K&L GATES

UNITED STATES

The H_2 Handbook

Legal, Regulatory, Policy, and Commercial Issues Impacting the Future of Hydrogen

While hydrogen has been used in industrial applications in the United States for decades, the potential for development of a global hydrogen economy seems more probable each day as countries and companies announce investment and support of hydrogen as part of the path to a cleaner energy future. With its substantial domestic energy demand, growing renewable energy markets, vast domestic natural gas reserves, experience with both energy imports and exports, and mature energy markets, the United States has a prime opportunity to play a significant role in this exciting piece of the energy puzzle.

When and to what degree the United States develops a domestic hydrogen market and advances the global hydrogen economy on a commercial scale will depend on a number of factors, including political support at federal, state, and local levels; development and expansion of federal and state regulatory regimes to ensure clear, transparent, intentional regulation; the ability to leverage existing energy infrastructure to produce, transport, and store hydrogen; the availability of project finance; and the resolution of various open commercial questions. While U.S. federal support for hydrogen already exists, more intentional and substantial federal government engagement could be tied to the outcome of the November 2020 presidential election. Nonetheless, the ability to produce hydrogen from a number of sources presents a unique opportunity for bipartisan support. In addition, a number of U.S. states also are taking action to incentivize the production and use of hydrogen.

This portion of *The Hydrogen Handbook* explores the regulatory, commercial, and policy issues that will shape the development of a U.S. hydrogen market and the United States' participation in a global hydrogen economy. In the sections that follow, we discuss existing laws, regulations, and government programs related to hydrogen and identify areas where further development is needed, as well as important considerations for industry participants. This discussion is driven by our team's deep understanding of U.S. energy regulation and policy, as well as our significant commercial experience in the energy sector.

We begin this discussion in **Part I** with several overarching issues that will impact the U.S. hydrogen economy more broadly, including federal and state incentives, and consideration of high-level commercial issues, project finance, insurance coverage, and stakeholder engagement. **Part II** explores regulatory, policy, and commercial issues related to hydrogen production, including production using wind and solar, natural gas and renewable natural gas, biomass, coal, and nuclear. Finally, in **Part III**, we discuss regulatory, policy, and commercial issues related to hydrogen transportation, distribution, storage, and end-use.

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PART I - OVERARCHING CONSIDERATIONS

As discussed in greater detail below, a number of overarching issues will be critically important to the development of a hydrogen economy in the United States and for participants to bear in mind as this industry expands.

From a financial perspective, these include the availability of federal and state incentives, such as grants, loan guarantee programs, rebate programs, and tax incentives. In addition, accessibility to project finance will be an important issue for new hydrogen projects, particularly those proposing use of new technology or technology that has not yet been tested at scale. Given the risks—both real and perceived—that hydrogen presents and the nascent nature of large-scale deployment of hydrogen, insurance coverage considerations also will play an important role for the industry and industry participants.

Arguably, one of the most critical overarching issues will be stakeholder engagement. Energy is in our headlines on a daily basis—it is both vital to nearly every facet of our lives and hotly debated as a political, environmental, and personal financial issue. Hydrogen will be no different, and the industry will need to continue to invest in educating and engaging with the public and lawmakers to help ensure continued and expanded support, as well as promulgation of well-reasoned and transparent laws and regulations.

I. Government Incentives

While still in its nascence, the U.S. federal government and many state governments already have recognized the potential that broader-scale deployment of hydrogen holds. Support for continued and increased development exists in the form of grant programs and tax incentives. These programs offer significant opportunity for the type of research and development (R&D) that is needed to make hydrogen cost competitive and drive demand. Continuation and expansion of these programs will be a critical factor in the development of a U.S. hydrogen economy.

A. U.S. Department of Energy Programs

The federal government's main hydrogen R&D entity is the U.S. Department of Energy's (DOE) Hydrogen and Fuel Cells Program.[1] This program funds R&D in hydrogen production, delivery, infrastructure, storage, fuel cells, and multiple end-uses across transportation, industrial, and stationary power applications. The program also manages activities in technology validation, manufacturing, analysis, systems development and integration, safety, codes and standards, education, and workforce development.

With appropriations from Congress, the DOE Hydrogen and Fuel Cells Program regularly announces solicitations for proposals. The focus of recent grants has been proposals that would advance hydrogen fueling technologies for medium- and heavy-duty fuel cell vehicles and also proposals that address technical barriers to hydrogen blending in natural gas. In July 2020, DOE announced 18 awards for a total of $64 million for proposals in these priority areas.

Hydrogen technologies also would qualify for the DOE Improved Energy Technology Loans through the DOE Loan Guarantee Program. Eligible projects for this program would reduce air pollution and greenhouse gas emissions and support early commercial use of advanced technologies, including biofuels and alternative fuel vehicles. The program is not intended for R&D projects, but instead to accelerate commercial use of improved energy technologies. DOE may issue loan guarantees for up to 100 percent of the amount of the loan for an eligible project. Eligible projects may include the deployment of fueling infrastructure, including associated hardware and software, for alternative fuels.[2]

Additionally, DOE has announced its intention to invest up to $100 million over five years in two new DOE National Laboratory-led consortia to advance hydrogen and fuel cell technologies R&D.[3] These consortia are dependent on federal appropriations. One consortium

1 *About the Hydrogen and Fuel Cells Program*, DEP'T OF ENERGY, http://www.hydrogen.energy.gov/about.html (last visited Aug. 7, 2020). 2019.

2 *Alternative Fuels Data Center: Hydrogen Laws and Incentives*, DEP'T OF ENERGY, https://afdc.energy.gov/fuels/laws/HY?states=US (last visited Aug. 7, 2020).

3 Michael Bates, *DOE to Invest in Advancements in Hydrogen and Fuel Cell R&D*, NGT NEWS (June 25, 2020), https://ngtnews.com/doe-to-invest-in-advancement-of-hydrogen-and-fuel-cell-rd.

would conduct R&D to achieve large-scale, affordable electrolyzers, which use electricity to split water into hydrogen and oxygen, and can be powered by various energy sources, including natural gas, nuclear, and renewables, as discussed in greater detail in **Part II**. This R&D will complement and support large industry deployment by enabling more durable, efficient, and low-cost electrolyzers. The other consortium will conduct R&D to accelerate the development of fuel cells for heavy-duty vehicle applications, including long-haul trucks. This initiative will have a five-year goal of proving the ability to manufacture a fully competitive heavy-duty fuel cell truck that can meet all of the durability, cost, and performance requirements of the trucking industry.

B. Other Federal Programs

In addition to the DOE programs, there are several other existing federal programs that support the production and deployment of hydrogen in the United States.

- The Airport Zero Emission Vehicle (ZEV) and Infrastructure Incentives is managed through the Federal Aviation Administration (FAA). Through this program the FAA can award Airport Improvement Program (AIP) grants for the acquisition and operation of ZEVs at an airport. This program provides funding to airports for up to 50 percent of the cost to acquire ZEVs and install or modify supporting infrastructure for acquired vehicles. Grant funding must be used for airport-owned, on-road vehicles used exclusively for airport purposes.[4]
- Hydrogen technologies also qualify for several federal tax credits, including the Alternative Fuel Infrastructure Tax Credit (set to expire 31 December 2020), and the Alternative Fuel Tax Exemption, as discussed in greater detail in the Tax section of **Part I (Section I.D.4)** below.
- The Alternative Fuel and Advanced Vehicle Technology Research and Demonstration Bonds program allows qualified state, tribal, and local governments to issue Qualified Energy Conservation Bonds subsidized by the U.S. Department of Treasury at competitive rates to fund capital expenditures on qualified energy conservation projects. Eligible activities include research and demonstration projects related to non-fossil fuels, as well as advanced battery-manufacturing technologies.[5]
- The Low and Zero Emission Public Transportation Research, Demonstration, and Deployment Fund provides financial assistance to local, state, and federal government entities; public transportation providers; private and non-profit organizations; and higher education institutions for research, demonstration, and deployment projects

4 *Alternative Fuels Data Center: Hydrogen Laws and Incentives*, DEP'T OF ENERGY, https://afdc.energy.gov/fuels/laws/HY?states=US (last visited Aug. 7, 2020).

5 *Id.*

involving low or zero emission public transportation vehicles.[6]

C. State Programs

As many states look to reduce carbon emissions, promote renewable energy and clean transportation, and investigate seasonal energy storage, programs that help support hydrogen production and distribution have emerged. The list below provides a high-level overview of several state-level programs, though it is not an exhaustive list.

California

California has several regulations and incentives related to the production, distribution, and use of hydrogen. Most of these regulations and incentives are tied into broader clean transportation programs administered by the California Air Resources Board (CARB) or local air districts or utilities. The California Energy Commission (CEC) also periodically makes significant grant funding available for the R&D of new hydrogen technologies and fueling stations.

The CARB and local air district programs include several rebate programs and mandates for ZEVs, which include hydrogen-powered vehicles, and/or grant preferential treatment for infrastructure required for hydrogen fueling stations (e.g., the Alternative Fuel Vehicle Parking Incentive Program). CARB also must periodically evaluate the need for publicly available hydrogen fueling stations and submit a report to the CEC. In turn, CEC can then make funding decisions for fueling infrastructure required to meet California's goal of 100 publicly available hydrogen fueling stations. Such stations are eligible to generate credits under California's Low Carbon Fuel Standard (LCFS).

California also requires its state agencies and utilities to more broadly consider the energy landscape through the middle of the 21st century. Every two years, the CEC must submit an Integrated Energy Policy Report (IEPR). Utilities also must submit Integrated Resource Plans (IRPs) to the California Public Utilities Commission (CPUC). In the last several years, the IEPR and IRPs have considered different types of energy storage technologies to integrate into California's renewables-heavy electricity sector. We anticipate that hydrogen will begin to play a larger role in the IEPR and IRPs over the next several years. One high-profile example is the Los Angeles Department of Water and Power's plan to convert the Intermountain Power Plant in Delta, Utah, from coal to a blend of natural gas and green hydrogen sourced from nearby wind and solar generators and stored seasonally in giant salt caverns.

Oregon

Like California, Oregon's regulations and incentives for hydrogen tie closely to its clean transportation and ZEV programs. Hydrogen used as a transportation fuel also can generate credits under Oregon's Clean Fuels Program, which is similar to California's Low Carbon Fuel Standard.

In September 2019, Oregon took a significant step in greening its natural

6 *Id.*

gas infrastructure with the passage of Senate Bill 98 (SB 98). SB 98 sets targets for utilities to deliver an increasing percentage of "renewable" natural gas to retail customers and allows utilities to include the higher cost of obtaining renewable natural gas in their rate base. Critically, SB 98 includes renewable hydrogen in its definition of renewable natural gas. Renewable hydrogen is hydrogen produced from excess wind, solar, and hydropower, and can be used by itself for use in the transportation sector and for industrial use, or can be blended into the natural gas pipeline system and delivered to traditional gas-fired resources.

Washington

Like Oregon and California, Washington state has several hydrogen incentives embedded in its clean transportation initiatives. Most of these programs, including grant funding for fueling infrastructure, are administered by the Washington State Department of Transportation.

Washington state also adopts tax relief for key components of the hydrogen economy. For instance, sales and use taxes do not apply to the sale of property used for hydrogen fueling infrastructure. Washington's 6.5 percent retail sales and state use tax does not apply to the sale or lease of new or used hydrogen-powered passenger vehicles, light-duty trucks, and medium-duty passenger vehicles.

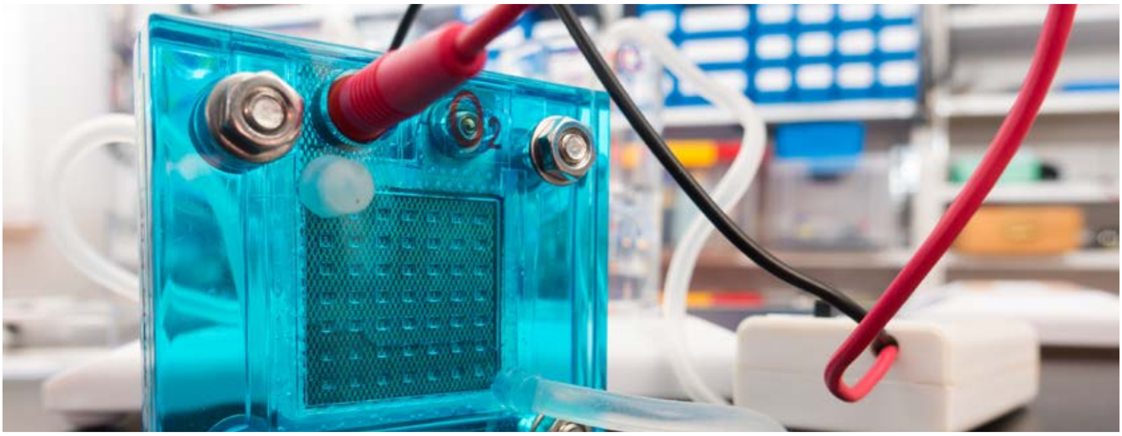
Finally, in April 2019, Substitute Senate Bill 5588 authorized Washington's public utilities to produce, distribute, and sell hydrogen produced from renewable resources like wind, solar, and hydropower. The bill was seen as a win for environmentalists, as well, because utilities would use excess midday wind and solar power and reduce excess spill from hydropower facilities, which has the potential to harm fish. While utilities may include the higher cost of acquiring green hydrogen in their rate base, the Washington bill (unlike Oregon's SB 98) stops short of setting targets for the delivery of renewable natural gas or renewable hydrogen to retail customers.

South Carolina

Because it hosts several domestic and foreign automobile manufacturing facilities interested in positioning themselves for hydrogen fuel cell vehicles, South Carolina was an early adopter of hydrogen-friendly regulation and incentives. In 2006, several universities, federal labs, and state agencies founded the South Carolina Hydrogen and Fuel Cell alliance to advance the cause of hydrogen fuel cells in the state. In June 2010, South Carolina passed the Hydrogen and Fuel Cell Permitting Law that placed statewide permitting authority within the Office of the State Fire Marshall. Until 2012, the South Carolina Research Authority administered the South Carolina Hydrogen Infrastructure Development Fund, although that program appears to have expired. As discussed in the **Government Incentives section of Part II (Section I)**, South Carolina also offers a sales tax exemption that helps to promote hydrogen production and fuel cell technologies.

D. Tax

Several U.S. federal income and excise tax credits encourage investment in



hydrogen projects. These credits include the investment tax credit (ITC) available under Code[7] Section 48 for qualified fuel cell property that generates electricity, a federal income tax credit for fuel cell motor vehicles placed in service during a given tax year under Code Section 30B, a federal income tax credit for placing alternative fuel vehicle refueling property into service during a given tax year under Code Section 30C, and a federal excise tax credit on the sale or use of liquefied hydrogen under Code Section 6426(d).

1. ITC for Fuel Cells

The ITC for qualified fuel cell property provides a percentage credit (subject to a per-kilowatt cap) against U.S. federal income tax for property placed in service before 1 January 2024.[8] Property is qualified fuel cell property if it is a "fuel cell power plant" with a nameplate capacity rating of at least 0.5 kilowatts (kw)[9] and has an electricity-only generation efficiency greater than 30 percent.[10] For this purpose, a fuel cell power plant is "an integrated system comprised of a fuel cell stack assembly and associated balance of plant components which converts a fuel into electricity using electrochemical means." Thus, an operational hydrogen fuel cell with a nameplate capacity of at least 0.5 kw generally qualifies for the ITC.

The percentage of ITC available varies depending on when construction of the property began, as shown in the table below.

Year Construction Began	Year Property Placed in Service	Credit Rate
2019 or before	2023, generally	30%
2020	2023	26%
2021	2023	22%

Regardless of the maximum credit amounts allowed above, the credit is capped at $1,500 for each 0.5 kilowatts of capacity of the qualified fuel cell property.[11]

[7] All references to the "Code" herein are to the Internal Revenue Code of 1986, amended.

[8] Code § 48(a)(7)(B).

[9] *Id.* at 48(c)(1)(A)(i).

[10] *Id.* at 48(c)(1)(A)(ii).

[11] *Id.* at 48(c)(1)(B).

Construction of ITC property may begin either by spending at least 5 percent of the total cost of the ITC property (the 5 Percent Safe Harbor) or completing significant physical work on the ITC property (the Physical Work Test), in each case, in the applicable year.[12] The 5 percent Safe Harbor is relatively straightforward for cash-method taxpayers. For accrual-method taxpayers, it is possible to pay 5 percent of the cost and take delivery or title up to 3.5 months after payment.[13] This delayed delivery or title transfer method is an accounting method that must be available to the purchaser. The Physical Work Test does not require that a minimum amount be spent, but does require that work on material components of ITC property be completed in the applicable year. The amount of work is not specifically delineated in guidance. Taxpayers should consult with experienced practitioners to develop a strategy using the Physical Work Test.

Financing structures involving fuel cells vary depending on the size of the fuel cell and financing facility. Taxpayers who have the need for both the electricity produced by hydrogen fuel cells (e.g., datacenter operators) and the ITC should consider owning the fuel cells outright, but should plan ahead for asset retirement and disposition. For all other taxpayers, sale-leaseback structures are particularly useful for smaller fuel cells, e.g., cells used to power warehouse equipment, and may also be used for larger, stationary fuel cells if the right counterparty can be obtained. Partnership flip structures and lease passthrough structures are also available.

A taxpayer that claims the ITC must reduce its basis in the ITC property by the amount of ITC claimed.[14] In addition, the ITC claimed in respect of qualified fuel cell property may be recaptured if the property is sold or ceases to be used for qualified purposes or at all within five years after the property is placed in service.[15]

2. New Qualified Fuel Cell Motor Vehicle Credit

New qualified fuel cell motor vehicles placed in service after 31 December 2009 generally qualify for a credit up to a per-vehicle maximum of $4,000 to $40,000 depending upon the gross vehicle weight rating of the vehicle.[16] The allowable credit amount will be increased by between $1,000 and $4,000 per vehicle if such vehicle achieves a fuel efficiency of between 150 percent and 300 percent of a statutory baseline fuel efficiency standard.[17] This credit is currently available only for motor vehicles placed in service through 31 December 2020.

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12 Notice 2018-59.

13 Treas. Reg. § 1.461-4(d)(6)(ii).

14 Code § 50(c)(1).

15 *Id.* at 50.

16 *Id.* at 30B(b).

17 *Id.* at 30B(b)(2).

A motor vehicle is a new qualified fuel cell[18] motor vehicle if (1) it is powered by a hydrogen fuel cell, (2) it meets applicable clean air standards,[19] (3) its original use commences with the taxpayer claiming the credit,[20] (4) it is acquired for use or lease by the taxpayer rather than for resale,[21] and (5) it was made by a manufacturer.[22] For this purpose, a motor vehicle is a vehicle that is capable of operating on public roads (or exclusively on rails) and that has four wheels.

Like the ITC, this credit is available to the owner of the new qualified fuel cell motor vehicle. However, if the motor vehicle is sold to a tax-exempt entity (e.g., a local government) and is not leased, the seller of the motor vehicle may claim the credit after clearly disclosing their claim in writing to the tax-exempt entity.[23] Taxpayers should note that their basis in any new qualified fuel cell motor vehicle will be reduced by the full amount of the credit available, regardless of whether the taxpayer can fully utilize the credit.[24] Thus, if it is more advantageous to retain the basis, the taxpayer should consider electing out of the credit[25] or use a financing structure whereby the refueling property may be owned directly or indirectly by a taxpayer that can use the credit. In addition, the new qualified fuel cell motor vehicle credit is subject to recapture, but guidance regarding recapture has not yet been issued.[26]

Portfolio transaction structures are attractive in the context of the new qualified fuel cell motor vehicle credit because of the caps on the available credit and relatively small acquisition cost of qualified property.

3. Alternative Fuel Vehicle Refueling Property Credit

A credit is also available in respect of qualified alternative fuel vehicle refueling property that is placed in service no later than 31 December 2020.[27] The credit is up to 30 percent of the cost of the property,[28] subject to a cap of $30,000 for depreciable property (i.e., property used in a trade or business) and $1,000 for any other property placed in service by the taxpayer “at a location.”[29] It is not clear what is meant by a location in this context.

18 *Id.* at 30B(b)(3)(A).

19 *Id.* at 30B(b)(3)(B).

20 *Id.* at 30B(b)(3)(C).

21 *Id.* at 30B(b)(3)(D).

22 *Id.* at 30B(b)(3)(E).

23 *Id.* at 30B(h)(6).

24 *Id.* at 30B(h)(4).

25 *Id.* at 30B(h)(9).

26 *Id.* at 30B(h)(8).

27 *Id.* at 30C(g).

28 *Id.* at 30C(a).

29 *Id.* at 30C(b).

Qualified alternative fuel vehicle refueling property must (1) be depreciable, (2) be owned by the taxpayer that put it to original use, (3) be used for the storage or dispensing of, among other things, fuel the volume of which is composed of at least 85 percent hydrogen, and (4) not be installed on property that is used as the principal residence of the taxpayer claiming the credit.[30] To the extent that all or a portion of this credit is attributable to property for which a Code Section 38(b) credit is allowed (for example, new markets tax credit property), the alternative fuel vehicle refueling property credit is not available.[31]

Like the credits discussed above, this credit is available to the owner of the refueling property. However, if the refueling property is sold to a tax-exempt entity (e.g., a local government) and is not leased, the seller of the motor vehicle may claim the credit after clearly disclosing their claim in writing to the tax-exempt entity.[32] Taxpayers should note that their basis in any new qualified fuel cell motor vehicle will be reduced by the full amount of the credit available, regardless of whether the taxpayer can fully utilize the credit.[33] Thus, if it is more advantageous to retain the basis, the taxpayer should consider electing out of the credit[34] or use a financing structure whereby the refueling property may be owned directly or indirectly by a taxpayer that can use the credit. In addition, the new qualified fuel cell motor vehicles credit is subject to recapture.[35]

Portfolio transaction structures are also attractive in the context of the qualified alternative fuel vehicle refueling property credit because of the caps on the available credit and relatively small acquisition cost of qualified property. However, the cap on a per location basis should be carefully evaluated.

4. Alternative Fuel Credit

The alternative fuel credit is available as an offset to the Code Section 4041 fuel excise tax. The credit is $0.50 per gallon equivalent of an alternative fuel (including liquefied hydrogen) produced in the United States and sold by a taxpayer for use as a fuel in a motor vehicle or motorboat, or for use as fuel in aviation, or consumed by the taxpayer.[36] Such fuel must meet carbon recapture requirements, which can be done by the fuel being certified as having been derived from coal produced at a gasification facility that separates and sequesters not less than 75 percent of such facility's total carbon dioxide emissions.[37] This credit

30 *Id.* at 30C(c), 179A(d).

31 *Id.* at 30C(d)(1).

32 *Id.* at 30C(e)(2).

33 *Id.* at 30C(e)(1).

34 *Id.* at 30C(e)(4).

35 *Id.* at 30C(e)(5).

36 *Id.* at 6426(d)(1), (d)(2)(D), (i)(2).

37 *Id.* at 6426(d)(4)(A), (d)(4)(B)(ii).

will available for fuel produced through 31 December 2020.[38]

Tax-exempt entities such as state and local governments that dispense qualified fuel from on-site refueling stations for use in vehicles should generally qualify for this credit, but must register with the IRS. The credit must first be taken against the entity's alternative fuel tax liability, with any excess claimed as a direct payment from the IRS.[39]

II. Project Finance

While hydrogen investing has been heating up, project financing for hydrogen has been very limited outside of select government-supported projects and small niche applications. In a recent paper, Barclays suggests hydrogen could be a $1 trillion market by 2050.[40] If the growth projections for new hydrogen applications over the next two decades are to become reality, then a massive expansion of hydrogen project financing options and expertise will be necessary.

As with any nascent industry or technology, leveraging existing project finance tools will be difficult until market and technological certainty has become more widely accepted. This is especially true for hydrogen because hydrogen production, particularly green and blue hydrogen, currently is more expensive than natural gas. Cost reductions will require scale, which will almost certainly require continued and potentially expanded government investment or subsidies similar to those discussed in the **Government Incentives sections (Part I, Section I; Part II, Section I; and Part III, Section V)**, for the initial commercial-scale growth of the industry. In fact, the Hydrogen Council recently estimated that the hydrogen market requires $70 billion of investment over the next decade to become competitive with the lowest-cost

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38 *Id.* at 6426(d)(5).

39 *Alternative Fuels Data Center: Alternative Fuel Excise Tax Credit*, DEP'T OF ENERGY, https://afdc.energy.gov/laws/319 (last visited Aug. 7, 2020).

40 *The Hydrogen Economy: Fuelling the Fight Against Climate Change*, BARCLAYS, https://www.investmentbank.barclays.com/our-insights/the-hydrogen-economy-fuelling-the-fight-against-climate-change.html (last visited Aug. 18, 2020).

low-carbon alternative.[41] Some of this investment, including investment in the buildout of necessary supporting infrastructure, will be in the type of capital-intensive assets that are well-suited for project finance structures.

Project finance refers to financing with limited recourse from lenders directly to the owner/sponsors. Financing is based on the economic viability of the project itself and relies on project revenue to service financing payments. With capital-intensive projects, project financing typically requires some form of long-term revenue certainty. The preferred approach to establishing revenue certainty is through long-term offtake contracts with fiscally strong counterparties. However, as markets mature, hedges and other financial arrangements can be used to support long-term revenue certainty. As the hydrogen industry initially develops, there will be opportunities to find these long-term agreements as buyers, sellers, and transporters all will need each other to support revenue certainty.

Historically, this isolated approach to financing has made it easier to raise large amounts of project debt and equity, and project finance has been vital for building projects where the capital demands of a project are larger than the capacity of an owner or sponsor. Lenders find this approach appealing because it allows them to isolate project credit risk from the sponsor owner and the project credit risk can be considerably lower than a sponsor's individual credit risk. Project finance is attractive to project developers because it insulates the developer's other corporate assets from project-specific risks and allows the developer to take on a significant amount of debt while preserving the parent company's debt-to-equity ratio and corporate borrowing capacity.

In the near-term, new hydrogen projects will carry market and regulatory uncertainty and will rely on technology that is new or not proven at scale, which will add risk, making traditional project finance difficult, and certainly much more expensive. Government support that offsets project level risk or provides subsidies to create higher returns likely will be necessary to support project financing. Even with government support, non-traditional project financing sources will be key to early successful financings. Innovation and hybrid approaches to financing likely will define the early hydrogen project finance market, and recent examples in renewable and LNG financing illustrate how these new financing tools may evolve. The renewable power industry was built with financing that incorporated and monetized tax incentives and other government supports, while tapping into long-term offtake contracts, which mitigated the market risk for financiers. Project finance for large-scale LNG export projects has required the construction and operation of the liquefaction facility, feed gas pipelines, natural gas supply contracts, and shipping and offtake agreements all to be aligned to prove

41 *Path to Hydrogen Competitiveness: A Cost Perspective,* HYDROGEN COUNCIL, p. vi, https://hydrogencouncil.com/en/path-to-hydrogen-competitiveness-a-cost-perspective/ (last visited Aug. 7, 2020).

project economics and revenue. One solution has been large upfront equity investments from private capital, such as hedge funds, until all project components were secured, followed by more traditional project financing once long-term revenue certainty was established through long-term take-or-pay offtake agreements.

The long-duration energy storage market for hydrogen may be more attractive to project financiers than the distributed hydrogen market, for several reasons. First, there is a clear model for financing power generation projects—investors provide capital for the construction of a single generation asset, and the asset generates revenue based on power prices. Second, the relative cost of long-duration hydrogen storage is expected to decrease significantly over the next 10 years. The Hydrogen Council recently predicted that "the cost of low-carbon and/or renewable hydrogen production will fall drastically by up to 60 per cent over the coming decade."[42] The Hydrogen Council attributes this significant decrease in costs to the falling costs of renewable electricity generation, which will be used to produce hydrogen via electrolysis, the cost of which will decrease because of the anticipated scaling up of electrolyzer manufacturing, for long-duration power storage.[43]

Beyond economics, public perception (as discussed in the **Stakeholder Engagement section below (Part I, Section IV)**) and politics likely will define the development of financing markets for the hydrogen economy as investors and lenders are, in significant numbers, searching for access to the growing renewable energy economy. Although more environmentally friendly than grey hydrogen, green hydrogen needs a material reduction in the cost of electrolysis technology and blue hydrogen needs a material reduction in the cost of carbon capture and sequestration technology to be competitive. Nevertheless, the broad trend among financial institutions of re-assessing the climate risk associated with energy investments may make grey hydrogen less attractive and green and blue hydrogen more attractive in the medium-term. Unless the economic challenges facing blue hydrogen diminish much more rapidly than those facing green hydrogen, green hydrogen may draw more interest than blue hydrogen. In the medium- to long-term, green hydrogen appears more likely to be the focus of the government support that will be necessary for the economics of financing hydrogen projects to work. In the near-term, the degree of U.S. federal government support for green hydrogen in particular likely will depend to some extent on the outcome of the November 2020 U.S. presidential elections, as well as the relative pace at which green hydrogen becomes a global commodity (which could compel further federal action). In addition, as discussed in the **Natural Gas/RNG section of Part II (Section II.D.5)**,

42 *Id.* at p. iv.

43 *Id.*

efforts are underway to advance carbon capture and sequestration technology as well. Ultimately, the perceived value of a zero carbon economy likely will be a driver for the flow of hydrogen project financing dollars.

III. Insurance Coverage

The energy industry is among the most dynamic in the world, as are the risks that it faces. Those risks have materialized into some of the most devastating and costly losses of any industry. Significant losses affecting the energy industry include the 2011 destruction of the Fukushima Daiichi nuclear power plant caused by a tsunami and earthquake; the 2010 BP Deepwater Horizon incident; the 1968 coal mine explosion in Farmington, West Virginia; the 1989 Exxon Valdez incident in Prince William Sound, Alaska; and the 1988 Piper Alpha oil and gas drilling rig incident in the North Sea. The Piper Alpha loss, valued at greater than $2 billion, is the largest property damage loss experienced within the hydrocarbon extraction, transportation, and processing industry.

More specific to hydrogen, the diverse methods of its production carry high risk, such as the release of harmful or flammable gasses, including carbon monoxide, carbon dioxide, and methane. Additional risks for all forms of hydrogen production, transportation, storage, and end-use include design flaws, human error, equipment failure, and natural disasters. As such, the development of opportunities in any segment of the energy industry, including the hydrogen market, carries with it the need for careful and sophisticated risk management.

The transfer of risk through insurance is a critical part of any enterprise's risk management program. Moreover, insurance is an important corporate asset and is often a company's largest source of contingent capital. Companies participating in the hydrogen market must carefully construct their insurance programs to meet the considerable risks of their operations. Insurance programs for energy companies also will reflect the complexity of their operations. This will require the placement of an insurance program of sufficient breadth (i.e., with appropriate lines of coverage), and likely will require spreading the risk across multiple insurers so as to provide sufficient amounts of coverage (i.e., limits of liability). Consideration also must be given to incorporating appropriate deductibles or self-insured retentions and may include the use of captive insurers.

Attention also must be paid to policy wording. Insurance policies are complex documents and most insurers write insurance through the use of standard "package" policies, incorporating a wide variety of forms that are drafted from the insurer's perspective. Further, insurance contract law varies by jurisdiction and in certain areas, such as notice of loss, may disproportionately favor the insurer. Opportunities exist, however, to negotiate for improved policy wording. Accordingly, it is important to review policy wording carefully to ensure that identifiable risks are covered.

Many companies are unaware—sometimes until it is too late to address—that they have gaps in their insurance policies and programs. These gaps may arise from a number of causes, including: (i) inadequate and unclear policy wording; (ii) inconsistencies within and among primary and excess layers of coverage; (iii) inadequately coordinated placements among complimentary lines of coverage; and (iv) insufficiently understood risks inherent in the insurance application process. Companies participating in the hydrogen market would be well advised to adopt a proactive approach during the underwriting process to avoid unexpected gaps in coverage and to spot opportunities to improve upon the wording of insurance policy terms and conditions.

In addition to a sophisticated insurance approach, another important risk management tool for companies in the hydrogen market is the proactive and coordinated management of contract-driven relationships with contractors and suppliers. Vendor contracts routinely include indemnification obligations and insurance requirements, including the requirement that the company be identified as an additional insured under various policies held by the contractors and suppliers. These contract provisions should be managed for consistency across vendors and for coordination with the company's own insurance program. Additionally, the insurance obligations that a company imposes upon its vendors should be routinely monitored for compliance. In sum, insurance coverage plays an important role in risk management for the hydrogen industry and should be proactively assessed and employed.

IV. Stakeholder Engagement

As the United States begins to adopt and integrate hydrogen as an energy source into the national infrastructure, public stakeholder engagement could be one of the most critical elements to ensure success. A lack of familiarity and experience with hydrogen on the part of the general public could lead to distrust and open opposition. For most of the U.S. public, the mention of hydrogen conjures up images of the Hindenburg Airship disaster in New Jersey in the 1930s. Moreover, opposition movements to infrastructure—NIMBY (Not In My Back Yard), NOPE (Not On Planet Earth), and BANANA (Build Absolutely Nothing Anywhere, Near Anybody)—do not discriminate against the infrastructure they oppose, as many U.S. wind and solar power developers have experienced.

Opportunities will abound for interests adverse to hydrogen to present challenges to various aspects of the industry and its robust development in the United States. The hydrogen industry, regulators, public policy leaders, and elected officials must develop robust education initiatives to counteract what is likely inevitable as hydrogen and the infrastructure to develop and deliver it become more present in our society—public opposition based on incomplete or inaccurate information. Engagement is key.

Much of the U.S. legal structure is built on the idea of public engagement in the democratic process, whether that is through special interest lobbying in Washington, D.C., regulatory proceedings before federal agencies, or civic engagement in local issues and elections. Frequently, defined processes afford opportunities for stakeholder engagement on safety and security issues, in particular. It will be no different for the build-out of a vibrant and integrated hydrogen economy. Such processes will include opportunities for written comments, public scoping meetings, technical conferences, and legal challenges and appeals to agencies' or executives decisions. Industry participants that will develop hydrogen infrastructure must: (1) understand any existing regulatory framework for engaging hydrogen safety and security issues; (2) establish a baseline understanding of hydrogen safety and security issues applicable to each particular project; and (3) identify key safety and security messages that are critical to convey to stakeholders.

As cities, local communities, and utilities adopt strategies to invest in and embrace hydrogen in order to meet sustainability objectives, particularly the use of fuel cells and other hydrogen transportation technologies, citizens and stakeholder groups are likely to become increasingly engaged in legal and regulatory processes, debates, and proceedings. Public officials and hydrogen project developers and advocates should actively map out all of the key stakeholders and develop a strategy to engage transparently with the identified stakeholders throughout the lifecycle of a particular project proposal.

Regulators and other governmental decision-makers should intentionally

explain the regulatory processes, highlighting elements that factor in to the decision-maker's conclusions, including a focus on:

- Coordination requirements between a project developer, and state and local officials with regard to safety and security issues;
- Development of any emergency response plans that may be required, including any procedures required for notification of the public and identification of any evacuation routes in the event of an incident; and
- Mitigation strategies that a developer may be required to develop to supplement the standard safety and security practices employed by the developer, including any ongoing training programs and any customized public action plans.

There will be no way to eliminate public participation and opposition in the development of the hydrogen economy in the United States. Each hydrogen infrastructure project will present new and different challenges requiring tailored engagement plans and outreach. As a result, the hydrogen industry must be deliberate and intentional about educating and engaging thoughtfully with impacted stakeholders and the general public.

PART II - HYDROGEN PRODUCTION

As the United States seeks to advance a hydrogen economy, government incentives promoting production likely will play a key role. A summary of several current incentive programs is provided in **Section I**, below. In addition, ability to access the resources required for hydrogen production will be critically important. As discussed in greater detail in **Section II** below, this access will depend on both the abundance of the resources required, as well as the politics and regulation of such resources.

I. Government Incentives to Promote Production

While the DOE Improved Energy Technology Loans discussed in **Part I (Section I.A)** are the only federal incentive to promote hydrogen production, many states have their own hydrogen production incentives, including those listed below.

Hawaii

Hawaii supports production of renewable fuels, including hydrogen, through the Renewable Fuels Production Tax Credit. Under this tax credit, renewable fuels produced from renewable feedstocks, such as hydrogen, ethanol, biodiesel, and biofuel; may qualify for an income tax credit equal to $0.20 per 76,000 British thermal units (BTUs) of renewable fuels sold for distribution in Hawaii. The facility must produce at least 15 billion BTUs of its nameplate capacity annually to receive the tax credit and may claim the tax credit for up to five years, not to exceed $3,000,000 per calendar year. Qualifying renewable fuel production facilities must provide written notification of their intent to produce renewable fuels before becoming eligible for the tax credit.[44]

New Mexico

New Mexico provides the Biofuels Production Tax Deduction, where the cost of purchasing qualified biomass feedstocks to be processed into biofuels, as well as the associated equipment, may be deducted in computing the compensating tax due under the New Mexico Gross Receipts and Compensating Tax Act. Accepted fuels include biofuels that include hydrogen, ethanol, methanol, and methane.[45]

North Dakota

In North Dakota, the sale of hydrogen used to power an internal combustion engine or a fuel cell is exempt from sales tax under the Sales Tax Exemption for Hydrogen Generation Facilities. In addition, any equipment used by a hydrogen generation facility for the production and storage of hydrogen is exempt from sales tax. Stationary and portable hydrogen containers or pressure vessels, piping, tubing, fittings, gaskets, controls, valves, gauges, pressure regulators, and safety relief devices are included as eligible equipment.[46]

South Carolina

South Carolina offers a sales tax exemption for "any device, equipment, or machinery operated by hydrogen or fuel cells, any device, equipment or machinery used to generate, produce, or distribute hydrogen and designated specifically for hydrogen applications or for fuel cell applications, and any device, equipment, or machinery used predominantly for the manufacturing of, or research and development involving hydrogen or fuel cell technologies."[47]

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44 *NC Clean Energy Technology Center - Database of State Incentives for Renewables & Efficiency*, NC Clean Energy Technology Center, NC STATE UNIVERSITY, https://www.dsireusa.org/ (last visited Aug. 7, 2020).

45 *Id.*

46 *Id.*

47 *Id.*

Utah

In Utah, the Hydrogen Fuel Production Incentive gives an oil and gas severance tax credit to businesses that convert natural gas to hydrogen fuel, or produce natural gas solely for use in the production of hydrogen fuel ZEVs. Each eligible applicant may receive a tax credit equal to the amount of the severance tax owed, up to $5 million per year. Entities that produce hydrogen fuel for use in ZEVs or hydrogen-fueled trucks may also qualify for grant funding or loans from the Community Impact Fund.[48]

II. Hydrogen Production Sources

Hydrogen production and the resources used in the process implicate various regulatory, policy, and commercial issues that are important for industry participants to bear in mind. The sections that follow briefly address these issues.

A. Water

As the industry scales towards producing green hydrogen, the availability of water resources is almost certain to create constraints, particularly with regard to the siting of facilities. Understanding where and how the necessary amounts of water will be available will be critical, as will understanding the administrative regimes that govern water use and how best to work with them to use and leverage this resource.

Using water as a feedstock for hydrogen production raises unique issues depending on the water rights regime in the jurisdiction in which the hydrogen is being produced. Water use in the eastern United States is primarily managed as a riparian resource, which means that if water runs through or abuts the land on which production occurs, it may be "reasonably used" as long as the use does not harm other users. This generally less-restrictive concept does not mean that water use is uncontrolled or abundantly available; many, if not all, riparian states have some form of monitoring or reporting requirements, particularly for large consumptive needs. However, compared to the mixed riparian or pure appropriative regimes of the Midwest, mountain states, and West Coast, riparian regimes generally offer more water and more flexible water use arrangements.

In most states west of the Mississippi, riparian use is either more regulated, mixed with "prior appropriation," or eliminated entirely. Prior appropriation is a more restrictive regime, requiring water rights or permits for nearly every type of use of groundwater or surface water. These "paper" rights have specific points of withdrawal and places and purposes of use, and are subject to relinquishment for periods of non-use. They are also highly regulated in times of scarcity—those with more "senior" rights have priority over those who obtained their rights later in time; during droughts, "junior" rights holders may see their water reduced significantly, sometimes to none at all.

48 *Id.*

Obtaining water rights in prior appropriation states is not impossible, but requires familiarity with the legal water rights landscape just as much as with the hydrogeological landscape. Rights can be bought, sold, transferred, leased, and banked; but nearly all forms of ownership transfer require legal advice, hydrogeological support, and navigation of regulatory processes, sometimes with multiple layers of agencies, to accomplish.

It is also worth noting that interstate water use is governed by interstate compacts, several of which have been under legal challenge for many years. As of the time of drafting, the United States Supreme Court is set to hear arguments on four cases involving interstate water rights disputes, governed by all types of water use regimes. These cases will set precedent regarding the management of large watershed resources as they seek the balance between ever-changing economic needs. As an emerging large-scale industry, hydrogen production will likely be impacted by these decisions.

All of this must be taken into consideration even before limits and permits required by the Clean Water Act (CWA) and the Safe Drinking Water Act (SDWA) come into play.

B. Solar, Wind, and Hydropower

Hydrogen production powered by renewable energy presents a compelling opportunity for commercialization, which is not lost on many of the most savvy energy project developers. The success of the market in driving down the cost of electricity produced by clean renewable resources has created an abundance of inexpensive power in certain markets at certain times. Where "grid parity" economics was a dream and rallying call of renewable energy not so many years ago, the reality is now that wind-, solar-, and hydropower-generated electricity is frequently the cheapest and easiest way of producing electricity. Producing hydrogen with cheap clean electricity has the potential of multiplying the benefits of decarbonization across the electricity market into the vast potential hydrogen market.

Market forces are driving opportunities for investment in new technology to meet the demand of hydrogen produced via renewable resources. The significant advantage of using renewable resources in hydrogen production is that not only can the production process occur with zero greenhouse gases, but also the hydrogen fuel can be stored to address the inherent intermittency that plagues solar and wind resources.[49] Moreover, recent corporate investor-perspective modeling demonstrates that the stark decline in the cost of renewable resources portend a competitive economic shift for power-to-gas hydrogen production.[50]

[49] Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 NATURE ENERGY 216, Feb. 25, 2019; *see also Hydrogen: A Renewable Energy Perspective*, INT'L RENEWABLE ENERGY AGENCY at 25 (Sept. 2019), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf.

[50] Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 NATURE ENERGY 216, Feb. 25, 2019 ("The recent precipitous decline in the cost of renewable power now suggests that the economic fundamentals of [power-to-gas] facilities are about to change.").

1. Technologies for Hydrogen Production from Renewable Resources

Over a decade ago, the FreedomCAR & Fuel Partnership, involving the DOE and major U.S. car manufacturers, published a report that highlighted seven hydrogen production technologies in development under three broad categories: thermal processes (i.e., using heat to produce hydrogen); electrolytic processes (i.e., splitting water molecules to produce hydrogen); and photolytic processes (i.e., splitting water by using light energy).[51] Today, many of these technologies are much further developed, and some are commercially available.[52] Two types of commonly used renewables-to-hydrogen technology available are (1) water electrolysis and (2) steam reforming of biomethane or biogas, as discussed in greater detail in the **Natural Gas/RNG section below (Part II, Section II.D)**.

Other hydrogen production technologies in development include biomass gasification (as discussed in the **Biomass section below (Part II, Section II.E)**), photocatalysis, thermochemical water splitting, and supercritical water gasification of biomass.

For renewable resources such as wind, solar, and hydropower, hydrogen production via electrolysis is currently the most commercially viable option.[53] During electrolysis, electricity splits water molecules into hydrogen and oxygen within a device, called an electrolyzer.[54] Each electrolyzer includes an anode and cathode divided by an electrolyte, which splits the water molecules. There are three primary electrolyzer technologies: (1) proton exchange membrane (PEM) electrolysis, in which a semipermeable membrane conducts protons, often with the electrolyte made of a thin specialty plastic; (2) alkaline (ALK) electrolysis, in which the electrolyte is a liquid ALK solution with two electrodes; and (3) solid oxide electrolysis, in which the electrolyte is a solid oxide or ceramic wall that selectively transfers oxygen ions with negative charges at increased temperatures.[55]

The chemical industry's use of ALK electrolysis dates back to the 1920s

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51 *Hydrogen Production: Overview of Technology Options*, DEP'T OF ENERGY, https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/h2_tech_roadmap.pdf.

52 *Hydrogen Production Processes*, DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-production-processes.

53 Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen,* 4 NATURE ENERGY 216, Feb. 25, 2019 ("[E]lectrolysers are already commercially available and entail the immediate potential of creating a buffer for the growing volume of intermittent wind and solar power."); *see also* Public Utility District No. 1 of Douglas County, "Renewable Hydrogen," available at https://douglaspud.org/Pages/Renewable-Hydrogen.aspx#:~:text=Traditionally%20hydrogen%20is%20produced%20using,or%20consumption%20of%20the%20fuel (last visited Aug. 23, 2020) (discussing production of hydrogen from hydropower).

54 *Hydrogen Production: Electrolysis*, DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

55 *Id.; Hydrogen from Renewable Power: Technology Outlook for the Energy Transition*, Int'l Renewable Energy Agency at 19 (Sept. 2018), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Sep/IRENA_Hydrogen_from_renewable_power_2018.pdf.

and the more modern PEM electrolysis recently reached commercial deployment.[56] While ALK is the most mature form of electrolysis, PEM electrolysis offers a more flexible and reactive technology that can serve differing load needs of varying industries.[57] PEM technology may participate directly in an electric market,[58] but ALK technology also made recent progress by becoming more compatible with grid services.[59] In 2018, the opinion of the International Renewable Energy Agency (IRENA) was that "[a]t present . . . ALK technology remains less flexible than PEM technology . . ."[60] In the future, solid oxide electrolysis may also provide an even more efficient electrolysis technology than other types, but it is currently in development and not yet commercially viable.[61]

Renewable power for hydrogen production provides three key advantages: it is cheaper, it is cleaner, and it allows efficiencies in the power generation system that will continue to drive down the cost of hydrogen production. The rapid growth and ongoing advancement of wind and solar power generation technology continues to drive down the cost of renewable energy. Cheaper and cleaner renewable power is the prime driver in the wave of retirements of the aging coal and gas-fired plants across the country. Renewable projects paired with battery storage capabilities are the next wave of cost compression and will continue to drive higher-cost facilities that emit carbon out of the market.

A challenge for renewable energy project development economics continues to be the intermittency and unpredictability of generation. Solar panels produce energy when the sun shines, wind energy flows when the wind blows, and hydropower projects can require instream flows. Energy storage has long been the ideal solution to this challenge. Development of equipment for energy storage remains a focus of the industry, and the price for lithium ion and flow battery solutions continues to fall rapidly. However, hydrogen production is another solution to this problem. Electrolyzers can be run in times of power abundance, for example when the wind is blowing and local wind generation is plentiful, and be curtailed when the opposite is true. With time-of-day pricing for electricity, this coincides nicely with cheap power prices. Electrolyzers also can cycle on and off quite rapidly. This is useful in regulating the frequency fluctuations on the electricity grid. In many markets, the facility can earn a payment for this type of "ancillary service."

Hydrogen production presents a real opportunity to leverage clean renewable

56 *Id.*

57 *Id.* at 20.

58 *Id.* at 24.

59 *Id.* at 21.

60 *Hydrogen from Renewable Power: Technology Outlook for the Energy Transition*, Int'l Renewable Energy Agency at 19 (Sept. 2018), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2018/Sep/IRENA_Hydrogen_from_renewable_power_2018.pdf.

61 *Id.* at 23.

power generation through production of an end-product that is not electricity, thus expanding the potential application of renewable energy projects out of the electricity market and into the commodity market.

2. Forecast for Cost Competitiveness of Renewable Energy Powered Hydrogen Production

In September 2019, IRENA estimated a "global economic potential for 19 [exajoules] of hydrogen from renewable electricity in total final energy consumption by 2050[,]" and renewables-based hydrogen making-up eight-percent of the total electricity consumption.[62] As reported in April 2020, the number of electrolyzer projects tripled in the preceding five months.[63] As of March 2020, one study found that planned electrolyzer capacity had increased to 8.2 gigawatts.[64] This increase is 31 times greater than the cumulative installed capacity in April 2020.[65]

Recent trade press forecasts an advantage for investors that pair renewable energy with a power-to-gas facility to convert a variable amount of power, depending on the peak and off-peak generation, to hydrogen.[66] Such an investor would have the power to either sell the power in real-time at market or convert it into hydrogen for later use or sale.[67] The September 2019 IRENA study found that "lowest cost wind and solar projects can provide hydrogen at a cost comparable to that of hydrogen produced from fossil fuels."[68]

This cost-competitiveness was exemplified in a recent case study that modeled the economic impact of pairing a PEM electrolyzer with wind facilities in Texas.[69] As wind energy often reaches peak production at night during off-peak hours with little demand from the grid, wind power prices remain uncompetitive against current wholesale energy prices.[70] The power-to-gas electrolyzer complements this offset production by allowing for its conversion to hydrogen, which can be stored for later use. Moreover, the PEM electrolyzer "can be ramped up rapidly and attain

62 *Hydrogen: A Renewable Energy Perspective*, INT'L RENEWABLE ENERGY AGENCY at 22 (Sept. 2019), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf.

63 Jason Deign, *Green Hydrogen Pipeline Surges on a Wave of Announced Mega-Projects*, GREENTECH MEDIA (Apr. 9, 2020), https://www.greentechmedia.com/articles/read/mega-projects-help-double-green-hydrogen-pipeline-in-just-five-months

64 *Id.*

65 *Id.*

66 Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 NATURE ENERGY 216, Feb. 25, 2019.

67 *Id.*

68 *Hydrogen: A Renewable Energy Perspective*, INT'L RENEWABLE ENERGY AGENCY at 28 (Sept. 2019), https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2019/Sep/IRENA_Hydrogen_2019.pdf.

69 Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 NATURE ENERGY 216, Feb. 25, 2019.

70 *Id.*

a near-constant efficiency once a small threshold utilization has been reached."[71] Based on the modeling data for Texas, renewable hydrogen production would be cost competitive for small- and medium-scale hydrogen supply, though not yet cost competitive with current industrial fossil fuel-based hydrogen supply.[72]

The study found the data suggests a strong continued decline in the price of electrolyzers, and when paired with the likely increase in the capacity factor of wind turbines, it presents a compelling opportunity for system-wide power-to-gas hydrogen production facilities.[73] As the study concludes, "[t]he central finding is that renewable hydrogen is projected to become cost competitive with large-scale fossil hydrogen supply within the next decade."[74] In certain niche applications, the study found renewable hydrogen is already cost-competitive, but predicts that hydrogen at an industrial-scale supply will be competitive by 2030.[75]

The co-development of renewable energy generating facilities paired with hydrogen production is likely to be a significant emerging trend. Electrolyzers located proximately to cheap renewables benefit most from low (or virtually no) costs of transmission and interconnection and may reap the upside of co-development efficiencies. A developer with both electricity generating assets and an electrolyzer maximizes its commercial position by having the ability to sell into either the electricity market or the hydrogen market, or both. For example, in late July 2020, NextEra Energy Inc. announced plans to build a green hydrogen pilot facility in Florida for $65 million, which will utilize unused solar power to create hydrogen via electrolysis.[76]

3. Environmental Regulation

The environmental regulation of these technologies is likely to be similar to the regulation of the facilities that are used to generate electricity. With respect to solar:

- Thermochemical production of hydrogen will involve the construction and use of utility-scale infrastructure to concentrate sunlight onto a reactor tower using a field of mirrors "heliostats." Where project proponents require federal permits, or seek to use federal land, the entire project would be subject to review under the National

71 *Id.*

72 *Id.*

73 *Id.* ("Our projects for the system prices of electrolysers are based on hand-collected data from manufacturers, operators of [power-to-gas] plants, articles in peer-reviewed journals and technical reports.").

74 Stefan J. Reichelstein & Gunther Glenk, *Economics of Converting Renewable Power to Hydrogen*, 4 Nature Energy 216, Feb. 25, 2019.

75 *Id.*; *see also Hydrogen to become a source of cleaner power on a massive scale*, GLOBALDATA ENERGY (June 23, 2020) (describing a study that estimates the cost of hydrogen fuel prices "could drop to $10 to $8/kg during the 2020-2025 period").

76 Karl-Erik Stromsta, *NextEra Energy to Build Its First Green Hydrogen Plant in Florida*, GREENTECH MEDIA (July 24, 2020), https://www.greentechmedia.com/articles/read/nextera-energy-to-build-its-first-green-hydrogen-plant-in-florida

Environmental Policy Act (NEPA).[77] NEPA review would entail creating a detailed analysis of the anticipated environmental impacts of the project, including impacts to land, water, and wildlife. Potential impact to wildlife under the Endangered Species Act (ESA) must also be considered and accounted for, and other environmental statutes also may be applicable depending on the project and location.

- Photolytic production of hydrogen likely will require the same level of environmental review as solar thermochemical hydrogen production. On a large scale, photolytic production of hydrogen would require the construction and use of utility-scale infrastructure with the potential for environmental impacts on the surrounding land, water resources, and wildlife. The projects would also potentially be subject to environmental review imposed by NEPA and the ESA, which includes a detailed assessment of the potential for environmental impact and the corresponding need to develop mitigation strategies.
- Additionally, the two processes described above create water as a byproduct. On a commercial scale, the disposal of this byproduct water may implicate issues under the CWA if the water will be discharged locally. Any federally permitted project that will discharge into navigable waters must obtain certification from the state in which the project is situated ensuring that it complies with state environmental laws.[78]

Effective integration of commercial hydrogen production with renewable wind energy or hydropower would likely require the construction and use of utility-grade electrolyzers adjacent or directly connected to wind farms or hydropower facilities. If subject to federal permit requirements, the construction and use of electrolyzers would require environmental review under NEPA, including an assessment of the environmental impacts involved in construction and operation of the electrolyzers.

As noted, these environmental regulatory processes usually involve opportunities for interested stakeholders to comment, and, if opposed to the project, file a protest. Developers must be thoughtful and engaged in planning to site a hydrogen facility.

C. Nuclear

Advocates of the hydrogen economy have suggested for decades that nuclear power can play an important role. Proponents of nuclear energy have recently joined in, noting that producing hydrogen may throw a lifeline to today's commercial fleet of nuclear reactors, struggling to remain competitive.

Nuclear power plants can produce hydrogen by generating both steam and electricity. The high-quality steam produced by nuclear reactors can be electrolyzed and split into pure hydrogen and oxygen. Nuclear paired with

[77] *See 40* C.F.R. § 1501.1.

[78] 33 U.S.C. § 1341(a)(1).

electrolyzers located adjacent to reactors can offer flexibility to the market.

DOE estimates that a conventional 1,000 MW nuclear reactor can produce more than 200,000 tons of hydrogen annually. Ten nuclear power plants could produce about two million tons every year, or 20 percent of the current hydrogen used in the United States.[79] This would allow utilities to produce and sell hydrogen as a commodity in addition to providing reliable baseload electricity for the grid. The new revenue source may be just what is needed for reactors to justify continued operation in the marketplace, which has seen nuclear lose its competitive edge given low-priced natural gas and the increasing growth of renewables like wind and solar.

The potential of using nuclear energy assets for hydrogen production has attracted interest from the private sector and DOE. The DOE is supporting at least four utilities in the development of pilot projects to demonstrate low-temperature electrolysis (LTE) and high-temperature steam electrolysis (HTSE) technologies using nuclear reactors to produce hydrogen. For instance, a consortium of three utilities, Energy Harbor, Xcel Energy, and Arizona Public Service, is starting a two-year pilot project to demonstrate hydrogen production using a two MW LTE technology at Energy Harbor's Davis-Besse nuclear power station in Ohio. The same consortium has also developed a proposal for a HTSE demonstration at one of Xcel Energy's nuclear units in Minnesota. Moreover, Exelon, which has the nation's largest nuclear fleet, is scheduled to commence later in 2020, a three-year $7.2 million pilot project to demonstrate hybrid nuclear-hydrogen systems, with a 50 percent DOE cost share. Despite the utilities' interest, there is uncertainty whether nuclear hydrogen production systems, especially HTSE technology, can scale to be commercially viable.[80] The scaling issue is critical since generating hydrogen using electrolyzers at existing nuclear power plants is not yet cost-competitive.[81]

Assuming it can scale to be cost-competitive, nuclear power offers a major advantage over the current predominant methods of producing hydrogen: it is 100 percent carbon free. The steam produced and the electricity generated that can be used for electrolysis do not result in carbon dioxide. Most of the hydrogen produced in the United States results from transforming the methane in natural gas, a process that releases carbon dioxide. The nuclear process of generating steam and electricity for the electrolysis process does not result in carbon dioxide emissions. Use of nuclear for hydrogen production could reduce carbon dioxide emissions for certain sectors of the economy, like heavy industry, manufacturing, and

79 Department of Energy, Office of Nuclear Energy, *Could Hydrogen Help Save Nuclear?*, https://www.energy.gov/ne/articles/could-hydrogen-help-save-nuclear (last visited June 22, 2020).

80 Sonal Patel, *Hydrogen May Be a Lifeline for Nuclear – But it Won't Be Easy*, POWER, June 11, 2020, https://powermag.com/hydrogen-may-be-a-lifeline-for-nuclear-but-it-wont-be-easy/.

81 US Nuclear Fleet Must Adapt by Operating Flexibly, Making Hydrogen: Officials, S&P GLOBAL PLATTS, Aug. 11, 2020.

aviation, which are among the most challenging to decarbonize.

Nuclear power obviously has other concerns regarding public perceptions of its risk, potential catastrophic accidents, and nuclear waste in the form of spent nuclear fuel, which is being stored awaiting the elusive answer on permanent disposal. These concerns can be somewhat addressed by a new generation of advanced nuclear reactors being developed. The new reactors are intended to use passive safety systems to reduce the risk of runaway accident scenarios. Many of the advanced reactors also would produce less spent nuclear fuel and other radioactive waste.

The next generation of advanced reactors offers further advantages to producing hydrogen. They will likely operate at higher temperatures and would therefore more efficiently generate steam for hydrogen production.[82] The advanced reactors also likely would be smaller than conventional reactors, and could be built as modules. These Small Modular Reactors or Microreactors could be built more quickly than today's reactors and placed strategically where there is a demand for hydrogen to minimize transport and distribution.

The environmental regulation of hydrogen electrolysis using nuclear energy will be closely related to the environmental regulation of nuclear power plants as a whole. Integration of commercial hydrogen production with existing nuclear power plants likely would require the construction and use of utility-grade electrolyzers adjacent or directly connected to the power plants. If subject to federal permit requirements, the construction and use of electrolyzers would require environmental review under NEPA, including an assessment of the environmental impacts involved in construction and operation of the electrolyzers. The Nuclear Regulatory Commission (NRC) may also have a role given that all commercial reactors are licensed by NRC and the large-scale, at-reactor production of hydrogen, given its explosive nature, may raise potential safety risks.

D. Natural Gas/RNG

Natural gas contains methane (CH4) and can be used to produce hydrogen via steam-methane reforming (SMR).[83] In the United States, the abundance of technically recoverable natural gas, as well as the growing biogas and renewable natural gas (RNG) markets, highly interconnected natural gas pipeline system, and developed natural gas commercial market make natural gas an attractive feedstock to produce hydrogen. However, with the presidential elections in November 2020, there is the potential for a change in administration and, with it, changes to the regulation of fossil fuels.

82 Department of Energy, Office of Nuclear Energy, 3 Ways Nuclear is More Flexible Than You Might Think, June 23, 2020, http://www.energy.gov/ne/articles/3-ways-nuclear-more-flexible-you-might-think.

83 While there are other pathways for producing hydrogen from natural gas, we have focused on SMR, as it appears to currently be the preferred method. Other pathways, including autothermal reforming, may gain increased popularity in the future.

1. Steam-Methane Reforming (SMR)

In SMR, the methane in natural gas reacts with steam under high pressure in the presence of a catalyst to produce hydrogen, carbon monoxide, and small amounts of carbon dioxide. The carbon monoxide and steam are then reacted using a catalyst to produce carbon dioxide and more hydrogen, in a process called the "water-gas shift reaction." Finally, carbon dioxide and other impurities are removed from the gas stream, leaving essentially pure hydrogen, in a process called "pressure-swing absorption." SMR is the most common method of producing hydrogen and can be used to produce blue or grey hydrogen from natural gas, depending on whether carbon capture and sequestration (CCS) technologies are employed. SMR can be used to separate hydrogen from methane at different points in the overall value chain. For example, SMR can be utilized closer to the point of natural gas production, which may require longer-haul transportation of hydrogen to the point of consumption. Alternatively, SMR can be used closer to the point of hydrogen consumption, which may require longer-haul transportation of natural gas to the SMR project and shorter distance transportation of hydrogen to the point of consumption.

2. Environmental Considerations for SMR

Producing hydrogen from either natural gas or biogas/RNG will be subject to similar environmental regulations, primarily to address the significant amount of carbon dioxide resulting from this process. For example, hydrogen production facilities are required to monitor their emissions and submit annual greenhouse gas reports to the Environmental Protection Agency (EPA).[84] The EPA does not presently require that stationary sources that produce only greenhouse gases obtain an operating permit under Title V of the Clean Air Act (CAA).[85] However, sources that already are subject to permitting under the CAA due to emission of conventional pollutions may be required to take measures to control greenhouse gas emissions. Additionally, individual states may impose more stringent controls on the release of greenhouse gases and place limitations on SMR operations to meet statewide goals to reduce greenhouse gas emissions.

Because of the carbon dioxide produced by SMR, successfully pairing SMR-produced hydrogen with CCS will be critical to securing a long-term role for this method of hydrogen production in decarbonizing industry sectors.

84 *See 40* C.F.R. §§ 98.2, 98.6, 98.160(c).

85 *See* EPA, Next Steps and Preliminary Views on Application of Clean Air Act Permitting Programs to Greenhouse Cases Following the Supreme Court's Decision in *Utility Air Regulatory Group v. Environmental Protection Agency 2* (July 24, 2014), https://www.epa.gov/sites/production/files/2015-12/documents/20140724memo.pdf. *See also Util. Air Regulatory Grp. v. E.P.A.*, 573 U.S. 302, 134 S. Ct. 2427, 189 L. Ed. 2d 372 (2014).

The EPA has established regulations under the SDWA governing the underground injection of carbon dioxide for the purposes of geologic sequestration.[86] The regulations impose requirements for the permitting, siting, construction, operation, financial responsibility, testing and monitoring, post-injection site care, and site closure of carbon capture and storage injection wells.[87] It seems inevitable in light of increasing environmental concerns that large-scale production of hydrogen from natural gas would inevitably involve construction of CCS facilities, including underground injection wells. These wells would have to be built and operated according to EPA regulations.

Biogas, or RNG, can be reformed to produce hydrogen in a process similar to natural gas reforming. This process ultimately produces both hydrogen and large amounts of carbon dioxide, likely would be subject to greenhouse gas reporting requirements, and CCS likely will need to be employed to offset the carbon dioxide impact of biogas reforming, subjecting projects to EPA permitting requirements for underground CCS wells. However, biogas is derived from plants that consume carbon dioxide from the atmosphere, which acts as an offset to the carbon dioxide produced during the gasification process. Coupled with CCS technology, biogas reformation has the potential to produce little to no carbon footprint.

3. Natural Gas and RNG Supply

a. Natural Gas

The United States has seen a significant expansion in natural gas proved reserves and marketed production in recent years from onshore and offshore resources.[88] Much of this increase in estimated natural gas proved reserves, unproved reserves, and marketed production can be attributed to increased horizontal drilling and hydraulic fracturing techniques in shale and other tight geologic formations. U.S. shale formations, or plays, are found in about 30 states, with Texas, Pennsylvania, Oklahoma, Louisiana, and Ohio taking the lead. The largest dry shale gas production areas in the United States by formation include the Marcellus Shale, the Permian Basin, the Utica Shale, the Haynesville Shale, the

86 *See 40* C.F.R. pts. 124, 144, 145 et seq.

87 *Id.*; *see also* Federal Requirements Under the Underground Injection Control (UIC) Program for Carbon Dioxide (CO2) Geologic Sequestration Wells, 75 Fed. Reg. 77,230, 77,246 (Dec. 10, 2010).

88 In 2018, estimated U.S. natural gas proved reserve capacity increased 9 percent year-over-year and increased just over 106 percent over the last decade according to the U.S. Energy Information Administration (EIA). U.S. ENERGY INFO. ADMIN., *Open Data, Natural Gas Reserves*, *United States, Annual*, https://www.eia.gov/opendata/qb.php?sdid=INTL.3-6-USA-TCF.A (last visited July 19, 2020). Of the total U.S. natural gas proved reserves, the EIA reported that in 2019 dry gas (primarily methane) comprised 474.821 trillion cubic feet (Tcf), an increase of about 8.3 percent year-over-year from 438.46 Tcf in 2018. Id. The EIA estimates that, as of 2019, the United States has about 2,137 Tcf of unproved dry natural gas resources. U.S. ENERGY INFO. ADMIN., *Natural Gas Explained: Where Our Natural Gas Comes From*, https://www.eia.gov/energyexplained/natural-gas/where-our-natural-gas-comes-from.php (last updated Nov. 13, 2019).

Eagle Ford Shale, the Barnett Shale, and the Woodford Shale.[89]

Technological advancements in natural gas identification, accessibility, and recovery and extraction methods have fueled increasing energy independence in the United States. Total natural gas imports have been declining steadily since 2007.[90] At the same time, natural gas exports have been increasing since 2000.[91] With the very recent emergence of the United States as a significant LNG exporter, the result is that the United States is now a net exporter of natural gas.

Onshore production of conventional natural gas generally is regulated by the states in which the activity occurs or will take place. Each state has its own regulatory regimes related to well spacing, production quotas, safety regulations, and other health-related considerations.[92] Offshore natural gas production, production on federal onshore lands, and production on Native American lands are regulated by the U.S. federal government through the U.S. Department of the Interior (DOI). Within the DOI, the Bureau of Land Management regulates and manages the production of natural gas on onshore federal lands; the Bureau of Ocean Energy Management manages federal outer continental shelf leasing programs and conducts resource assessments; and the Bureau of Indian Affairs regulates and manages the production of natural gas on Native American territories, in addition to local tribal laws.

b. The Politics of Natural Gas

The political environment and policy goals in the United States have the potential to drive natural gas production and demand in the future. Natural gas often has been considered a bridge fossil fuel for a clean energy future due to its lower greenhouse gas emissions and may provide the link between

89 *Id.*

90 U.S. ENERGY INFO. ADMIN., *Natural Gas Explained: Natural Gas Imports and Exports*, https://www.eia.gov/energyexplained/natural-gas/imports-and-exports.php (last updated July 21, 2020).

91 *Id.*

92 While the doctrine of supremacy does not allow local governments (i.e., cities and counties) to regulate the natural gas industry, zoning and district ordinances may limit natural gas production within certain areas of a municipality or near residences.

the two policy positions. With the abundance of U.S. natural gas, maintaining energy independence is likely achievable during this transition process. The use of natural gas to produce hydrogen (particularly blue hydrogen) could provide an opportunity for bipartisan support and advancement of legislation and regulations that encourage blue hydrogen production.

Public sentiment on hydraulic fracturing has altered the drilling landscape in the United States. To date, New York, Maryland, and Vermont have banned hydraulic fracturing, often citing health risks as the predominant factor. State regulations and public sentiment on this recovery method likely will continue to be a factor in natural gas production in the future.

Upcoming U.S. elections have the potential to significantly change the trajectory for fossil fuels. On one end of the spectrum, the Green New Deal[93] and measures announced in Democratic presidential nominee Joe Biden's climate change task force report[94] have the potential to greatly reduce the production of natural gas in the United States, with a stated goal for the United States to be emissions-free by 2030. On the other end of the spectrum, President Trump has executed on a number of agenda items beneficial to natural gas development in the United States, including directing DOI to expand offshore oil and gas drilling, opening more leases to develop onshore and offshore resources, eliminating methane emissions limitations for drilling on federal lands, and promoting infrastructure to increase exports to foreign markets.

c. Biogas and Renewable Natural Gas

Biogas is produced from biomass from a variety of sources[95] and can be used to produce RNG by removing constituent elements including water, carbon dioxide, hydrogen sulfide, and other trace elements, leaving only pure methane. RNG is comparable to natural gas produced by conventional methods and can be transported through pipelines, trucks, or other methods in the same way as conventional natural gas.

By 2018 estimates, there are more than 2,200 sites across the United States in all 50 states producing

93 Recognizing the Duty of the Federal Government to Create a Green New Deal, H.R. Res. 109, 116th Cong. § 4 (2019), https://www.congress.gov/116/bills/hres109/BILLS-116hres109ih.pdf.

94 *Biden-Sanders Unity Task-Force Recommendations: Combating the Climate Crisis and Pursuing Environmental Justice*, July 8, 2020, https://joebiden.com/wp-content/uploads/2020/08/UNITY-TASK-FORCE-RECOMMENDATIONS.pdf (last visited Aug. 7, 2020).

95 Sources of biogas include landfills, animal waste, wastewater, and industrial, institutional, and commercial organic waste. *Energy Analysis: Biogas Potential in the United States*, U.S. DEP'T OF ENERGY, Office of Energy Efficiency and Renewable Energy, National Renewable Energy Laboratory (October 2013), https://www.nrel.gov/docs/fy14osti/60178.pdf.

biogas.[96] This includes 250 anaerobic digesters on farms, 1,269 water resources recovery facilities using an anaerobic digester, 66 stand-alone systems that digest food waste, and 652 landfill gas projects.[97] By far, the largest contributor to the biogas volume comes from landfills. The states with the largest biogas production are California, Texas, Wisconsin, Pennsylvania, and North Carolina,[98] and many states have programs to incentivize biogas and RNG production.[99] It is estimated that there are over 14,958 new sites ripe for development, which could reduce emissions equivalent to removing 117 million passenger vehicles from the road while creating over 25,000 new permanent jobs.[100]

Regulations under the CAA require municipal solid waste landfills to install and operate gas collection and control systems. While some landfills capture and burn the landfill gas through flaring, others capture it, remove the carbon dioxide and other constituents, and sell the resulting methane to third-party purchasers. The federal government provides a number of incentive programs for biogas production, including an Alternative Fuel Excise Tax Credit for the use of biogas as a transportation fuel and the Federal Renewable Energy Production Tax Credit for electricity generated by qualified energy resources including biogas.

4. Transportation of Natural Gas

Two primary methods of transporting natural gas in the United States are by pipeline, in a gaseous state, and by truck, either as compressed natural gas (CNG) or liquefied natural gas (LNG). While there has been interest in LNG by rail, the use of cryogenic railcars is still nascent in the United States.[101]

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96 *Biogas Market Snapshot*, AM. BIOGAS COUNCIL, https://americanbiogascouncil.org/biogas-market-snapshot/ (last updated Apr. 26, 2018).

97 *Id.*

98 *Id.*

99 For example, in 2012 California passed legislation requiring the California Public Utilities Commission to develop standards for certain constituents found in biogas to protect human health and ensure pipeline safety. H.B. 1900, 2011-2012 Gen. Assemb., Reg. Sess. (Ca. 2012) (enacted). From 2012 through 2019, the Oregon Department of Energy promulgated a system of incentives established by the Oregon legislature known as Renewable Energy Development Grants to promote and foster renewable energy development to reduce greenhouse gas emissions. H.B. 3672, 76th Leg. Assemb., Reg. Sess. (Or. 2011) (enacted). More specifically, this grant system awarded over $9 million for 92 renewable energy projects statewide, including biogas facilities. In May 2018, the North Carolina Energy Policy Council draft report included specific recommendations for bioenergy research. Currently, Duke University, through a R&D grant, has budgeted $250,000 each year for two years to research biogas inventory and quantify the amount of technically recoverable biogas. The South Carolina Energy Office provides funding through a loan program to incentivize renewable project development, including biogas and biomass. South Carolina also provides tax credits and incentives for the purchase and installation of equipment used to create heat, power, steam, electricity, or other forms of energy for commercial use consisting of no less than 90 percent biomass resources. S.C. ENERGY OFFICE, South Carolina Tax Incentives, http://www.energy.sc.gov/lpage?m=701 (last visited July 19, 2020).

100 *Id.*

101 Pipeline and Hazardous Materials Safety Administration issued a final rule on July 24, 2020, authorizing the bulk transportation of LNG by rail in specialized railcars. Hazardous Materials: Liquefied Natural Gas by Rail, 85 Fed. Reg. 44,994 (July 24, 2020) (to be codified at 49 C.F.R. pts. 172–74, 179, and 180).

a. Natural Gas Pipelines[102]

In addition to a significant domestic supply of natural gas, the United States also has a highly developed and heavily interconnected natural gas pipeline system. It is currently estimated that there are over 300,000 miles of natural gas transmission pipelines[103] and over 1.2 million miles of natural gas distribution pipeline systems[104] in the United States. These pipeline systems provide the opportunity for efficient natural gas transportation from the wellhead to an SMR project site. However, these pipelines and the capacity that they offer also are subject to significant regulation.

In addition to understanding natural gas quality specifications, which are discussed in the **Pipeline section of Part III (Section I.C.2.b)**, it is critical that entities looking to ship natural gas via pipeline understand the applicable regulatory regimes to assess potential economic impacts to the commerciality of a particular hydrogen production development project.

Under the Natural Gas Act (NGA), the Federal Energy Regulatory Commission (FERC) regulates the siting, construction, and operation of interstate natural gas pipelines and storage, the rates and terms and conditions of service offered, and sales for resale of natural gas in interstate commerce. FERC's regulation does not include gathering pipelines or local distribution pipelines. These pipelines are instead regulated by state agencies.

Importantly, interstate natural gas pipeline and storage capacity holders must abide by FERC's regulations and policies. Interstate natural gas pipelines must offer capacity on an open access basis, meaning that capacity must be made publicly available and pipelines cannot discriminate between or among similarly situated shippers. As part of its jurisdiction over interstate natural gas pipelines, FERC regulates capacity holders, imposing restrictions on how shippers can use and resell their capacity. Overall, these restrictions are aimed at promoting a transparent, non-discriminatory, efficient capacity market. Notably, FERC has civil penalty authority of up to $1 million per day per violation, as well as criminal penalty authority; thus, any entity that seeks to develop natural gas-based hydrogen production facilities needs to be very familiar with laws and regulations governing access to and transportation of natural gas in the United States and seek guidance from legal experts prior to finalizing any transaction.

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[102] A discussion of transportation of hydrogen by pipeline is in Part III, Transportation and Distribution — Pipeline (Section I.C).

[103] *Annual Report Mileage for Natural Gas Transmission & Gathering Systems*, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN. (July 1, 2020) https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems.

[104] *Id.*

b. Natural Gas Trucking

Another significant method for transportation of natural gas in the United States is by truck. FERC has found that its NGA jurisdiction does not include the interstate transportation of natural gas by truck.[105] CNG and LNG trucking are regulated by the Federal Motor Carrier Safety Administration (FMCSA), which requires, among other things, that CNG and LNG motor carriers obtain a Hazardous Materials Safety Permit to transport in bulk.[106] While transporting natural gas by truck can be efficient, particularly when pipeline transportation to an end-user is not feasible, there are constraints to bear in mind. For example, FMCSA prescribes vehicle weight limits that can constrain the quantity of natural gas that can be transported by truck. In addition, transporting natural gas as LNG by truck presents the potential for product loss as a result of boil-off.

5. CCS

Concerns regarding climate change are driving a resurgence of interest in hydrogen derived from natural gas paired with CCS. According to the CCS Association, "The CCS chain consists of three parts; capturing the carbon

[105] *See, e.g., Southern LNG Inc.*, 131 FERC ¶ 61,155 at p. 17 (2010) (FERC declined to assert NGA jurisdiction over LNG trucking, finding that "[its] NGA section 3 jurisdiction over LNG import facilities and services would not follow the LNG tanker trucks after they exit the boundary of the terminal . . . .").

[106] 49 C.F.R. § 385.403.

dioxide, transporting the carbon dioxide, and securely storing the carbon dioxide emissions, underground in depleted oil and gas fields or deep saline aquifer formations."[107] Capturing the carbon dioxide from an energy or industrial source can be done one of three ways: pre-combustion; post-combustion; and oxy-fuel combustion.

- Pre-combustion carbon capture occurs, as the name suggests, before combustion of the feedstock is complete. Pre-combustion occurs through the production of a syngas from the original feedstock using gasification. The syngas then undergoes the water-gas shift reaction described above, resulting in a mixture of hydrogen and carbon dioxide, with levels of carbon dioxide ranging from 15 percent to 50 percent. According to DOE, commercially available pre-combustion carbon capture technologies are expensive at approximately $60/ton. DOE is researching technologies that can improve the affordability of pre-combustion capture, targeting $39/ton.
- Post-combustion carbon capture is the capture of carbon dioxide from the flue after the feedstock has been combusted. The main challenge with post-combustion capture is separating the carbon dioxide from large amounts of nitrogen found in flue gas. DOE is working to advance a solution by focusing R&D on advanced solvents, solid sorbents, and membrane systems.
- Finally, Oxy-fuel combustion combusts the feedstock in oxygen diluted with recycled flue-gas, rather than air. This process results in flue-gasses that mainly consist of carbon dioxide and water. The carbon dioxide is more concentrated and easier to purify than alternative carbon capture processes.

Following capture, the carbon dioxide is compressed into a liquid and transported by pipeline or ship to be stored in geological rock formations typically located several kilometers below the earth's surface.

DOE's Office of Fossil Energy (FE) is the main federal entity supporting R&D to improve carbon capture and sequestration. Recently, FE announced selected proposals for the first solicitation of the Coal FIRST (Flexible, Innovative, Resilient, Small, and Transformative) initiative. Coal FIRST is aimed at R&D to develop the zero-emission coal facility of the future through cost-shared projects. Coal FIRST power plants will use CCS to generate carbon neutral energy or hydrogen.

In addition to R&D, the federal government supports CCS through the 45Q tax credit, which was expanded and reformed in the 2018 Balanced Budget Act. The 45Q tax credit can be claimed by the owner of the carbon capture equipment, but it may also be transferred by the owner to another entity that would store or beneficially utilize the carbon. To receive the credit, a threshold amount of carbon dioxide must be captured and sequestered or utilized. The Balanced

107 THE CARBON CAPTURE AND SEQUESTRATION ASS'N, http://www.ccsassociation.org/ (last visited Aug. 21, 2020).

Budget Act increased the value of the 45Q credits to $35/ton for enhanced oil recovery and beneficial use and $50/ton for carbon sequestration. 45Q is intended to incentivize carbon capture deployment across a variety of industries including electric power production, steel and cement manufacturing, ethanol and fertilizer production, and natural gas production.

A number of fossil fuel and industrial companies, governments in Europe, Japan, and Australia, and the state of California are in the early stages of exploring blue hydrogen technologies that capture and store carbon emitted from the hydrogen production process. In theory, the low-carbon hydrogen would then be used for indoor heating, as a transportation fuel, for industrial processes, or potentially even to provide electricity to balance out intermittent renewable generation.

E. Biomass

Like wind, solar, and biogas/RNG, biomass can be a renewable source of or feedstock for hydrogen generation. Biomass is organic material often collected from municipal organic solid waste and can also include agriculture crop residue, forest residues, and energy crops.[108] There are several methods for converting biomass into hydrogen, which can be described as either biological or thermochemical.[109] The biological methods include anaerobic digestion, fermentation, and metabolic processing, while the thermochemical methods include gasification, high pressure aqueous, and pyrolysis.[110]

The most common method of producing hydrogen from biomass is gasification. The conversion of organic material or fossil carbon from biomass occurs at a high temperature (>700 degrees Celsius) without combustion and in conjunction with a specific amount of oxygen or steam, which breaks down the material into hydrogen, carbon dioxide, and carbon monoxide. The reformed gas undergoes a water gas shift reaction, converting it into hydrogen, and often is paired with a pressure swing adsorption for purification.[111]

Historically, the hurdle of making biomass-to-hydrogen technology cost-competitive with natural gas steam reforming was considered high.[112] Today, however, the pilot projects are proving out new technologies,[113] and the cost

108 *Hydrogen Production: Biomass Gasification*, DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification (last visited Aug. 4, 2020); Havva Balat and Elif Kirtay, Hydrogen from biomass – Present scenario and future prospects, 35 Int'l J. of Hydrogen Energy 7416, 7418 (2010).

109 Havva Balat and Elif Kirtay, *Hydrogen from biomass – Present scenario and future prospects*, 35 INT'L J. OF HYDROGEN ENERGY 7416, 7418–19 (2010).

110 *Id.*

111 *Id.*

112 *Id.* at 7421.

113 *See* Mark Luth, Hydrogen Production from Biomass and Organic Waste, Fuel Cell & Hydrogen Energy Assoc. (July 8, 2019) http://www.fchea.org/in-transition/2019/7/8/hydrogen-production-from-biomass-and-organic-waste (describing pilot projects currently exploring electricity generation from biomass).

of equipment and feedstocks continues to decline.[114] Research indicates that there is potential for both methods for converting biomass to hydrogen to be cost-competitive with other forms of hydrogen production.[115]

As with steam methane reforming of natural gas, gasification of biomass produces carbon dioxide as a byproduct. The regulatory constraints on biomass gasification are likely to mirror those on natural gas SMR. Any gasification process will have to account for and accommodate greenhouse gas reporting requirements and potentially will require constructing and operating CCS facilities in accordance with EPA regulations.

F. Coal

Hydrogen also may be produced from coal by a process called "gasification," but the use of coal to produce hydrogen faces many hurdles both in process as well as in perception. Globally, China and Australia use coal to produce hydrogen more than any other nation, since both have abundant coal reserves, but the use of coal is still relatively small when compared to other hydrogen production methods such as natural gas and renewables discussed previously. Coal gasification creates a significant amount of carbon dioxide—approximately four times as much as natural gas. As a result, hydrogen producers are left with an emissions problem without effective—and likely expensive—carbon capture technologies. Moreover, in the United States, there has been a substantial decline in coal production in recent years and an even more precipitous decline in demand with the country's aging fleet of coal-fired power plants and the corresponding decommissioning of many of those plants. In short, the future of coal is uncertain at best, and public opinion and a focus on climate change further compound this uncertainty and likely will limit any robust use of coal for hydrogen production.

1. Coal Gasification

Coal is used to create hydrogen through coal gasification. Hydrogen is produced by first reacting coal with oxygen and steam under high pressures and temperatures to form synthetic gas, consisting primarily of carbon monoxide and hydrogen. The carbon monoxide is then reacted with steam (again) through the water-gas shift reaction to produce additional hydrogen and carbon dioxide. This results in a highly concentrated carbon dioxide stream. DOE's Office of Energy Efficiency and Renewable Energy anticipates that hydrogen production through coal gasification could be deployed in the mid-term time frame.[116] However, the DOE notes that carbon capture and other technologies will need

[114] *Hydrogen Production: Biomass Gasification*, DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-production-biomass-gasification (last visited Aug. 4, 2020).

[115] Bamidele Victor Ayodele, et al., *A Mini-Review on Hydrogen-Rich Syngas Production by Thermo-Catalytic and Bioconversion of Biomas and Its Environmental Implications*, FRONT. ENERGY RES. (Oct. 25, 2019) https://doi.org/10.3389/fenrg.2019.00118/full.

[116] *Hydrogen Production: Coal Gasification*, U.S. DEP'T OF ENERGY https://www.energy.gov/eere/fuelcells/hydrogen-production-coal-gasification (last visited July 27, 2020).

more R&D to produce hydrogen at target costs and with near-zero emissions, noting that there are still several challenges to overcome.

Regulation of coal gasification will be similar to that of traditional coal-fired power production. The gasification process, like traditional coal burning, produces carbon dioxide, as well as coal ash and slag. The emission of carbon dioxide is regulated under the CAA, and provides specific reporting requirements for greenhouse gas emissions from hydrogen production sources. Similarly, the byproducts of the gasification process, such as coal ash, are regulated in the same way as those produced at traditional power plants, including disposal requirements under the Resource Conservation and Recovery Act (RCRA), and discharge requirements of the CWA. State-level regulation of energy production from coal also would likely apply to gasification production.

2. Hydrogen Production through Coal Gasification: Emissions

Using coal gasification to produce hydrogen produces around four times the amount of carbon dioxide compared to natural gas, requiring higher carbon sequestration volumes. Therefore, the tradeoff is between the cheap cost of coal and the costs of carbon dioxide sequestration and residual emissions.[117] However, with public opinion changing as climate change becomes a top priority—and without large-scale, widely available, effective carbon capture technologies to handle these large amounts of carbon dioxide—coal gasification faces many hurdles.

3. U.S. Coal Reserves and Production

The United States has the most proved coal reserves in the world with 22 percent of the world share in 2017.[118] The country with the next largest share of proved coal reserves is Russia

117 *Path to Hydrogen Competitiveness, A Cost Perspective,* HYDROGEN COUNCIL at 25, Jan. 20, 2020, https://hydrogen-council.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf (last visited July 27, 2020).

118 *Coal Explained: How Much Coal is Left,* U.S. ENERGY INFO. ADMIN., https://www.eia.gov/energyexplained/coal/how-much-coal-is-left.php (last updated Nov. 12, 2019).

at 15 percent.[119] The United States' demonstrated reserve base coal reserves was 474 billion short tons; however, the United States has seen a precipitous decline in production as a result of cheap natural gas and decreasing cost of commercial-scale renewables.[120]

U.S. coal production decreased 2.4 percent year-over-year to 756.2 million short tons (MMst) in 2018 when compared to 2017.[121] U.S. coal production further decreased 7.2 percent year-over-year to 705.3 MMst in 2019 when compared to 2018.[122] U.S. coal production was 9.8 percent lower in the first quarter of 2020 than the previous quarter (4Q of 2019) and 17 percent lower than the first quarter of 2019.[123] U.S. coal production estimates for the second quarter of 2020 were 113 MMst, down 37 percent from the same period a year ago.[124]

4. Economic Outlook for Coal

The average U.S. coal-fired power plant is over 40 years old,[125] and there are no commercial coal plants under construction in the United States as of July 2020.[126] Some scenarios have coal generation remaining flat over the next few decades, but as clean energy initiatives begin to take hold and market conditions continue to respond to changing public opinion, further declines should be expected.[127] Approximately 546 coal-fired power units have announced their retirement in just the past decade alone.[128] It is further estimated that over 85 percent of existing coal plants will be uneconomic compared to local renewables by 2025.[129]

5. The Politics of Coal

As with natural gas, the U.S. elections in November 2020 have the potential to shape the coal industry for years to come. In 2016, President Trump campaigned on ending the Obama administration's "war on coal," and since taking office has rescinded

119 *Id.*

120 *Id.*

121 *2018 Annual Coal Report,* U.S. ENERGY INFO. ADMIN. (Oct. 3, 2019), https://www.eia.gov/coal/annual/.

122 *Table 1. U.S. Coal Production, 2014–2020*, U.S. ENERGY INFO. ADMIN. (Mar. 2020), https://www.eia.gov/coal/production/quarterly/pdf/t1p01p1.pdf.

123 *Quarterly Coal Report January–March 2020,* U.S. ENERGY INFO. ADMIN. (July 1, 2020), https://www.eia.gov/coal/production/quarterly/.

124 *Short-Term Energy Outlook July 2020: Coal,* U.S. ENERGY INFO. ADMIN. at 16 (July 2020), https://www.eia.gov/outlooks/steo/archives/Jul20.pdf.

125 *Today in Energy: Most Coal Plants in the United States were Built Before 1990,* U.S. ENERGY INFO. ADMIN. (Apr. 17, 2017), https://www.eia.gov/todayinenergy/detail.php?id=30812.

126 *Global Coal Plant Tracker*, GLOBAL ENERGY MONITOR, https://endcoal.org/tracker/ (last visited July 27, 2020).

127 *Today in Energy: EIA Projects Generation from Coal and Nuclear Power Plants will Plateau after 2025,* U.S. ENERGY INFO. ADMIN. (Feb. 7, 2020), https://www.eia.gov/todayinenergy/detail.php?id=42755.

128 *Today in Energy: More U.S. Coal-Fired Power Plants are Decommissioning as Retirements Continue*, U.S. ENERGY INFO. ADMIN. (July 26, 2019), https://www.eia.gov/todayinenergy/detail.php?id=40212.

129 Joshua Rhodes, *Is the U.S. Coal Industry Completely Burned Out?*, FORBES (Feb. 12, 2020), 11:25 AM, https://www.forbes.com/sites/joshuarhodes/2020/02/12/is-the-us-coal-industry-almost-completely-burned-out/#29a5a65e594f.

former President Barack Obama's Clean Power Plan and taken steps to try to limit the transition away from coal. Nonetheless, despite the Trump Administration's deregulation agenda, including rescinding methane emissions reductions and relaxing fuel standards, these policies have done little to stem the market transition away from coal.

In contrast, former U.S. vice president and Democratic presidential nominee Joe Biden has issued an energy and environmental plan that includes a stated intention to achieve net-zero emissions by no later than 2050. As part of his vision for a clean energy future, Biden intends to achieve a carbon pollution-free power sector by 2035. With heavy investment proposals in renewable, carbon-free emission energy production, as well as the production of carbon-free hydrogen through renewable feedstock and innovative technologies, it is unlikely that coal will play a major role, if any, in America's energy future under a Biden administration.

The use of coal to produce hydrogen faces many hurdles. The United States has seen large declines in coal production over the past decade, and this trend is likely to continue over the next few decades as natural gas and renewable energy resources become less expensive and continue to build their market share. Shifting public opinion and awareness on climate change will likely exacerbate this downward trend. The future of coal is uncertain, but advances in technology to reduce emissions and generate coal-produced hydrogen at target costs have the potential to change the narrative of this important feedstock in the future.

PART III – TRANSPORTATION, DISTRIBUTION, END-USE, AND STORAGE

The United States has a highly developed and evolving energy economy that includes a range of modes of transportation, distribution, and storage. The United States already has robust regulatory regimes that apply to these transportation, distribution, and storage modes to help ensure safety and reliability, as well as to provide both access and competition. However, as discussed in greater detail in the sections that follow, regulation and policies in these areas likely will need to evolve to accommodate and include hydrogen, and industry participants will have an opportunity to play a role to ensure clear, transparent, and focused regulations and policies.

In addition, how and where end-uses of hydrogen develop likely will influence the growth of and policies applicable to hydrogen transportation, distribution, and storage. Government incentives to promote end-use will be an important piece to this puzzle, and several current incentives are discussed below.

I. Transportation and Distribution

This section discusses the current and potential future regulatory regimes that apply to four modes of U.S. hydrogen transportation and distribution: motor carrier, rail, pipeline, and vessel. As the U.S. hydrogen economy continues to develop and grow, regulation of these modes of hydrogen transportation may as well.

At the outset, while regulation of these modes of hydrogen transportation and distribution may be robust, there appear to be far fewer traditionally "environmental" regulatory regimes that apply. Unlike concerns with direct water and ground pollution with heavy hydrocarbons and other compounds in crude oil or petroleum liquids products, hydrogen in gaseous or liquefied form is "lighter than air." Hydrogen gas does not linger near the earth's surface and also is not a direct greenhouse or other deleterious gas in the earth's atmosphere. Hydrogen in liquefied form "boils off" almost instantaneously when depressurized.

Perhaps unsurprisingly then, hydrogen is not listed as an "extremely hazardous substance" or a "toxic chemical" under the Emergency Planning and Community Right-to-Know Act (EPCRA), a "hazardous substance" under the Comprehensive Environmental Response, Compensation, and Liability Act (CERCLA), or a "hazardous waste" under the RCRA. For nearly all forms of hydrogen transportation, this is notable. Similarly, hydrogen might not fall under the CWA definition of "pollutant" given that hydrogen cannot linger in water or other liquids unless contained at extremely high pressures, but the EPA's stance on this issue is not known with certainty at this time. This will, of course, be relevant for shippers and transportation providers going forward. Hydrogen does appear on the CAA list of regulated substances under Section 112(r), which triggers EPA's Risk Management Plan (RMP) rule for certain larger storage quantities of hydrogen, but hydrogen appears on this list only due to its flammability.[130]

While hydrogen has been on regulators' radar for decades given its use in industrial metallurgical, crude oil refining, and semiconductor applications, transportation of hydrogen by motor carrier, rail, pipeline, and vessel has not been considered as environmentally sensitive as transportation of other materials. As the hydrogen economy evolves, it is possible that all regulatory regimes that touch on hydrogen transportation—safety, environmental, and others—may as well. In addition, as hydrogen is touted by many as indispensable to decarbonizing the world economy, environmental regulators may have renewed interest in the transportation of this resource as well.

A. Motor Carrier

Hydrogen currently is transported by truck in the United States in compressed gaseous form using tube trailers and in liquid form in cryogenic tanker trucks.

[130] 40 C.F.R. § 68.130 (Table 3).

Considerations for truck transport include volume limitations resulting from the U.S. Department of Transportation's (DOT) pressure and vehicle weight restrictions, as well as the potential product loss due to boil-off during transport for liquid hydrogen (LH2) given the extremely low temperature required to liquefy hydrogen.

The Federal Motor Carrier Safety Administration (FMCSA) is the agency with primary jurisdiction over the transportation of hydrogen and related hazardous materials via commercial trucking. FMCSA's authority is outlined in the federal regulations at 49 C.F.R. Parts 390–397, Subtitle B, Chapter III, Subchapter B. Part 397 provides guidance on the transportation of hazardous materials, including instruction for compliance with federal motor carrier safety regulations (§397.2), routing of non-radioactive hazardous materials (Subpart C), and preemption procedures (Subpart E). In addition, general federal motor carrier regulations (Part 390) provide guidance for obtaining hazardous material safety permits and providing intermodal equipment provider identification reports (§390.19).

Additionally, the Pipeline and Hazardous Materials Safety Administration (PHMSA) is responsible for regulatory oversight of the carriage of hazardous materials by rail, aircraft, vessel, or public highway under its Hazardous Materials Regulations (49 C.F.R. Parts 171–180, Subtitle B, Chapter I, Subchapter A). More specifically, PHMSA provides material hazard class guidance for Class 2.1 flammable gases (§173.115) and Class 3 flammable and combustible liquids (§173.120). It also outlines general requirements for loading, inspection, and lading pressure associated with hazardous materials in cargo tank motor vehicles (§173.33). Part 177 also provides PHMSA with the authority to regulate carriage by public highway, including inspection procedures (§177.802), compliance with federal motor carrier safety regulations (§177.804), and unacceptable hazardous materials shipments (§177.801).

Federal regulation of hazardous material transportation is applicable to all intrastate, interstate, and foreign commerce. State regulation may also apply, however, pursuant to the Hazardous Materials Transportation Act of 1975, which provides that state directives that are inconsistent with federal law are preempted unless they afford equal or greater protection to the public.

Advancements in tube trailers and cryogenic tanker technologies may push reconsideration or revision of these regulatory requirements, particularly as the U.S. hydrogen economy continues to grow and over-the-road transportation increases.

B. Rail

As noted above, hydrogen has been used in industrial applications in the United States for decades. As such, there already is interest in transporting hydrogen by rail and current U.S. regulations address hydrogen transportation by rail. As discussed further in this section, current regulations impose restrictions that rail carriers and shippers should bear in mind as the U.S. hydrogen economy expands and the need to ship hydrogen by rail in greater volumes increases.

As noted above, PHMSA governs the carriage of hazardous materials by rail, aircraft, vessel, or public highway under its Hazardous Materials Regulations (HMR).[131] Under 49 U.S.C. §§ 5101–5127, the Secretary of Transportation has the authority to promulgate regulations that govern the transportation of hazardous materials in commerce. The HMR applies to any person that transports or causes to be transported or shipped hazardous materials in interstate, intrastate, and foreign commerce. The Federal Railroad Administration enforces the HMR, as promulgated by PHMSA, as they pertain to rail transportation.

PHMSA's regulations at 49 C.F.R. Part 174 contain provisions addressing the carriage of hazardous materials by rail, including necessary inspections and safety precautions. Compressed hydrogen and refrigerated LH2 are both defined as hazardous materials under PHMSA's regulations at 49 C.F.R. § 172.101. Further, all flammable cryogenic liquids, which includes liquefied hydrogen, are also defined as hazardous materials within PHMSA's regulatory scope. Certain cryogenic flammable liquids, including hydrogen, may be transported by rail. PHMSA's regulations provide for special handling requirements, including precautions against loading, transporting, or storing flammable liquid materials in rail cars that are equipped with any type of lighted heater or open-flame device, or in rail cars that utilize an internal combustion engine.

Notably, flammable liquids can only be transported by rail if the original consigned party or the subsequent consigned party has a private track on which the liquid will be delivered and unloaded, or if the flammable liquids will be consigned or reconsigned to a party using specialized railroad siding facilities. There are also regulations governing routing, speed restrictions, standards for new tank cars, and more with which parties transporting flammable liquids, such as liquefied hydrogen, by rail need to comply.[132]

Finally, the HMR authorizes transportation of cryogenic flammable liquids in specialized tank cars.[133] DOT-113 class tank cars currently are authorized under the HMR to move flammable liquids like hydrogen. However, according to recent comments, PHMSA "does not believe cryogenic hydrogen UN1966 is currently transported in this manner in the United States" [in DOT-113 rail cars].[134]

PHMSA is considering similar railcars for the movement of LNG. PHMSA recently published a final rule that allows for the bulk transportation of LNG in

131 49 C.F.R. §§ 171–180 (2020).

132 49 C.F.R. § 174 (2020).

133 49 C.F.R. § 179 (2020).

134 PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., SP 20534 SPECIAL PERMIT TO TRANSPORT LNG BY RAIL IN DOT113C120W RAIL TANK CARS, FINAL ENVIRONMENTAL ASSESSMENT (2019).

DOT-113 specification tank cars that have enhanced outer tank requirements.[135] The final rule also requires remote monitoring of the pressure and location of LNG tank cars and additional requirements for trains that are transporting several LNG tank cars on the same train. Similar tank cars as those proposed to carry LNG have been authorized to carry hydrogen for decades. In the Final Environmental Assessment for the movement of LNG by rail, PHMSA highlighted this long-standing authorization as support for allowing the movement of LNG by rail as well.[136]

C. Pipeline

Gaseous hydrogen is currently transported in the United States through a few existing hydrogen-specific pipelines. At the federal level, hydrogen pipelines currently are regulated by the DOT as a flammable gas.[137] State-level regulations related to pipeline safety may also be applicable. Construction of new, commercial-scale hydrogen pipelines in the United States will give rise to a range of issues. This section addresses a few of the more challenging issues related to a robust deployment of pipeline transportation for hydrogen in the United States.

1. Use of Existing Pipelines

One of the major considerations for the robust development of a hydrogen economy in the United States is the potential use of existing natural gas pipelines for transportation of hydrogen, either blended with the existing natural gas stream or alternatively through the conversion of natural gas pipelines to ship hydrogen exclusively. Given that there are hundreds of thousands of miles of natural gas transportation pipelines and over a million miles of natural gas distribution pipelines across the United States,[138] this presents a very real, potentially lower-cost opportunity[139] for the hydrogen industry to deliver commercial-scale volumes of hydrogen. Note that, unlike interstate natural gas pipelines, there is not presently a centralized federal regulatory regime applicable to the siting, construction, and operation of interstate hydrogen pipelines. While the issue has not been raised squarely before FERC, based on years of precedent it appears clear that FERC considers its jurisdiction under the NGA, as currently drafted, to apply specifically to interstate natural gas pipelines.

The DOE's National Renewable Energy Laboratory found in a 2013 study that blending in the range of 5 percent-15 percent hydrogen in the natural gas stream could result in "only minor

135 Hazardous Materials: Liquefied Natural Gas by Rail, 85 Fed. Reg. 44994 (July 24, 2020).

136 PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., SP 20534 SPECIAL PERMIT TO TRANSPORT LNG BY RAIL IN DOT113C120W RAIL TANK CARS, FINAL ENVIRONMENTAL ASSESSMENT at 20–21 (2019).

137 49 C.F.R. pt. 192.

138 *Annual Report Mileage for Natural Gas Transmission & Gathering Systems*, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN. (July 1, 2020) https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-natural-gas-transmission-gathering-systems.

139 The capital cost of long-haul, larger diameter, new build hydrogen pipelines and the hydrogen-specific compression required to ship hydrogen through such pipelines is significant.

issues … depending on site-specific conditions and particular natural gas compositions," and noted that with appropriate mitigation and modifications (likely to end-user equipment and household appliances) even up to 50 percent hydrogen in the natural gas stream could be acceptable.[140] The International Energy Agency (IEA) indicates that blending hydrogen into a natural gas pipeline stream would require "upper … limits of around 20 percent to 30 percent, depending on the pipeline pressure and regional specification of steel quality."[141] As noted in the **Government Incentives section of Part I (Section I.A)**, DOE recently solicited proposals and awarded grants for programs addressing technical barriers to hydrogen blending in natural gas. Given the extensive geographic coverage of the entire United States with natural gas pipelines, this could represent a significant means to effectuate broader distribution of hydrogen.

There are significant barriers, however, to implementing such a shift in the U.S. natural gas pipeline grid, including practical, safety, and legal issues. The existing natural gas pipeline system in the United States is fully optimized to transport methane, and intentionally injecting hydrogen into the stream poses many operational and safety challenges.[142] Both interstate natural gas transportation lines and local natural gas distribution lines are heavily regulated and, as a result, to the extent the hydrogen industry desires to utilize such lines for the transportation of hydrogen, there are a number of issues and challenges that the industry will need to address. Most importantly, two key threshold issues include the development of practices for nominating hydrogen to flow on a particular natural gas pipeline and the establishment of specifications for gas composition.

a. Nominating Hydrogen to Interstate Natural Gas Pipelines[143]

Interstate natural gas pipelines are regulated by FERC, which has plenary jurisdiction over interstate natural gas pipelines and storage pursuant to the NGA.[144] Every interstate natural gas pipeline has a "tariff" that is publicly filed with FERC. The tariff is the physical document that provides nearly all the operating documents for the

140 Melaina, M.W. et al. "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues," National Renewable Energy Laboratory, (Mar. 2013), https://www.nrel.gov/docs/fy13osti/51995.pdf (herein 2013 NREL Pipeline Study).

141 *Technology Roadmap: Hydrogen and Fuel Cells*, INTERNATIONAL ENERGY AGENCY (2015), at p. 23, https://www.iea.org/reports/technology-roadmap-hydrogen-and-fuel-cells.

142 For example, it is well understood that hydrogen can "embrittle and accelerate crack growth" in welds in steel pipes and can more easily permeate typical elastomer seals and plastic pipe than natural gas leading to a greater leak rate. *See* PG&E Gas R&D and Innovation White Paper, "Pipeline Hydrogen," (Sept. 18, 2018), at pp. 14–15, https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/Whitepaper_PipelineHydrogenAnalysis.pdf; and Hydrogen Delivery Infrastructure Options Analysis, U.S. DEP'T OF ENERGY, https://www.energy.gov/sites/prod/files/2014/03/f11/delivery_infrastructure_analysis.pdf.

143 Intrastate natural gas pipelines are usually regulated by each state's public utility commission.

144 *See* 15 U.S.C. §§ 717 et seq.

pipeline, including the schedule setting the rates for service, the general terms and conditions of service (GT&C), and pro forma agreements for service on the pipeline. Included in all GT&Cs for every pipeline are provisions outlining how a customer requests and receives service from the pipeline, including prescriptive guidelines for nominating gas to flow on the pipeline. Therein lies the barrier for any effort to move hydrogen by existing natural gas interstate (and likely intrastate) pipelines—the system currently is set up to only allow for natural gas to be nominated to the pipeline. As a result, for any business interested in utilizing a FERC-regulated interstate natural gas pipeline for hydrogen, there will be a threshold issue of whether they are even able to put hydrogen on the pipeline.

As discussed further below, there may be a few pipelines that allow hydrogen as an ancillary element in the natural gas injected into the pipeline, but currently there does not appear to be any interstate natural gas pipeline that would accept nominations of hydrogen gas for the pipeline. A company that wishes to do so will need to engage with the pipeline first. The pipeline company will not be obligated under current law to accept hydrogen on the system, nor will it be obligated to change its operating GT&Cs to allow hydrogen.

Moreover, to make such a change, the pipeline would be required to seek authorization from FERC. The proceeding would be public and likely would generate significant scrutiny and engagement from many interested stakeholders, including utilities, industrial manufacturers, end-users, and trade associations who represent different interests, who will have the opportunity to file comments in the proceeding and challenge or support such a proposal. Given the potential complexity of the issues involved, the proceeding likely would be contentious and would not be resolved quickly.

If the U.S. hydrogen industry wants to pursue the possibility of using existing interstate natural gas pipelines to allow some blending of hydrogen into the existing natural gas stream, the hydrogen industry will need to engage extensively with the natural gas industry to try and develop some path forward to avoid protracted regulatory proceedings that delay hydrogen blending.

2. Construction of New Pipelines

As the hydrogen economy in the United States continues to mature, the need for dedicated hydrogen pipelines likely will increase. Pipelines offer an economy of scale relative to trucking and are able to reach inland areas that cannot be served directly by vessels. DOE estimates that there are 1,600 miles of hydrogen pipeline operating

in the United States.[145] While there has been opposition to natural gas and oil/oil products pipeline construction, the opposition has been based on a variety of underlying arguments, not all of which may be present with hydrogen. More specifically, some opposition groups have focused on fossil fuel infrastructure as part of a broader argument against fossil fuel production. As described in **Part II** above, hydrogen can be produced from a variety of sources, including renewable energy. Consequently, while landowner, pipeline routing, environmental protection, and safety concerns likely will remain for hydrogen pipelines, it is possible that these projects will not face the same level of opposition as natural gas and oil/oil products pipelines.

Given the extremely low temperature required to liquefy hydrogen (-252.8 degrees Celsius or -423 degrees Fahrenheit), absent technological advancements, distribution and transmission pipelines most likely will carry hydrogen in a gaseous state. A number of studies have recognized several potential challenges to transporting hydrogen by pipeline, including steel embrittlement, the need to develop odorization or a similar method for leak detection, and the need for less permeable seals.[146]

Development of new hydrogen gas pipelines could be subject to federal permitting regimes, which could include permits under the CWA, the Rivers and Harbors Act, the Endangered Species Act, as well as environmental review under NEPA, if federal funding or permits are required. A state water quality certification may also be required if construction of the pipeline requires a federal permit and has the potential to discharge into state waters. Other state and local permits may also be required for construction. Ultimately, the regulation of existing, and future, hydrogen pipelines will depend, in part, on whether the pipelines are intrastate or interstate.

a. Intrastate Pipelines

As hydrogen demand increases, it is likely that dedicated intrastate hydrogen pipelines will be needed to transport hydrogen from production

145 *Hydrogen Pipelines,* DEP'T OF ENERGY, https://www.energy.gov/eere/fuelcells/hydrogen-pipelines (last visited Aug. 21, 2020).

146 *See* PG&E Gas R&D and Innovation White Paper, "Pipeline Hydrogen," (Sept. 18, 2018), at pp. 14–15, https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/interconnection-renewables/interconnections-renewables/Whitepaper_PipelineHydrogenAnalysis.pdf; and *Hydrogen Delivery Infrastructure Options Analysis,* DEP'T OF ENERGY, https://www.energy.gov/sites/prod/files/2014/03/f11/delivery_infrastructure_analysis.pdf (last visited Aug. 21, 2020).

sites to various end-users. In states that do not currently have a regime applicable to hydrogen pipelines, the regulatory regimes that exist for intrastate natural gas pipelines could serve as a model for intrastate hydrogen pipelines, though modifications may be required to address hydrogen's relative characteristics, including its smaller molecule size and higher flammability.

The siting, construction, and operation of intrastate pipelines generally are regulated by the individual states and the specific requirements vary by state. This regulation typically includes state public utility commission approval of rates for transportation and storage service, as well as terms and conditions of service (which may include the terms of interconnection). However, some states currently permit hydrogen pipelines to operate as proprietary pipelines and therefore do not require state public utility commission approval of rates and terms of service.[147] As discussed in **Gas Composition and Issues of Interchangeability below (Part III, Section I.C.2.b)**, U.S. pipelines generally maintain product quality standards to help ensure system safety and reliability. Industry stakeholders and states likely will develop similar standards for hydrogen.

With respect to pipeline safety, the PHMSA regulates the safety of the transportation of natural and other gas by pipeline and prescribes minimum federal safety standards applicable to such pipelines under 49 C.F.R. Part 192. Through partnerships with PHMSA, states may regulate intrastate gas pipelines if their regulations are at least as stringent as the federal minimum safety standards.[148]

PHMSA's jurisdiction includes pipelines that transport flammable gas, like hydrogen, and PHMSA has regulated hydrogen under 49 CFR Part 192 since 1970.[149] In discussing its role in a developing hydrogen economy, PHMSA has noted that it will "need to focus on supporting activities to ensure that hydrogen is transported safely. This will include: a clear technical focus regarding the safety implications of infrastructure materials, designs and systems; preparation to address any regulatory barriers towards a hydrogen economy; research in support of additional industry consensus standards; [and] efforts to educate and prepare emergency responders."[150] Consequently, while PHMSA's regulations currently cover hydrogen, it is possible that the

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[147] Nexant, Inc., Hydrogen Delivery Infrastructure Options Analysis: Final Report, Task Report: Task 1: Data and Knowledge Base, p. 56 (Dec. 2006) (explaining "Hydrogen pipelines in the U.S. are currently operated by the companies which own the hydrogen being transported. . . there are no common carrier companies").

[148] 49 U.S.C. §§ 60105–60106.

[149] *Hydrogen*, PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., https://primis.phmsa.dot.gov/comm/Hydrogen.htm (last visited July 25, 2020).

[150] *Id.*

agency will develop additional or supplemental regulations as hydrogen demand and the need for pipeline transportation further develop.

b. Gas Composition and Issues of Interchangeability

Relatedly, in the event that hydrogen could flow on the interstate natural gas pipelines, one of the most significant challenges may be addressing gas composition issues. In order to address gas quality issues, participants in the hydrogen industry will need to understand how such pipelines are regulated and some recent history related to gas composition issues.

As the United States began to ramp up its imports of LNG in the early to mid-2000s, questions emerged in the industry and among end-user groups about "foreign gas" and the risks it posed to infrastructure in the United States. Concerns over differences in composition and the ability to blend the imported natural gas with historical U.S. Gulf Coast supplies ("interchangeability") prompted natural gas industry stakeholders to convene over the course of many months to try and develop an industry-sponsored, science-based approach. While there were commercial reasons for this approach, one of the most significant factors that led to this effort was a desire to forestall overly simplified federal regulatory engagement on the issue by FERC.

After significant industry input, FERC developed a set of five principles intended to facilitate the introduction of broader range of supplies of natural gas to the United States and protect existing infrastructure from differences in supply while providing a road map for all participants on how to move forward.[151] These principles are:

1. Only natural gas quality and interchangeability specifications contained in a FERC-approved gas tariff can be enforced.

2. Pipeline tariff provisions on gas quality and interchangeability need to be flexible to allow pipelines to balance safety and reliability concerns with the importance of maximizing supply, as well as recognizing the evolving nature of the science underlying gas quality and interchangeability specifications.

3. Pipelines and their customers should develop gas quality and interchangeability specifications based on technical requirements.

4. In negotiating technically based solutions, pipelines and their customers are strongly encouraged to use the Natural Gas Council Plus interim guidelines filed with FERC as a common reference point for resolving gas quality and interchangeability issues.

[151] "Policy Statement on Provisions Governing Natural Gas Quality and Interchangeability in Interstate Natural Gas Pipeline Company Tariffs," *Natural Gas Interchangeability,* Docket No. PL04-3-000 (June 15, 2006) (herein 2006 Policy Statement).

5. To the extent pipelines and their customers cannot resolve disputes over gas quality and interchangeability, those disputes can be brought before FERC to be resolved on a case-by-case basis, on a record of fact and technical review.[152]

   With the advent of the U.S. shale gas revolution and the production of domestic natural gas with sometimes significantly different compositions than historical gas streams, these five principles served as the foundation as many interstate pipeline companies initiated complex, lengthy negotiations with their shippers and related proceedings at FERC in order to develop more robust gas quality specifications in their FERC-approved tariffs. The goal was to accommodate additional gas supplies while also providing more detailed guidance to customers as to acceptable gas streams. These proceedings frequently involved dozens of interested parties, including interconnecting pipelines, local distribution companies, utilities, large industrial end-users with direct connects to the pipeline, and LNG importers. Settlements often were hard-fought and occasionally disputes resulted in FERC-litigated proceedings. In all cases, all interested parties spent substantial economic resources and time advocating for their particular position and providing data backing up their position.

Since the mid- to late-2000s, there have been few disputes related to the natural gas quality issues and the industry generally seems to have acclimated to the gas specification changes that were implemented. As the hydrogen industry considers the possibility of flowing hydrogen gas on natural gas pipelines, this context should guide its approach.

A recent review by K&L Gates of more than 40 major interstate natural gas pipeline companies' FERC tariffs indicates:

- only five pipelines include a hydrogen specification in the pipeline's tariff;[153]
- four include a reference to hydrogen with no particular specification or limitation;[154] and
- two others include a limitation on "non-hydrocarbon gases,"[155] which presumably would include hydrogen, though it is not specifically identified.

[152] *See* 2006 Policy Statement at p. 2.

[153] The five pipelines are Gulf South Pipeline, Enable – Mississippi River Transmission, Natural Gas Pipe Line Company of America, Southern Star Central Gas Pipeline, and Texas Gas Transmission.

[154] The four pipelines are Midcontinent Express, Midwestern Gas Transmission, Trailblazer Pipeline, and Viking Gas Transmission.

[155] The two pipelines are Algonquin Gas Transmission and Maritimes & Northeast Pipeline.

For example, Gulf South Pipeline's tariff provides that "[t]he gas shall contain no carbon monoxide, halogens or unsaturated hydrocarbons, and no more than four hundred parts per million (400 ppm) of hydrogen."[156] Texas Gas Transmission's tariff states that natural gas delivered to the pipeline shall contain 0% hydrogen.[157] The two pipelines that provide specifications for "non-hydrocarbon gases," Algonquin and Maritimes & Northeast, state that any gas tendered to the system "[s]hall not contain more than four percent (4.0%) by volume of a combined total of any non-hydrocarbon gas including, without limitation carbon dioxide, nitrogen, krypton, helium, argon, xenon, and neon."[158] While there is no specific reference to hydrogen, it is reasonable to infer that it would be included and, therefore, the limitation of four percent would apply to a customer that wanted to flow hydrogen on the system. The remaining 30 pipelines contain no provisions at all addressing hydrogen, and most pipelines' tariffs give the pipeline discretion to exclude gas from the system that could harm pipeline operations.

As a result, there is significant work that the hydrogen industry will need to undertake to effectively accomplish hydrogen blending in the U.S. natural gas pipeline transmission grid. The industry should understand inflection points for the various stakeholders in the natural gas industry looking to these prior gas quality and interchangeability issues and engage technical, economic, and legal advisors to develop and execute a strategy to achieve its pipeline blending objectives.

c. Interstate Pipelines

Interstate hydrogen pipelines also may play a role in the growth of a U.S. hydrogen economy. As noted above, it does appear likely that FERC

[156] Gulf South Pipeline Company, LLC, FERC NGA Gas Tariff, Seventh Revised Volume No. 1, Version 1.0.0, General Terms and Conditions, § 6.3.1(j) – Quality of Gas, https://infopost.bwpipelines.com/?tspid=1.

[157] Texas Gas Transmission, LLC, FERC NGA Gas Tariff, Fourth Revised Volume No. 1, Version 4.0.0, General Terms and Conditions, § 6.3.1(d) – Quality of Gas, https://infopost.bwpipelines.com/?tspid=100000.

[158] Algonquin Gas Transmission, LLC, FERC Gas Tariff, Sixth Revised Volume No. 1, Version 6.0.0, General Terms and Conditions, § 6.4.3(f) – Quality of Gas, https://infopost.spectraenergy.com/infopost/AGHome.asp?Pipe=AG; Maritimes & Northeast Pipeline, L.L.C., FERC Gas Tariff, Second Revised Volume No. 1, Version 3.0.0, General Terms and Conditions, Section 12.3(c) – Quality of Gas, https://infopost.spectraenergy.com/infopost/MNUSHome.asp?Pipe=MNUS.

would regulate interstate hydrogen pipelines under the NGA nor does it appear that there is presently a centralized federal regulatory regime applicable to the siting, construction, and operation of interstate hydrogen pipelines. Consequently, the regulatory regime for the construction of new interstate hydrogen pipelines is likely to be more akin to the regime applicable to interstate oil/oil products pipelines, as described below. As such, interstate hydrogen pipeline developers likely would need to obtain certificates of public convenience and necessity (or similar permits) from each state that the pipeline project traverses.

While the NGA likely does not currently apply to hydrogen, there are certain advantages to the federal regime that it establishes that are worth industry consideration as the U.S. hydrogen economy evolves, particularly as compared to interstate oil/oil products pipelines. More specifically, under the NGA, a single federal agency—FERC—issues the certificate of public convenience and necessity required for an interstate natural gas pipeline project. FERC's order authorizes the facility as a whole, subject to receipt of other required federal authorizations (e.g., air and water permits under the CAA and CWA, respectively). Further, FERC serves as the lead agency for the federal environmental review required under NEPA and coordinates with other federal and state agencies with jurisdiction over the project. While other federal agencies with jurisdiction, and state agencies with delegated federal authority, will issue separate permits and associated NEPA documents, the overall process is largely coordinated through FERC.

With respect to state and local authorities, the U.S. Supreme Court has ruled that the NGA preempts state law for the construction and operation of natural gas facilities.[159] FERC has since clarified that projects must "comply with appropriate state and local regulations where no conflict exists," but "state and local regulations are preempted by the NGA to the extent they conflict with federal regulation, impose conditions above the federal requirements, or would delay the construction and operation of facilities approved by this Commission."[160] In addition, the NGA provides approved project developers with eminent domain authority across the entire project, helping to streamline the process of obtaining rights-of-way from landowners.

By contrast, permitting for interstate oil/oil products pipeline facilities is more of a patchwork. Federal jurisdiction focuses more on the specific resources that may be impacted, as opposed to the project as a whole. FERC has jurisdiction over oil/oil products pipeline

159 *Schneidewind v. ANR Pipeline Co.*, 485 U.S. 293, 299–301 (1988).

160 *Dominion Transportation, Inc.*, 143 FERC 61,148, at p. 21 (2013).

companies under the Interstate Commerce Act—but its jurisdiction pertains only to the rates and terms of service and does not extend to the siting, construction, and operation of oil/oil products pipelines. While the U.S. Army Corps of Engineers may act as the lead NEPA agency, it also does not have jurisdiction over the pipeline project as a whole. Instead, individual states issue the certificates of public convenience and necessity (or similar permits) for these projects. This less-centralized approach means that project developers must meet the varied filing requirements in each of the states that their projects cross, each state's decision on an application for authorization to construct the pipeline is subject to challenge, and one state or state court's decision can significantly affect or even halt the overall project. A recent example is the Keystone XL pipeline, which faced litigation of its state permits in several states. While it appears that the current approach to interstate hydrogen pipeline project development is more akin to the oil/oil products pipeline model, the NGA demonstrates that a more centralized approach for project developers is possible.

As noted above with respect to intrastate pipelines, it is likely that industry participants and regulators will develop quality specifications for interstate hydrogen pipelines. Further, PHMSA's regulations under 49 C.F.R. Part 192 apply to interstate hydrogen pipelines and, as noted, PHMSA may seek to promulgate additional regulations as demand for hydrogen increases and the need for hydrogen pipelines further increases.

D. Vessel

The potential to transport hydrogen in bulk by vessel presents significant opportunities to reach markets that cannot be reached easily by pipeline or efficiently by truck. Given that LH2 has a volume ratio of 1:848 compared to hydrogen in a gaseous state, tremendous economies of scale can be realized if hydrogen is transported in a liquid state, as has been done with natural gas. This section discusses the requirements that may apply to the bulk transportation of LH2 by vessel in the United States.

1. Liquefaction

a. Permitting and safety

A critical aspect of the development of a long-term, sustainable, global hydrogen economy is the establishment of a robust import and export market. As the United States considers its role in capturing a share of a hydrogen market, it is well-placed to be a significant exporter of hydrogen. However, in the absence of a consistent regulatory framework for hydrogen export facilities, a patchwork of state regulatory regimes and standards for the construction and operation of coastal export facilities likely will emerge. Such a regulatory patchwork could create uncertainty for project developers and the investment community and, ultimately, present a challenge to the United States' ability to achieve sizable market share.

One possible solution could be the utilization of the country's proven regulatory framework for the export of natural gas as a regulatory foundation for the export of hydrogen. Like natural gas, hydrogen gas can be converted to LH2 through a process that cools the gas to -252.8 degrees Celsius (or -423 degrees Fahrenheit).[161] Like LNG, the transportation of LH2 is more efficient than transporting hydrogen gas because LH2 occupies 1/848th the volume as its gaseous form.[162] While there are, of course, major differences between LNG and LH2, similarities in the overall scope of facilities for export could be sufficient to allow for existing federal LNG and natural gas regulations to be applied to the export of hydrogen. Doing so likely would require congressional action to amend the NGA, which governs the export of natural gas.

LNG generally is exported from the United States in one of two ways: (1) the construction and operation of coastal LNG terminals at which LNG is produced and transferred by pipeline directly onto LNG tankers; and (2) less commonly, the production of LNG at inland liquefaction facilities that is then loaded into ISO containers that are trucked to ports and exported on general cargo vessels. Based on early market indicators, the export of LH2 may take the same form. Consider, for example, Australia's pilot LH2 export project described in the Australia portion of *The Hydrogen Handbook.* The project plans both to develop a carrier specifically designed for transporting LH2 in bulk, like LNG carriers that are used to export LNG in bulk, and to store LH2 in containers that will be loaded onto a standard shipping carrier for smaller-scale exports. Further, the United States already is home to eight hydrogen liquefaction facilities from which LH2 is transported via LH2 tube trailers to industrial end-users[163] that could also be used for export.

The export of LNG from the United States is governed primarily by Section 3 of the NGA.[164] Over time and through both executive branch and judicial precedent, that authority is now bifurcated between DOE and FERC. DOE is responsible for authorizing the export of the commodity,[165] while FERC is responsible for authorizing the siting, construction, operation, and expansion of coastal LNG facilities. That authority involves a robust environmental and safety review

161 *See, e.g.,* Port of Hastings, HYDROGEN ENGINEERING AUSTRALIA, https://hydrogenenergysupplychain.com/port-of-hastings/ (last visited Aug. 21, 2020).

162 *Id.*

163 *Hydrogen Delivery Technical Team Roadmap,* U.S. DRIVE at 7 (Jan. 2017), https://www.energy.gov/sites/prod/files/2017/08/f36/hdtt_roadmap_July2017.pdf.

164 15 U.S.C. §§ 717, *et seq.* (2018).

165 As described in Part III, Export Controls (Section III), *infra*, the Department of Commerce's export regime covers hydrogen.

pursuant to the NGA and NEPA, for which FERC serves as the lead federal authority coordinating with other federal and state agencies that act as cooperating agencies within their sphere of authority. This process allows for a more streamlined approach that is more manageable for project developers. In several orders over the last few years, FERC has limited its authority to coastal facilities only and has not exercised NGA Section 3 jurisdiction over the inland facilities associated with ISO container exports. The same approach should be taken with respect to LH2 exports.

In addition to potentially expanding FERC's approval authority over LNG under the NGA to include LH2, the development of an LH2 export industry would benefit from the development of a unified safety regime. Such a regime should be under PHMSA's jurisdiction, which already applies to hydrogen pipelines,[166] and the transportation of hazardous materials, including hydrogen, by other means, such as truck, railcar, and vessel.[167] The Natural Gas Pipeline Safety Act (NGPSA)[168] grants PHMSA the authority to develop safety regulations specific to LNG production facilities,[169] including coastal LNG facilities and other inland LNG facilities that are connected to the interstate gas transmission system.[170] LNG facilities that only are connected to intrastate gas transmission and distribution systems are typically regulated by the relevant state government through an agreement with PHMSA.[171] Like the NGA, amending the NGPSA to add hydrogen liquefaction facilities to PHMSA's jurisdictional purview would be a streamlined and effective way of having the agency with the relevant expertise develop a hydrogen safety regime.

Each of these opportunities to establish unified, consistent regulatory frameworks for hydrogen exports likely will require action by the U.S. Congress to amend existing laws, including the NGA and NGPSA, to accommodate hydrogen. Doing so will provide the regulatory certainty needed for U.S. project developers and investors to compete effectively in the hydrogen export market.

Of course, regardless of the overall regulatory framework for LH2 liquefaction facilities, liquefaction plants will be subject to a wide

166 49 C.F.R. pt. 192 (2020). *See also Hydrogen*, U.S. DEP'T OF TRANSP. PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., https://primis.phmsa.dot.gov/comm/Hydrogen.htm?nocache=4348 (last visited Aug. 21, 2020).

167 49 C.F.R. §§ 171–180 (2020). For example, PHMSA has design specifications for cylinders used to transport cryogenic liquids, including LH2. 49 C.F.R. § 173.316 (2020).

168 49 U.S.C. §§ 60101, *et seq.* (2018).

169 49 C.F.R. § 193.2001(a) (2020).

170 *LNG Regulatory Documents,* U.S. DEP'T OF TRANSP. PIPELINE AND HAZARDOUS MATERIALS SAFETY ADMIN., https://www.phmsa.dot.gov/pipeline/liquified-natural-gas/lng-regulatory-documents (last visited Aug. 21, 2020).

171 *Id.*

array of environmental laws and regulations. This will be the case regardless of whether the plants are near vessel ports or are inland. As noted above, construction of large liquefaction facilities could implicate NEPA and Endangered Species Act concerns, just as any other major construction project would. Because hydrogen's flammability qualifies it under Section 112(r) of the CAA, it is subject to EPCRA's risk management programming for on-site storage of hydrogen at 10,000 pounds or greater. It is likely that liquefaction facilities would trigger this risk management requirement of the CAA. Other major safety-related laws surrounding workplace safety, including those falling under the Occupational Safety and Health Administration's (OSHA) jurisdiction, and local fire or explosion hazards will apply to liquefaction facilities, likely including state and local parallels to federal safety laws as well as local fire codes. While energy intensive, however, the liquefaction process does not appear to pose environmental hazards that facility owners should be concerned with regarding other substances that are regulated by CERCLA, RCRA, and other similar environmental laws.

2. Vessel Transits

There are several important areas of consideration for those looking to transport hydrogen by vessel within, to, or from the United States. As noted above, hydrogen is listed in the CAA list of regulated substances under Section 112(r). While hydrogen appears on the list as a result of its flammability, the listing may trigger EPA's RMP rule for certain larger storage quantities of hydrogen.[172] Consequently, for storage or staging of hydrogen at ports, docks, and other stationary facilities integral to vessel transportation, shippers and carriers will want to be aware of its RMP obligations.[173]

a. International Requirements - Foreign Flag Vessels Calling on U.S. Ports

As a general matter, the transportation of liquefied gas in bulk by vessels that operate on international voyages is regulated under the International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk (IGC Code). Pursuant to Chapter VII, Part C, of International Convention for the Safety of Life At Sea, the IGC Code is mandatory for all vessels that carry liquefied gas or other products listed in Chapter 19 of the IGC Code. For example, this includes vessels carrying LNG, anhydrous ammonia, propane, and other similar liquefied gas products in bulk.

As with all similar international maritime conventions and codes, enforcement is carried out by inspectors in "port states" in the ports where the vessel calls, and by "flag states" where the vessel is registered, with the assistance of vessel classification societies. Under U.S. law, foreign flag vessels calling on U.S. ports that carry liquefied gas products in bulk must have an International Certificate of Fitness issued by the vessel's flag state, pursuant to the IGC Code.[174] Additionally, such vessels must be inspected by the U.S. Coast Guard (USCG) and obtain a Certificate of Compliance with the proper endorsement for the carriage of liquefied gas in bulk. The Certificate of Compliance is issued by the USCG after the foreign flag vessel has been examined and found to be in compliance with applicable international and U.S. regulatory requirements. This requires, among other things, that foreign flag vessels submit vessel plans and other information for review by the USCG, at least seven days before arrival in the U.S. prior to completion of the Certificate of Compliance exam.[175] In some areas, the applicable U.S. regulations may exceed that which is required under the IGC Code.

The general requirements above apply to all foreign flag vessels calling on U.S. ports that carry certain liquefied gas products in bulk. However, the IGC Code currently does not address specific requirements for the carriage of liquefied hydrogen in bulk. In 2016,

172 40 C.F.R. § 68.130 (Table 3).

173 PHMSA regulates shipment of "cryogenic liquids" on board vessels within its regulatory scope regarding packaging design and filling, as well as storage requirements for portable tanks, cargo tanks, and tank cars. 49 CFR 176.76(g); *see also* 49 CFR 176.83 (segregation of, among other materials, flammable liquids on board vessels).

174 *See* 46 C.F.R. § 154.24.

175 *See* 46 C.F.R. § 154.22; 46 C.F.R. § 154.1802.

with a recognition of the emerging interest in the transportation of LH2 in bulk, and a lack of requirements in the IGC Code, the International Maritime Organization (IMO) adopted interim recommendations for the carriage of liquefied hydrogen in bulk by vessel.[176] The IMO Recommendations set forth various special considerations and hazards in connection with the carriage of LH2 in bulk. For foreign flag vessels carrying LH2 in bulk in the United States, the USCG will consider the IMO Recommendations, and other applicable requirements in 46 CFR Subchapter O, in its process to conduct the Certificate of Compliance examination. Additionally, any commercial vessel carrying hazardous materials, such as hydrogen, in the navigable waters of the United States must comply with PHMSA regulations in 49 CFR § 176, which provide additional requirements for operations and cargo stowage and handling.

The carriage of liquefied hydrogen in bulk in all transportation sectors is an evolving practice.[177] Accordingly, the IMO Recommendations will most certainly evolve over time to accommodate industry changes, but will serve as a baseline standard, in conjunction with the IGC Code, to be applied by flag states and port states, including the United States, to help ensure the safe and efficient transportation of LH2 by sea.

b. U.S. Law and Regulation Applicable to U.S. Flag Vessels

Construction and operation of U.S.-flag commercial vessels carrying certain bulk dangerous cargos, in either liquid or compressed gas form, are regulated by the USCG under 46 C.F.R. Parts 151, 153, and 154 of Subchapter O. For example:

- Part 151 provides hull construction, equipment, operating, cargo tank, cargo transfer, environmental control, and temperature and pressure control requirements for commercial barges carrying bulk liquid hazardous materials.
- Part 153 provides general requirements, equipment design requirements, operations requirements, and procedures for stripping liquid residues from cargo tanks for self-propelled commercial vessels carrying bulk liquid, liquefied gas, or compressed gas hazardous cargoes.
- Part 154 provides safety standards for commercial self-propelled vessels carrying liquefied liquid bulk gasses.

Additionally, any commercial vessel carrying hazardous materials, such as hydrogen, in the navigable waters of the U.S. waters must comply

176 *See* IMO Resolution MSC.420(97), *Interim Recommendations for Carriage for Liquefied Hydrogen in Bulk* (IMO Recommendations).

177 In December 2019, the world's first LH2 carrier—the SUISO FRONTIER—was launched in Japan.

with regulations in 49 C.F.R. § 176, enforced by the USCG, which provide additional requirements for operations and cargo stowage and handling.

The USCG has not yet developed specific regulations for the carriage of hydrogen in either compressed gas or liquid form. Consequently, any U.S.-flag vessel being designed to do this would need to receive technical approval from USCG Headquarters instead of the local USCG Captain of the Port. The USCG is likely to use the IMO Recommendations as a starting point for U.S.-flag vessels that will carry LH2 in bulk. Vessel operators considering constructing a U.S.-flag vessel for this purpose should consult with the appropriate legal and regulatory advisors and then USCG Headquarters staff early in the design process. Note that if the hydrogen is converted to ammonia for shipment, then the requirements of Parts 151, 153, and 154 would apply.

c. Jones Act Considerations

The **"Jones Act"** generally refers to several provisions of United States law known as the coastwise laws that impose limitations on foreign flag vessels operating in U.S. territorial waters. The agency responsible for enforcing and administering the coastwise laws is U.S. Customs and Border Protection (CBP) within the Department of Homeland Security. The USCG is responsible for implementing the vessel documentation requirements for U.S.-flag coastwise qualified vessels.

Importantly, with respect to the potential development of a U.S. coastwise hydrogen market, the coastwise laws prohibit the transportation of merchandise and passengers between any two points in the United States embraced within the coastwise laws in any vessel other than a vessel (1) built in the United States (and never rebuilt abroad), (2) documented under U.S. law with a "coastwise endorsement," and (3) owned by U.S. citizens.[178] The term merchandise is broadly defined to include goods, wares, and chattels of every description including valueless material, as well as merchandise owned by the U.S. government. A passenger is any person carried on a vessel who is not connected with the operation and navigation of the vessel or the ownership or business of the vessel. Other provisions encompassed in 46 U.S.C. Chapter 551 deal with particular aspects of domestic waterborne transportation and are generally classified in the family of laws known as the Jones Act.

U.S. territorial waters include all inland navigable waterways and extend three nautical miles seaward of the territorial sea baseline. The coastwise laws also apply to certain artificial islands and similar structures, and include mobile oil drilling rigs, drilling platforms, and other devices attached to the seabed

[178] 46 U.S.C. 55102, 55103.

of the outer continental shelf for the purpose of resource exploration operations.[179]

Coastwise transportation is broadly defined to include "any part of the transportation of merchandise by water, or by land and water," between any two U.S. points embraced by the coastwise laws. These generally include U.S. territories, but not the U.S. Virgin Islands, America Samoa, and the Northern Mariana Islands, which are exempt from the coastwise laws.[180] Therefore, foreign-flag vessels can transport cargo between these islands and other U.S. points.

CBP has interpreted the coastwise laws with respect to "lightering" activities, for example, such that a tanker to be lightered that is anchored to the seabed within three nautical miles of shore is a U.S. point requiring vessels lightering product from that tanker to a U.S. port to be coastwise qualified. CBP also has determined that if merchandise is transformed (manufactured or processed) into a new and different product at an intermediate foreign port, the vessels transporting the original product from a U.S. port to this foreign port and transporting the transformed product from the foreign port to a U.S. port do not to need to be coastwise qualified.

For the vessel itself to be coastwise qualified it must be documented under U.S. flag with a coastwise endorsement, which in turn requires the vessel to be built in the United States and to be owned by U.S. citizens.[181] The USCG National Vessel Documentation Center is responsible for implementing these requirements.

In order to be considered U.S. built, all major components of the hull and superstructure must be fabricated in the United States and the vessel must be assembled entirely in the United States. The vessel cannot be subsequently rebuilt outside of the United States without permanently losing its coastwise endorsement.

In order to qualify as a U.S. owner, the corporation or owning entity must be organized under the laws of the United States, and the Chief Executive Officer, by whatever title, and the Chairman of the Board, as well as a majority of the Board of Directors, must be U.S. citizens, and at least 75 percent of the equity in the entity must be owned and controlled by U.S. citizens.[182]

In addition, the licensed officers on a U.S.-flag vessel must all be U.S. citizens and unlicensed crew must be either U.S. citizens or lawfully admitted to the U.S. for permanent residence (i.e., "green card holders") subject to a 25 percent cap.[183]

179 43 U.S.C. 1333(a).

180 46 U.S.C. 55101.

181 46 U.S.C. 12112.

182 46 U.S.C. 50501(d).

183 46 U.S.C. 8103.

Advance CBP rulings are available should there be any question about compliance with the coastwise laws. This is particularly advisable given the significant penalties for violations. The penalty for transportation of merchandise on a non-coastwise vessel is forfeiture of the merchandise so transported, or the value thereof.[184] Transportation of passengers in violation of the coastwise laws is $778 per passenger so transported. In addition, there are daily civil penalties for vessels operating in violation of the USCG documentation regulations, as well as the potential seizure and forfeiture of the vessel and its equipment under certain circumstances.

The navigation laws, including the coastwise laws, can be waived by the Secretary of Homeland Security under very limited statutory authority when requested by the Secretary of Defense and only then to the extent considered necessary in the interest of national defense. Such waivers have been granted in connection with hurricane relief efforts, for example, and other extraordinary circumstances.[185]

d. U.S. Law and Regulation Applicable to U.S. Marine Terminal Operations

USCG regulations for commercial waterfront facilities in the U.S. handling hazardous cargoes, including liquefied gasses, do not list hydrogen as a cargo to which those regulations apply. Therefore, waterfront facility operators in the United States that are considering handling hydrogen as vessel cargo should consult with USCG Headquarters for guidance. Most likely, such operators will be required to comply with the below USCG requirements applicable to other compressed or liquefied hazardous gasses.

A commercial waterfront facility in the United States that handles certain compressed hazardous gasses as cargo must comply with the regulations in 33 C.F.R. Part 154 regarding the handling of bulk dangerous cargoes at waterfront facilities. These regulations provide general, operations manual, equipment, and operations requirements for facilities transferring bulk dangerous cargoes other than liquefied hazardous gasses. Note that these regulations would apply if the hydrogen was converted to ammonia for shipment before arriving at the waterfront facility.

Commercial waterfront facilities in the United States that handle certain liquefied hazardous gasses as cargo must comply with the regulations in 33 C.F.R. Part 127, Subparts A and C. Subpart A provides general requirements regarding USCG oversight of waterfront facilities handling hazardous cargoes. Subpart C provides regulations on design, construction, equipment, operation, maintenance, fire protection, and firefighting equipment for waterfront facilities transferring liquefied hazardous gasses.

184 46 U.S.C. 55102(c).

185 46 U.S.C. 501.

3. Commercial Issues in Contracting for Bulk LH2

While there are alternatives to bulk transactions of hydrogen in a liquid state, most of these alternatives are still in early stages of development and, as a result, the approaches to contracting for these alternatives can be difficult to predict. In contrast, transacting in bulk LH2 has a readily available precedent.[186]

Transactions for the bulk purchase and sale of LH2 are likely to have much in common with LNG contracts. As noted in the **Project Finance section of Part I (Section II),** for example, the infrastructure to produce, store, and transport bulk LH2 requires massive capital investments across the supply-chain much like that required in the not-so-distant past for LNG, and these capital requirements, at least initially, will drive the type of long-term contracts that the LNG sector required in its early stages. In addition, as the process technology and safety principles that are applicable to LNG also are generally applicable to LH2,[187] the contracts for LH2 likely will be based on the precedent created in the LNG industry.[188]

As the history of LNG contracting has shown, LH2 contracting is unlikely to lead to a standard form of contract in the near term. While the LNG industry has attempted to develop industry forms, the sector is still dominated by forms that are generally the products of the larger market participants.

As a result of the precedent set by LNG, however, it is possible that many of the shorter-term solutions for contracting in LNG can provide commercial support for LH2 much sooner than occurred in the case of LNG. As the market for hydrogen grows and more alternatives are available for supply and offtake, for example, some of the unique revenue sharing products that have sped the development of LNG may also make their way into the hydrogen marketplace.

However, some of the characteristics of hydrogen that differ from LNG should drive differences in the contracts and the eventual development of a more robust trading market. For example, the very low boiling temperature of hydrogen[189] may slow development of long-distance offtake alternatives as losses over long routes may deter sales to more distant destinations. If so, both buyers and sellers likely will have less flexibility in dealing with non-performance by the other party until alternatives for supply and demand

186 As noted, there are other bulk methods of moving LH2, but transactions involving this method of delivery either require further development at present and/or will involve transactions on a much smaller scale. As a result, the discussion below is limited to bulk transactions involving vessel delivery.

187 A number of the hazards associated with liquid hydrogen are still being studied. Interestingly, the LNG industry was in a similar position about 20 years ago. As these hazards are defined and the associated safety requirements are codified, compliance with those requirements can be built into the sale and purchase agreements.

188 The applicability of the LNG contract models assumes that the liquid hydrogen will be transported as a cryogenic liquid. If hydrogen is compressed, then CNG model agreements would be an appropriate reference point. CNG model agreements, however, are less developed than their LNG counterparts.

189 *See, e.g., From LNG to Hydrogen? Pitfalls and Possibilities,* THE MOTORSHIP, https://www.motorship.com/news101/alternative-fuels/from-lng-to-hydrogen-the-pitfalls-and-the-possibilities (last visited Aug. 21, 2020).

are available. While this was obviously also true in the early years for LNG, the ability to move LNG long distances with limited losses from boil-off has certainly accelerated the ability to contract in LNG for shorter term supply.

Another characteristic of hydrogen that differs from LNG is that hydrogen has a much lower energy density by volume, approximately 40 percent compared to LNG.[190] In other words, one needs 2.5 vessels of hydrogen to carry the same energy moved in the same size of vessel carrying LNG. Given that hydrogen also needs greater insulation to maintain its much colder temperature requirements for a liquid state and better equipment to avoid the escape of the smaller hydrogen molecules, this vessel math, albeit simplistic, provides a sense of the magnitude of the challenge.

Even if the economics of this difference can be overcome, from a contracting standpoint, the scheduling, loading, and unloading constraints become even more critical than they are for LNG. Already complicated matters for LNG, like berth constraints, inventory management, and planning horizons, will take on an even greater level of importance with LH2

190 *See, e.g., id.*

with more vessels having to use limited dock and storage facilities. Considering the complexity of this process and real-world likelihood of disruption events, contracting around these issues with hydrogen will be as challenging, if not more so, than it has been for LNG.

A related constraint on transacting in bulk LH2 arises from the additional safety issues associated with hydrogen and the limits this currently places on transport. Unlike the numerous LNG carriers currently traversing the globe, the first LH2 transport vessel is a relatively small vessel by LNG standards and is still under construction.[191] The extremely wide range of hydrogen's flammability limit in air has generated calls for testing the flammability of liquid pools and gas leaks of hydrogen under working and emergency conditions, as was done with LNG pools and natural gas leaks, long before large tankers are commissioned.[192] In any event, this, and other safety issues unique to hydrogen, may put large-scale vessels of the type typically relied on by bulk LNG traders as something for the future. In the meantime, bulk hydrogen purchases likely will remain the product of the particular projects to which the purchases are tied and contracts will be drafted to meet the peculiar needs of these specific projects. More standardized contracts incorporating general market expectations will thus need to wait until there is a larger market than exists today.

Further, the fact that the amount of energy required to liquefy hydrogen is multiples of the energy required to liquefy LNG also will have an impact on contracting. As a result of this additional energy input, contracts for the supply of hydrogen will be more sensitive than LNG to energy price changes, particularly for the producer in the market where the liquefaction occurs. Where the LNG has been indexed to a price in the liquefaction market, it creates a problem for buyers because there is no correlation to competing energy sources in their domestic market at the point of destination. This potential disconnect between the energy costs in the supply market and the destination market presents an even bigger potential for disputes for hydrogen as tying the price to energy prices at the point of liquefaction will be harder to index, and this benchmark has the potential to have a great deal of volatility. We note that a number of LNG agreements are now indexed to a price in the regasification market, and that likely will be an attractive option for buyers of LH2 as well, but the same seller issues

191 One estimate is that there are approximately 360 LNG vessels moving on the high seas and some vessel sizes exceed 260,000 m3. *See, e.g.,* LNG Tankers – Different Types And Dangers Involved, https://www.marineinsight.com/types-of-ships/lng-tankers-different-types-and-dangers-involved/. In contrast, Kawasaki expects completion of the first such vessel for hydrogen in late in 2020 and it is an anticipated cargo capacity of only 1,250 m3. *See* Kawasaki announces World's First Liquefied Hydrogen Carrier SUISO FRONTIER Launches Building an International Hydrogen Energy Supply Chain Aimed at Carbon-free Society, https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487.

192 *See, e.g.,* Bulk Storage and Shipping of Liquid Hydrogen Is Hazardous (arguing that the existing IGC Code entitled "Draft Interim Recommendations for Carriage of Liquefied Hydrogen in Bulk" interim recommendations for carriage of liquefied hydrogen in bulk are not adequate), https://cryogenicsociety.org/34991/news/bulk_storage_and_shipping_of_liquid_hydrogen_is_hazardous/.

will be present as well—especially concerns about a disconnect with the seller's production costs and lender requirements.

One approach to addressing this indexing issue in the LNG market has been to include price review mechanics.[193] Not surprisingly, the specific triggers for the application of the price review mechanism are heavily negotiated and are prone to dispute. These also can complicate project financing as lenders are not in the business of taking the market risk that these might create. As a result, if included, these must be negotiated in such a way as to ensure that revenue generation remains sufficient to cover any debt and tax equity that might be associated with the relevant infrastructure projects at both the point of sale and the delivery point.

In short, while the contracting for hydrogen will benefit greatly from the precedent created in the LNG sector, it will have its own set of issues and challenges that are unique to hydrogen. Much like LNG, early market participants will create precedents that will eventually be used by later market participants. To speed hydrogen's adoption as an energy alternative, however, these early market participants need to focus on the differences between these two products or risk the possibility that their contracts will do little more than fit their square hydrogen peg into a round LNG hole.

II. Storage

As the U.S. hydrogen industry matures, the ability to store hydrogen safely and cost-effectively will offer critical commercial flexibility. Hydrogen storage, especially large-scale or "bulk" storage methodologies, need further development and investment before they are ready for broad deployment. This necessary development is underway and there are several pathways for building out hydrogen storage infrastructure in the coming years. Existing regulatory programs apply to these nascent storage approaches, but further regulatory certainty will help assure project developers and operators that they

193 For a discussion of LNG price reviews, *see* "Taming Price Review Clauses: Lessons from the Transactional and Arbitration Battlefields," LNG18, Apr. 2016.

understand and can comply with legal and regulatory requirements.

A. Very Long Duration Energy Storage

Most of the electric energy storage technologies that have been deployed to date are capable of discharging stored electricity for a relatively short period of time. The instantaneous capacity of the storage system is combined with the duration of discharge to produce a short-hand description of the system's capabilities: thus, a 10 MW system that can discharge for four hours is described as a 10MW/40MWh system. Batteries may be capable of discharging for two to eight hours, depending on the technology deployed. Pumped storage hydroelectric facilities and compressed air energy storage systems may be able to discharge for 10 hours or more. Longer duration systems can take advantage of peak shifting and price arbitrage, charging the system when prices are low (e.g., on a weekend), and then discharging during peak hours when prices are high.

However, most existing storage systems will cycle fairly often (usually at least once per day), which means that they store electricity only for a relatively short period of time. For example, an energy storage system coupled with a solar photovoltaic generator may charge when surplus solar energy is being generated during peak daylight hours and then discharge later in the day to partially offset the decline of solar generation in the late afternoon and evening. The difference between the quantity of energy stored and the amount available for discharge is known as the system's "round-trip efficiency." Discharge of electricity within a few hours after being stored in the system has the added benefit of reducing the electricity lost during storage.[194]

The growing penetration of variable renewable energy resources, such as wind and solar, is creating a need for "very long duration storage" (which is also known as "seasonal storage"), and the storage technologies currently being deployed do not address this need. For example, a utility's demand for electricity might decline in the spring, when heating load is tapering off and air conditioning load has not yet begun to ramp up.[195] But variable renewable resources, such as wind and hydroelectric, may achieve peak generation at the same time that the system's load is low. The system must remain in balance, so surplus generation that cannot be used by the load must be curtailed. This results in a loss of revenue for the generators affected and produces even more significant problems for wind projects relying on the production tax credit, which the generator can only earn by generating and selling electricity. The challenge for variable renewable energy as it seeks higher levels of penetration will be to move excess generation from the months where it is not needed to months where it can be used to serve as a "decarbonized" source of fuel or electricity.

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194 For a discussion of energy storage generally, *see* K&L Gates, Energy Storage Handbook (5th ed.)(2019).

195 PAUL DENHOLM & TRIEU MAI, TIMESCALES OF ENERGY STORAGE NEEDED FOR REDUCING RENEWABLE ENERGY CURTAILMENT (2017).

Hydrogen is a synthetic fuel that can be used to accomplish very long-duration storage by a number of means. For example, an electrolysis unit could be co-located with a wind or solar generator where variable electricity is being curtailed. Instead of curtailing the surplus electricity, the generator continues to produce it and sells it to a co-located electrolysis unit to produce hydrogen. The hydrogen could be delivered directly to a natural gas pipeline (subject to limits required to address safety, leakage, or gas quality concerns as discussed previously in the **Pipeline section of Part III (Section I.C)**), or it could be used as a feedstock for a methanization process that produces methane suitable for injection to the pipeline.[196] If the local geology is favorable, the hydrogen could also be stored in depleted hydrocarbon reservoirs or salt caverns for later use (as discussed below). The stored hydrogen could later be used in fuel cells to generate electricity directly or as fuel for hydrogen cars, or it could be used to produce an intermediate product in order to overcome hydrogen storage and transportation challenges.[197]

The economic case for seasonal storage in a given region depends on a number of variables, including renewable energy penetration, resource adequacy needs, the growth of carbon taxes or other carbon regulation, the price of natural gas, and seasonal or annual variation in generation or in loads.[198] The prospects are daunting at this point, and very long-duration hydrogen storage may not be economically viable in the United States for some time, although several European projects are underway.[199] That said, those who have followed the development of the wind, solar, natural gas, and energy storage industries in the United States know that cost barriers can tumble quickly and unexpectedly. At least one consortium of developers is pursuing a large-scale storage project in Utah: the Advanced Clean Energy Storage project is intended to provide storage services for 1,000 MW of wind in the form of compressed air or hydrogen stored in a salt cavern.[200]

B. Hydrogen Storage Strategies

As noted above, hydrogen can be compressed or liquefied and, in a compressed or liquid state, the same number of hydrogen molecules take up less volume, decreasing the footprint necessary for hydrogen storage facilities. Compressed hydrogen is hydrogen placed under pressures of 5,000–10,000 pounds per square inch (PSI).[201] By

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196 KEN DRAGOON, POWER TO GAS: OPPORTUNITIES FOR GREENING THE NATURAL GAS SYSTEM at 19–21 (2018).

197 ROB VAN GERWEN, MARCEL EIJGELAAR, & THEO BOSMA, THE PROMISE OF SEASONAL STORAGE at 27 (2020).

198 *Id.*

199 DRAGOON, *supra* note 79, at 27–28.

200 Umar Ali, *How Salt Caverns Could Transform Renewable Energy Storage for the US*, POWER TECHNOLOGY, Aug. 29, 2019, https://www.power-technology.com/features/how-salt-caverns-could-transform-renewable-energy-storage-for-the-us/#:~:text=A%20new%20project%20called%20Advanced,or%20compressed%20air%20by%202025. (last visited Aug. 13, 2020).

201 U.S. DEP'T OF ENERGY OFFICE OF ENERGY EFFICIENCY & RENEWABLE ENERGY, https://www.energy.gov/eere/fuelcells/physical-hydrogen-storage (last visited Aug. 9, 2020).

comparison, liquefied hydrogen is cryogenically cooled hydrogen so that the hydrogen reaches -252.8 degrees Celsius (or -423 degrees Fahrenheit) and condenses to a liquid.[202] Compressed hydrogen contained in high-pressure tanks is the technology of choice for mobile transportation applications, especially for light-duty vehicles.[203] Liquefied hydrogen storage is often used for bulk stationary hydrogen storage in above-ground tanks and truck transportation of liquefied hydrogen.

In addition to storing pure hydrogen through compression or liquefaction, there are other methods for storing hydrogen. Hydrogen can be deposited on the surfaces of or within solid materials by absorption.[204] Some project developers envision storing hydrogen molecules in other compounds, like ammonia, during transportation and storage, then breaking those intermediary materials down to access the hydrogen closer to the point of end use.[205] For the purposes of *The Hydrogen Handbook,* we are focusing on storing hydrogen as its own substance and not interposed with other materials or as constituent parts of other substances.

C. Bulk Hydrogen Storage

Hydrogen can be stored in bulk in a variety of ways, depending on the requirements of the storage system (e.g., the cycling frequency, or the frequency of withdrawals and refills) and geologic availability. For hydrogen production and end-use locations on small and medium scales, operators often use high-pressure cylinder tanks. These tanks can be transported relatively easily and sized for specific applications.

For larger-scale storage on-site, large cryogenic tanks store liquefied hydrogen since they have a higher volumetric density than pressurized gas storage systems.[206] The U.S. National Aeronautics and Space Administration has used spherical tanks to store very large volumes of liquefied hydrogen for decades.[207] Most industrial or commercial applications do not require such large volumes of hydrogen and instead they employ large cylindrical cryogenic tanks to store liquefied hydrogen.[208]

These tank solutions are useful for applications that do not depend on the region's geology and require frequent

202 *Id.*

203 *Id.*

204 *Id.*

205 Krystina E. Lamb, *Ammonia for Hydrogen Storage; A Review of Catalytic Ammonia Decomposition and Hydrogen Separation and Purification*, 44 INT'L J. OF HYDROGEN ENERGY 3,580 (2019), https://www.sciencedirect.com/science/article/abs/pii/S0360319918339272?via%3Dihub; Ola Osman & Sgouris Sgouridis, Optimizing the Production of Ammonia as an Energy Carrier in the UAE, 5TH INTERNATIONAL CONFERENCE ON RENEWABLE ENERGY: GENERATION AND APPLICATIONS (2018) https://ieeexplore.ieee.org/document/8337611.

206 U.S. DRIVE PARTNERSHIP, HYDROGEN DELIVERY TECHNICAL TEAM ROADMAP at 18, https://www.energy.gov/sites/prod/files/2017/08/f36/hdtt_roadmap_July2017.pdf (last visited Aug. 21, 2020).

207 *Id.* at 19. Spherical tanks are useful because they have lower surface areas compared to cylinders and therefore decrease the liquefied hydrogen's rate of evaporation. *Id.*

208 *Id.*

withdrawals and refilling of the storage tanks. But, where very large hydrogen storage would be required, such as to replace the output of a wind farm or utility-scale solar generation facility during an outage, underground storage in geologic formations can be used. Commonly used to store hydrocarbons like oil or natural gas, underground salt caverns and aquifers can store hydrogen gas as well. For example, an underground salt cavern, which could contain up to 500,000 cubic meters of hydrogen at 2,900 PSI, could produce some 100 gigawatt hours of electricity.[209] In addition to salt caverns, depleted oil and gas wells are also under consideration as options to store hydrogen underground.[210] These depleted well assets could be particularly useful if the wells are connected to pipeline infrastructure that could be repurposed to transport hydrogen.

To date, there are two salt cavern storage facilities for hydrogen in Texas[211] and opportunities for further development of underground storage across the United States and around the world.[212] But, there are challenges that must be addressed. Hydrogen is a small molecule compared to conventional hydrocarbons and it therefore has a higher potential to leak into the walls of depleted wells, which would decrease the inventory of hydrogen and potentially introduce impurities to the hydrogen.[213] Frequently cycling hydrogen inventories at an underground storage facility could also damage the integrity of the rock formation. As such, cycling may be limited to once or twice per year at a facility, limiting use cases to seasonal storage rather than to address acute supply-demand mismatches. Additionally, although there are opportunities to develop underground storage in some places, salt cavern or other geologic formations useful for hydrogen storage are not located near every market, so significant transportation infrastructure (e.g., pipeline, trucking, or marine transport) will be needed to make efficient use of bulk underground storage in salt caverns.

D. Regulatory Oversight of Hydrogen Storage

Multiple U.S. federal agencies exercise jurisdiction over hydrogen storage equipment and facilities and likely will have a role in regulating hydrogen storage in the future. As explained in the **Pipeline section of Part III (Section I.C)**, PHMSA exercises regulatory oversight of interstate gas pipelines, including hydrogen gas pipelines.[214]

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209 *Hydrogen Energy Storage,* ENERGY STORAGE ASS'N, https://energystorage.org/why-energy-storage/technologies/hydrogen-energy-storage/ (last visited Aug. 9, 2020).

210 Justin Gerdes, Enlisting Abandoned Oil and Gas Wells as "Electron Reserves," Greentech Media (Apr. 10, 2018), https://www.greentechmedia.com/articles/read/enlisting-abandoned-oil-and-gas-wells-as-electron-reserves#gs.ByNEEjY.

211 *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*, NEXANT, INC. ET AL. at 2–82 (May 2008), https://www.energy.gov/sites/prod/files/2014/03/f9/nexant_h2a.pdf.

212 Emiliano Bellini, *Hydrogen Storage in Salt Caverns*, PV MAGAZINE (June 16, 2020), https://www.pv-magazine.com/2020/06/16/hydrogen-storage-in-salt-caverns/.

213 *Storing Hydrogen Underground Could Boost Transportation*, Energy Security, SANDIA NATIONAL LABORATORIES (Dec. 9, 2014), https://share-ng.sandia.gov/news/resources/news_releases/underground_hydrogen/#.Wsp9GIjwY2w.

214 *Hydrogen*, PIPELINE & HAZARDOUS MATERIALS SAFETY ADMIN., https://primis.phmsa.dot.gov/comm/Hydrogen.htm?nocache=4348 (last visited Aug. 9, 2020).

In the natural gas and oil contexts, PHMSA exercises exclusive jurisdiction over storage facilities that serve interstate natural gas or oil pipelines. In accordance with its final rule issued in February 2020, PHMSA is applying its new safety rules for underground natural gas storage facilities to intrastate storage facilities.[215] Although the new rule on underground natural gas storage facilities does not explicitly mention hydrogen storage, it is conceivable that PHMSA would apply this rule to hydrogen storage facilities that are connected to pipelines since the agency uses the same statutory authority to regulate natural gas pipelines as hydrogen pipelines. But, to date, PHMSA has not explicitly extended this rule to underground facilities storing hydrogen.

Although it does consider hydrogen storage to be a form of energy storage,[216] FERC has indicated that it considers bulk storage of hydrogen in underground to be outside the agency's jurisdiction.[217]

PHMSA, OSHA, and the EPA all have regulations that apply to hydrogen storage equipment and facilities that are not part of pipeline transportation. For storage of hydrogen in containers that would be transported, like compressed hydrogen in cylinders or spherical pressure vessels, PHMSA applies 49 C.F.R. § 173.301.[218] For the storage of hydrogen in stationary facilities, like large compressed or liquefied hydrogen storage tanks, OSHA applies its regulations at 29 C.F.R. Part 1910 for hazardous materials and hydrogen-specific rules at 29 C.F.R. § 1910.103. In addition, the EPA applies its RMP program requirements to hydrogen storage facilities that hold 10,000 pounds or more of hydrogen.[219]

Although there are some regulatory programs addressing hydrogen in the United States, these programs likely will need to expand to address the growing hydrogen market. For example, systematizing the ways that project operators can transition existing assets, such as existing hydrocarbon storage facilities to store hydrogen, will streamline the expansion of the hydrogen sector. Providing clear regulatory guidance will support investment in hydrogen storage infrastructure, which in turn will support development of the hydrogen sector.

Clear regulatory treatment will also assist stakeholders, like local governments

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215 Pipeline Safety: Safety of Underground Natural Gas Storage Facilities, 85 Fed. Reg. 8,104 (Feb. 12, 2020).

216 *Final Rule: Third-Party Provision of Ancillary Services*, 144 FERC ¶ 61,056 at p. 172 (Jul. 18, 2013) (indicating that FERC would consider hydrogen storage to be a form of energy storage for accounting purposes).

217 *Magnum Gas Storage, LLC*, 171 FERC ¶ 61,069 at p. 2 and n. 4 (Apr. 23, 2020) (suggesting that it agrees with the applicant that underground storage of hydrogen in salt caverns is not within FERC's jurisdiction).

218 Pipeline and Hazardous Materials Safety Admin, Interpretation Response #16-0010 (Apr. 5, 2017), https://www.phmsa.dot.gov/regulations/title49/interp/16-0010 (last visited Aug. 9, 2020).

219 *List of Regulated Substances Under the Risk Management Plan (RMP) Program*, U.S. ENVTL. PROTECTION AGENCY, https://www.epa.gov/rmp/list-regulated-substances-under-risk-management-plan-rmp-program (last visited Aug. 9, 2020). EPA's RMP program requires operators of facilities that hold the threshold quantity or more of a regulated substances, such as 10,000 pounds for hydrogen, to prepare and submit an RMP to EPA that identifies the potential effects of a chemical accident, identifies steps the facility is taking to prevent an accident, and spells out emergency response procedures if an accident occurs. Risk Management Plan (RMP) Rule Overview, U.S. ENVTL. PROTECTION AGENCY, https://www.epa.gov/rmp/risk-management-plan-rmp-rule-overview (last visited Aug. 9, 2020).

and neighbors of facilities with hydrogen storage, to understand the potential risks and significant investments that project developers and operators have made in safe operations of their storage facilities. Above-ground storage facilities, especially those with large hydrogen storage tanks, will attract the attention of local stakeholders.

To the extent that hydrogen storage facilities re-use the same facilities previously used by the hydrocarbon industry, those communities likely will be familiar with storage infrastructure. However, as the hydrogen economy expands across regions that have not had high visibility hydrocarbon infrastructure in the past, local communities may have more questions about the safety of hydrogen storage facilities. Clear regulatory guidance that project developers can point to will help developers, operators, and local stakeholders understand safety requirements and operational expectations.

III. Export Controls

As noted above, hydrogen does not appear to be regulated by the NGA, pursuant to which DOE regulates imports and exports of natural gas. However, the United States imposes export controls on a wide array of commodities under the Export Administration Regulations (EAR) administered by the U.S. Department of Commerce, Bureau of Industry and Security (BIS). Commodities that are subject to specific licensing requirements under the EAR are described in the Commerce Control List under a particular Export Control Classification Number (ECCN). Commodities not described under an ECCN are classified under the catch-all "EAR99." Hydrogen is EAR99 and, therefore, hydrogen generally does not require a license for export to most countries. One exception is that licensing requirements apply for hydrogen derived from the Naval Petroleum Reserves of the United States (NPR) and for hydrogen that has become available for export as a result of an exchange of any NPR produced or derived commodities.

It should also be noted that even EAR99 commodities, like hydrogen, generally require a license from BIS (and sometimes from the Office of Foreign Assets Control) before they can be exported: (1) to any embargoed country (i.e., Iran, Cuba, Syria, North Korea, Sudan, and the Crimean region of Ukraine); (2) for any prohibited end-users (e.g., parties on BIS's "Entity List"); or (3) for any restricted end-use (e.g., certain nuclear, missile, military, chemical, or biological weapons uses).

IV. End-Use

Hydrogen has many end-uses, including industrial, transportation, heating, and as a medium for storing energy. While historical end-uses for hydrogen focused on industrial applications, hydrogen technologies are increasingly being explored across different forms of transportation and energy. More recently, entrepreneurs and well established companies are looking into the application of hydrogen fuel cell technology in air transportation. Government incentives, commercial considerations, and regulatory regimes for transportation and distribution will help shape how the United States and other countries use hydrogen over the next century.

A. Road Vehicle Fuel

There is heightened interest in the use of hydrogen in the road transportation sector, and in particular in the heavy-duty vehicle market segment. Hydrogen fuel cell electric vehicles (FCEVs), which are considered zero-emission vehicles, are attractive replacements for internal combustion engine vehicles because they can offer performance similar to that of conventional vehicles, along with several additional advantages. These advantages include enhanced environmental performance, quiet operation, rapid acceleration from a standstill, and lower maintenance requirements. Furthermore, FCEVs can potentially perform functions for which conventional vehicles are poorly suited, such as providing remote electrical power and acting as distributed electricity generators when parked and connected to a fuel supply.

Light-duty FCEVs are now available in limited quantities to the consumer market. The market is also developing for fleet vehicles, material handling equipment, ground support equipment, medium- and heavy-duty vehicles, and stationary applications. As discussed in the **U.S. Department of Energy Programs section in Part I (Section I.A)**, federal programs, like DOE's grant programs and federal investment in a consortium to focus on development of heavy duty FCEVs, will be important to grow this sector. The success

of hydrogen in the transportation sector will depend on developing and commercializing competitive FCEVs. Researchers continue to develop increasingly lightweight and compact automotive fuel cell systems that are tolerant to rapid cycling and on-road vibration; reliable for hours of non-continuous, all-weather use; able to respond rapidly to transient demands for power; and able to use hydrogen of varying purity.

Further cost reductions in hydrogen fuel cell technology and the construction of hydrogen refueling infrastructure will be required for the FCEV market to expand. Policy, regulation, and government incentives, like those discussed in the **U.S. Department of Energy Programs section in Part I (Section I.A)**, are likely to play an important role in the development of hydrogen refueling infrastructure, particularly in the early stages of adoption.

California leads the nation in funding and building hydrogen fueling stations. As of 2019, there were 40 retail hydrogen stations in California and 20 more in various stages of construction or planning. The California Energy Commission is authorized to allocate a maximum of $20 million annually through 2024, until there are at least 100 operational stations in the state. In addition, 12 retail stations are planned for the northeast United States. Non-retail stations also continue serving FCEVs, including buses, for research or demonstration purposes. Multiple stakeholders have announced plans regarding the production of heavy-duty vehicles such as line-haul trucks that will push fueling stations to have much higher capacities than existing light-duty stations.

B. Marine Fuel

Hydrogen is also being explored as a maritime fuel. The shipping industry primarily relies on diesel engines, with oceangoing vessels using heavy fuel oil or marine diesel to power propulsion. A small fraction of vessels use LNG or CNG. However, the use of high-emission fuels is increasingly regulated as pollution and greenhouse gas emission concerns mount. On 1 January 2020, the IMO required all shipping fuels to contain no more than 0.5 percent sulfur. This recent cap is a significant reduction from the prior sulfur limit of 3.5 percent and is well below the industry average of 2.7 percent.

Powering ships with hydrogen fuel cells could curb emissions of pollutants in maritime applications. Such fuel cells, however, also must compete with low-sulfur marine gas oil and LNG combustion engines on the basis of total cost of ownership before they can supersede these technologies. While hydrogen's lower fuel mass can benefit the economics of oceanic transport, for the time being, hydrogen-powered vessels are not considered cost competitive. In addition, international technical standards still need to be developed to use gaseous fuels like hydrogen for transoceanic shipping.

The first zero-emission vessels are expected to be powered by a hybrid of fuel cells and batteries. Even for smaller passenger ships, ferries, or recreational crafts, the use of hydrogen-powered fuel cells for ship propulsion is still at an early design or trial phase. Fuel cells have yet to be scaled for and used on large merchant vessels. Despite the nascence of marine propulsion applications, fuel cells can serve other purposes for such vessels. Because fuel cells deliver substantial direct current (DC) power, they can also serve on-board electric loads, and surplus heat generated by the fuel cells could be used to heat water for HVAC, laundry, and other systems.

C. "Hydrail" Hydrogen as Rail Fuel

The EPA regulates the exhaust emissions from locomotives by establishing different tiers depending on the construction year of the locomotive. The EPA's increasingly stringent emission reduction requirements have presented challenges to locomotive manufacturers. Other countries have begun to reduce rail emissions by electrifying route miles, meaning those routes are zero-carbon if powered by a renewable source of electricity. U.S. railroads, however, are a regulated private sector industry, which makes financing electrification upgrades more difficult for railroad companies. As a result, electrified rail is currently used on less than 1 percent of U.S. railroad tracks, compared to the more than one-third of the electric energy that powers trains globally.

Because rail is already among the lowest greenhouse gas emitting modes of transportation, the massive overhaul required to electrify railroad systems may provide only incremental benefits and not justify the costs. On the other hand, hydrogen-powered trains could play a role in decarbonizing rail systems without incurring the high cost of electrifying tracks. Hydrogen-powered trains are less expensive, do not require massive track overhauls, and commenters predict that they can be created by retrofitting existing diesel trains.

Hydrogen-fueled trains pose a host of benefits and hurdles. Like electric trains, they are much quieter than their diesel counterparts. Hydrogen-powered trains have additional benefits, such as the ability to switch to fuel cells when electricity lines are down. Given relative volumes of freight volume in the United States, the ability to convert freight trains to hydrogen power will be key to implementing this technology on a mass scale.

D. Industrial and Manufacturing Feedstock

According to the IEA, 33 percent of hydrogen is used in oil refining, 27 percent is used for ammonia production (principally for fertilizer), 11 percent for methanol production, and 3 percent for steel production via the direct reduction of iron ore. There is significant potential for green hydrogen to clean up the production of ammonia for fertilizer. Currently, fertilizer consumes 3-5 percent of global natural gas production and causes 1.5 percent of global carbon emissions. Ammonia made from hydrogen produced by renewable electricity could significantly reduce emissions as almost 90 percent of ammonia goes into fertilizer production. With fewer stakeholders and less reliance on associated infrastructure, green fertilizer solutions can be developed and implemented comparatively quickly.

The direct reduction of iron ore uses hydrogen and synthesis gas to separate oxygen from iron. Green hydrogen could serve an important industrial process in steel manufacturing, compared to the traditional blast furnace method that releases large amounts of carbon. While direct reduction with natural gas is well-established in steel production, production methods based on hydrogen exist only in pilot programs.

Hydrogen is also used to process crude oil into refined fuels, such as gasoline and diesel, and also to remove contaminants, such as sulfur. Hydrogen use in refineries has increased in recent years due to regulations requiring low sulfur in diesel, the increased consumption of low quality ”heavy” crude oil (which requires more hydrogen to refine), and the increased oil consumption in developing economies. Hydrogen is also an important basic component for producing methanol, which can be used directly as a fuel in internal combustion engines. Methanol is also used to produce fuel additives and transesterify vegetable oils to form biodiesel. Hydrogen’s other industrial applications include metalworking, flat glass production, the electronics industry, and applications in electricity generation, for example, for generator cooling or for corrosion prevention in power plant pipelines.

E. Heating

While the generation of low-carbon electricity has increased dramatically, heating systems still rely significantly on fossil-based fuels and are significantly less green. The IEA estimates that nearly 28 percent of global energy-related carbon dioxide emissions result from energy use in buildings. Hydrogen could reduce these heating-related emissions if green hydrogen is blended with natural gas to reduce the carbon intensity of the feedstock. Trials have used blends of up to 20 percent hydrogen, but the production costs of low-carbon hydrogen—although decreasing—are likely to be an initial barrier to wider adoption. Overall, however, the decreasing costs of hydrogen and related technologies will be the most important factors in galvanizing widespread adoption for heating uses.

F. Very Long Duration Energy Storage

Once hydrogen is produced through electrolysis, it can be stored as a compressed gas, cryogenic liquid, or wide variety of loosely bonded hydride compounds for later use. Unlike batteries, which suffer from storage degradation and can store a limited amount of energy, hydrogen fuel can be stored for long periods of time and in quantities only limited by the size of the storage facility. Hydrogen compares well to other long-duration storage technologies, like pumped water storage, that can only be used in limited geographic areas and require vast areas of land. Hydrogen offers the potential to provide energy-storage solutions for off-grid electricity systems and to balance electric grids. For the time being, use of large-scale hydrogen storage and dispatchable hydrogen power generation systems remains expensive due to significant energy losses. Current technologies only allow for the re-electrification of hydrogen in fuel cells with efficiencies of up to 50 percent or burning in combined cycle gas power plants with efficiencies of up to 60 percent. As discussed in the **Project Finance section of Part I (Section II)**, the cost of very long duration energy

storage for hydrogen is expected to drop significantly in the next decade.

V. Government Incentives for Hydrogen Use

In addition to the federal incentives discussed in the **U.S. Department of Energy Programs section in Part I (Section I.A)**, several states have implemented incentive programs that will help promote the use of hydrogen. Examples of such programs are discussed below.

Arizona

Arizona offers several incentives, including the Reduced Alternative Fuel Vehicle (AFV) License Tax, the State Vehicle Acquisition and Fuel Use Requirements, and the Alternative Fuel and Alternative Fuel Vehicle Use Tax Exemption. Under the Reduced AFV License Tax program, the vehicle license tax for an AFV registered in Arizona is $4 for every $100 in assessed value. The minimum amount of the annual AFV license tax is $5. AFV assessed values are determined as follows:

- AFVs registered prior to 1 January 2022: 1 percent of the manufacturer's suggested retail price (MSRP).
- AFVs initially registered between 1 January 2022 and 31 December 2022: 20 percent of the MSRP.
- For each succeeding year, for the purpose of calculating the license tax, the value of the AFV is reduced by 15 percent from the value for the preceding year.

For the purpose of this tax, AFVs include those powered exclusively by propane, natural gas, electricity, hydrogen, or a blend of hydrogen with propane or natural gas.[220]

The State Vehicle Acquisition and Fuel Use Requirements directs Arizona state agencies, boards, and commissions to purchase hybrid electric vehicles, AFVs, or vehicles that meet set greenhouse gas emissions standards. At least 75 percent of light-duty state fleet vehicles operating in counties with a population of more than 250,000 people must be capable of operating on alternative fuels. If the AFVs operate in counties with populations of more than 1.2 million people, those vehicles must meet EPA emissions standards for Low Emission Vehicles. Alternatively, the state fleet may meet AFV acquisition requirements through biodiesel or alternative fuel use or apply for waivers. For the purpose of these requirements, alternative fuels include propane, natural gas, electricity, hydrogen, qualified diesel fuel substitutes, E85, and a blend of hydrogen with propane or natural gas.[221] The Alternative Fuel and Alternative Fuel Vehicle Use Tax Exemption exempts Arizona use taxes on natural gas or propane used in an AFV, AFVs converted to operate on alternative fuels, or the equipment used to convert

220 *NC Clean Energy Technology Center: Database of State Incentives for Renewables & Efficiency*, NC STATE UNIVERSITY, https://www.dsireusa.org/ (last visited Aug. 7, 2020).

221 *Id.*

a diesel vehicle to an AFV. Recognized alternative fuels include propane, natural gas, electricity, hydrogen, and a blend of hydrogen with propane or natural gas.[222]

California

In California, several localities have offered incentives for alternative fuels, including hydrogen. The Sacramento Emergency Clean Air and Transportation Program provides grants to offset the costs of zero-emission heavy-duty vehicles that reduce on-road emissions within the counties of El Dorado, Placer, Sacramento, Sutter, Yolo, and Yuba in California. Eligible projects include the purchase of battery electric or hydrogen fuel cell trucks, buses, and shuttles. Other advanced technology implementation projects may also qualify.[223] Additionally, the San Joaquin Valley Air Pollution Control District (SJVAPCD) administers the Drive Clean! Rebate Program, which provides rebates for the purchase or lease of eligible new vehicles, including qualified natural gas, hydrogen fuel cell, propane, all-electric, plug-in electric vehicles, and zero emission motorcycles. The program offers rebates of up to $3,000, which are available on a first-come, first-served basis for residents and businesses located in the SJVAPCD.[224]

Connecticut

The Connecticut Hydrogen and Electric Automobile Purchase Rebate Program offers rebates for the incremental cost of the purchase or lease of a hydrogen FCEV, all-electric vehicle (EV), or plug-in hybrid electric vehicle (PHEV). The manufacturer suggested retail price for eligible vehicles may not exceed $60,000 for FCEV models and $42,000 for EV and PHEV models.[225]

District of Columbia

The District of Columbia offers the Alternative Fuel Vehicle Conversion and Infrastructure Tax Credit. This tax credit makes businesses and individuals eligible for an income tax credit of 50 percent of the equipment and labor costs for the conversion of qualified AFVs, up to $19,000 per vehicle. A tax credit is also available for 50 percent of the equipment and labor costs for the purchase and installation of alternative fuel infrastructure on qualified AFV fueling property. The maximum credit is $1,000 per residential electric vehicle charging station and $10,000 per publicly accessible AFV fueling station. Qualified alternative fuels include ethanol blends of at least 85 percent, natural gas, propane, biodiesel, electricity, and hydrogen.[226]

Indiana

Indiana's Alternative Fuel Vehicle Inspection and Maintenance Exemption exempts dedicated AFVs from inspection and maintenance requirements if they operate exclusively

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222 *Id.*

223 *Id.*

224 *Id.*

225 *Id.*

226 *Id.*

on natural gas, propane, ethanol, hydrogen, or methanol.[227]

Massachusetts

The Massachusetts Department of Energy Resources' Clean Vehicle Project offers grants for public and private fleets to purchase alternative fuel vehicles and infrastructure, as well as idle reduction technology. Eligible vehicles include those fueled by natural gas, propane, and electricity, including hybrid electric and hydraulic hybrid vehicles. Eligible infrastructure includes natural gas and hydrogen fueling stations as well as electric vehicle supply equipment (EVSE), including solar powered EVSE.[228] Moreover, the Massachusetts Department of Environmental Protection's Volkswagen Open Solicitation Grant Program provides up to 80 percent of the cost of new diesel or alternative fuel replacements and repowers for eligible government entities. For eligible non-government entities, the program provides up to 40 percent of the cost of a new diesel or alternative fuel repower, up to 25 percent of the cost of a new diesel or alternative fuel vehicle, and up to 75 percent of the cost of an all-electric repower or replacement, with associated charging infrastructure. Qualifying alternative fuels include, but are not limited to, natural gas, propane, hydrogen, and diesel electric hybrid.[229]

Michigan

The Michigan Department of Environmental Quality requirement to obtain an installation permit does not apply to qualified natural gas, hydrogen, and propane storage and handling equipment at dispensing facilities.[230]

Missouri

Missouri offers an Alternative Fuel Vehicle Emissions Inspection Exemption for vehicles powered exclusively by electricity, including low-speed vehicles, hydrogen, or fuels other than gasoline that are exempt from motor vehicle emissions inspection under federal regulation.[231]

New Mexico

The New Mexico Energy, Minerals and Natural Resources Department's Alternative Fuel Acquisition Revolving Loan Program provides loans to state agencies, political subdivisions, and educational institutions for AFV acquisitions. Funds must be used for the purchase of vehicles that operate on natural gas, propane, electricity, or hydrogen.[232]

New York

Under New York's Alternative Fueling Infrastructure Tax Credit, residents can gain a tax credit for 50 percent of the cost of alternative fueling infrastructure, up to $5,000. Qualifying infrastructure includes

227 *Id.*

228 *Id.*

229 *Id.*

230 *Id.*

231 *Id.*

232 *Id.*

electric vehicle supply equipment and equipment to dispense fuel that is 85 percent or more natural gas, propane, or hydrogen. Unused credits may be carried over into future tax years.[233]

Pennsylvania

The Pennsylvania AFV Program offers rebates to assist eligible residents with the incremental cost of the purchase or lease of new AFVs, including EVs, PHEVs, FCEVs, CNG vehicles, electric motorcycles, and propane vehicles. Eligible FCEVs must have a total purchase price not exceeding $75,000, and all other eligible AFVs must have a total purchase price not exceeding $50,000. An additional rebate of $1,000 is available for all vehicles if an applicant meets the low-income requirement, as defined by the U.S. Department of Health and Human Services.[234] Additionally, the Alternative Fuels Incentive Grant Program provides reimbursement grants for the installation of alternative fuel infrastructure along Pennsylvania interstate highway corridors. Grants are available for reimbursement of 50 percent of the cost, up to $500,000, to install public electric, hydrogen, propane, and compressed natural gas fueling infrastructure along "Signage Ready" or "Signage Pending" highway corridors in Pennsylvania, as defined by the U.S. Department of Transportation.[235]

Pennsylvania also offers the Electric Vehicle Supply Equipment and Hydrogen Fuel Cell Infrastructure Grants through the Pennsylvania Department of Environmental Protection. Under this program, grants are offered for the acquisition, installation, operation, and maintenance of publicly available DC fast charging equipment and hydrogen fueling infrastructure. Eligible project locations are transportation corridors, destination locations, and locations that serve as community charging or fueling hubs.[236]

South Carolina

South Carolina offers a sales tax exemption for "any device, equipment, or machinery operated by hydrogen or fuel cells, any device, equipment or machinery used to generate, produce, or distribute hydrogen and designated specifically for hydrogen applications or for fuel cell applications, and any device, equipment, or machinery used predominantly for the manufacturing of, or research and development involving hydrogen or fuel cell technologies."[237]

Texas

The Texas Commission on Environmental Quality (TCEQ) administers the Light-Duty Motor Vehicle Purchase or Lease Incentive Program for the purchase or lease of a new light-duty vehicle powered by CNG, propane, hydrogen, or electricity. CNG and propane vehicles, including bi-fuel vehicles, are eligible

233 *Id.*

234 *Id.*

235 *Id.*

236 *Id.*

237 *Id.*

for a rebate of $5,000 for the first 1,000 applicants. Electric drive vehicles powered by a battery or hydrogen fuel cell, including plug-in hybrid electric vehicles with a battery capacity of at least 4 kilowatt hours, are eligible for a rebate of $2,500, for the first 2,000 applicants.[238] TCEQ also provides funding for eligible medium- and heavy-duty on-road alternative fuel vehicles or engine repowers and replacements, as well as for associated electric vehicle and hydrogen fueling infrastructure. Both government and non-government entities that own and operate diesel fleets and equipment are eligible for funding.[239]

Additionally, Texas exempts propane, natural gas, electricity, and hydrogen, also known as clean fuel or special fuel, used to operate motor vehicles from state fuel taxes, but subject to a special fuel tax at the rate of three-nineteenths of the conventional motor fuel tax. A reduction in special fuel tax is permissible if the fuel is already taxed by the Navajo Nation. Retailers, wholesalers, and suppliers of special fuel are eligible for a refund of the special fuel tax if dyed diesel fuel is mixed with special fuel and the mixed special fuel is returned to the refinery.[240]

Utah

In Utah, qualified taxpayers are eligible for a tax credit for the purchase of a qualified heavy-duty AFV. Qualifying fuels include natural gas, electricity, and hydrogen. At least 50 percent of the qualified vehicle's miles must be driven in the state. A single taxpayer may claim credits for up to 10 AFVs or $500,000 annually. If more than 30 percent of the total available tax credits in a single year have not been claimed by May 1, a taxpayer may apply for credits for an additional eight AFVs. Up to 25 percent of the tax credits are reserved for taxpayers with small fleets of less than 40 vehicles.[241]

Virginia

Under Virginia's Green Jobs Tax Credit, qualified employers are eligible for a $500 tax credit for each new green job created that offers a salary of at least $50,000, for up to 350 jobs per employer. The credit is allowed for the first five years that the job is continuously filled. For the purposes of this tax credit, a green job is defined as employment in industries relating to renewable or alternative energy, including hydrogen and fuel cell technology, landfill gas, and biofuels.[242]

Virginia also offers the Alternative Fuel and Hybrid Electric Vehicle (HEV) Emissions Testing Exemption. This exemption is offered to vehicles that are powered exclusively by natural gas, propane, hydrogen, a combination of compressed natural gas and hydrogen. Qualified HEVs with EPA fuel economy

238 *Id.*

239 *Id.*

240 *Id.*

241 *Id.*

242 *Id.*

ratings of at least 50 miles per gallon (city) are also exempt from the emissions inspection program unless remote sensing devices indicate the HEV may not meet current emissions standards.[243]

Washington

Washington state offers the most incentives for alternative fuel in the country. The Plug-In Electric Vehicle (PEV) and Fuel Cell Electric Vehicle Infrastructure and Battery Tax makes public lands used for installing, maintaining, and operating PEV infrastructure exempt from leasehold excise taxes. Additionally, the state sales and use taxes do not apply to PEV and FCEV batteries or fuel cells; labor and services for installing, repairing, altering, or improving PEV and FCEV batteries or fuel cells and PEV and hydrogen fueling infrastructure; the sale of property used for PEV and hydrogen fueling infrastructure; and the sale of zero emission buses.[244]

The Alternative Fuel Commercial Vehicle and Fueling Infrastructure Tax Credit allows businesses to receive tax credits for purchasing new alternative fuel commercial vehicles and installing alternative fueling infrastructure. Eligible alternative fuels are natural gas, propane, hydrogen, dimethyl ether, and electricity. Tax credits for qualified alternative fueling infrastructure are for up to 50 percent of the cost to purchase and install the infrastructure. Commercial vehicle tax credit amounts vary based on gross vehicle weight rating and are up to 75 percent of the incremental cost. This exemption also applies to qualified used vehicles modified with an EPA-certified aftermarket conversion, as long as the vehicle is being sold for the first time after modification. Modified vehicles are eligible for credits equal to 30 percent of the commercial vehicle conversion cost, up to $25,000. Each entity may claim up to $250,000 or credits for 25 vehicles per year.[245]

Additionally, the Washington state Department of Transportation (WSDOT) offers competitive grants to strengthen and expand the West Coast Electric Highway network by deploying electric vehicle supply equipment with Level 2 and DC fast chargers and hydrogen fueling infrastructure along highway corridors in Washington. Eligible project costs include siting, equipment purchases, electrical upgrades, installation, operations, and maintenance.[246] WSDOT will also establish a green transportation capital grant program to fund projects to reduce the carbon intensity of the Washington transportation system, including fleet electrification, modification, or replacement of facilities to facilitate fleet electrification and hydrogen fueling, upgrades to electrical transmission and distribution systems, and construction of charging and fueling infrastructure. In order to receive funding for a project, a

243 *Id.*

244 *Id.*

245 *Id.*

246 *Id.*

transit authority must provide matching funding for that project that is at least equal to 20 percent of the total cost of the project.[247]

Finally, Washington state also offers the Retail Sales and Use Tax Exemption whereby the retail sales and state use tax of 6.5 percent does not apply to the sale or lease of new or used passenger vehicles, light-duty trucks, and medium-duty passenger vehicles that are exclusively powered by an alternative vehicle fuel or are capable of running solely on electricity for at least 30 miles. Eligible alternative fuels are natural gas, propane, hydrogen, and electricity. Vehicles must not have a selling price plus trade-in property value that exceeds \$45,000 for new vehicles and \$30,000 for used vehicles. The maximum eligible amount for used purchased or leased vehicles is \$16,000.[248]

247 *Id.*

248 *Id.*

GLOSSARY UNITED STATES

AFV	Alternative Fuel Vehicle
AIP	Airport Improvement Program
ALK	alkaline electrolysis
Bcf	billion cubic feet
BIS	U.S. Department of Commerce, Bureau of Industry and Security
BTU	British thermal unit
CAA	Clean Air Act
CARB	California Air Resources Board
CBP	U.S. Customs and Border Protection
CCL	Commerce Control List
CCS	carbon capture and sequestration
CEC	California Energy Commission
CERCLA	Comprehensive Environmental Response, Compensation, and Liability Act
CNG	compressed natural gas
CPUC	California Public Utilities Commission
CWA	Clean Water Act
DC	direct current
DOE	U.S. Department of Energy
DOI	U.S. Department of the Interior
DOT	U.S. Department of Transportation
EAR	Export Administration Regulations
ECCN	Export Control Classification Number
EIA	U.S. Energy Information Administration
EPA	U.S. Environmental Protection Agency
EPCRA	Emergency Planning and Community Right-to-Know Act
ESA	Endangered Species Act
EV	all-electric vehicle
EVSE	electric vehicle supply equipment
FAA	Federal Aviation Administration
FCEVs	fuel cell electric vehicles
FE	U.S. Department of Energy's Office of Fossil Energy
FERC	Federal Energy Regulatory Commission
FMCSA	Federal Motor Carrier Safety Administration
GT&C	general terms and conditions of service
HEV	hybrid electric vehicle
HMR	Hazardous Materials Regulations
HTSE	high temperature steam electrolysis
IEA	International Energy Agency

IEPR	Integrated Energy Policy Report
IGC Code	International Code for the Construction and Equipment of Ships Carrying Liquefied Gases in Bulk
IMO	International Maritime Organization
IRENA	International Renewable Energy Agency
IRPs	Integrated Resource Plans
ITC	investment tax credit
kw	kilowatts
LCFS	Low Carbon Fuel Standard
LH2	liquid hydrogen
LNG	liquefied natural gas
LTE	low temperature electrolysis
Mcf	million cubic feet
MMst	million short tons
MSRP	manufacturer's suggested retail price
NAESB	North American Energy Standards Board
NEPA	National Environmental Policy Act
NGA	Natural Gas Act
NGPSA	Natural Gas Pipeline Safety Act
NPR	Naval Petroleum Reserves of the United States
OFAC	Office of Foreign Assets Control
OSHA	Occupational Safety and Health Administration
PEM	proton exchange membrane electrolysis
PEV	plug-in electric vehicle
PHEV	plug-in hybrid electric vehicle
PHMSA	Pipeline and Hazardous Materials Safety Administration
PSI	pounds per square inch
R&D	research and development
RCRA	Resource Conservation and Recovery Act
RMP	EPA's Risk Management Plan
RNG	renewable natural gas
SDWA	Safe Drinking Water Act
SJVAPCD	San Joaquin Valley Air Pollution Control District
SMR	steam methane reforming
TCEQ	Texas Commission on Environmental Quality
Tcf	trillion cubic feet
USCG	U.S. Coast Guard
WSDOT	Washington State Department of Transportation
ZEV	zero emission vehicle

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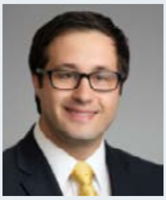

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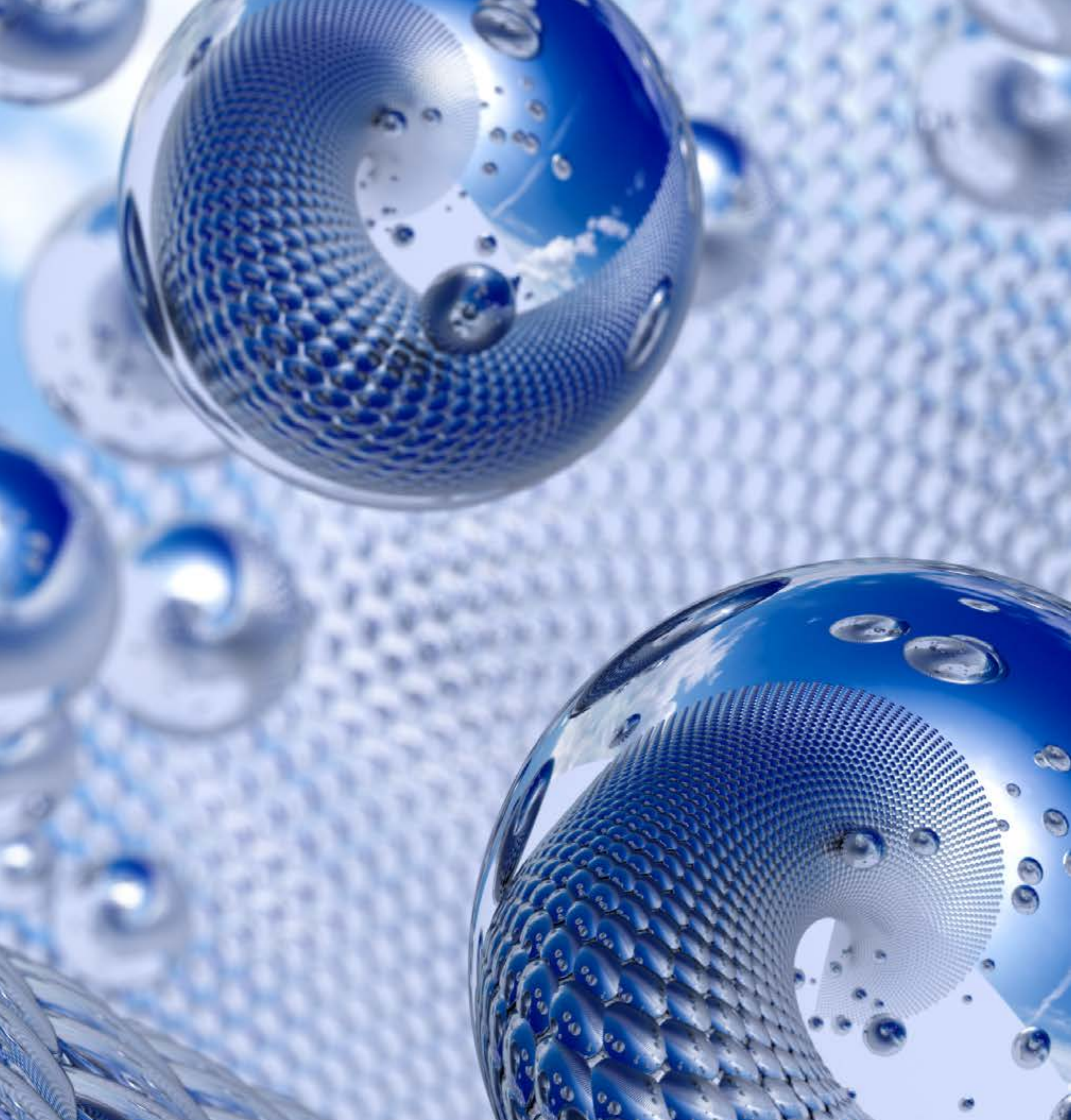

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