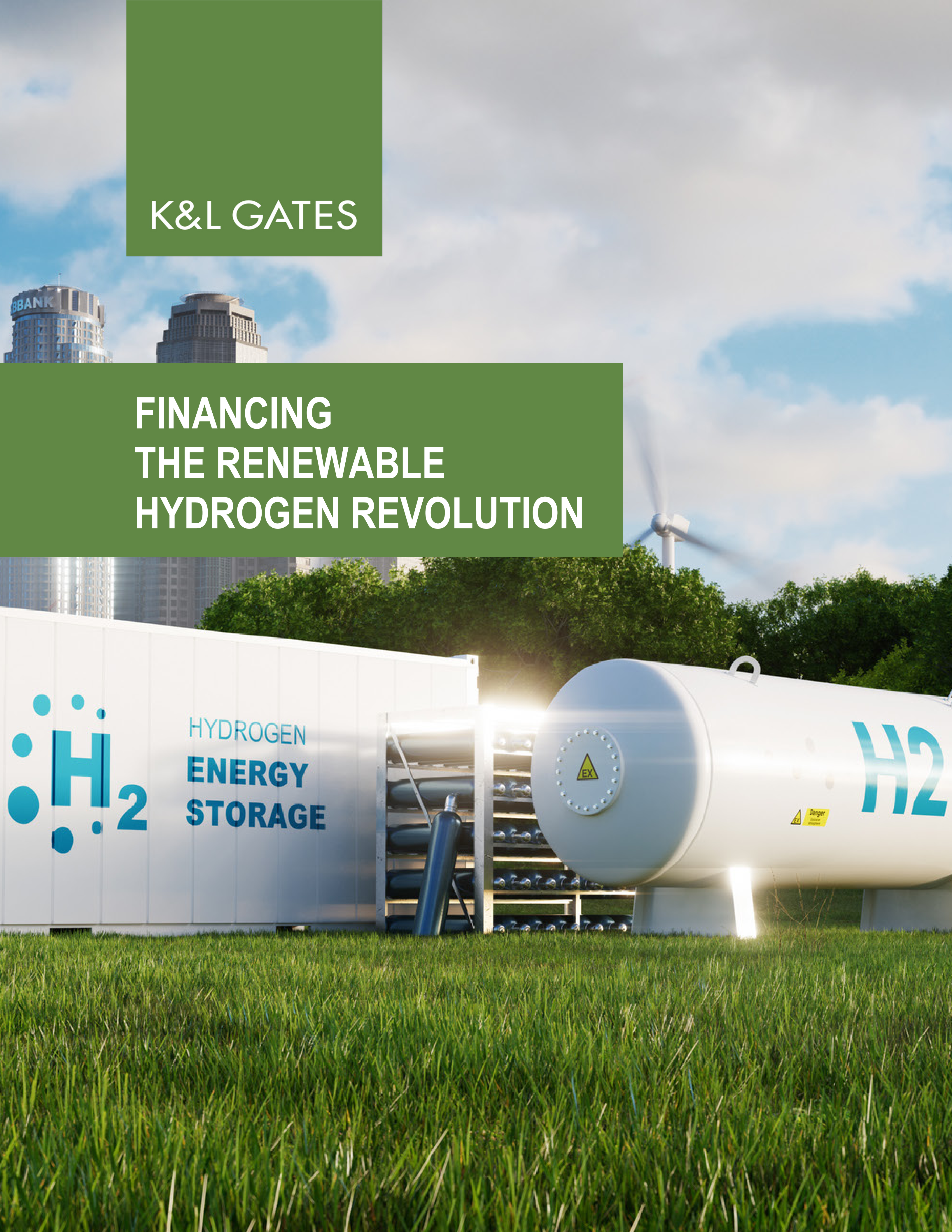
K&L GATES

FINANCING THE RENEWABLE HYDROGEN REVOLUTION



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INTRODUCTION

Now is the time for renewable hydrogen in the United States. Or is it? Hydrogen produced using renewable inputs has been a hot topic for several years. But "future fuel" has been the term of choice until very recently.

Today, the early action taken by several leaders in the field is being combined with federal and, in some places, state government grant programs and federal tax credits. And, there is increasing demand for renewable hydrogen as fuel for transit and logistics vehicles, industrial applications, and as an input for agricultural ammonia and methanol fuels.

But does all that add up to financeable projects yet? The answer is yes, sometimes. The field of renewable hydrogen is complicated and no two projects are exactly the same. Moreover, only certain technologies are currently viable at scale. Our clients are pursuing mega projects in blue ammonia and multi-node regional projects in green hydrogen. They are adapting impressive and proven e-methanol technologies to U.S. regulatory regimes and market realities, and creating demand for green hydrogen fuels. The market is moving and more and more U.S. projects are reaching financial investment decision every month, if not yet every day.

We hope this short guide helps you to think about the risk factors for renewable hydrogen, particularly green hydrogen, in the United States today. For more information, we hope you will refer to our acclaimed *The Hydrogen Handbook*[i], which addresses the hydrogen industry in many parts of the world, as well as the United States.

Today and every day, we salute you for your work to advance the energy transition. We would be honored to help you plan and execute your next moves in the hydrogen revolution.

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IDENTIFYING THE RISKS

Risk in the hydrogen industry spans multiple areas, from feedstock and power supply to offtake and transportation. Understanding the regulatory and practical considerations of each of these areas is essential for formulating an investment strategy for renewable hydrogen.

Before we start, one quick note about scope: while we discuss “blue” hydrogen to a limited extent below, given that renewable electricity has a more limited impact in that context, the majority of this white paper is focused on “green” hydrogen produced using water, renewable electricity, and electrolyzers. Similarly, we have not provided any focused discussion of hydrogen derivatives such as ammonia and methanol. The shape of demand and supply for those commodities is somewhat different to hydrogen, and the regulatory requirements may be as well. We’re glad to discuss these topics individual, however.

Risk: Access to Feedstock

Most hydrogen today is “gray”, that is, produced using natural gas in a steam methane reformation system (SMR). Some is “blue”, i.e., produced using natural gas in an SMR process, but rather than emitting the carbon dioxide that is a byproduct of the SMR process, the carbon dioxide is captured and sequestered. Hydrogen can also be produced using water and electricity and is dubbed “green” when that electricity is generated by renewable resources. While other technologies are emerging and, in some cases, are already available, we focus here on water, electricity, and renewable natural gas.

Water

As the U.S. green hydrogen industry scales, the availability of water will create constraints, both because of volume available and the legal regimes that impact access.

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, riparian regimes generally offer more water and more flexible water use arrangements than other legal structures.

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.

Obtaining water rights in prior appropriation states is not impossible. Rights can be bought, sold, transferred, leased, and banked. However, nearly all forms of ownership transfer require hydrogeological support and significant interaction with multiple regulatory agencies. Sound advice from experienced legal counsel is essential.

Renewable Electricity

Solar, Wind, and Hydropower

Renewable electricity provides two key advantages: low cost and low emissions. Although we have seen a few years of cost increases, many analysts today predict another period of falling prices due to reduced supply chain congestion and increased efficiency born of technological advancement. Moreover, hope is growing for large scale revitalization of transmission infrastructure. Renewable power also appears to be the cleanest way of achieving an optimal carbon intensity score for hydrogen under the Argonne Labs Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation, which is essential to maximize available U.S. federal income tax credits.

Intermittency in renewable generation is a well-known risk. Energy storage has long been the ideal solution to this challenge. Energy storage improvements and innovations remain an industry focus, and the price for lithium ion and flow battery solutions continues to fall rapidly. However, hydrogen is another solution to this problem. Electrolyzers can be run in times of power abundance and be curtailed when electricity is more valuable on the grid. Time-of-day pricing can make this business model viable, particularly because electrolyzers can cycle on and off rapidly. This is useful in regulating the frequency fluctuations on the electricity grid, so in many markets, the facility may earn a payment for this ancillary service.

Where it is necessary for renewable generation to be collocated with hydrogen production equipment to be considered “green”, typical regulatory requirements will apply to the generation equipment. For example, when a project is located on federal land or requires federal permits, the National Environmental Policy Act (NEPA)[ii] must be addressed. Potential impact to wildlife under the Endangered Species Act (ESA) must also be considered and accounted for. State and local environmental regulations also must be considered.

Interconnection requirements for behind-the-meter electricity produced solely for hydrogen production will vary by jurisdiction, but often can be substantially reduced or eliminated, also creating significant cost savings.

Nuclear

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 electrolyzers located adjacent to reactors can offer flexibility to the market. Assuming it can scale to be cost-competitive, nuclear power also offers a major advantage over the current predominant methods of producing hydrogen: it is 100% carbon free.

The potential of using nuclear energy assets for hydrogen production has attracted interest from the private sector and the U.S. Department of Energy (DOE). The DOE recently is supporting at least four utilities in the development of pilot projects to demonstrate low-temperature electrolysis and high-temperature steam electrolysis technologies using nuclear reactors to produce hydrogen. However, there is uncertainty as to whether nuclear hydrogen production systems, especially HTSE technology, can scale to be commercially viable.[iii] The scaling issue is critical since generating hydrogen using electrolyzers at existing nuclear power plants is not yet cost-competitive.[iv]

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. The next generation of advanced reactors will feature safety systems to mitigate that risk, and offer further advantages to producing hydrogen. They will also likely operate at higher temperatures and would therefore more efficiently generate steam for hydrogen production.[v] 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. Moreover, 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, an explosive gas, may raise potential safety risks.

Renewable Natural Gas

Natural gas contains methane (CH4) and can be used to produce hydrogen via SMR. 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.

While fossil gas has been used to produce hydrogen in SMR processes (and some gasification technologies) for many years, using renewable natural gas (RNG) is an intriguing possibility. RNG is methane derived from biomass such as dairy and agricultural waste, wastewater, food waste, and landfill.[vi] The methane content of RNG is comparable to fossil gas and can be transported using the same infrastructure. In 2018, there were more than 2,200 sites across the United States in all 50 states producing biogas.[vii]

However, biomass-to-hydrogen technologies may need carbon capture and sequestration (CCS) to achieve the low carbon intensity score necessary to obtain the most lucrative U.S. federal income tax credits. CCS generally requires careful compliance with EPA regulations, particularly with regard to the sequestration phase, as well as additional transportation and offtake pressures.

Risk: Siting and Permitting

Siting and permitting considerations vary based on the type of hydrogen production equipment used. While considerations pertinent to routine electrolyzer plants may be limited, all industrial facilities inherently require analysis of environmental regulation. These considerations may compound for other types of technologies. For example, large-scale photolytic production of hydrogen would require the construction and use of utility-scale infrastructure that may impact surrounding land, water resources, and wildlife. Similarly, solar thermochemical production of hydrogen would require utility-scale infrastructure to concentrate sunlight onto a reactor tower using heliostats. And don't forget the potential complications of adding local storage and pipeline interconnection, if and when available.

In all cases, NEPA will be at issue if the project is located on federal land or, more likely, requires federal permits. ESA requirements also must be considered, as well as exposure to state and local requirements. Additionally, processes that create water as a byproduct may implicate the Clean Water Act (CWA) if the water will be discharged locally. Navigating environmental regulations for new and emerging technologies can be fraught and should always be done with careful consideration of the pros and cons of different approaches.

Risk: Transportation

The United States generally has robust transportation regulatory regimes to ensure safety and reliability, as well as access and competition. However, transportation of hydrogen is a distinctly underdeveloped area today. This adds up both to current challenges as well as opportunities to shape the regulatory environment as federal and state agencies address the need for pipelines and large-scale storage.

Modes of Transportation

Hydrogen can be transported in a variety of ways, but today most hydrogen is transported by truck as a compressed gas in tube trailers and as a liquid in cryogenic tankers. Since hydrogen is a potentially hazardous substance, it is subject to significant regulation by the Federal Motor Carrier Safety Administration and the Pipeline and Hazardous Materials Safety Administration (the PHMSA). In additional, truck transport is generally subject to Department of Transportation pressure and vehicle weight restrictions.

Rail is an increasingly attractive option for hydrogen transportation that has been authorized for many years, but not fully utilized. The PHMSA also has jurisdiction over rail travel and regulates hydrogen transportation by rail under it Hazardous Materials Regulations. One reason why green hydrogen production at disused coal-fired generation facilities has recently become a very popular option is because of each access to rail transportation (as well as existing electricity interconnection).

Achieving scale for hydrogen use in distributed applications would be facilitated by extensive pipelines for its transportation. Small amounts of hydrogen can be added to existing natural gas pipelines and the mixed gas is generally suitable for applications that would otherwise use pipeline quality natural gas.[viii] However, transportation of mixed gas with larger quantities of hydrogen or pure hydrogen generally requires purpose-built pipeline, not merely repurposed natural gas infrastructure. While there are currently a few small hydrogen-specific pipelines in the United States, there is not yet a major interstate pipeline and constructing one would be a major regulatory undertaking under current law.

Finally, in recent years, there has been a marked increase in interest in vessel transportation of liquefied hydrogen, as well as ammonia and methanol. Like pipeline transportation, the regulatory environment for maritime transportation is complex, particularly in regard to foreign flag vessels calling on U.S. ports.

Environmental Regulation

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. It is therefore 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 Resource Conservation and Recovery Act (RCRA). This is important for every mode of transportation.

Similarly, hydrogen may not fall under the CWA definition of "pollutant" given that hydrogen cannot linger in water or other liquids unless contained at extremely high pressures. However, the EPA's precise stance on this issue is not currently known. Hydrogen does appear on the Clean Air Act list of regulated substances under Section 112(r), which triggers EPA's Risk Management Plan rule for certain larger storage quantities of hydrogen, but hydrogen appears on this list only due to its flammability.

Despite the light touch under current environmental law, we expect additional regulatory pressure in transportation as the industry evolves.

Risk: Procurement and Construction

Production Equipment

The field of original equipment manufacturers (OEMs) in the hydrogen industry is currently quite limited, particularly when considering the electrolyzers used to produce green hydrogen. Historically, most electrolyzer OEMs were headquartered and typically operated in Europe, where demand is already strong. In recent years, American and Chinese manufacturers have entered the field and BloombergNEF reported that in 2022, Chinese manufacturers led global production of alkaline and PEM electrolyzers.[ix] Nonetheless, electrolyzer costs are still seen as a significant hurdle to scalable production of green hydrogen. Significant federal government investment in electrolyzer manufacturing through the Hydrogen Hubs program, other DOE grant programs, and the Code[x] Section 48C tax credit are expected to help push the industry to invest in additional manufacturing facilities in the United States, which should help to increase the supply and drive down the cost of electrolyzers in the near to medium term.

Warranties

In renewable energy, a project developer's goal is generally to engage a single engineering, procurement, and construction (EPC) contractor that provides all engineering, design, equipment selection and purchasing, subcontracting, installation, construction, performance testing and guarantees, and warranties. In this case, the EPC contract is typically structured as a fully "wrapped" contract, i.e., the contract aggressively shifts as much risk as possible from the project owner to the EPC contractor. This has become the norm in the U.S. renewable electricity industry.

However, in a renewable hydrogen project, it is more likely that a project owner will enter into separate contracts, for example, one EPC contract for renewable electricity generation (which may be all inclusive and fully wrapped), another for installation of the hydrogen production facility, and another for electrolyzer procurement and commissioning. We currently see this pattern because electrolyzer suppliers typically do not offer installation services, but prefer to supervise installation of and commission their proprietary equipment. As a result, any EPC contractor involved (whether for purposes of installing electricity generation equipment or as a general contractor for an electrolyzer installation) may not be willing to wrap the portions of the project covered by the electrolyzer supplier and the installer of the hydrogen production facility. In this case, it's essential to find a hybrid solution for managing procurement and construction risk, e.g., by coordinating the contracts to ensure that the multiple EPC contractors (and equipment suppliers and installers, as applicable) take responsibility for their respective portions of the project under coordinated contracts. For this structure to work well, both the EPC contract and the supply and installation contract need to clearly delineate responsibility for delays, performance shortfalls and warranties in a coordinated manner.

This pattern may sound similar to that seen in the solar + storage market. As in that industry, we expect the hydrogen industry to evolve toward fully wrapped EPC contracts, but that requires the emergence of contractors that are willing to act as integrated providers of renewable hydrogen production facilities, with or without collocated renewable electricity generation equipment.

Completion and Performance Guarantees

As in typical project financing transactions, it is essential to obtain firm assurances from EPC contractors that a renewable hydrogen facility be completed on time and in accordance with technical and performance expectations. Performance is generally demonstrated by testing prior to final payment to the EPC contractor. (In the context of green hydrogen, performance tests may include flow rate, output pressure and output purity.) Failure to achieve targets may trigger performance liquidated damages. Even when performance-related failures are ultimately resolved, delays in achieving sufficient test results generally push out the commercial operation date, thus potentially triggering delay liquidated damages.

EPC and procurement contracts should directly and explicitly set forth remedies for failure to achieve any of the performance guarantees. Particularly in the context of the new tax credits, setting appropriate liquidated damages can require some complicated financial modeling on the owner and lender side to ensure that the guarantee and damages are adequate to protect the project's expected economic performance. For example: is a daily rate appropriate? Is a percentage of the contract price preferable? What is an appropriate cap on damages, if any? In addition to damages, it's also important to ensure that the contract requires the contractor to cure the performance shortfall. This "make good" obligation is often triggered only if the facility fails to reach a specified minimum level of performance. A failure to achieve the specified minimum generally is specified as an event of default.

Intellectual Property

The design of a hydrogen production system and its software programs will incorporate proprietary processes and equipment configurations developed by parties who will be concerned about protecting their important knowledge from theft, misappropriation, or loss of the exclusive right to such proprietary knowledge. Intellectual property (IP) rights may be addressed in the applicable EPC or supply and installation contract or may be the subject of a separate license or similar agreement. The primary technology risk from the project owner's perspective is IP infringement, particularly as new suppliers enter the market. The contracts should include robust IP indemnification obligations by the supplier in favor of the project owner.

Risk: Evolving Use Cases

The primary use of hydrogen in the United States today is as an industrial and manufacturing feedstock. A recent report by the International Energy Agency indicated that global demand for the nearly 90 megatons of hydrogen available in 2020 was almost exclusively in the refining, chemicals, and iron and steel industries.[xi] While still very small, there have been some increases in demand year over year in other sectors, including fuel cell electric vehicles and the inclusion of small amounts of hydrogen in natural gas grids. While there are inherent challenges to the large-scale use of hydrogen in many sectors, ammonia and methanol (which are produced with significant hydrogen inputs) have been identified by some countries as key fuels for the energy transition in commercial, rail, and maritime transportation.[xii] Moreover, hydrogen demand in the iron and steel industry is expected to significantly increase in the near term as a consequence of policy-driven changes in manufacturing processes.[xiii] In all cases, the sheer volume of demand in any one location will be a challenge for significant adoption of green hydrogen today (near-term emissions reductions appear to be much more tenable for SMR processes coupled with CCS), but as production of green hydrogen ramps up and technologies beyond electrolyzers reach commercial scale, we will see more green hydrogen in the supply chain.

Risk: Offtake Contracts

As in renewable electricity generation projects, hydrogen offtake contracts provide the key source of revenue necessary to meet debt service ratios and the return expectations of equity investors in any hydrogen project. While all hydrogen molecules are essentially the same, green hydrogen offtake contracts present somewhat unique financing considerations compared to renewable power, or even gray and blue hydrogen contracts.

First, counterparty risk plays a heightened role in offtake and financing negotiations. Project developers are looking for offtake contracts of at least 10 years, and usually much longer, to attract the financing necessary to build and operate the electrolyzer and associated infrastructure and to secure a source of green electrons. Due to the current level of supply and demand for green hydrogen, the identity and creditworthiness of the offtaker is extremely important. A customer who breaches a firm offtake commitment will leave a developer with either idle equipment (that also isn't producing production tax credits) or quantities of expensive green hydrogen that the developer will have a tough time re-selling at a comparable price. Presently there are no liquid green hydrogen markets, pricing hubs, or easy transportation solutions that allow a developer to quickly mitigate the generally higher damages caused by a breaching counterparty in respect of a green hydrogen contract. A financeable offtake agreement will have a take-or-pay obligation backed by a letter of credit or strong parent guaranty.

A strong take-or-pay obligation is particularly important given the predictions that the cost of green hydrogen will drop significantly over the next several years. An early buyer may naturally look elsewhere to cheaper options if locked into a contract that is out-of-the-money. Appropriate liquidated damages or buy-down provisions may be necessary to give lenders comfort that revenue will continue despite a lack of production or competition from future, cheaper sources. Note also that the take or pay payment must be sufficient to make up for lost U.S. federal income tax credits. Even though a sale of hydrogen is not required to earn the credits, the project owner likely cannot simply vent the hydrogen and still claim the credits.

On the other side of the transaction, many green hydrogen customers are “early adopters” making significant investments in their own processes to accommodate a lower carbon replacement fuel. Due to the transportation, pricing, and market risks, such customers may demand a “deliver and pay” obligation and significant concessions on normal indemnity and limitation of liability protections. Lenders will scrutinize an offtake contract to ensure that a developer is not insuring a customer against any and all forms of business interruption caused by a lack of hydrogen production or failure of delivery.

Offtake arrangements may be further complicated if the green hydrogen project is located on a customer site. Given the limited options for hydrogen transport, many green hydrogen projects are being built “behind the meter.” Often, this requires a developer to integrate its electrolyzer or fuel cell into a customer’s existing power, gas, and process infrastructure and enter into a separate ground lease. Risks and conditions precedent become commingled, and the offtaker will naturally exercise a level of control over project construction and operation that is absent in traditional utility-scale power and gas projects. Should disputes arise, or should the offtaker require less hydrogen than anticipated, rerouting or repurposing the hydrogen commodity could be difficult or even prohibited under these arrangements. Lenders will want to ensure that an offtake agreement evidences a clear understanding of project scope and purpose between buyer and seller.

Cover damages are another heavily negotiated aspect of green hydrogen offtake agreements. Because green electrolytic hydrogen usually costs more than hydrogen produced by conventional means, offtakers will pay a premium only if the developer can promise that its green hydrogen will meet a certain carbon intensity (CI) score. Customers rely on the CI score to represent to their customers, regulators, and investors that their products or services meet some metric of sustainability. If the electrolytic hydrogen plant fails to produce (due to mechanical or economic reasons), developer may have difficulty sourcing replacement hydrogen with the same CI score as the hydrogen promised in the offtake agreement. While a customer’s most immediate need may be replacement hydrogen to continue operations, at some point within the quarter or within the year developers may be obligated to deliver offsets, renewable energy certificates, or low carbon fuel standard credits to cover the difference in a higher-carbon replacement product.

Green hydrogen’s CI score raises another point on regulatory and market risk. Presently, the federal tax code and most industry participants measure hydrogen’s CI score by using the Argonne Laboratory’s Greenhouse gases, Regulated Emissions, and Energy use in Transportation (GREET) model, a complicated spreadsheet that measures the carbon and emissions inputs at each stage of the hydrogen production process. While the reference in the Code to the GREET model is a good incentive for the U.S. hydrogen industry to continue to use GREET, the model can be changed in subtle and material ways. If that happens, an offtake contract’s representations and warranties on CI score may be worthless. Thus, including regulatory and change-in-law protections in an offtake contract is particularly important where the environmental attributes of green hydrogen are still evolving.

GREET: Time to Panic?

The biggest concern with the H2 PTC (and the Clean Fuel PTC (see below) is how the Argonne GREET model will be applied.

The GREET model uses technology pathways and broad assumptions to calculate what amount to default scores for fuels that can be used in transportation. The assumptions can be extensively changed to calculate a score for a specific facility.

Section 45V and 45Z are silent as to exactly how the GREET model will be implemented, but Congressional records indicate that Senator Ron Wyden, who is largely recognized as the major force behind the tax credit provisions of the IRA, intended that book-and-claim systems such as those used in tracking renewable energy credits be used to calculate how “green” the electricity used to power an electrolyzer is. Nonetheless, there are still very big questions about matters such as whether and to what extent time and geographic matching of electron production and consumption should be used, how to account for variable grid power, and whether the CI score for hydrogen will be averaged over a time period.

The White House task force on IRA implementation has met with a variety of participants in the hydrogen market. We expect practical guidance from Treasury on these points.

MITIGATING RISK WITH U.S. FEDERAL INCOME TAX CREDITS

The tax credit provisions of the Inflation Reduction Act of 2022 (the IRA), enacted on 16 August 2022, completely changed the game for renewable hydrogen production in the United States. Relevant provisions include the Section 45V Clean Hydrogen Production Credit (PTC) (with a choice to claim the Section 48 Investment Tax Credit (the ITC) in lieu of the PTC) and the Code Section 45 renewable electricity PTC.[xiv]

Additionally, the new Section 6417 direct pay provision and Section 6418 transfer provision have the potential to revolutionize monetization strategies for a variety of U.S. federal income tax credits.

Section 45 and 45Y Clean Electricity PTCs

We mention the Section 45 and 45Y (which applies to electricity produced after 2024) clean electricity PTCs here only to note that the IRA removed the requirement that electricity be produced and sold to an unrelated third party in the limited instance when that electricity is used to produce hydrogen that qualifies for the H2 PTC (defined below) and that production is verified by an unrelated person. We're happy to discuss this in greater detail, as useful.

Section 45V Clean Hydrogen PTC

Similar to the Section 45 PTC for clean electricity, the new Section 45V Clean Hydrogen PTC (the H2 PTC) becomes available as a taxpayer produces hydrogen that meets certain CI thresholds. The hydrogen must be produced in the United States or a U.S. possession in the ordinary course of a trade or business and the production of the hydrogen must be verified by an unrelated party. However, it is not necessary to sell the hydrogen produced. Thus, producers may consume the hydrogen in their own operations, whether to power a hydrogen fuel cell or produce value-added products such as ammonia or methanol. The credit is available for kilograms of qualified clean hydrogen produced after 31 December 2022 at any facility that began construction prior to 1 January 2033 (we expect the typical four-year continuous construction requirement to apply, but guidance has not yet been issued). The H2 PTC is available in respect of hydrogen produced during the first 10 years after the date the production facility was placed in service.

The amount of H2 PTC available depends on the CI score of the hydrogen, as determined by reference to the Argonne Laboratory's GREET model on an expressly well-to-gate basis, as shown in the table below. Note that carbon capture and sequestration will be accounted for when finding the CI score of the hydrogen, but the Section 45Q Carbon Capture PTC (see below) is not available in respect of carbon captured by carbon capture equipment that is placed in service at a facility that also produces hydrogen when the H2 PTC (or ITC) is claimed. The reverse is also true.

As for most other federal income tax credits post-IRA, the H2 PTC uses a base rate that is multiplied by five when certain prevailing wage and apprenticeship rules are met.[xv]

CI SCORE	BASE RATE	5X RATE
2.5-4KG CO_2E/KG H_2	US$0.12/kg H_2	US$0.60/kg H_2
1.5-2.49KG CO_2E/KG H_2	US$0.15/kg H_2	US$0.75/kg H_2
0.45-1.49KG CO_2E/KG H_2	US$0.20/kg H_2	US$1/kg H_2
0.0-0.44KG CO_2E/KG H_2	US$0.60/kg H_2	US$3/kg H_2

The H2 PTC is not increased further for meeting domestic content thresholds or locating the facility in an energy community[xvi], but see the discussion about the ITC below. Note also that the amount of H2 PTC will be reduced up to 15% (of the total credit available) when tax-exempt financing is used to build the production facility.

Section 48 Clean Hydrogen ITC

A taxpayer may choose to claim a Section 48 ITC for clean hydrogen production equipment in lieu of the H2 PTC. (As in renewable electricity, it is not possible to claim both the ITC and the PTC in respect of the same facility.) While the H2 PTC is generally more lucrative, claiming the ITC may be useful for unproven technology or facilities that have less certain feedstock or offtake arrangements. In addition, the energy communities and domestic content bonus credits are available in the context of the ITC (but not the H2 PTC, as noted above).

As for the Section 48 ITC generally, the ITC for clean hydrogen production property is available in respect of the adjusted basis of qualified property and is taken in the year in which the property is placed in service. In the context of ammonia or methanol facilities, note that it appears the ITC will be available only in respect of the property used to produce hydrogen and not additional property used to produce ammonia or methanol.

The ITC for hydrogen production facilities varies in a manner similar to the H2 PTC, as shown in the table below.

CI SCORE	BASE RATE	5X RATE
2.5-4KG CO_2E/KG H_2	1.2%	6%
1.5-2.49KG CO_2E/KG H_2	1.5%	7.5%
0.45-1.49KG CO_2E/KG H_2	2%	10%
0.0-0.44KG CO_2E/KG H_2	6%	30%

Structuring for the H2 PTC

Project owners often cannot efficiently use federal income tax credits, which has spawned an entire industry of tax equity investments. While historic structures like the partnership flip, inverted lease, and sale leaseback should still be relevant post-IRA, we also have two new tools that are particularly useful in the context of clean hydrogen: temporary direct pay for the H2 PTC and the ability to transfer the H2 PTC and ITC.

Direct Pay

A person that is eligible to claim the H2 PTC may elect instead to receive a check from the U.S. Department of the Treasury (Treasury) for the amount of tax credit available. This option is available for qualified clean hydrogen produced in the year in which the clean hydrogen facility is placed in service and for the following four tax years. Direct pay is not available in respect of the H2 ITC. Note that because direct payments must be requested from the government, there is likely to be a delay between production and payment. Many industry participants have urged Treasury in public comments to make this process as simple and efficient as possible, but project owners should count on significant delays relative to the typical tax equity funding cycle.

While direct pay sounds attractive and we are aware of projects that are expected to be fully paid for through direct pay, note that a failure to obtain tax equity financing for the balance of the 10-year period during which the H2 PTC is available may be very expensive. Fortunately, the IRA also created the concept of transferability.

Transfer

Section 6418, which was enacted in the IRA, expressly permits a *taxable* person[xvii] to transfer the H2 PTC or ITC in exchange for cash.

Transfer is not all gravy, however.

- Depreciation deductions cannot be transferred, so the project owner must monetize them separately.

- It is widely expected that the market will ultimately settle on a price that is near 90% of the value of the tax credit. While tax equity structures can be expensive, 90% still represents a material haircut.

- The transferee will become the taxpayer vis-à-vis the Internal Revenue Service. Accordingly, the transferor will need to provide comfort to the transferee around tax credit availability and, in the case of the H2 ITC, recapture. Appropriate risk mitigation through timing and contractual provisions is strongly advised.

- Mitigating risk by delaying tax credit transfers may require project owners to secure alternative funding sources for operating expenses.

For additional detail about structuring possibilities post-IRA, please view our webinar, The Tax Credit Revolution: What You Need to Know About Structuring Opportunities, Direct Pay, and Transferability, available at **https://www.klgates.com/The-Tax-Credit-Revolution-What-You-Need-to-Know-About-Structuring-Opportunities-Direct-Pay-and-Transferability-9-1-2022-1**

MITIGATING RISK WITH INSURANCE

Although insurance is an established tool in the energy industry, the diverse methods of producing even green hydrogen carry high risk, including from the emission of flammable and explosive gases. 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.

Companies participating in the hydrogen market should carefully design and tailor their insurance programs based on 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. Many companies are unaware—sometimes until it is too late to address—that they have gaps in their insurance policies and programs. 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.

Finally, tax credit insurance has been increasingly deployed in the renewable electricity context. We expect that similar policies will be used in the hydrogen context without major variations in scope and style of policy, exclusions, and limits.

ENDNOTES

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[i] **https://www.klgates.com/The-Hydrogen-Handbook**
[ii] *See* 40 C.F.R. § 1501.1.
[iii] 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/**; U.S. DEP'T OF ENERGY, OFFICE OF NUCLEAR ENERGY, *Four Nuclear Power Plants Gearing Up for Clean Hydrogen Production*, (Nov. 9, 2022) **https://www.energy.gov/ne/articles/4-nuclear-power-plants-gearing-clean-hydrogen-production**
[iv] *US Nuclear Fleet Must Adapt by Operating Flexibly, Making Hydrogen: Officials*, S&P GLOBAL PLATTS (Aug. 11, 2020).
[v] U.S. DEP'T 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**.
[vi] U.S. DEP'T OF ENERGY, OFFICE OF ENERGY EFFICIENCY AND RENEWABLE ENERGY, NATIONAL RENEWABLE ENERGY LABORATORY, *Energy Analysis: Biogas Potential in the United States* (Oct. 2013), **https://www.nrel.gov/docs/fy14osti/60178.pdf**.
[vii] Biogas Market Snapshot, AM. BIOGAS COUNCIL, **https://americanbiogascouncil.org/biogas-market-snapshot/**.
[viii] We note that there is an extensive interstate ammonia pipeline in the Midwest that is attractive for transportation of green and blue ammonia both for domestic use and for vessel transportation out of the Gulf of Mexico.
[ix] Klevstrand, Agnete, "Chinese companies take top three slots in BNEF's list of world's 20 largest hydrogen electrolyser makers", *Hydrogeninsight*, Nov. 17, 2022, available at **https://www.hydrogeninsight.com/electrolysers/chinese-companies-take-top-three-slots-in-bnefs-list-of-worlds-20-largest-hydrogen-electrolyser-makers/2-1-1355610**
[x] All references to the "Code" herein are to the Internal Revenue Code of 1986, as amended and restated.
[xi] INTERNATIONAL ENERGY AGENCY, *Global Hydrogen Review 2021* (Oct. 2021), p 43, **https://iea.blob.core.windows.net/assets/e57fd1ee-aac7-494d-a351-f2a4024909b4/GlobalHydrogenReview2021.pdf**.
[xii] *Id*. at 38.
[xiii] *Id*. at 59.
[xiv] For blue and blue-green hydrogen, the Section 45Z Clean Fuel PTC and Section 45Q Carbon Capture PTC should also be considered. The Section 48C Qualifying Advanced Energy Project Credit may also be useful for manufacturers of electrolyzers and other equipment used to produce green hydrogen. We have not addressed these credits here, but are happy to discuss them as useful.
[xv] For more information about the prevailing wage and apprenticeship rules, see our alert "Update on the Tax Credit Revolution: Prevailing Wage and Apprenticeship Clock Starts Soon," available at **https://www.klgates.com/Update-on-the-Tax-Credit-Revolution-Prevailing-Wage-and-Apprenticeship-Clock-Starts-Soon-11-30-2022** and our webinar *The Tax Credit Revolution, What You Need to Know About the Wage and Apprenticeship Requirements*, available at **https://www.klgates.com/The-Tax-Credit-Revolution-What-You-Need-to-Know-About-the-Wage-and-Apprenticeship-Requirements-9-2-2022-1**
[xvi] For more information about the domestic content and energy communities bonus credits, please see our summary of the IRA, *Welcome to the Tax Credit Revolution: New Opportunities for the Energy Industry in the Inflation Reduction Act*, available at **https://www.klgates.com/Welcome-to-the-Tax-Credit-Revolution-New-Opportunities-for-the-Energy-Industry-in-the-Inflation-Reduction-Act-8-18-2022** and our webinar *The Tax Credit Revolution, What You Need to Know About the Domestic Content Requirements*, available at **https://www.klgates.com/The-Tax-Credit-Revolution-What-You-Need-to-Know-About-the-Domestic-Content-Requirements-9-8-2022-1**
[xvii] More specifically, those types of generally tax-exempt persons that are permitted to claim direct pay of most of the federal income tax credits are not permitted to transfer tax credits to a third person. Code Section 6418(f)(2).

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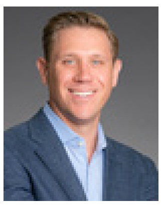

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