in this country.

Future Scale

Global interest in hydrogen as an energy source is expected to keep growing over the next decade and toward 2050, with an increased share of hydrogen in the projected global energy mix of various sovereign and corporate climate change commitments. The falling price of renewables to power electrolyzers has also increased the potential for availability of cheap green hydrogen for replacing fossil power plants with hydrogen-fueled power stations (this would be true as well for price reduction for other zero-carbon electricity supplies).

With about 50 targets, mandates, and policy incentives globally today that directly support green hydrogen production, spending on hydrogen energy research, development, and demonstration by national governments has also risen (IEA 2019a). These investments have led to deployment of green hydrogen projects with the potential of meeting about 18 percent of the world's total energy needs by 2050 using hydrogen technologies (Hydrogen Council 2020), giving rise to a \$12.09 trillion potential market globally by 2050, or about 13 percent of current global GDP (2018) (Gandolfi et al. 2020). Key drivers needed for adequate future growth will be reduced cost and improved energy efficiency of electrolyzers; cheaper and more reliable renewable power, at \$0.03/kWh or less to reduce LCOH to about \$2/kg; and government policy support for green financing. Investment in green hydrogen production is projected to exceed \$1 billion per year globally by 2023, along with expected increased



demand for hydrogen (IHS Markit 2020).

Rising demand for green hydrogen is seen mostly in the following markets:

- Europe: The EU projects that the share of hydrogen in the EU energy mix will increase from about 2 percent in 2019 to 15 percent in 2050 (Hydrogen Europe 2020b). This would create a €2.2 trillion (\$2.4 trillion) potential hydrogen market by 2050, mostly for utilities, and much of it green hydrogen (Gandolfi et al. 2020). The electrolyzer market is projected to increase by over 650 times by 2030 and over 8,000 times to 500 GW of electrolyzer capacity, by 2050 (Lapides et al. 2020). To produce the green hydrogen projected, EU annual renewables additions would have to triple from 35 GW to 90 GW until 2050 (Hydrogen Europe 2020a). That level of renewable power production (e.g., at a projected solar electricity price of €27/MWh [\$30/MWh] from Iberia solar plants) results in €1.5/kg (\$1.7/kg) of green hydrogen, which is dramatically lower than today's prices.
- USA: Future hydrogen demand in the US might grow by four times to reach 41 megatons per annum by 2050 while the maximum “serviceable” demand is as high as 106 Mtpa (Greenhalgh 2020), with almost half the potential market for industrial processes, including synthetic hydrocarbon production (14 Mtpa), metals refining (12 Mtpa), oil refining (7 Mtpa), ammonia production (4 Mtpa), and biofuels production (9 Mtpa). US renewables capacity is also projected to reach 144 GW in 2050 with a total market of about \$3.5 trillion (Gandolfi et al. 2020).
- Asia: Leading Asian economies (i.e., Japan and South Korea) plan to import the majority of clean hydrogen needed to meet projected demand for clean energy. Pacific-Asia demand for hydrogen exported from Australia (as ammonia) could reach three million tons each year by 2040, worth about \$10 billion per annum (ARENA 2021). South Korea's road map outlines the goal of producing 6.2 million FC electric vehicles (FCEVs) (Ha 2019), 41,000 hydrogen buses, 1,200 refilling stations and generating 15 GW of hydrogen-fueled power by 2040 (IEA 2020g). Japan's hydrogen road map includes importing 300,000 tons of hydrogen per year by 2030 to achieve its goal of having 800,000 FCEVs, 1,200 FC buses, 10,000 FC forklifts, and FC trucks and trains (Niunoya and Shima 2020). It also aims to commercialize hydrogen power generation by 2030. This would require new renewable energy capacity of 480 GW to supply Japan and Korea, for a total market of €4.4 trillion (\$4.8 trillion) (Gandolfi et al. 2020). More details on Japan's current and anticipated policies are discussed in the next sections for its leading position.
- Americas: Chile plans to meet 25 percent of its 2050 carbon neutrality target using green hydrogen, with midterm target electrolysis capacity of 25 GW, and less than \$1.5/kg of cheap green hydrogen by 2030 (Ministry of Energy, Government of Chile 2020). Chile is particularly well configured for this goal due to exceptional solar, wind, and hydropower resources. Other nations, including Brazil, Argentina, Columbia, and Uruguay are examining hydrogen both for domestic use and potential export (Berkenwald and Bermudex 2020).



Infrastructure Needs

Beyond the high cost of low-carbon hydrogen production today, the scale-up of low-carbon hydrogen markets is limited by infrastructure, specifically infrastructure associated with the transport, storage, delivery, and dispensing of hydrogen. Transport of gaseous hydrogen requires compressors and special tanks, and liquid transport requires liquefaction trains and special containers. Pipeline infrastructure and fueling infrastructure are also severely limited today. To enable ease of storage and transport, green hydrogen may require ammonia synthesis, storage, handling, and fueling infrastructure to utilize ammonia as a hydrogen carrier. In addition to the enormous amounts of zero-carbon power discussed above, green hydrogen production requires corresponding electricity generation infrastructure, which is desirable nonetheless for economy-wide decarbonization. Green hydrogen's blue counterparts (which use fossil fuel production with carbon capture) will primarily require CO₂ compression or liquefaction and transport infrastructure and dedicated storage (sequestration) facilities.

To quantify infrastructure requirements to meet future global demand of low-carbon hydrogen, the authors assessed several scenarios:

- 88 Mt/yr of global hydrogen demand, corresponding to the IEA's Stated Policies Scenario for 2030;
- 530 Mt/yr, consistent with the IEA's Sustainable Development Scenario for 2070; and,
- 750 Mt/yr, which represents an accelerated and more ambitious target for well below 2°C.

The authors determine the infrastructure needs for each market scenario either with 100 percent green hydrogen, 100 percent blue hydrogen, or a mix of 70 percent green and 30 percent blue hydrogen.

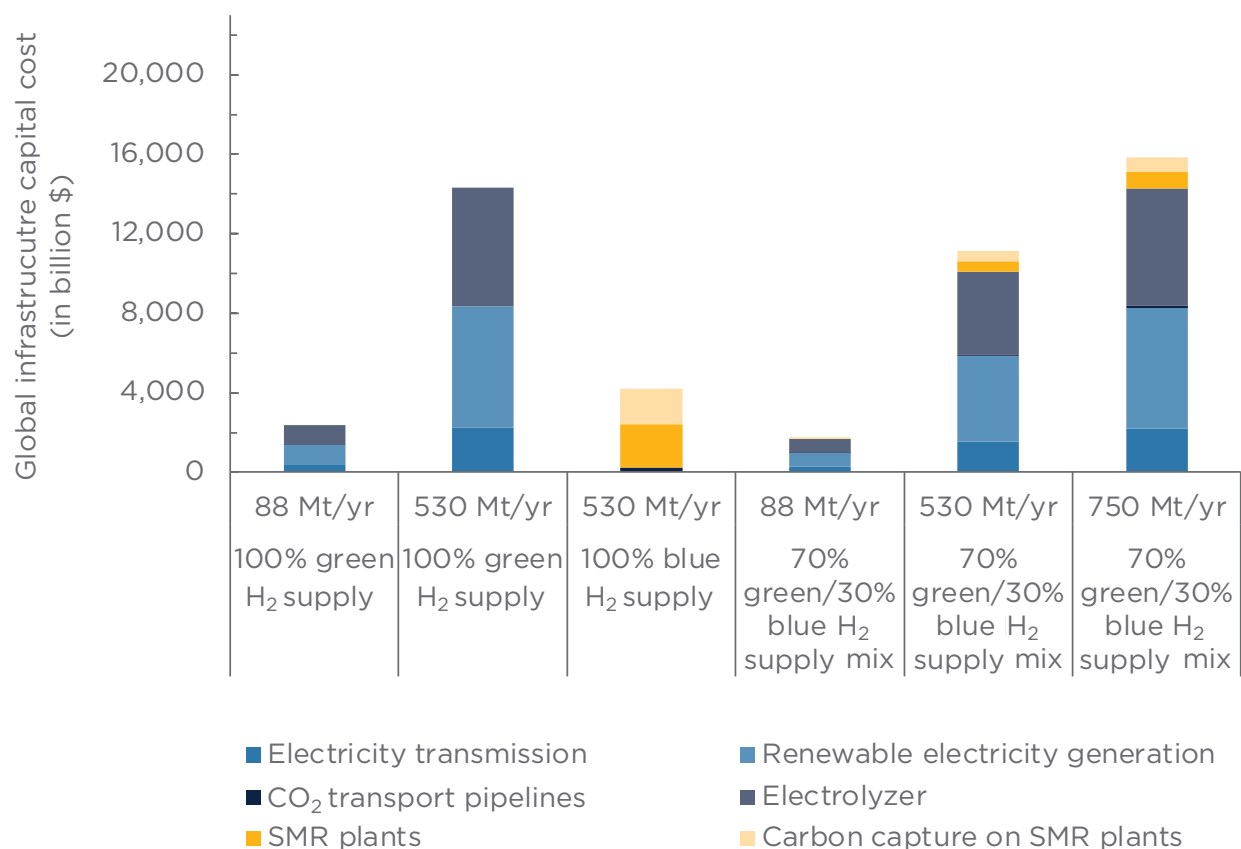
The 750 Mt/yr of hydrogen scenario assumes an accelerated deployment of low-carbon hydrogen (the highest hydrogen application potential of the three) supplied by 70 percent green hydrogen and 30 percent blue hydrogen; it does not consider 100 percent blue or green hydrogen because those are not reasonable production share assumptions for this amount.

For each scenario, the global capital investment required for zero-carbon electricity capacity, electricity transmission, CO₂ transport, electrolyzers, steam methane reforming plants, and carbon capture infrastructure was estimated. This estimate did not include the costs of hydrogen transport infrastructure. The results are summarized in Figure 13. In the cases that involve green hydrogen, the total CAPEX for the required critical infrastructure is in the trillions of dollars. The total CAPEX for the 88 Mt/yr with 100 percent green hydrogen scenario is \$2.4 trillion. Zero-carbon generation infrastructure is the largest component of infrastructure CAPEX, followed by electrolyzer and then transmission infrastructure. In the 100 percent blue hydrogen case with 530 Mt/yr of hydrogen demand, the capital cost for new SMR and CCS infrastructure is also in the trillions but is a fraction of the infrastructure costs for the 100 percent green hydrogen case with the same size hydrogen market. The CO₂



transport infrastructure cost in this scenario is significantly smaller than the other forms of infrastructure at \$243 billion. The low costs associated with 100 percent blue hydrogen and 30 percent blue hydrogen mixes demonstrate the role blue hydrogen can play in developing a hydrogen economy. Blue hydrogen is examined more deeply in a companion report by the Global CCS Institute (Zapantis 2021).

Figure 13: Capital cost of infrastructure for renewable electricity, electrolyzer, CO₂ transport pipeline, SMR plants, and carbon capture for SMR required to support several green/blue hydrogen global market scenarios



Source: Authors' analysis.

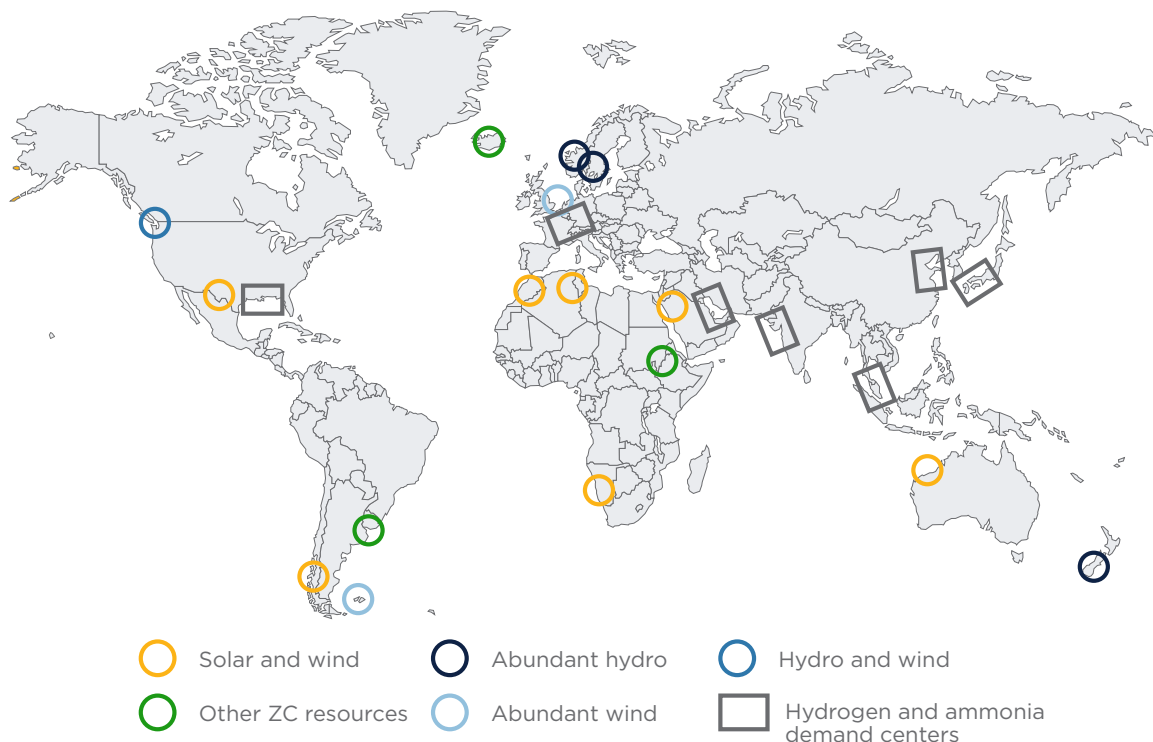


OPPORTUNITIES

Because it is so versatile, green hydrogen presents opportunities for uptake and use in many sectors across a circular carbon economy. Because zero-carbon electricity is the principal cost to hydrogen development at scale, regions and nations with high renewable electricity generation potential are well positioned to take advantage of emerging markets enabled by emerging policies. Similarly, limits to green hydrogen uptake and deployment must be countered to maximize its economic and environmental potential.

Zero-carbon electricity resource economics (chiefly electricity cost and availability) remain a core requirement. As discussed in the LCOH analysis, a key threshold is ~80 percent capacity factor at <\$30/MWh (Friedmann et al. 2019). A handful of regions have the combination of high capacity factors (e.g., hydropower, solar PV plus wind) at a sufficiently low generation cost (Figure 14). These geographies are already seeing explosive growth in investment, planning, and production of green hydrogen and fuels (mostly ammonia), including Chile, NEOM, and AREH. Figure 14 is meant to be representative, not comprehensive; as new areas emerge with a combination of high-capacity factors and low cost, they may receive attention and investment as well.

Figure 14: Geographies with combined zero-carbon resources of high capacity and low cost



Note: Hydrogen demand centers represent regions of current and projected demand for hydrogen and ammonia based on existing infrastructure announced policies.

Source: Authors' analysis.



Near-Term Market Opportunities

Low-cost green hydrogen production still requires markets for sale. The key geographies identified in Figure 14 are not current centers of heavy industry, natural gas consumption, and transportation corridors (e.g., the Falkland Islands), indicating a mismatch between prospective green hydrogen production and market use. To supply sectors and specific markets before 2030, near-term opportunities will use existing infrastructure and will be subject to infrastructure limits. The authors examine a set of cases where a combination of renewable resources, market demand, and enabling infrastructure create opportunities for early deployment, which will in turn provide lessons for users, producers, regulators, policymakers, and investors.

Congestion and Curtailment

The rapid expansion of solar and wind energy capacity in recent years has resulted in the growing occurrences of renewable energy congestion in many energy grids. There are three primary mechanisms for renewable energy curtailment: economic curtailment, self-scheduled cuts, and exceptional dispatch, in which balancing authorities require specific renewable plants to reduce their energy output (e.g., CAISO 2017). To combat the congestion of renewable energy on the grid, the Federal Energy Regulatory Commission (FERC) recommends that independent system operators curtail the production of renewable energy as a last resort. This is important in parts of the midwestern US where there's an overabundance of generated wind energy and insufficient transmission capacity due to limited market demand and limited loads (e.g., Wiser et al. 2020). When curtailed, prices for zero-carbon electricity can be extremely low or negative (a source of revenue for load centers rather than cost). The same is true for curtailment in other jurisdictions (e.g., China and the EU).

Rates of renewable energy curtailment vary across the US. The 2018 national curtailment average for wind energy was at 2.2 percent (Wiser et al. 2018). Locally, rates may be much higher—the Electric Reliability Council of Texas reported that four of its projects, representing 600 MW of generation, experienced curtailment rates of 18–25 percent (Wiser et al. 2018). As of November 2019, economic curtailment of solar energy in the US was reported at a rate of more than 40 percent (approximately 400 GW) in some locations (Frew et al. 2019). In California, rates of renewable energy curtailment hit record high levels during the COVID-19 pandemic as the demand for electricity in businesses and restaurants decreased with social-distancing measures (CAISO 2020).

The extraordinary low power prices during curtailment provide an opportunity for low-cost green hydrogen production. Two different properties of curtailment limit this opportunity:

- By design, curtailment is meant to be rare, yielding low capacity factors. This makes the project economics challenging and the volume of hydrogen produced limited.
- To optimize the outputs of solar and wind energy, transmission of the energy produced may expand, either by adding more transmission lines or by storing the renewable electricity (e.g., in battery energy storage systems). This would limit curtailment, furthering challenging project economics. (Note that these alternative options are also economically limited by low capacity factors.)



These two properties prevent curtailment from serving as a major element of a circular carbon economy. Nonetheless, there are likely to be projects in the near term where green hydrogen can be generated with curtailed power, a combination of on-site and curtailed power, or a combination of on-site and market-delivered low-cost power and either sold into adjacent markets (e.g., trucking) or stored and returned to the grid as electricity. This will help scale supply chains for green hydrogen as well as organize markets around hydrogen-based energy services and contracts.

Low Fraction Blending

Blending hydrogen into natural gas grid infrastructure is considered an important way to increase direct end use applications of hydrogen (IEA 2019a). Low fraction blending has multiple benefits in addition to natural gas end-user decarbonization: (1) it accelerates cost reduction of low-carbon hydrogen production by a high consumption rate (even at low fraction), (2) it encourages wider application for other purposes, and (3) it uses existing infrastructure for natural gas, making it a short-term opportunity with less infrastructure requirement and lower cost (IEA 2019a).

Hydrogen use in gas networks is not new: historical use of “town gas” (mostly hydrogen, carbon, and methane) was ubiquitous around the world during the industrial revolution, the infrastructure for which has been converted in more recent decades (e.g., in Europe and the US) to transport and store natural gas (Arapostathis et al. 2013). Hydrogen blended into natural gas has wide applications, such as space heating, electricity power generation, and chemical synthesis (e.g., methane, ammonia, and methanol). Blending limits have already been established in many jurisdictions, but the limits vary greatly (IEA 2019a). The IEA estimates that some EU countries like the Netherlands, Germany, France, and Spain have high blending ratio limits >5 percent (the countries are listed from highest to lowest blending allowances), but most countries are limited to <2 percent. A report from the National Renewable Energy Laboratory estimates that a less than 15 percent to 25 percent blend ratio won’t cause significant risks to end uses of the blended gas and would ensure general safety of the existing natural gas infrastructure (Melaina et al. 2013; Blanton et al. 2021).

As mentioned earlier in the paper, a 5 percent (by volume) blend of green hydrogen can reduce natural gas’s CO₂ emission by 2 percent (IEA 2019a). The IEA’s sustainable development scenario by 2040 shows that among the total of 57.7 megatons of oil equivalent (Mtoe) hydrogen in final energy use, over 25 Mtoe are likely to be blended into the gas grid, making blending the largest and widest end use application of hydrogen. Low fraction blending also makes the cost impact of the hydrogen–natural gas mixture low, which could help promote near-term opportunities for large-scale production. Limits such as reduced energy density (H₂ energy density is roughly one-third that of natural gas) (Quarton and Samsatli 2018) will eventually lead to larger consumption by volume, which limits its application to certain industrial applications that depend on carbon content (e.g., methanol requires carbon atoms and iron production needs carbon as a reduction agent).

Importantly, blending small amounts of hydrogen into the natural gas system has substantial value in the short term to enable a massive increase in the installation and use of renewable solar and wind power generation. If blend limits were established around the world in the 5



percent range, they could engender at least a doubling of renewable electricity generation capacity (Lapides et al. 2020). However, near elimination of fossil natural gas use is required to completely decarbonize economies, which would require investments that eventually transform the natural gas system from managing fossil fuel to transporting, storing, and delivering renewable fuel. This could be accomplished by piece-wise conversion of parts of the gas infrastructure to support pure hydrogen (or a hydrogen derivative) in many jurisdictions after the initial conceptual transformation design developed for the northern UK H21 project, which proved that the gas network could safely transport hydrogen in a nondisruptive and cost-effective way (H21 2021).

Japan's Hydrogen and Ammonia Market

A series of recent policy measures have established Japan as the primary global market for low-carbon ammonia and hydrogen. Lessons can be learned from these actions and the prior decade of investment in RD&D and infrastructure regarding costs, infrastructure needs, and time to market. Much of the support for this industry comes through grants and subsidies from Japan's Ministry of Economy, Trade, and Industry (METI), including an RD&D budget of \$664 million in 2020 targeted (IEA 2021) at driving down the cost of producing hydrogen through technological improvement as well as subsidies for fuel cell vehicles and fueling stations.

In October 2020, Japanese Prime Minister Yoshihide Suga announced Japan's goal to become carbon neutral by 2050 (Dooley et al. 2020). Before this announcement, Japan was on an ambitious pathway to reduce emissions by 80 percent by 2050 (Nakano 2020). The country has the third largest economy and is the sixth largest emitter of greenhouse gases in the world (Friedrich et al. 2020). Today, 70 percent of Japan's power sector relies on fossil fuels, which accounts for about half the country's emissions (Nakano 2020).

In December 2020, the trade ministry introduced a road map that both divests Japan's economy from fossil fuels and invests in green energy industries. The report identifies 14 key industries that will be key drivers for decarbonization (Takahashi 2020). These industries span across power, transportation, shipping, agriculture, housing, and waste sectors. In recognition of the important role green ammonia will play as a carbon-neutral fuel source that can be applied directly to fuel cell engines, METI established the Ammonia Energy Council, which "consists of 4 entities from the public sector and 10 from the private sector" (Crolius 2020). METI's road map for decarbonization by 2050 includes two relevant key milestones: reduce Japan's 2013 emissions by 26 percent by 2030 and invest in research and development of decarbonization technologies to achieve net zero emissions by 2050 (METI 2021).

In December 2020, METI released a policy statement announcing its goal of converting 14 coal power plants to be cofired with ammonia (Crolius 2021). According to METI, "one coal-fired unit with 20 percent cofiring requires 500,000 tons of ammonia annually." If implemented on all domestic coal-fired power plants, 20 million tons of ammonia would be required annually—about one-eighth of current global ammonia consumption (Crolius 2021). Within the decade, Japan expects to produce or procure green ammonia for thermal fuel generation and shipping (Kumagai 2020).



In many cases, Japan has pursued public-private partnerships to lead both fueling infrastructure and industrial development. Fuel cell vehicles, including trucks and buses, provide one example. Direct government procurement policies to accelerate domestic utilization of electric vehicles, such as buses, resulted in major automotive companies such as Toyota and Honda commencing lease sales of fuel cell electric vehicles in 2002, with plans to commercialize over 30,000 FCEVs per annum globally after 2020 (Hornyak 2019). Toyota also has partnered with PACCAR to develop a hydrogen fuel cell truck, with 10 prototypes to date (Eisenstein 2019). Government policies are expected to scale the production of fuel cell vehicles to 200,000 by 2025 and 800,000 by 2030, from the 3,800 currently produced domestically (Okutsu and Shibata 2020). The Koto City hydrogen fueling facility supplies green hydrogen to large-scale fuel cell buses at a rate of four per hour, with over 100 fuel cell buses in the city (Fuel Cell Bulletin 2020). Accelerated development and deployment of fueling infrastructure falls within the road map's target of 320 hydrogen refueling stations by 2025 and 900 by 2030, up from the 131 hydrogen refueling stations in Japan today.

As an example of progress in the power sector, Mitsubishi Power is developing a 100 percent ammonia-powered, 40 MW class gas turbine. Upon completion in 2025, this will be the world's first commercialized gas turbine fueled by ammonia (Mitsubishi Power 2021). Acknowledging the issue of NO_x emissions from direct ammonia production, Mitsubishi's H-25 Series gas turbines combine "selective catalytic reduction with a newly developed combustor that reduces NO_x emissions" (Mitsubishi Power 2021). These steps are consistent with Japan's rapidly developing hydrogen power generators, which are expected to be commercialized by 2030.

Japan is investing in creating and expanding a global hydrogen supply chain (blue and green) to ensure market penetration through a flexible shipping network. Kawasaki Heavy Industries launched the world's first liquefied hydrogen tanker in 2019, using technology that will facilitate the global trade in hydrogen. Foreign partnerships are a key element of Japan's policy framework. As one example, METI and Abu Dhabi National Oil Company signed a Memorandum of Cooperation on Fuel Ammonia and Carbon Recycling in January 2021 (METI 2021). Similar partnerships include Saudi Arabia and Australia (including the Hydrogen Energy Supply Chain project near Melbourne and the Asia Renewable Energy Hub near Pilbara). Discussions have begun in Russia, Canada, Chile, Brunei, and Indonesia.



Europe's RED II Policy and Related Policies

The European Commission's revised Renewable Energy Directive (RED II), which went into effect on January 1, 2021, and is binding for all EU member states, aims to increase shares of renewable energy to 27 percent by 2030 within three sectors: electricity, heating and cooling, and transportation (ICCT 2017). The directive mandates 6.8 percent of transportation fuels must derive from renewable sources, specifically from renewable energy and advanced alternative fuels (including green hydrogen), which the European Commission will reassess in 2025.

Food-based biofuels are excluded from the transportation fuel mandate, and the directive advises a decline in the contribution of food-based biofuels over time (because they compete with the food supply), including through introduction of the renewable fuels of nonbiological origin (REFUNOBIOs) as a new category (Hydrogen Europe 2021b). Beginning in 2021, fuel suppliers must achieve 1.5 percent of the 6.8 percent renewable energy mandate, with advanced biofuels (e.g., green hydrogen) contributing at least 0.5 percent. To ensure a competitive advantage to REFUNOBIOs and other maturing technologies, the contribution of conventional biofuels produced from organic wastes and residues cannot exceed 1.7 percent of the 6.8 percent mandate. A system of guarantees of origin among member states would enable the effective trade of green hydrogen (Bieliszczuk 2020). These actions create opportunities for green hydrogen, although the total fraction of hydrogen-derived fuel is projected to account for a small percentage of the renewable fuel target. This is partly because RED II does not include benefits of the use of green hydrogen in the fuels production process in GHG emissions reduction accounting as part of its statutory design and limits comparing with other renewable sources such as biofuel and renewable electricity (FuelsEurope 2017).

Near-Term Limits

The ability of green hydrogen services and goods to scale rapidly into major markets is limited by technical, economic, policy, infrastructure, and public acceptance challenges. To manifest the opportunities of green hydrogen to maximal climate and economic benefit, several actions and investments will be needed.

Techno-Economic Limits and Innovation

Water splitting to make hydrogen and oxygen through electrolysis has been documented and used for over 200 years (Levie 1999; Snelders 2013). However, commercial use of electrolysis at scale has only just begun. The high cost and limited experience with many large-scale hydrogen production methods limits the speed and scale of deployment today. For example, mass production of alkaline and PEM electrolyzers, the two most mature green hydrogen production technologies, remains limited and expensive today. Although some groups have projected rapid cost reductions, these are not yet matched by an innovation agenda focused on applied science and demonstration in most countries. Furthermore, important technology



options for green hydrogen production, such as solid oxide electrolysis, are at low levels of technology readiness and have received almost no RD&D funding. These low levels of funding and policy support are especially stark in comparison to the amount of RD&D and policy funding support given to comparably important solar, wind, and battery energy storage technologies around the world (Energizing America 2020).

Innovation in green hydrogen would need to involve both investment in improving the cost, performance, and efficiency to move it beyond the low technology readiness level as well as development and demonstration of enabling engineering and technology that can further reduce cost and improve performance. At low TRLs, innovation investments could include catalysts and special materials to reduce energy requirements and costs for water splitting (e.g., photocatalytic materials or ceramic membranes). At higher TRLs, the innovation focus could include seals, coatings, low-cost manufacturing and balance-of-system optimization concerns for alkali and PEM electrolyzer stacks. Although the US and EU have started to increase programmatic investments, much more investment, on the order of billions of dollars, is needed to achieve rapid scale (Sivaram et al. 2020).

Low-Carbon Fuel Standards and the International Maritime Organization

The essential feature of hydrogen, that it is a low-carbon fuel, is not explicitly valued in many markets. The Japanese market has begun to value low-carbon hydrogen and ammonia explicitly by paying a green premium for ammonia and hydrogen fuels as a function of associated production carbon content. Not many other markets do. Many policies to date (e.g., European Green Deal) have focused on supporting production of hydrogen (policy push) rather than valuing its market application (demand pull). The lack of market pull is a profound limit to green hydrogen commercialization today.

One set of policy options to address this limit involves creating low-carbon fuel standards (LCFS). These effectively act as a regulatory cap on GHG emissions. The longest-lived program of this kind is California's LCFS program (California Air Resources Board 2020), which has operated since 2016. The regulatory cap is matched with a credit trading program that helps manage overall compliance cost and enable low-carbon fuel adoption across the California vehicle fleet, and since 2019 credits have traded at up to \$200/ton CO₂, which appears sufficiently high to stimulate investment. Similar programs have emerged in other jurisdictions, including draft bills in Washington State and New York (Washington Dept. of Commerce 2020; Lane 2020) as well as Canada's proposed clean fuel standard (Government of Canada 2020). In these jurisdictions, hydrogen fuel cell vehicles are considered electric vehicles, which allows them to qualify for additional subsidies and incentives. To accelerate transition away from fossil fuels, nations that support hydrogen vehicles, such as Japan, Korea, and EU member states, could adopt LCFS policies that would spur market pull for green hydrogen, particularly for trucks and other heavy-duty applications.

Another policy approach involves sectoral fuel standards. These policies bind parties within an operating sector to compositional, performance, and emissions standards. One example is the International Maritime Organization (IMO), which recently adopted standards for low-sulfur fuels across all international shipping, hastening the displacement of bunker fuel with low-sulfur diesel (IMO 2020). Because of the potential value of green ammonia and hydrogen



as shipping fuels, the IMO could adopt a low-carbon standard for fuels, which could accelerate the flow of hydrogen fuels into shipping markets. The IMO has already announced plans for net-zero GHG emissions under their 2050 plan (IMO 2021). With sufficient coordination between key nations and companies, the 2050 timeline could be accelerated (say, to 2040) and interim milestones enacted (e.g., 30 percent zero-carbon shipping fuels by 2030). Adoption of these standards by the IMO would accelerate deployment of green hydrogen globally. Other sectors could pursue and adopt similar policies, led in part by trade groups (e.g., the World Steel Institute or the National Association of Manufacturers).

Policies to Meet Infrastructure Needs

Maximizing the scale and benefit of green hydrogen will require trillions of dollars of investment in new zero-carbon electricity generation and in the transmission and distribution of energy, likely via many thousands of kilometers of electric power lines and/or low-carbon hydrogen pipelines. Although many works have documented these requirements (Larson et al. 2020; ETC 2020), few geographies have adopted policies that can credibly scale the needed infrastructure. Notably, the European Green Deal provides generous subsidies for generation and electrolyzers but not the associated transmission, storage, and distribution infrastructure. At the same time, investment in power lines and pipelines has decreased across North America over the past decade (Meyer 2021).

A set of policies would be needed to create, build, and permit infrastructure at scale, especially in OECD countries where demand will be greatest this decade. These policy options include a set of incentives (e.g., grants or tax breaks for builders) as well as policies to streamline permitting and construction (e.g., FERC Order 689 under section 1221) (Vann 2010). Absent dedicated funding and proactive authorities to accelerate investments and infrastructure construction, the benefits of a low-carbon economy will be slow to materialize.

Another policy option that could speed the transition would be offering green hydrogen technologies access to cheaper electricity rates (e.g., wholesale electricity prices) in return for grid services provided. Cheaper inputs could support this initial market against which the cost of comparable solutions of massive energy storage, resilient and reliable transmission and distribution, and long-duration storage are currently less expensive than the hydrogen alternative. This type of policy is analogous to the support provided in previous decades to the solar, wind and battery energy storage technologies that have successfully managed to lower costs and engender large renewable energy use.

It was wise for policymakers in many jurisdictions to first invest in solar and wind and battery technologies, which, with the support of local gas and electric utility grid infrastructure, were the first and only technologies needed (in the short term) to achieve relatively low percentages (e.g., 20–40 percent) of renewable energy conversion in the electric grid. But if the desire is now to completely decarbonize the electric grid and all other economic sectors, a versatile zero emissions fuel like hydrogen is required (Davis et al. 2019).



FINDINGS AND RECOMMENDATIONS

Finding 1: Green hydrogen could play a major role in a circular carbon economy.

Green hydrogen and fuels made from green hydrogen (e.g., ammonia, methanol, aviation fuels) can reduce GHG emissions substantially through fuel substitution in the transportation sector, industrial sector, and power sector. They can provide heat to buildings and industrial processes; serve as a feedstock to chemical and fuel production, including synthetic hydrocarbon fuels; and serve as a reducing gas in manufacturing processes (e.g., steel, glass, computer chips). They could anchor the recycling of CO₂ through conversion to fuels, chemicals, and materials. Hydrogen also could enable greater contribution of renewable and/or nuclear electricity in the power grid by adding reliability of supply (e.g., through storage, fuel cells, and hydrogen turbines). Many nations have large renewable energy resources that could produce hydrogen, and the technology to produce, convert, and use green hydrogen today is mature.

Finding 2: The primary challenge to green hydrogen adoption and use is cost.

The production cost of green hydrogen is high today and may remain high without subsidies or other supportive policies. Even in geographies with significant renewable resources, electricity is the primary cost element of production (greater than 50 percent), followed by electrolyzers and the balance-of-system cost. A combination of low prices for industrial zero-carbon power and high capacity factors is required to produce green hydrogen for less than \$2/kg. This cost level has been achieved in the handful of green hydrogen projects worldwide but is atypical. Standard costs today are more in the range of \$6-12.

A significant drop in electrolyzer costs would help—a reduction of \$200/kW in electrolyzer costs would result in ~\$0.33 to \$0.84/kg reduction in LCOH for alkaline electrolyzers and a decrease of \$0.36 to \$0.91/kg for PEM electrolyzers. Similarly, an improvement in electrolyzer efficiency of 5 percentage points would decrease LCOH by \$0.5 to \$0.8/kg for alkaline electrolyzers and by \$0.48 to \$0.75/kg for PEM. However, this would not surmount requirements for high capacity/low-cost zero-carbon power in most geographies or markets. It is unlikely costs will change enough for green hydrogen to become competitive with other energy supplies in the near to medium term absent market aligning policies, such as providing electrolyzers access to wholesale renewable power markets.

Finding 3: Green hydrogen commercialization is limited by existing infrastructure.

Growing production of green hydrogen will require enormous investments in and construction of infrastructure. The most important elements include electricity transmission, distribution and storage networks, and enormous volumes of zero-carbon power generation, as well as



electrolyzer production systems, some hydrogen pipelines, and hydrogen fueling systems. To grow green hydrogen production to 88 Mtpa by 2030, system costs would likely approach or exceed \$2.4 trillion and require 1,238 GW of additional zero-carbon power generation. Also, most ports lack the infrastructure necessary to ship hydrogen or ammonia or to receive it, limiting trade and adoption. To achieve or exceed the IEA 2°C scenario, buildout, transmission, generation, and electrolyzer investment would need to approach or exceed \$10 trillion by 2070.

Finding 4: Some nations have developed hydrogen road maps with large green hydrogen components.

The governments of Japan, Canada, and the EU (including some member nations, notably Germany) have published formal road maps for hydrogen production, use, and growth. These plans include industrial policy (e.g., subsidies for manufacturing electrolyzer and fuel cells), port infrastructure (e.g., industrial hubs), and market aligning policies. These plans may provide these nations a competitive advantage in scaling, using, and adopting green hydrogen. Other nations, including China, include hydrogen in sectoral discussions and in some cases have local goals but no comprehensive plan economy wide.

Finding 5: Additional factors could support or limit rapid scale-up of hydrogen production.

Use of green hydrogen and hydrogen fuels could provide substantial additional benefits to local economies and environments, including reduction of particulate and sulfur pollution, maintenance or growth of high-wage jobs, and new export opportunities (fuels, commodities, and technologies). Public concerns about hydrogen and hydrogen fuels, including ammonia toxicity, increased NOx emissions, and safety, could limit acceptance and deployment of hydrogen systems and present challenges in key countries, especially OECD countries, to infrastructure development and early use of hydrogen (e.g., blending in existing gas lines).

Recommendation 1: Given the state of knowledge, markets, and infrastructure, nations and regions that wish to pursue green hydrogen production and use should prioritize detailed analysis and planning today.

Although numerous public and private studies have emerged in the last two years, they do not yet provide important information for the development of detailed strategies and plans. Key questions include the location and scale of infrastructure bottlenecks, limits to electrolyzer and fuel cell production, potential trade-offs in cost and speed with competition, resource availability, public risks, and financial gaps in specific markets and applications. Nations that wish to pursue green hydrogen production and use should gather critical data, such as duty cycles for industrial applications and reliability of power supply, to explore emerging important questions. Analysis is needed to better understand near-term market potential and constrain the wide range of current estimates for market growth. Similarly, more detailed assessment of applications in key sectors (e.g., steel, chemicals, trucks) is needed for planning and implementation. Analysis could also identify maps and cost estimates for near-term opportunities, e.g., due to power congestion or exceptional renewable energy resources.



Recommendation 2: To reduce emissions rapidly through green hydrogen deployment, nations and regions should adopt market aligning policies and production standards.

The substantial price gap between green hydrogen and gray hydrogen calls for active policy intervention to bring production online to serve existing and future markets. These can come in the form of mandates (e.g., Europe's RED II restrictions), grants (e.g., Germany's \$1.1 billion electrolyzer awards to support 500 MW electrolyzers) (Franke 2021), capital reduction incentives (e.g., investment tax credits), preferential market access, or revenue enhancements (e.g., production tax credit, the UK's contract for differences). Similar policies solely in the power sector will produce secondary but substantial reductions in LCOH and considerable additions of renewable power generation capacity; roughly 50 percent or more of green hydrogen costs are associated with the purchase of zero-carbon electricity. To avoid adding substantially to atmospheric GHG loading, nations and regions could develop and legislate standards for the life-cycle footprint of green hydrogen to incentivize contracting and development of zero-carbon power supplies and avoid lock-in of green hydrogen supplied by carbon-intense grid power (e.g., below 200 kg CO₂/MWh and reducing over time).

Recommendation 3: Local, regional, and national governments interested in green hydrogen development should prioritize the construction of necessary infrastructure.

Under all scenarios, major new infrastructure and infrastructure transformation (e.g., gas grid transformation for transporting and storing green hydrogen) is required for electricity transmission, hydrogen production, hydrogen storage, hydrogen transmission, and fueling for mobility applications (both hydrogen and ammonia). In particular, ports represent an opportunity and an urgent necessity to scale production, distribution, and use. In some OECD nations, issues associated with permitting, rights of way, and resilience must be resolved through policy or contract completion with equal priority.

Recommendation 4: Governments pursuing green hydrogen should increase investments in innovation, including RD&D.

With notable exceptions (e.g., Japan, Germany), investment levels in green hydrogen production and use today are a relatively small fraction of innovation commitments. Early-stage research should focus on approaches that improve the commercial readiness of products at the low technology readiness level (TRL), ranging from photolytic and biological pathways to solid oxide fuel cells and electrolyzers. Specific targeted innovation investment could focus on improvements in seals, coatings, catalysts, and other enabling components of electrolyzers and fuel cells. Applied science and pilots could focus on manufacturing chains, automation, balance-of-system cost reduction, and mixed-fuel combustion applications. These innovation investments would likely reduce the cost of market policies and accelerate adoption by providing key information to investors and users. Finally, continued investment in novel technologies to improve the cost and capacity factor of zero-carbon electricity would help all aspects of the green hydrogen ecosystem.



Recommendation 5: Policymakers should appreciate and account for green hydrogen benefits outside of carbon abatement when crafting policies.

The analyses presented here focus on hydrogen's role in the decarbonization of hard-to-abate sectors. Additional benefits can include reduction of criteria pollutants (e.g., sulfur, particulates, and nitrogen oxides) and grid reliability and resilience, especially in combination with fuel cell use to convert hydrogen back to electricity and heat without pollution. Valuation of these benefits should factor into the design of policies that support decarbonization to result in deployment at the speed and scale needed to capture green hydrogen benefits in full.



APPENDIX

Monte Carlo Simulation Methodology

The authors conducted a Monte Carlo simulation to estimate the LCOH and emissions intensity of hydrogen production in 2030. To do so, probability density functions were assigned based on a truncated normal distribution to the emissions intensity of electricity, electrolyzer efficiency, electricity price, electrolyzer capital cost, and capacity factor in each scenario. The means of the truncated normal distributions were determined based on projections to 2030 for each metric in the literature and are listed in Table A.1. For each normal distribution, a standard deviation equivalent to 40 percent of the mean value was used and distribution was truncated at +/- one standard deviation from the mean. The authors ran 20,000 simulations that randomly selected values for these two parameters from their probability density functions and used the selected values to calculate the resulting LCOH and emissions intensity of hydrogen production. The LCOH calculation used the same discrete formula (see below) used for the present cost calculation. To determine the emissions intensity, emissions intensity of electricity was multiplied by the energy density of hydrogen HHV (39.4 kWh/kg) divided by the electrolyzer efficiency. The Monte Carlo simulation produced distributions of 20,000 LCOH and emissions intensity of hydrogen values, and the mean of each distribution was plotted along with the 5th and 95th percentiles of the distribution. The histogram plots in this study show the probability density distribution of the Monte Carlo results, with the distribution grouped into 50 bins of equal width. The vertical axis values for the histograms were found by dividing the number of entries in each bin by the total number of entries (20,000) and then dividing by the bin width.

$$\text{LCOH} = \frac{\text{Total lifetime costs}}{\text{Total lifetime H}_2 \text{ production}} = \frac{\text{CAPEX} + \text{OPEX} + \text{O\&M}}{\text{mass}(\text{H}_2)}$$

$$\text{Mass (H}_2\text{)} = \frac{\text{electrolyzer lifespan} * \text{electrolyzer capacity} * \text{electrolyzer efficiency}}{\text{H}_2 \text{ specific energy}}$$

$$\text{CAPEX} = \text{electrolyzer capacity} * \text{unit CAPEX}$$

$$\text{OPEX} + \text{O\&M} = \frac{\text{electricity price} * \text{electrolyzer efficiency}}{\text{H}_2 \text{ specific energy}}$$

$$\text{O\&M} = 3.2\% * \text{CAPEX} * \text{electrolyzer life span}$$



Table A1: Input assumptions for 2030 projections in Monte Carlo simulation

| Scenario name | Electricity price (\$/kWh) | Capacity factor | Unit CAPEX (\$/kW) | Carbon intensity of electricity (kgCO ₂ /kWh) | Electrolyzer efficiency |
|-----------------------|----------------------------|-----------------|--------------------|--|-------------------------|
| US-grid-alkaline | 0.066 | 0.9 | 770 | 0.302 | 0.78 |
| US-grid-PEM | 0.066 | 0.9 | 1010 | 0.302 | 0.83 |
| US-renew-alkaline | 0.05 | 0.4102 | 770 | 0.025 | 0.78 |
| US-renew-PEM | 0.05 | 0.4102 | 1010 | 0.025 | 0.83 |
| Europe-grid-alkaline | 0.1035 | 0.9 | 770 | 0.1346 | 0.78 |
| Europe-grid-PEM | 0.1035 | 0.9 | 1010 | 0.1346 | 0.83 |
| Europe-renew-alkaline | 0.0752 | 0.3955 | 770 | 0.025 | 0.78 |
| Europe-renew-PEM | 0.0752 | 0.3955 | 1010 | 0.025 | 0.83 |
| CIJ-grid-alkaline | 0.124 | 0.9 | 770 | 0.5 | 0.78 |
| CIJ-grid-PEM | 0.124 | 0.9 | 1010 | 0.5 | 0.83 |
| CIJ-renew-alkaline | 0.1024 | 0.378 | 770 | 0.025 | 0.78 |
| CIJ-renew-PEM | 0.1024 | 0.378 | 1010 | 0.025 | 0.83 |

Note: Listed values were used as the mean of the probability density function defined for each variable. Source: Electricity prices, capacity factor, and carbon intensity from IEA and IRENA; electrolyzer CAPEX and efficiency combined Table 1 data and cost/efficiency learning rate from IEA and IRENA.



Table A2: Sample green hydrogen cost calculation based on formula

| Inputs | | |
|------------------------------------|---------|--------|
| CAPEX | | |
| Per capacity electrolyzer cost | 300 | \$/kW |
| Electrolyzer life span | 175,200 | hr |
| Electrolyzer capacity factor | 80% | N/A |
| OPEX | | |
| Electricity cost | 15 | \$/MWh |
| Hydrogen specific energy | 143 | MJ/kg |
| Electrolyzer conversion efficiency | 78% | N/A |

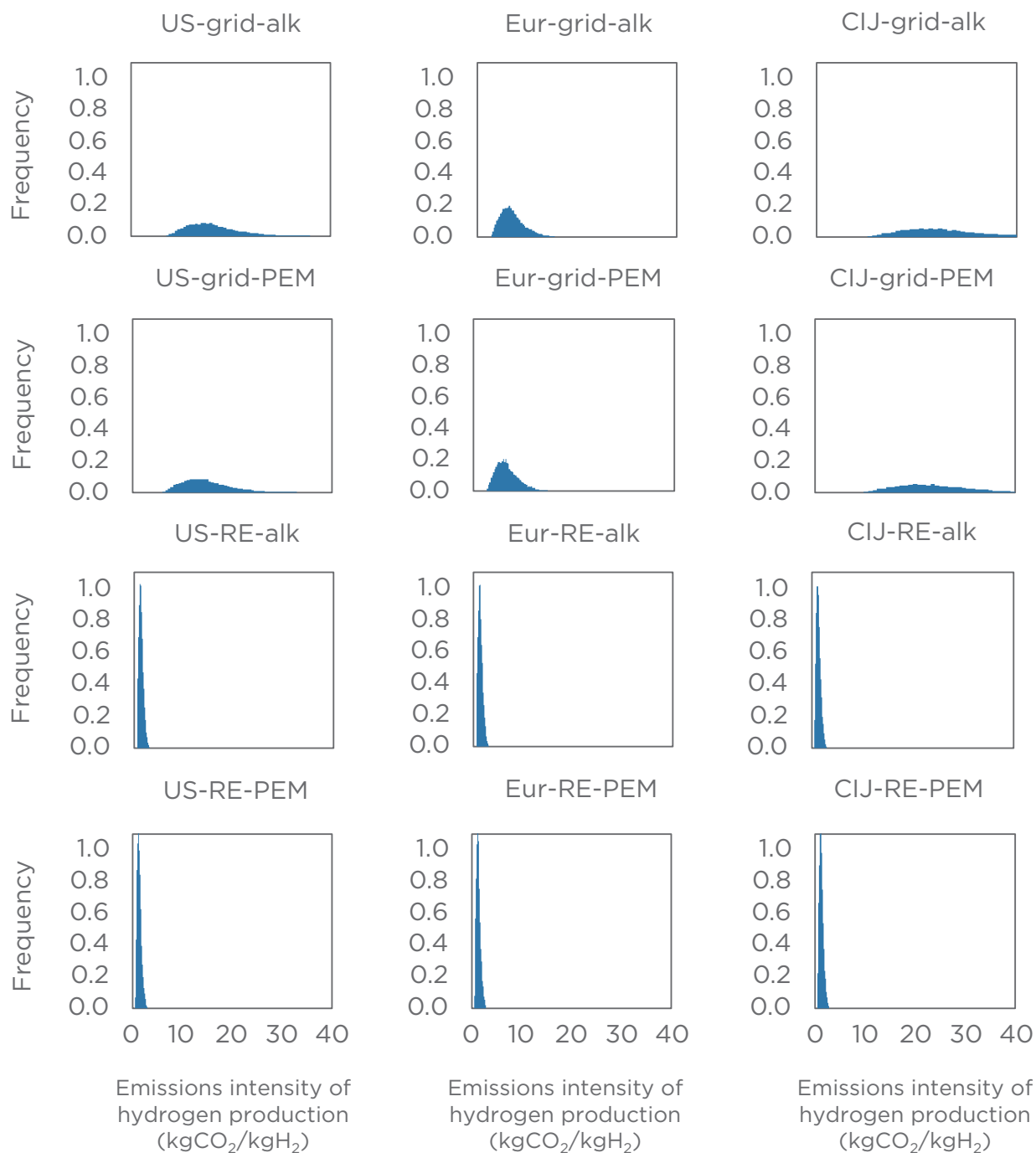
| Calculations | | |
|---|----------|--------|
| CAPEX | | |
| Per capacity life span energy consumption | 140,160 | kWh/kW |
| Per capacity life span hydrogen production | 2,752.23 | kg/kW |
| Per kg-H ₂ CAPEX | 0.11 | \$/kg |
| OPEX | | |
| Per kg H ₂ electricity consumption | 50.93 | kWh/kg |
| Per kg H ₂ OPEX (electricity cost) | 0.76 | \$/kg |

| Other cost component | | |
|---------------------------|--------|-------|
| O&M (annual), % of CAPEX | 3.20% | N/A |
| Lifetime O&M | 192.00 | \$/kW |
| Per kg H ₂ O&M | 0.07 | \$/kg |

Source: Authors' analysis.



Figure A1: Histograms of 2030 emissions intensity forecast distributions from Monte Carlo simulations for all 12 scenarios



Note: All values are emissions intensity of H₂ production (kgCO₂/kgH₂).

Source: Authors' analysis.



Glossary of Abbreviations and Terms

| Abbreviation | Terms |
|--------------------|--|
| AE | alkaline electrolyzer |
| CAPEX | capital expenditure |
| CCS | carbon capture and storage |
| CH ₃ OH | methanol |
| CO ₂ | carbon dioxide |
| GHG | greenhouse gas |
| H ₂ | hydrogen (molecular) |
| HHV | higher heating value |
| LCOH | levelized cost of hydrogen |
| LNG | liquified natural gas |
| Mtpa | million tons per annum |
| NGOs | nongovernmental organizations |
| NH ₃ | ammonia |
| O&M | operations and maintenance |
| OECD | Organisation for Economic Co-operation and Development |
| OPEC | Organization of the Petroleum Exporting Countries |
| PEM | polymer electrolyte membrane |
| PV | photovoltaic |
| SOEC | solid oxide electrolysis cell |
| ton | metric ton = 1,000 kg |
| TRL | technology readiness level |
| WACC | weighted average cost of capital |



REFERENCES

- Abraham, Spencer. 2004. “The Bush Administration’s Approach to Climate Change.” *Science* 305, no. 5684 (July 30): 616–17. <https://doi.org/10.1126/science.1098630>.
- Air Products. 2020. “Air Products, ACWA Power and NEOM Sign Agreement for \$5 Billion Production Facility in NEOM Powered by Renewable Energy for Production and Export of Green Hydrogen to Global Markets.” July 7, 2020. <https://www.airproducts.com/news-center/2020/07/0707-air-products-agreement-for-green-ammonia-production-facility-for-export-to-hydrogen-market>.
- AlZahrani, Abdullah A. and Ibrahim Dincer. 2018. “Modeling and performance optimization of a solid oxide electrolysis system for hydrogen production.” *Applied Energy* 225: 471–485. <https://doi.org/10.1016/j.apenergy.2018.04.124>.
- Apodaca, Lori. 2020. “Nitrogen (Fixed)—Ammonia.” US Geological Survey (January). <https://pubs.usgs.gov/periodicals/mcs2020/mcs2020-nitrogen.pdf>.
- Arapostathis, Stathis, Anna Carlsson-Hyslop, Peter J. G. Pearson, Judith Thornton et al. 2013. “Governing Transitions: Cases and Insights from Two Periods in the History of the UK Gas Industry.” *Energy Policy*, Special Section: “Transition Pathways to a Low Carbon Economy,” 52 (January 1): 25–44. <https://doi.org/10.1016/j.enpol.2012.08.016>.
- AREH. 2021. “The Asian Renewable Energy Hub: Low cost renewable energy for local and export markets.” <https://asianrehub.com/>.
- ARENA. 2021. “Hydrogen Energy.” Australian Renewable Energy Agency. <https://arena.gov.au/renewable-energy/hydrogen/>.
- Baker McKenzie. 2020. “Shaping Tomorrow’s Global Hydrogen Market.” https://www.bakermckenzie.com/-/media/files/insight/publications/2020/01/hydrogen_report.pdf?la=en.
- Baker, Sarah, Joshua Stolaroff, George Peridas, Simon Pang et al. 2020. “Getting to Neutral: Options for Negative Carbon Emissions in California.” Lawrence Livermore National Laboratory. https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf.
- Bartlett, Jay and Alan Krupnick. 2020. “Decarbonized Hydrogen in the US Power and Industrial Sectors: Identifying and Incentivizing Opportunities to Lower Emissions,” (December). <https://www.rff.org/publications/reports/decarbonizing-hydrogen-us-power-and-industrial-sectors/>.
- Benkenwald, Mariano and Jose Bermudez. 2020. “Latin America’s hydrogen opportunity: from national strategies to regional cooperation.” (November). <https://www.iea.org/commentaries/latin-america-s-hydrogen-opportunity-from-national-strategies-to-regional-cooperation>.
- Bhardwaj, Amar A., Colin McCormick, and Julio Friedmann. 2021. “Opportunities and Limits of CO₂ Recycling in a Circular Carbon Economy: Techno-Economics, Critical Infrastructure



Needs, and Policy Priorities.” Center on Global Energy Policy (May). <https://www.energypolicy.columbia.edu/research/report/opportunities-and-limits-co2-recycling-circular-carbon-economy-techno-economics-critical>.

Bhardwaj, Amar A., Johannes G. Vos, Marissa E. S. Beatty et al. 2021. “Ultrathin Silicon Oxide Overlayers Enable Selective Oxygen Evolution from Acidic and Unbuffered PH-Neutral Seawater.” *ACS Catalysis* 11, no. 3 (February 5): 1316–30. <https://doi.org/10.1021/acscatal.0c04343>.

Bieliszczuk, Bartosz. 2020. “Clean Gas: Prospects of Hydrogen Energy Development in the EU.” *PISM Bulletin*, no. 168, https://pism.pl/publications/Clean_Gas_Prospects_of_Hydrogen_Energy_Development_in_the_EU.

Blank, Thomas K., and Patrick Molly. 2020. “Hydrogen’s Decarbonization Impact for Industry.” Rocky Mountain Institute (January). https://rmi.org/wp-content/uploads/2020/01/hydrogen_insight_brief.pdf.

BloombergNEF. 2020. “Hydrogen Economy Outlook Key messages.” (March 30). <https://data.bloomberglp.com/professional/sites/24/BNEF-Hydrogen-Economy-Outlook-Key-Messages-30-Mar-2020.pdf>.

Böhm, Hans, Andreas Zauner, Sebastian Goers, Robert Tichler et al. 2018. “Innovative large-scale energy storage technologies and Power-to-Gas concepts after optimization.” European Commission Research & Innovation (October 31). <https://ec.europa.eu/research/participants/documents/downloadPublic?documentIds=080166e5beb60938&appId=PPGMS>.

Bonhoff, Klaus, Thorsten Herbert, and Hanno Butsch. 2012. “50 Hydrogen Refueling Stations in Germany.” OECD (November 30). <https://www.oecd.org/futures/50%20Hydrogen%20Refueling%20Stations%20in%20Germany%20.pdf>.

Brown, Andy. 2019. “Uses of Hydrogen in Industry.” *The Chemical Engineer* (July 18). <https://www.thechemicalengineer.com/features/uses-of-hydrogen-in-industry/>.

Brown, Andy, and Mike Welch. 2020. “Hydrogen as a Fuel for Gas Turbines.” *The Chemical Engineer* (March 2). <https://www.thechemicalengineer.com/features/hydrogen-as-a-fuel-for-gas-turbines/>.

CAFCP. 2021. “California Fuel Cell Partnership – station map.” <https://cafcp.org/stationmap>.

CAISO. 2017. “Impacts of Renewable Energy on Grid Operations.” <https://www.caiso.com/documents/curtailmentfastfacts.pdf>.

—. 2020. “Summer Load and Resources Assessment.” California ISO (May 15). <https://www.caiso.com/Documents/2020SummerLoadsandResourcesAssessment.pdf>.

California Air Resources Board. 2020. “Low Carbon Fuel Standard.” <https://ww2.arb.ca.gov/sites/default/files/2020-09/basics-notes.pdf>.

Calise, Francesco, Massimo D’Accadia, Massimo Santarelli, Andrea Lanzini, and Domenico Ferrero, eds. 2019. *Solar Hydrogen Production*. London: Elsevier. <https://doi.org/10.1016/C2017-0-02289-9>.



Cecere, D., E. Giacomazzi, and A. Ingenito. 2014. “A Review on Hydrogen Industrial Aerospace Applications.” *International Journal of Hydrogen Energy* 39, no. 20 (July 3): 10731–47. <https://doi.org/10.1016/j.ijhydene.2014.04.126>.

Chambers, Matthew, and Rolf Schmitt. 2015. “Diesel-Powered Passenger Cars and Light Trucks.” Bureau of Transportation Statistics. https://www.bts.gov/archive/publications/bts_fact_sheets/oct_2015/entire.

Chen, Chen, Eri Saikawa, Bryan Comer, Xiaoli Mao et al. 2019. “Ship Emission Impacts on Air Quality and Human Health in the Pearl River Delta (PRD) Region, China, in 2015, With Projections to 2030.” *GeoHealth* 3, no. 9: 284–306. <https://doi.org/10.1029/2019GH000183>.

Cohn, Lisa. 2017. “Long-Term Energy Storage: What Are the Options When Lithium-Ion Falls Short?” *Microgrid Knowledge* (blog), March 17, 2017. <https://microgridknowledge.com/long-term-energy-storage/>.

Colwell, K. C. 2020. “How Long Does It Take to Charge an Electric Vehicle?” *Car and Driver*, May 22, 2020. <https://www.caranddriver.com/shopping-advice/a32600212/ev-charging-time/>.

Connelly, Elizabeth, Michael Penev, Amgad Elgowainy, and Chad Hunter. 2019. “Current Status of Hydrogen Liquefaction Costs.” US Department of Energy (September). https://www.hydrogen.energy.gov/pdfs/19001_hydrogen_liquefaction_costs.pdf.

Crolius, Stephen. 2021. “Ammonia Featured in Japan’s New Green Growth Strategy.” *Ammonia Energy Association* (blog), January 14, 2021. <https://www.ammoniaenergy.org/articles/ammonia-featured-in-japans-new-green-growth-strategy/>.

———. 2021. “Japan, UAE to Cooperate on Ammonia Energy.” *Ammonia Energy Association* (blog), January 28, 2021. <https://www.ammoniaenergy.org/articles/japan-uae-to-cooperate-on-ammonia-energy/>.

———. 2020. “METI Forms Ammonia Energy Council.” *Ammonia Energy Association* (blog), November 5, 2020. <https://www.ammoniaenergy.org/articles/meti-forms-ammonia-energy-council/>.

———. 2017. “Renewable Hydrogen in Fukushima and a Bridge to the Future.” *Ammonia Energy Association* (blog), October 19, 2017. <https://www.ammoniaenergy.org/articles/renewable-hydrogen-in-fukushima-and-a-bridge-to-the-future/>.

Crooks, Ed. 2020. “The Long Haul for Electric Heavy Trucks,” *Wood Mackenzie*, September 25, 2020. <https://www.woodmac.com/news/opinion/the-long-haul-for-electric-heavy-trucks/>.

Davis, S. J., N.S. Lewis, M. Shaner, S. Aggarwal et al. 2018. “Net-zero emissions energy systems.” *Science* 360: 6396.

Deffeyes, Kenneth S. 2021. *Hubbert’s Peak: The Impending World Oil Shortage (New Edition)*. STU-Student edition. Princeton, NJ: Princeton University Press. <http://www.jstor.org/stable/j.ctt7t9r1>.

Deloitte China. 2020. “Fueling the Future of Mobility.” <https://www2.deloitte.com/content/dam/Deloitte/cn/Documents/finance/deloitte-cn-fueling-the-future-of-mobility-en-200101.pdf>.



- Dimitriou, Pavlos, and Rahat Javaid. 2020. "A review of ammonia as a compression ignition engine fuel." *International Journal of Hydrogen Energy* 45, no. 11 (February 28): 7098–7118. <https://doi.org/10.1016/j.ijhydene.2019.12.209>.
- DOE. 2005. "FutureGen Project Launched." Energy.gov, December 6, 2005. <https://www.energy.gov/articles/futuregen-project-launched>.
- . 2020. "Hydrogen Production Cost From High Temperature Electrolysis." Energy.gov, February 14, 2020. <https://www.hydrogen.energy.gov/pdfs/20006-production-cost-high-temperature-electrolysis.pdf>.
- Dooley, Ben, Makiko Inoue, and Hikari Hida. 2020. "Japan's New Leader Sets Ambitious Goal of Carbon Neutrality by 2050." *The New York Times*, October 26, 2020. <https://www.nytimes.com/2020/10/26/business/japan-carbon-neutral.html>.
- Dresp, Sören, Fabio Dionigi, Malte Klingenhof, and Peter Strasser. 2019. "Direct Electrolytic Splitting of Seawater: Opportunities and Challenges." *ACS Energy Letters* 4, no. 4 (April 12): 933–42. <https://doi.org/10.1021/acsenergylett.9b00220>.
- EIA. 2020a. "Factors Affecting Natural Gas Prices." August 21, 2020. <https://www.eia.gov/energyexplained/natural-gas/factors-affecting-natural-gas-prices.php>.
- . 2020b. "What is U.S. electricity generation by energy source?" March 5, 2020. <https://www.eia.gov/tools/faqs/faq.php?id=427&t=3>.
- . 2021. "Annual Energy Outlook 2021." February 3, 2021. <https://www.eia.gov/outlooks/aeo/pdf/00%20AEO2021%20Chart%20Library.pdf>.
- Eisenstein, Paul A. 2019. "Toyota, Paccar Team up on Clean Hydrogen Trucks for Polluted LA Ports." *CNBC News*, January 19, 2019. <https://www.cnbc.com/2019/01/10/toyota-paccar-team-up-on-clean-hydrogen-trucks-for-la-ports.html>.
- EPA. 2016. "Health and Environmental Effects of Particulate Matter (PM)." Overviews and Factsheets. EPA, April 26, 2016. <https://www.epa.gov/pm-pollution/health-and-environmental-effects-particulate-matter-pm>.
- . 2020. "Fast Facts: U.S. Transportation Sector Greenhouse Gas Emissions 1990–2018." (June). <https://nepis.epa.gov/Exe/ZyPDF.cgi?Dockey=P100ZK4P.pdf>.
- ETC. 2020. "Making Mission Possible: Delivering a Net-Zero Economy." (September). <https://www.energy-transitions.org/publications/making-mission-possible/>.
- ETN Global. 2020. "The Path Towards A Zero-Carbon Gas Turbine." (January), accessed March 7, 2021. <https://etn.global/wp-content/uploads/2020/01/ETN-Hydrogen-Gas-Turbines-report.pdf>.
- Eurostat. 2019. "Electricity Prices Components for Non-Household Consumers."
- Fan, Z., and S. J. Friedmann. 2021. "Low-Carbon Production of Iron and Steel: Technology Options, Economic Assessment, and Policy." *Joule* 5, (April): 1–31. <https://doi.org/10.1016/j.joule.2021.02.018>.



- Franke, Andreas. 2021. “Germany to support 500 MW electrolyzers abroad with \$1.1 billion.” S&P Global, June 14, 2021. <https://www.spglobal.com/platts/en/market-insights/latest-news/electric-power/061421-germany-to-support-500-mw-electrolyzers-abroad-with-11-billion>.
- Frassoldati, A., T. Faravelli, and E. Ranzi. 2006. “A wide range modeling study of NO_x formation and nitrogen chemistry in hydrogen combustion.” *International Journal of Hydrogen Energy* 31, no. 15 (December): 2310–2328. <https://doi.org/10.1016/j.ijhydene.2006.02.014>.
- Frew, Bethany, Wesley Cole, Paul Denholm, A. Will Frazier et al. 2019. “Sunny with a Chance of Curtailment: Operating the US Grid with Very High Levels of Solar Photovoltaics.” *IScience* 21 (November 22): 436–47. <https://doi.org/10.1016/j.isci.2019.10.017>.
- Friedmann, S. Julio, Zhiyuan Fan, Zachary Byrum, Emeka Ochu et al. 2020. “Levelized Cost Of Carbon Abatement: An Improved Cost-Assessment Methodology For A Net-Zero Emissions World.” Center on Global Energy Policy. October, <https://www.energypolicy.columbia.edu/research/report/levelized-cost-carbon-abatement-improved-cost-assessment-methodology-net-zero-emissions-world>
- Friedmann, S. Julio, Zhiyuan Fan, and Ke Tang. 2019. “Low-Carbon Heat Solutions for Heavy Industry: Sources, Options, and Costs Today.” 100, October, <https://energypolicy.columbia.edu/research/report/low-carbon-heat-solutions-heavy-industry-sources-options-and-costs-today>
- Fuel Cells Bulletin. 2020. “Fukushima Hydrogen Energy Research Field in Japan Ready for Green Hydrogen Production.” *Fuel Cells Bulletin* 2020, no. 3 (March 1): 1. [https://doi.org/10.1016/S1464-2859\(20\)30089-4](https://doi.org/10.1016/S1464-2859(20)30089-4).
- FuelCellsWorks. 2020. “U.S. Is Building Salt Mines to Store Hydrogen.” *FuelCellsWorks* (blog). November 28, 2020. <https://fuelcellworks.com/news/u-s-is-building-salt-mines-to-store-hydrogen/>.
- FuelsEurope. 2017. “Renewable Energy Directive II.” (June). <https://www.fuelseurope.eu/wp-content/uploads/2017/07/FuelsEurope-position-RED-II.pdf>.
- Gandolfi, Alberto, Ajay Patel, Michele Della Vigna, Mafalda Pombeiro et al. 2020. “Green Hydrogen.” The Goldman Sachs Group, Inc. <https://www.goldmansachs.com/insights/pages/gs-research/green-hydrogen/report.pdf>.
- GE. 2021. “Decarbonizing Power with Hydrogen Fuel for Gas Turbines.” GE Power. <https://www.ge.com/power/gas/fuel-capability/hydrogen-fueled-gas-turbines>.
- Gorman, Will, Andrew Mills, and Ryan Wiser. 2019. “Improving Estimates of Transmission Capital Costs for Utility-Scale Wind and Solar Projects to Inform Renewable Energy Policy.” *Energy Policy* 135 (December): 110994. <https://doi.org/10.1016/j.enpol.2019.110994>.
- Government of Canada. 2020. “Clean Fuel Standard.” <https://www.canada.ca/en/environment-climate-change/services/managing-pollution/energy-production/fuel-regulations/clean-fuel-standard.html>.
- Greenhalgh, Keiron. 2020. “US Demand for Hydrogen May Quadruple by 2050: NREL.” IHS



Markit, November 16, 2020. <https://ihsmarkit.com/research-analysis/us-demand-for-hydrogen-may-quadruple-by-2050-nrel.html>.

Grimm, Alexa, Wouter A. de Jong, and Gert Jan Kramer. 2020. “Renewable Hydrogen Production: A Techno-Economic Comparison of Photoelectrochemical Cells and Photovoltaic-Electrolysis.” *International Journal of Hydrogen Energy* 45, no. 43 (September 3): 22545–55. <https://doi.org/10.1016/j.ijhydene.2020.06.092>.

Gruenspecht, Howard. 2019. “The U.S. Coal Sector.” *Brookings* (blog), January 2019, <https://www.brookings.edu/research/the-u-s-coal-sector/>.

H21. 2021. “Pioneering a UK hydrogen network... Led by Northern Gas Networks.” <https://h21.green/>.

Ha, Jeong Eun. 2019. “Hydrogen Economy Plan in Korea.” Netherlands Enterprise Agency, January 18, 2019. <https://www.rvo.nl/sites/default/files/2019/03/Hydrogen-economy-plan-in-Korea.pdf>.

Hallenbeck, P.C., and J.R. Benemann. “Biohydrogen—The Microbiological Production of Hydrogen Fuel.” *Biotechnology - Vol. VII*. <https://www.eolss.net/sample-chapters/c17/E6-58-06-18.pdf>.

Hansson, Julia, Selma Brynolf, Erik Fridell, and Mariliis Lehtveer. 2020. “The Potential Role of Ammonia as Marine Fuel—Based on Energy Systems Modeling and Multi-Criteria Decision Analysis.” *Sustainability* 12, no. 8 (January): 3265. <https://doi.org/10.3390/su12083265>.

Hauch, A., R. Küngas, P. Blennow, A.B. Hansen, J.B. Hansen et al. 2020. “Recent Advances in Solid Oxide Cell Technology for Electrolysis.” *Science* 370, no. 6513, eaba6118. <https://science.sciencemag.org/content/370/6513/eaba6118?rss=1>.

Hiroi, Yoichiro. 2020. “Fukushima Powers up One of World’s Biggest Hydrogen Plants.” *Nikkei Asia*, March 8, 2020. <https://asia.nikkei.com/Business/Energy/Fukushima-powers-up-one-of-world-s-biggest-hydrogen-plants>.

Hornyak, Tim. 2019. “How Toyota Is Helping Japan with Its Multibillion-Dollar Push to Create a Hydrogen-Fueled Society.” *CNBC News*. February 26, 2019. <https://www.cnbc.com/2019/02/26/how-toyota-is-helping-japan-create-a-hydrogen-fueled-society.html>.

Hosseini, Seyed Ehsan, and Brayden Butler. 2020. “An Overview of Development and Challenges in Hydrogen Powered Vehicles.” *International Journal of Green Energy* 17, no. 1: 13–37.

Hydrogen Council. 2020. “Path to Hydrogen Competitiveness.” Jan 20, 2020. https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf.

Hydrogen Europe. 2020a. “Hydrogen 2030: The Blueprint.” https://hydrogeneurope.eu/sites/default/files/Hydrogen%202030_The%20Blueprint.pdf.

———. 2020b. “The EU Hydrogen Strategy: Hydrogen Europe’s Top 10 Key Recommendations.” https://www.asktheeu.org/en/request/8399/response/27720/attach/4/Hydrogen%20Europe%20H2%20Strategy%20Top%2010%20key%20recommendations%20FINAL.pdf?cookie_passthrough=1.



- . 2021a. “H2ero Net Zero: Hydrogen Europe Position Paper on the ‘Fit for 55 Package’” (June). <https://www.hydrogeneurope.eu/wp-content/uploads/2021/06/Hydrogen-Europe-Position-Paper-on-the-Fit-for-55-Package.pdf>.
- . 2021b. “Hydrogen Europe’s position paper on the sustainable and smart mobility strategy.” (December). https://www.hydrogeneurope.eu/wp-content/uploads/2021/04/Hydrogen-Europe_SSMS_Paper-compressed.pdf.
- ICCT. 2017. “The European Commission’s Renewable Energy Proposal for 2030.” The European Commission: 8. <https://theicct.org/publications/european-commissions-renewable-energy-proposal-2030>.
- IEA. 2019a. “The Future of Hydrogen.” (June). <https://www.iea.org/reports/the-future-of-hydrogen>.
- . 2019b. “Market Report Series: Gas 2019.” (June). <https://www.iea.org/reports/gas-2019>.
- . 2019c. “World Energy Outlook 2019.” (November). <https://www.iea.org/reports/world-energy-outlook-2019>.
- . 2020a. “CCUS in Clean Energy Transitions.” Sept. <https://www.iea.org/reports/ccus-in-clean-energy-transitions>
- . 2020b. “Cross-Cutting: Hydrogen.” Circular Carbon Economy KAPSARC (January). <https://www.iea.org/areas-of-work/technology-collaboration/cross-cutting>.
- . 2020c. “Decarbonising Industry with Green Hydrogen – Analysis.” (November). <https://www.iea.org/articles/decarbonising-industry-with-green-hydrogen>.
- . 2020d. “Global Average Levelised Cost of Hydrogen Production by Energy Source and Technology, 2019 and 2050.” (September). <https://www.iea.org/data-and-statistics/charts/global-average-levelised-cost-of-hydrogen-production-by-energy-source-and-technology-2019-and-2050>.
- . 2020e. “Global Energy and CO₂ Emissions in 2020 – Global Energy Review 2020.” (July). <https://www.iea.org/reports/global-energy-review-2020/global-energy-and-co2-emissions-in-2020>.
- . 2020f. “Hydrogen.” (June). <https://www.iea.org/reports/hydrogen>.
- . 2020g. “Korea Hydrogen Economy Roadmap 2040.” <https://www.iea.org/policies/6566-korea-hydrogen-economy-roadmap-2040>.
- . 2020h. “Tracking Industry 2020.” <https://www.iea.org/reports/tracking-industry-2020>.
- . 2020i. “Tracking Transport 2020.” <https://www.iea.org/reports/tracking-transport-2020>.
- . 2021. “Energy Technology RD&D Budgets: Overview.” May 2021. <https://www.iea.org/reports/energy-technology-rdd-budgets-overview>.



IHS Markit. 2020. “Investment in Green Hydrogen Production Set to Exceed \$1billion USD by 2023.” December 3, 2020. https://news.ihsmarket.com/prviewer/release_only/slug/2020-12-03-investment-in-green-hydrogen-production-set-to-exceed-1-billion-usd-by-2023.

Ikeda, Tetsufumi. 2018. “Status of Hydrogen Fueling Station Technologies in Japan.” The Association of Hydrogen Supply and Utilization Technology, September 11, 2018. <https://www.energy.gov/sites/prod/files/2018/10/f56/fcto-infrastructure-workshop-2018-16-ikeda.pdf>.

IMO. 2020. “Cutting Sulphur Oxide Emissions.” <https://www.imo.org/en/MediaCentre/HotTopics/Pages/Sulphur-2020.aspx>.

———. 2021. “Reducing Greenhouse Gas Emissions from Ships.” <https://www.imo.org/en/MediaCentre/HotTopics/Pages/Reducing-greenhouse-gas-emissions-from-ships.aspx>.

IRENA. 2020a. “Green Hydrogen Cost Reduction: Scaling up Electrolysers to Meet the 1.5°C Climate Goal.” (December). <https://www.irena.org/publications/2020/Dec/Green-hydrogen-cost-reduction>.

———. 2020b. “Renewable Power Generation Costs in 2019.” (June). <https://www.irena.org/publications/2020/Jun/Renewable-Power-Costs-in-2019>.

———. 2020c. “Renewables Increasingly Beat Even Cheapest Coal Competitors on Cost.” (June). <https://www.irena.org/newsroom/pressreleases/2020/Jun/Renewables-Increasingly-Beat-Even-Cheapest-Coal-Competitors-on-Cost>.

Johnson, Samuel C., F. Todd Davidson, Joshua D. Rhodes, Justin L. Coleman et al. 2019. “Chapter Five - Selecting Favorable Energy Storage Technologies for Nuclear Power.” In *Storage and Hybridization of Nuclear Energy*, edited by Hitesh Bindra and Shripad Revankar, 119–75. Cambridge, MA: Academic Press. <https://doi.org/10.1016/B978-0-12-813975-2.00005-3>.

Kalinci, Yildiz, Arif Hepbasli, and Ibrahim Dincer. 2012. “Life Cycle Assessment of Hydrogen Production from Biomass Gasification Systems.” *International Journal of Hydrogen Energy* 37, no. 19 (October): 14026–39. <https://doi.org/10.1016/j.ijhydene.2012.06.015>.

Kawakami, Azusa. 2020. “Mitsubishi Heavy to Build Biggest Zero-Carbon Steel Plant - Nikkei Asia.” Nikkei Asia, December 28, 2020. <https://asia.nikkei.com/Spotlight/Environment/Climate-Change/Mitsubishi-Heavy-to-build-biggest-zero-carbon-steel-plant>.

Kilmer, Susan, Keisha Williams, and MDEQ Air Quality Division. n.d. “48217 Community Air Monitoring Project.” Michigan Department of Environmental Quality, April 27, 2018. https://www.michigan.gov/documents/deq/deq-aqd-amu-48217_air_monitoring_report_621859_7.pdf.

Kramer, David. 2020. “Hydrogen-Powered Aircraft May Be Getting a Lift.” *Physics Today* 73, no. 12 (November 20): 27–29. <https://doi.org/10.1063/PT.3.4632>.

Krishnan, Subramani, Matthew Fairlie, Philipp Andres, Thijs de Groot et al. 2020. “Chapter 10 - Power to Gas (H₂): Alkaline Electrolysis.” In *Technological Learning in the Transition to a Low-Carbon Energy System*, edited by Martin Junginger and Atse Louwen, 165–87. Cambridge, MA: Academic Press. <https://doi.org/10.1016/B978-0-12-818762-3.00010-8>.



Kumagai, Takeo. 2020. “Japan to Introduce Ammonia for Thermal Power, Shipping Fuels in Late 2020s.” S&P Global Platts. December 7, 2020. <https://www.spglobal.com/platts/en/market-insights/latest-news/coal/120720-japan-to-introduce-ammonia-for-thermal-power-shipping-fuels-in-late-2020s>.

Kumar, S. Shiva, and V. Himabindu. 2019. “Hydrogen production by PEM water electrolysis – A review.” *Materials Science for Energy Technologies* 2, no. 3: 442–454. <https://doi.org/10.1016/j.mset.2019.03.002>.

Lane, Bob. 2020. “Insights: States with Low Carbon Fuel Standards & Those Considering One.” *The Jacobsen* (blog), November 16, 2020. https://thejacobsen.com/news_items/states-considering-lcfs/.

Lapides, Michael, Insoo Kim, David Fishman, and Chao Ji. 2020. “Green Hydrogen: The next transformational driver of the Utilities industry.” Goldman Sachs (September). <https://www.goldmansachs.com/insights/pages/gs-research/green-hydrogen/report.pdf>

Larson, Eric, Chris Greig, Jesse Jenkins, Erin Mayfield et al. 2020. “Net-Zero America: Potential Pathways, Infrastructure, and Impacts.” Princeton University, (December). https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf.

Lee, Andrew. 2020. “Japan Opens World’s Largest Green-Hydrogen Plant near Fukushima Disaster Site | Recharge.” Recharge, March 9, 2020. <https://www.rechargenews.com/transition/japan-opens-worlds-largest-green-hydrogen-plant-near-fukushima-disaster-site/2-1-769361>.

Leeds City Gate. 2017. “H21.” <https://www.northerngasnetworks.co.uk/wp-content/uploads/2017/04/H21-Report-Interactive-PDF-July-2016.compressed.pdf>.

Leigh G.J. 2004. “Haber-Bosch and Other Industrial Processes.” In: Smith B.E., Richards R.L., Newton W.E., eds., *Catalysts for Nitrogen Fixation*. Part of book series, Nitrogen Fixation: Origins, Applications, and Research Progress, vol 1. Springer, Dordrecht. https://doi.org/10.1007/978-1-4020-3611-8_2.

LevelTen Energy. 2020. “LevelTen Energy PPA Price Index, Europe.” (July). <https://www.leveltenenergy.com/post/q2-2020>.

Levie, R. de. 1999. “The Electrolysis of Water.” *Journal of Electroanalytical Chemistry* 476, no. 1 (October 21): 92–93. [https://doi.org/10.1016/S0022-0728\(99\)00365-4](https://doi.org/10.1016/S0022-0728(99)00365-4).

Liu, Xinyu, Amgad Elgowainy, and Michael Wang. 2020. “Life Cycle Energy Use and Greenhouse Gas Emissions of Ammonia Production from Renewable Resources and Industrial By-Products.” *Green Chemistry*, no. 17., <https://doi.org/10.1039/D0GC02301A>

Manish, S., and R. Banerjee. 2008. “Comparison of Biohydrogen Production Processes.” *International Journal of Hydrogen Energy* 33, no. 1 (January): 279–86. <https://doi.org/10.1016/j.ijhydene.2007.07.026>.



Manoharan, Yogesh, Seyed Ehsan Hosseini, Brayden Butler, Hisham Alzahrani et al. 2019. “Hydrogen Fuel Cell Vehicles; Current Status and Future Prospect.” *Applied Sciences* 9, no. 11 (January): 2296. <https://doi.org/10.3390/app9112296>.

Mansouri, Noura Y., Alma Alhousseini, Noura T. Al-Saud, S. Alshalan et al. 2020. “A carbon management system of innovation: Towards a circular carbon economy.” G20 Insights, December 10, 2020. https://www.g20-insights.org/policy_briefs/a-carbon-management-system-of-innovation-towards-a-circular-carbon-economy/.

Markets and Markets. 2020. “Green Ammonia Market by Technology (Alkaline Water Electrolysis (AWE), Proton Exchange Membrane (PEM), and Solid Oxide Electrolysis (SOE)), End User (Transportation, Power Generation, and Industrial Feedstock), and Region - Global Forecast to 2030.” (July). <https://www.marketsandmarkets.com/Market-Reports/green-ammonia-market-118396942.html>.

Mayyas, Ahmad T., Mark F. Ruth, Bryan S. Pivovar, Guido Bender et al. 2019. “Manufacturing Cost Analysis for Proton Exchange Membrane Water Electrolyzers.” US Department of Energy, August 13, 2019. <https://doi.org/10.2172/1557965>.

McDonald, Zane. 2020. “Injecting Hydrogen in Natural Gas Grids Could Provide Steady Demand the Sector Needs to Develop.” S&P Global Platts. May 19, 2020. <https://www.spglobal.com/platts/en/market-insights/blogs/natural-gas/051920-injecting-hydrogen-in-natural-gas-grids-could-provide-steady-demand-the-sector-needs-to-develop>.

McKenna, Phil. 2018. “Pollution Controls Failed Within Years on Certain Heavy Duty Trucks, Study Finds.” *Inside Climate News* (blog), October 31, 2018. <https://insideclimatenews.org/news/31102018/truck-pollution-emission-controls-failed-health-climate-change-black-carbon-soot/>.

Mehmeti, A., A. Angelis-Dimakis, G. Arampatzis, S.J. McPhail, and S. Ulgiati. 2018. “Life Cycle Assessment and Water Footprint of Hydrogen Production Methods: From Conventional to Emerging Technologies.” *Environments* 5, no. 1: 1-19. <https://doi.org/10.3390/environments5020024>.

Melaina, M.W., O. Antonia, and M. Penev. 2013. “Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues.” NREL (March). <https://www.nrel.gov/docs/fy13osti/51995.pdf>.

Menzies, Mike. 2019. “Hydrogen: The Burning Question.” *The Chemical Engineer* (September). <https://www.thechemicalengineer.com/features/hydrogen-the-burning-question/>.

METI. 2021. “Japan’s Roadmap to ‘Beyond-Zero’ Carbon.” Accessed February 18, 2021. https://www.meti.go.jp/english/policy/energy_environment/global_warming/roadmap/.

———. 2021. “Minister Kajiyama Holds Meeting with H.E. Dr. Sultan Ahmed Al Jaber, CEO, Abu Dhabi National Oil Company (ADNOC), and Minister of Industry and Advanced Technology, UAE.” Jan 14, 2021. https://www.meti.go.jp/english/press/2021/0114_001.html.

Meyer, Gregory. 2021. “US Power Line Tensions Grow over Green Energy Surge.”



Financial Times, February 18, 2021. <http://www.ft.com/content/1742140f-5dd6-4808-8ad7-526404482058>.

Miller, Hamish Andrew, Karel Bouzek, Jaromir Hnat, Stefan Loos et al. 2020. "Green Hydrogen from Anion Exchange Membrane Water Electrolysis: A Review of Recent Developments in Critical Materials and Operating Conditions." *Sustainable Energy & Fuels* 4, no. 5 (May 6): 2114–33. <https://doi.org/10.1039/C9SE01240K>.

Ministry of Energy, Government of Chile. 2020. "National Green Hydrogen Strategy." https://energia.gob.cl/sites/default/files/national_green_hydrogen_strategy_-_chile.pdf.

Mitsubishi Power. 2021. "Mitsubishi Power Commences Development of World's First Ammonia-Fired 40MW Class Gas Turbine System -- Targets to Expand Lineup of Carbon-Free Power Generation Options, with Commercialization around 2025 --." March 1, 2021. <https://power.mhi.com/news/20210301.html>.

Moore, Jon, and Nat Bullard. 2021. "BNEF Executive Factbook." 100.

Nadeem, Muhammad Amtiaz, Mohd Adnan Khan, Ahmed Abdeslam Ziani, and Hicham Idriss. 2021. "An Overview of the Photocatalytic Water Splitting over Suspended Particles." *Catalysts* 11, no. 1 (January): 60. <https://doi.org/10.3390/catal11010060>.

Nagashima, Monica. 2018. "Japan's hydrogen strategy and its economic and geopolitical implications." *Ifri* (October). https://www.ifri.org/sites/default/files/atoms/files/nagashima_japan_hydrogen_2018_.pdf.

Nakano, Jane. 2020. "Japan Seeks Carbon Neutrality by 2050." Center for Strategic and International Studies (November). <https://www.csis.org/analysis/japan-seeks-carbon-neutrality-2050>.

NEDO. 2020. "The World's Largest-Class Hydrogen Production, Fukushima Hydrogen Energy Research Field (FH2R) Now Is Completed at Namie Town in Fukushima." Toshiba Energy Systems and Solutions Corp, March 7, 2020. https://www.toshiba-energy.com/en/info/info2020_0307.htm.

Niunoya, Miho, and Mihoko Shima. 2020. "Hydrogen Law and Regulation in Japan." CMS Expert Guides. <https://cms.law/en/int/expert-guides/cms-expert-guide-to-hydrogen/japan>.

Northwestern University. 2020. "New Technique Seamlessly Converts Ammonia to Green Hydrogen: Researchers Leverage Renewable Electricity for Widespread, Distributed Hydrogen Fuel Production." *ScienceDaily* (November). <https://www.sciencedaily.com/releases/2020/11/201118141718.htm>.

Nugent, Daniel, and Benjamin K. Sovacool. 2014. "Assessing the Lifecycle Greenhouse Gas Emissions from Solar PV and Wind Energy: A Critical Meta-Survey." *Energy Policy* 65 (February 1): 229–44. <https://doi.org/10.1016/j.enpol.2013.10.048>.

O'Connor, Timothy. 2020. "100% Zero-Emissions Trucks. How Close Are We?" Environmental Defense Fund (blog), September 16, 2020. <https://www.edf.org/blog/2020/09/16/100-zero->



Roberts, Karen B. 2018. “Cleaner Ship Fuels Benefit Health, but Affect Climate Too.” University of Delaware (February). <https://www.udel.edu/udaily/2018/february/shipping-fuel-health/>.

Romm, Joseph J. 2004. *The Hype About Hydrogen: Fact and Fiction in the Race to Save the Climate*. Washington, DC: Island Press. <https://ezproxy.cul.columbia.edu/login?qurl=https%3a%2f%2fsearch.ebscohost.com%2flogin.aspx%3fdirect%3dtrue%26db%3d025xna%26AN%3d118241%26site%3dehost-live%26scope%3dsite>.

Saeedmanesh, A., M. A. Mac Kinnon, and J. Brouwer. 2018. “Hydrogen is essential for sustainability.” *Current Opinion in Electrochemistry*, 12: 166–181.

Salkuyeh, Y., B. A. Saville, and H. L. MacLean. 2017. “Techno-Economic Analysis and Life Cycle Assessment of Hydrogen Production from Natural Gas Using Current and Emerging Technologies.” *International Journal of Hydrogen Energy* 42, no. 30: 18894–18909. <https://doi.org/10.1016/j.ijhydene.2017.05.219>.

Sandalow, David, Julio Friedmann, Roger Aines, Colin McCormick et al. 2019. “ICEF Industrial Heat Decarbonization Roadmap.” ICEF Roadmap Series, December, https://www.icef-forum.org/pdf/2019/roadmap/ICEF_Roadmap_201912.pdf.

Sandalow, David, Roger Aines, Julio Friedmann, Colin McCormick et al. 2021. “Biomass Carbon Removal and Storage (BiCRS) Roadmap.” ICEF, December. <https://www.icef-forum.org/pdf/2020/roadmap/roadmap.pdf?0128>.

Schiavo, Massimo, and Karl Nietvelt. 2020. “How Hydrogen Can Fuel The Energy Transition.” S&P Global Ratings, November 19, 2020. <https://www.spglobal.com/ratings/en/research/articles/201119-how-hydrogen-can-fuel-the-energy-transition-11740867>.

Schlömer, S., T. Bruckner, L. Fulton, E. Hertwich et al. 2014. *Annex III: Technology-Specific Cost and Performance Parameters. In: Climate Change 2014: Mitigation of Climate Change. Contribution of Working Group III to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*. Cambridge: Cambridge University Press. <https://doi.org/10.1017/CBO9781107415416>.

Scully, Jules. 2021. “Total, Engie Plan French Hydrogen Project Powered by More than 100MW of Solar.” *PV Tech* (blog), January 13, 2021. <https://www.pv-tech.org/total-engie-plan-french-hydrogen-project-powered-by-more-than-100mw-of-solar/>.

Shi, Xunpeng, Xun Liao, and Yanfei Li. 2020. “Quantification of Fresh Water Consumption and Scarcity Footprints of Hydrogen from Water Electrolysis: A Methodology Framework.” *Renewable Energy* 154 (July): 786–96. <https://doi.org/10.1016/j.renene.2020.03.026>.

Singh, Sonal, Shikha Jain, Venkateswaran Ps, Avnish K. Tiwari et al. 2015. “Hydrogen: A Sustainable Fuel for Future of the Transport Sector.” *Renewable and Sustainable Energy Reviews* 51 (November 1): 623–33. <https://doi.org/10.1016/j.rser.2015.06.040>.

Sivaram, Varun, Colin Cunliff, David Hart, Julio Friedmann et al. 2020. *Energizing America: A Roadmap to Launch a National Energy Innovation Mission.*, Center on Global Energy Policy



Report, September, <https://energypolicy.columbia.edu/energizing-america>

Snelders, H. A. M. 2013. “The Amsterdam Experiment on the Analysis and Synthesis of Water (1789).” *Ambix* 26, no. 2: 116–33. <https://doi.org/10.1179/amb.1979.26.2.116>.

Sofiev, Mikhail, James J. Winebrake, Lasse Johansson, Edward W. Carr et al. 2018. “Cleaner Fuels for Ships Provide Public Health Benefits with Climate Tradeoffs.” *Nature Communications* 9, no. 1 (February 6): 406. <https://doi.org/10.1038/s41467-017-02774-9>.

Spiegel, Colleen. 2020. “The Use of Hydrogen as an Energy Storage System.” FuelCellStore, December 8, 2020. <https://www.fuelcellstore.com/blog-section/use-of-hydrogen-as-an-energy-storage-system>.

St. John, Jeff. 2020. “How to Build a Green Hydrogen Economy for the US West.” Greentech Media, November 17, 2020. <https://www.greentechmedia.com/articles/read/how-to-build-a-green-hydrogen-economy-for-the-u.s-west>.

Takahashi, Ryusei. 2020. “Japan Lays out Plan to Steer Economy Away from Carbon by 2050.” *The Japan Times*, December 25, 2020. <https://www.japantimes.co.jp/news/2020/12/25/business/japan-2050-carbon-plan/>.

Timperley, Jocelyn. 2020. “The Fuel That Could Transform Shipping.” BBC, November 29, 2020. <https://www.bbc.com/future/article/20201127-how-hydrogen-fuel-could-decarbonise-shipping>.

Transport & Environment. 2020. “Comparison of Hydrogen and Battery Electric Trucks.” (June). https://www.transportenvironment.org/sites/te/files/publications/2020_06_TE_comparison_hydrogen_battery_electric_trucks_methodology.pdf.

UN. 2021. “Climate Action – United Nations Sustainable Development.” <https://www.un.org/sustainabledevelopment/climate-action/>.

UNESCO. 2019. “The United Nations World Water Development Report 2019: Leaving No One Behind.” UNESCO World Water Assessment Programme. <https://en.unesco.org/themes/water-security/wwap/wwdr/2019>.

US Congress. 2010. “Text - H.R.2454 - 111th Congress (2009-2010): American Clean Energy and Security Act of 2009.” Congress.Gov, Library of Congress. <https://www.congress.gov/bill/111th-congress/house-bill/2454/text>.

Vann, Adam. 2010. “The Federal Government’s Role in Electric Transmission Facility Siting.” EveryCRSReport, September 8, 2011. <https://www.everycrsreport.com/reports/R40657.html>.

Wang, Ligang, Ming Chen, Rainer Küngas, Tzu-En Lin et al. 2019. “Power-to-fuels via solid-oxide electrolyzer: Operating window and techno-economics.” *Renewable and Sustainable Energy Reviews* 110: 174–187. <https://doi.org/10.1016/j.rser.2019.04.071>.

Washington Department of Commerce. 2020. “Washington State 2021 Energy Strategy.” <https://www.commerce.wa.gov/wp-content/uploads/2020/11/WA-2021-State-Energy->



[Strategy-FIRST-DRAFT.pdf](#).

Webber, Michael E. 2007. “The Water Intensity of the Transitional Hydrogen Economy.” *Environmental Research Letters* 2, no. 3 (September 1): 034007. <https://doi.org/10.1088/1748-9326/2/3/034007>.

Weger, Lindsey B., Joana Leitão, and Mark G. Lawrence. 2021. “Expected Impacts on Greenhouse Gas and Air Pollutant Emissions Due to a Possible Transition towards a Hydrogen Economy in German Road Transport.” *International Journal of Hydrogen Energy* 46, no. 7 (January 27): 5875–90. <https://doi.org/10.1016/j.ijhydene.2020.11.014>.

Winton, Neil. 2020. “Could Hydrogen Fuel Cells Revive, Threaten Battery Technology In Cars?” *Forbes*, April 26, 2020. <https://www.forbes.com/sites/neilwinton/2020/04/26/could-hydrogen-fuel-cells-revive-threaten-battery-technology-in-cars/?sh=36d728255e4b>.

Wiser, Ryan, Mark Bolinger, Galen Barbose, Naim Darghouth et al. 2018. “2018 Wind Technologies Market Report.” US Department of Energy. <https://www.energy.gov/sites/prod/files/2019/08/f65/2018%20Wind%20Technologies%20Market%20Report%20FINAL.pdf>.

Wiser, Ryan, Mark Bolinger, Ben Hoen, Dev Millstein et al. n.d. “Wind Energy Technology Data Update: 2020 Edition.” Electricity Markets & Policy. <https://emp.lbl.gov/publications/wind-energy-technology-data-update>

Zapantis, Alex. 2021. “Blue Hydrogen.” Global CCS Institute (April). <https://www.globalccsinstitute.com/resources/publications-reports-research/blue-hydrogen/>.

Zayat, Billal, Debanjan Mitra, and S. R. Narayanan. 2020. “Inexpensive and Efficient Alkaline Water Electrolyzer with Robust Steel-Based Electrodes.” *Journal of The Electrochemical Society* 167, no. 11 (July): 114513. <https://doi.org/10.1149/1945-7111/aba792>.

Zeng, Kai, and Dongke Zhang. 2010. “Recent progress in alkaline water electrolysis for hydrogen production and application.” *Progress in Energy and Combustion Science* 36: 307–326. https://www.epfl.ch/labs/tic/wp-content/uploads/2018/10/Art11_Alkaline-water-electrolysis.pdf.

Zero Emission Resource Organisation. 2016a. “GreenGen.” <http://www.zeroco2.no/projects/greengen>.

———. 2016b. “ZeroGen.” <http://www.zeroco2.no/projects/zerogen>.

Zero Emission Platform. 2010. “The Costs of CO₂ Transport.” European Technology Platform for Zero Emission Fossil Fuel Power Plants. <https://zeroemissionsplatform.eu/about-ccs-ccu/what-is-ccs/transport/>.

Yun Zhao, Brian P. Setzler, Junhua Wang, Jared Nash et al. 2019. “An Efficient Direct Ammonia Fuel Cell for Affordable Carbon-Neutral Transportation.” *Joule* 3, no. 10: 2472–2484. <https://doi.org/10.1016/j.joule.2019.07.005>.



NOTES

1. An electrolyzer contains a cathode (negative charge), an anode (positive charge), and a separator. Alkaline systems use an alkaline liquid electrolyte solution to create the ideal water splitting environment.
2. There are some successful practices for development and use of ammonia fuel cells but still many challenges to overcome. Source: Georgina Jeerh, Mengfei Zhang, and Shanwen Tao, "Recent Progress in Ammonia Fuel Cells and their Potential Applications," *Journal of Materials Chemistry A* no. 9 (2021): 727-752, <https://doi.org/10.1039/D0TA08810B>.



 COLUMBIA | SIPA
Center on Global Energy Policy

