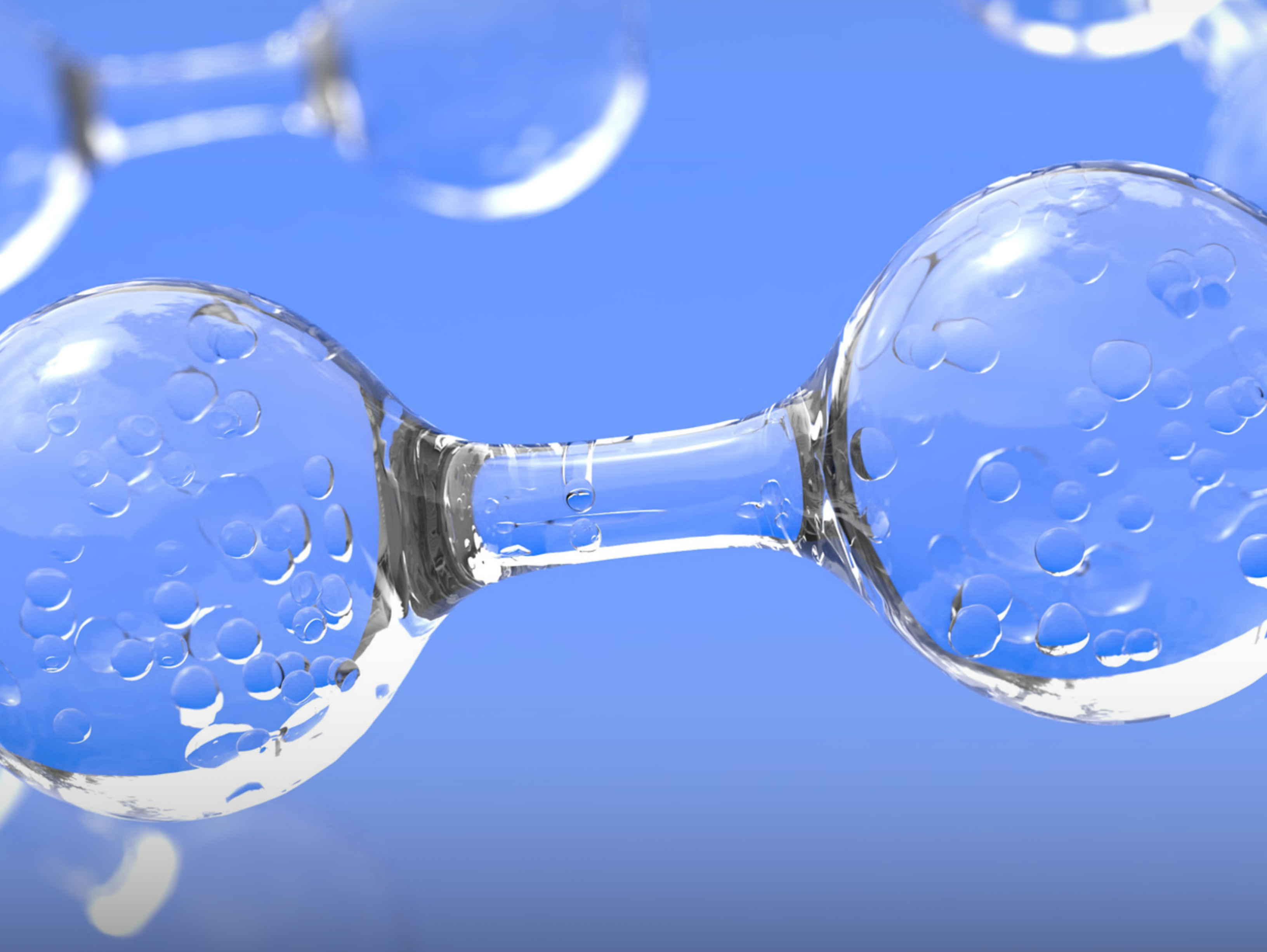
The Hydrogen Highway

How distributed hydrogen production can maximize existing infrastructure, avoid costs and complications, and jumpstart national hydrogen demand



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The Hydrogen Highway: *How distributed hydrogen production can maximize existing infrastructure, avoid costs and complications, and jumpstart national hydrogen demand.*

Executive Summary

Hydrogen is often considered one of the most promising fuels of the future. Its simple molecular structure and combustibility make it highly promising for producing carbon-free energy and resources. It can be described in such a way that the average person sees only upside and questions why greater investment is not taking place to convert the entire power grid and vehicle fleet into hydrogen-based assets.

There are a number of hydrogen production options being discussed and evaluated in policymaking and academia, each with their own advantages and challenges. Hydrogen has broad potential applications for electricity generation, battery storage, process heating, and more, yet many obstacles must be overcome to fully unlock this potential. Whether assessing the resource by its color designation or economic factors, each hydrogen solution has a critical infrastructure dependency to resolve, each with differing costs and timespans.

As an element, hydrogen (H) is most often found on earth within another molecule like water (H_2O) or methane (CH_4), and it must be "produced" by splitting these types of molecules to form useable gaseous hydrogen (H_2) – an energy-intensive and specialized process. In a power-hungry world, adding new energy capacity or diverting power just to make a power-generating resource can seem counterintuitive, but the broad applications and advantages of hydrogen justify the investments.

The energy required for hydrogen gas production carries a carbon footprint of its own, which partially undermines the goal of using hydrogen energy to reduce carbon emissions[1] from other energy sources. Conventional approaches to reducing the carbon intensity of hydrogen production can introduce additional challenges.

There is also a considerable logistical challenge. Because hydrogen generally must be produced, it then requires transportation and storage solutions to get the hydrogen to its end users. Unlike natural gas, which is moved across the country by vast pipeline networks and longstanding transportation solutions, hydrogen does not yet have its own facilitating infrastructure on a large scale. The unique properties of hydrogen require more specialized transportation and storage specifications, making the investment more daunting.

These challenges cumulatively dampen the inspiring promise of hydrogen as an attainable carbon-free resource. Even with a robust market, it could take decades to fully deploy the extensive infrastructure needed for large-scale hydrogen production. Without the structural requirements in place, the demand for hydrogen is somewhat in limbo. If identified in the short term, a scalable proven solution to instill confidence and jumpstart demand could bring more investment into production, transportation, storage, and delivery.

Identifying and tapping into the interest needed to jumpstart the hydrogen industry has been a challenge that many are working to solve. The primary approach to date has been large-scale and federally-incentivized hubs to bring all the resources together in a concentrated region. However, many of the challenges listed above remain barriers to progress. To address part of the infrastructure challenge, many have proposed utilizing existing infrastructure. This presents both opportunities and obstacles, which must be understood and accounted for. The key to jumpstarting demand is the way existing infrastructure is used in the short term.

Simply stated, the start of the “hydrogen highway” is already in place. Rather than thinking outside the box, policymakers must consider the box itself – what existing infrastructure can facilitate hydrogen production, transportation, storage, and utilization?

This report focuses on natural gas pipelines as that key infrastructure component available to promote further development of hydrogen infrastructure. However, unlike some popular proposals that hydrogen can be run through existing or retrofitted natural gas pipelines – a solution that generates its own costs and unintended consequences – Aii evaluates the potential to continue to use natural gas pipelines simply for natural gas. Through investment in distributed production right now, the adoption of clean hydrogen can be accelerated with more flexibility for future deployment of resources. This ready-solution has the potential to jumpstart hydrogen demand in a way that promotes investment in hydrogen solutions upstream and downstream.

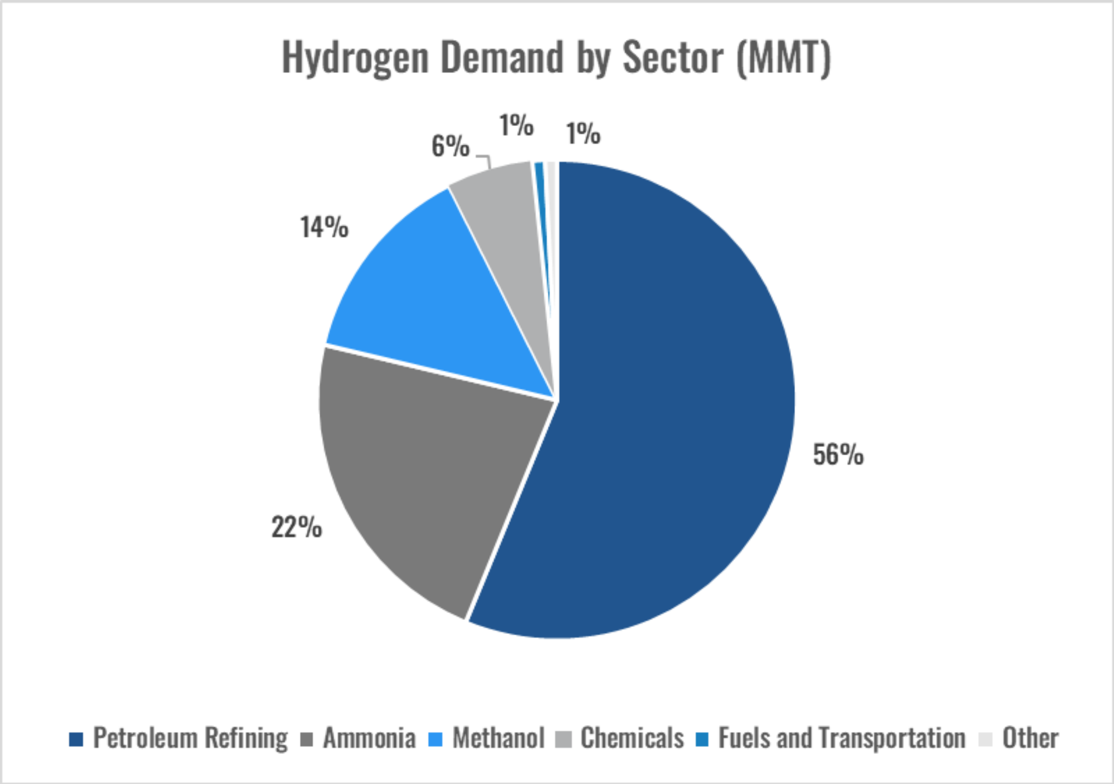
Background

Hydrogen comprises approximately 75 percent of all mass in the universe. Despite this, pure hydrogen gas (H_2) is not a common naturally occurring molecule on Earth because it is lighter than air and bonds quickly in the atmosphere to form water (H_2O).[2] Since its discovery in the 17th Century, hydrogen has been used in an array of applications, including heating, airships, electricity generation, industrial processes, batteries, and even rocket fuel. Hydrogen is often touted as the fuel of the future because it is a clean-burning fuel that avoids carbon emissions.[3] Various low-emission production techniques are competing for attention from policymakers and industry leaders seeking to decarbonize. Hydrogen can become a viable and clean energy alternative and chemical resources if innovation and public policy align to overcome a number of challenges.

Current annual hydrogen production in the U.S. is approximately 11.3 million metric tons, of which more than half is used for petroleum refining.[4] Ammonia, methanol, and chemical production demand most of the remaining hydrogen, with more minor uses including transportation, electronics, metals, and food. By contrast, the United States produces approximately 787 million metric tons of natural gas, most of which goes to electricity generation and heating applications.[5]

Hydrogen production is already significant for certain applications, but its expansion into power generation, transportation, and process heat will require substantial technological and infrastructure advancement and policy changes in order to be self-sustaining and scalable. Moreover, the production method has to-date been emission-agnostic, but future hydrogen focus has been on ultra-low emission production to maximize the impact of the clean hydrogen itself.

Considering expansion of hydrogen to other sectors, the U.S. Energy Information Administration (EIA) shows that in 2023, hydrogen has not yet made a blip on the utility-scale electricity generation mix. In general, hydrogen-based electricity is mainly used in backup power-supply systems or high-capacity batteries. As a share of total electricity generated last year, hydrogen was less than 0.2 percent (under 10 billion kWh) – a share found within the "other sources" category that also includes "other (utility-scale) sources includ[ing] non-biogenic municipal solid waste, batteries, hydrogen, purchased steam, sulfur, tire-derived fuel, and other miscellaneous energy sources."[6]



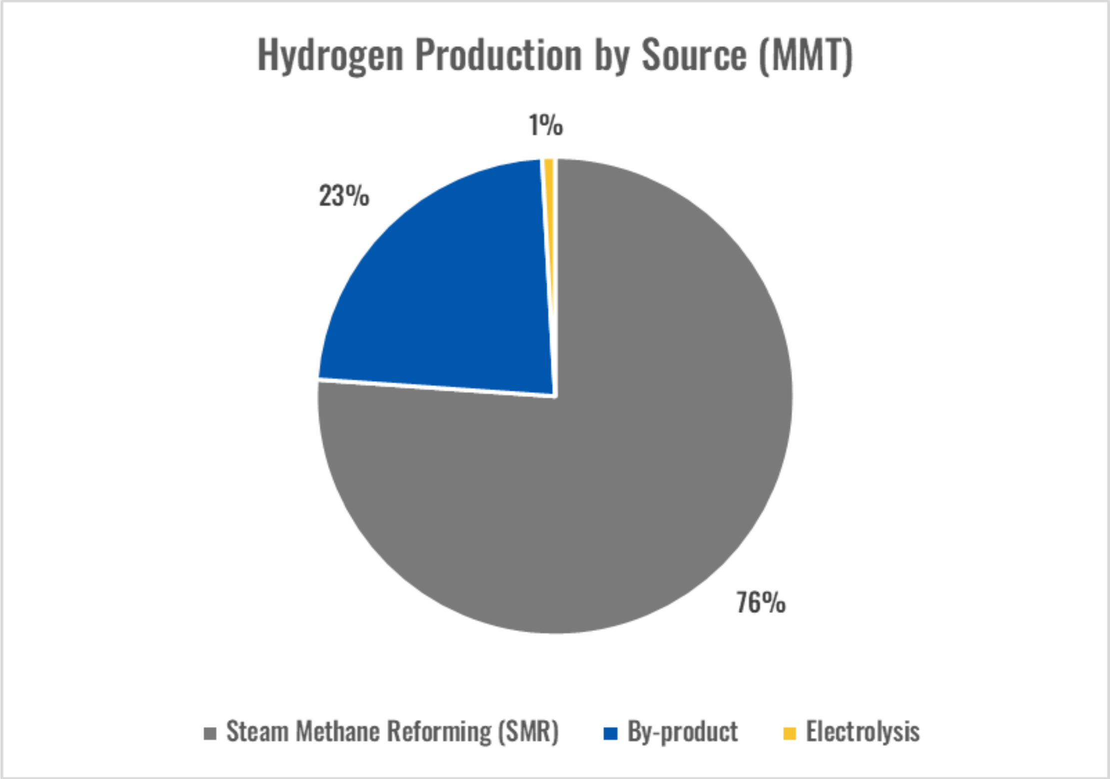
Aii Figure 1: *Hydrogen Demand by Sector*.[7]

About half of current hydrogen production is created in integrated facilities by the primary user, while the other half is sold and transported by merchants.[8] These are key facts to consider for evaluation of the proposed production models. Hydrogen is used most commonly in petroleum refining, but it is also used in fertilizer production, methanol, and other chemicals.

With fuels and transportation making up less than a single percentage of hydrogen use, it is curious that the resource has gained so much attention and its potential application is so focused on energy and transportation. Not only is innovation required to economically produce hydrogen for these uses, but demand must be present – a two-way street seemingly keeping hydrogen in a state of limbo.

One proven way hydrogen can already be utilized is in fuel cells.[9] Hydrogen fuel cells operate like large batteries and are used in some electric vehicles and in electricity generation as backup power supplies for individual facilities. These fuel cells may be an effective way to store large amounts of energy to counteract intermittency with renewables.[10] Progress has also been made in blending hydrogen with natural gas for power generation. Even so, there have been few adopters to date, and the exact mix of gases is not standardized nor is the future ramp up clearly defined.[11,12]

Even with proven fuel cell technology and fuel blending, hydrogen remains a mere footnote in the wider energy landscape. This is partly due to the economic and environmental trade-offs related to the methods of producing hydrogen. The overwhelming majority of hydrogen produced today comes from Steam Methane Reforming (SMR), or else as a by-product of other industrial processes. SMR uses natural gas (CH_4) and steam to create hydrogen, but it also results in substantial CO_2 emissions. Most current hydrogen production from SMR lacks emissions capture. Clean-hydrogen produced through electrolysis represents a tiny amount of the total, while there is no clear data on the total amount created by other production processes.



Aii Figure 2*: Hydrogen Production by Source.*[13,14]

Because hydrogen must be extracted from compounds that contain hydrogen, such as natural gas (CH_4) or water (H_2O), the production method has a significant impact on cost, emissions, and logistical considerations. In recent years, demand for hydrogen has been generally low outside of industrial processes, and wider demand for hydrogen in energy, industry, heating, and fuel has yet to materialize. To date, industrial users have put little focus on the emission-rate associated with hydrogen production and more on its cost and availability. As policymakers examine new avenues for hydrogen, they project and potentially influence future demand to focus more on the environmental and economic considerations.

Hydrogen is generally categorized by a color nickname based on the type of process used. The most relevant color designations for the numerous current and proposed hydrogen production processes are summarized below along with key considerations. While not all factors are addressed, the table helps acquaint decision makers with some of the basic trade-offs. Beyond these are logistical considerations like the level of energy needed and the infrastructure dependencies to produce (upstream) or transport and store (downstream) the hydrogen gas.

Color Designations[i]	**Resource Used**	**Production Technique**	**Cost** (USD/kg H_2)	**Carbon Intensity** (kg CO_2e per kg H_2)
Black	Coal	Coal gasification	0.90-1.46 (China)[15]	18 - 20[16] 19.37 - 22.87[17]
Gray	Natural Gas	SMR	0.98-2.93[18] 1.50[19] Approx 1.00[20]	8 - 12[21] 8 - 10[22] 9.4[23]
Blue	Natural Gas with CCS[ii]	SMR/ATR[iii]	1.69-2.55[24] 1.8-4.7[25]	3.91 - 8.20[26] 3.39 - 3.88[27]
Green	Water	Electrolysis (renewables)	4.5-12[28] 5-7[29]	0.8 - 4.6[30] 1.06 - 1.57[31]
Turquoise	Natural Gas	Methane Pyrolysis	2.87-3.53[32] Approx 2[33] 3.21 (Europe)[34]	0.82 - 2.09[35] -8.54 – 0[36] (Biogas) 0.91[37]
Pink	Water	Electrolysis (nuclear)	2.75-5.29[38]	0.3 - 0.6[39]
White	Geologic Reserve	Exploration and Extraction	0.5 - 1[40]	0.4 - 1.5[41]
Biomass	Biomass	Grown feedstock	1.21 - 2.42 (estimate)[42]	Highly variable.[43]

Aii Figure 3: *Hydrogen Color Profiles*

The two most prominent forms of low-carbon hydrogen in popular discussion are blue hydrogen and green hydrogen. Each of these processes are featured heavily in the U.S. National Clean Energy Strategy and Roadmap (hereafter "Roadmap") from the U.S. Department of Energy.

[i] See Appendix B for discussion.
[ii] Carbon Capture and Storage
[iii] Autothermal reforming (**ATR**)

Both processes have certain up-front limitations and key downstream challenges as well. Methods of hydrogen production are often discussed in relation to regional hydrogen hubs. When hydrogen is centrally produced – generally referred to as hydrogen hubs – new energy demand, technology, equipment, storage, and transportation solutions are required.

Challenges with Centralized Hydrogen Production

As detailed and incentivized in recent legislation, including the Bipartisan Infrastructure Law and Inflation Reduction Act – which promote the development of hydrogen hubs – centralized hydrogen production has a number of challenges that must be overcome. Centralized hydrogen production assumes production will take place in large groups of facilities in a central location, with hydrogen then transported outwards to various consumers. The most difficult aspect of centralized hydrogen is the transport and storage of the hydrogen product, which is more complex than natural gas.

Hydrogen has high energy density by weight but is the least dense element by volume. Being lighter than air and resistant to compression, it requires more space to store than traditional hydrocarbons. Hydrogen can be stored as a gas, liquid, or within other chemicals, all of which require additional energy. Storing it as a gas is likely the most practical method for large-scale use. Above-ground storage tanks have high upfront capital costs, while storing hydrogen in underground reservoirs is a complicated process currently under study.[44] More research is needed to determine the effects and strategies for storing hydrogen underground.[45]

Pipeline networks and tanker trucks will be needed to move the hydrogen from regional production hubs to points of use.[46] Hydrogen pipelines are required to follow stricter standards than natural gas pipelines, with added regulatory rules. For added context, a traditional large natural gas pipeline takes approximately four years on average to become operational but can take up to nine.[47,48] A standard 30-inch natural gas pipeline that spans 50 miles could cost between $169.5 million and $342 million.[iv] Hydrogen pipelines are likely to cost more than natural gas pipelines.[49]

In other words, centralized hydrogen hubs can help bring the benefits of hydrogen on a large scale, but the supply chains will take a significant investment of time and resources. It could be decades until these hubs are fully realized, even with permitting reforms and favorable policy treatment. There is concern that without careful consideration of all variables, a scaled hydrogen industry will struggle to match supply with demand.[50] In the short-term, these present structural barriers to quick adoption, new demand, and economic viability, all of which can be addressed with policy reforms and on longer timelines.

[iv] See Appendix C for Discussion

While centralized production of hydrogen gas has certain upstream and downstream challenges, another dimension of challenges and tradeoffs exists by production color – whether centralized or distributed. These obstacles can be addressed with the right policy framework, and hydrogen can reach larger scales more quickly; however, in the short term these are structural considerations.

	Front-End Challenges	Back-End Challenges	
Blue Hydrogen	Investment in carbon capture	Managing hydrogen	Managing CO_2
Green Hydrogen	New renewable capacity	Managing hydrogen	

Aii Figure 4: *Short-term Infrastructure Obstacles*

Short-term Constraints on Blue Hydrogen

Blue hydrogen is one of two low-carbon production methods that receives the most significant attention from hydrogen advocates and policymakers. Blue hydrogen uses natural gas to produce hydrogen, while employing Carbon Capture and Storage (CCS) technology to capture most of the resulting carbon dioxide emissions. Several blue-hydrogen plants are already operating, but it still constitutes a very small percentage of total production. The primary challenge with blue hydrogen involves carbon management. Specifically, the economic capture and storage of CO_2 requires solutions independent from hydrogen production.

Although not directly comparable, power plants that install CCS technology are estimated to require between 40 and 100 percent additional capital costs.[51] One study found the estimated cost of capturing CO_2 in the U.S. in 2019 ranged between $20 and $120 per metric ton removed.[52] Capture specifically for hydrogen production was estimated between $50 and $80 per metric ton. The technology has received significant government funding, including in the Infrastructure Investment and Jobs Act.[53]

Most of the costs from CCS are related to the 'capture' of carbon, but transport and storage need additional resources and are dependent on specific geography.[54,55] The most economic and common way to transport CO_2 is pipelines, while storage often utilizes underground geologic formations.[56] With respect to geologic storage, CO_2 is pumped underground into porous rock half a mile below the surface, or else used in enhanced oil recovery (EOR).[57] EOR uses CO_2 to dislodge the remaining oil in reservoirs. It is currently the most common way to use and sequester CO_2, and the improved oil extraction helps offset the costs of CCS.[58] Utilizing depleted natural gas or oil reservoirs to store the carbon gas is also being explored along the Gulf coast by energy companies with existing infrastructure.[59]

A study recently found that regional geology has a significant impact on the cost of CO_2 storage and can range from \$4 to \$45 per ton.[60,61] If CO_2 storage has a cost of \$10 per ton, it will cost roughly 10 cents extra per kg of hydrogen.[62] With government incentives, this cost is very manageable, but the required infrastructure must be in place first.

While blue hydrogen plants are already in operation, innovation of the technology is changing constantly. Currently, blue hydrogen has higher emissions than green hydrogen and depending on design and results, may not qualify for certain government tax-credits (as written or interpreted).[63,64] To unlock large-scale blue hydrogen, there must be a buildup of infrastructure to transport and store CO_2 (in addition to the infrastructure needed for the hydrogen itself). Geology must be studied to determine where the carbon gas can be stored, and regional differences could dictate where blue hydrogen is most effective. This constrains greater scalability of blue hydrogen in the short-term, but if hydrogen demand is increased, many of these considerations will secure the necessary investment to be realized.

Short-term Constraints on Green Hydrogen

Green hydrogen is a production method for low-carbon hydrogen that is popular among environmental advocates. By utilizing electricity, electrolyzers can separate the hydrogen and oxygen in regular water, producing no direct carbon dioxide emissions, with oxygen as the only byproduct. However, green hydrogen is expensive due to its demand of renewable energy and technological/capital investments. Electrolyzers are advanced technology and green hydrogen currently costs at least two to three times as much as gray hydrogen and is more expensive than blue hydrogen.[65]

The overall goal of the Department of Energy is 10 million metric tons (MMT) of "clean hydrogen" by 2030, 20 MMT by 2040, and 50 MMT by 2050. Electrolysis requires around 50 kWh of electricity per kg of hydrogen. This results in emissions of 1 to 2 kg of CO_2 for every kilogram of hydrogen when using renewable energy sources. However, if an electrolyzer used regular grid energy, it would result in 19.5 kg of CO_2 for every 1 kilogram of hydrogen produced.[66] Green hydrogen is only labeled 'green' if it has a source of low-carbon electricity.

Green hydrogen is undoubtedly a source of very low-carbon hydrogen, but it will necessitate significant changes to the energy infrastructure to become feasible at scale. It would take approximately 500 billion kWh to produce 10 MMT of hydrogen using electrolysis, or about 12 percent of domestic electricity generation in 2023.[67] A massive buildout of low-cost and low-emissions electricity production will be needed in order to fully utilize green hydrogen. Because of green hydrogen's reliance upon an expanded electricity grid, a transition to hydrogen may take extra time. Transmission infrastructure has become a bottleneck for renewable energy projects, delaying the buildout of new electricity capacity.[68] Other decarbonization strategies in the transportation and space heating sectors will also necessitate increased electricity production, not to mention the growing energy-needs of AI and data centers.[69] Other than electricity, other challenges facing green hydrogen include material constraints and water access.[v]

Green hydrogen has shown promise as a low-emissions hydrogen solution, but further infrastructure investments are needed to fully realize the potential. Abundant low-emissions electricity is essential to green hydrogen. The technology will mature as the hydrogen market evolves and structural barriers are slowly removed, but in the short-term the expansion of green hydrogen is limited.

Opportunities and Obstacles in Existing Infrastructure

One possible solution discussed by stakeholders and policymakers to speed up the adoption of hydrogen is to leverage existing infrastructure. The popular conception of leveraging natural gas infrastructure is to centrally produce hydrogen upstream and then send hydrogen through the existing natural gas network, either on its own or blended, as a solution to the largest back-end challenge.

Taking the hydrogen transportation element out of the challenge column and leveraging existing infrastructure to alleviate new infrastructure dependency may make the entire hydrogen market more feasible to develop more quickly. Various models suggest that retrofitting natural gas pipelines to carry a blend of hydrogen and natural gas can reduce costs and requires minimal pipeline retrofitting.[70,71] The DOE Roadmap suggests using existing natural gas infrastructure as well.[72]

The natural gas network is well established in the United States, comprising over three million miles of pipelines along with supporting facilities.[73] Several studies have shown that retrofitting existing infrastructure can significantly lower costs compared to building new pipelines.[74,75] The Hydrogen Council along with McKinsey & Company released a report in 2021 that suggested retrofitted transmission pipeline will cost between $600,000 and $1.2 million per kilometer, compared to between $2.2 million and $4.5 million for a new hydrogen pipeline.[76] Utilizing the existing natural gas network is an intriguing idea that saves both time and money, but unfortunately it does not address all of the issues, and creates several challenges of its own.

Natural gas pipelines will need significant retrofitting to move hydrogen. While this may cost less than building new pipelines, it will take time, also taking existing lines out of service and potentially disrupting supply lines. Additionally, most studies proposing this solution are based on data from Europe, where different regulations govern retrofitting, and often conclude that even a retrofit will be costly with limited greenhouse gas mitigation potential.[77] Another problem is that by retrofitting natural gas pipelines, they may no longer be optimized to transport natural gas. In theory, natural gas is capable of moving through hydrogen pipelines, but regulatory rules

[v] See Appendix D for Discussion

and calibrated components could add complications. Natural gas is still crucial for U.S. energy and heating needs and will continue to be for many years to come. Pipeline retrofits may only be feasible for smaller pipelines with consumers transitioning from natural gas to hydrogen, unless the pipeline utilizes blending.

Blending is the concept of running hydrogen and natural gas together in the same pipeline, and either using it together as a mixed heating gas, or else separating downstream. This idea allows for natural gas to continue to be used and may require less upgrades to existing pipelines. Hydrogen could be adopted more quickly using this option, but it comes with several notable constraints.

Blending may reduce the effectiveness of hydrogen as an emission-reducing alternative to natural gas depending on the timeline and mix strategy. Downstream gas separation technology requires extensive technology improvement and energy, not to mention regulatory changes.[78] New hydrogen-capable separation facilities would need to be constructed, with high capital costs.

Hydrogen is far less volumetrically dense than natural gas and requires additional energy for compressor stations to keep the gas moving along the pipeline. The exact cost of these compression stations varies, but a 2019 study found a pipeline that is 40 percent blended hydrogen will require 52 percent more power to move an equivalent energy quantity as a regular natural gas pipeline.[79] For a 100 percent hydrogen pipeline, it will require 280 percent more power to transport the same quantity of energy. The International Energy Agency (IEA) estimates that hydrogen pipeline compressor costs are three times the cost for a natural gas pipeline.[80] Not only will more power be required to transport hydrogen through pipelines, but less total energy will reach the destination without larger diameter pipelines that hydrogen is better suited for.[81]

Using natural gas infrastructure to move hydrogen seems like it would be a more efficient use of resources, but the infrastructure investment will still be significant. Additionally, current regulatory rules make this retrofit impractical if not impossible. Hydrogen pipelines currently fall under specific safety standards that are notably different from natural gas pipelines in the U.S.[82] Pipeline regulations that allow retrofitting or blending may take years to change, requiring a rulemaking petition, public comments, and regulatory burdens.

Hydrogen pipelines in particular may require extra consideration, as hydrogen can cause increased pipeline embrittlement and fatigue, and will leak faster than natural gas transmission lines,[83] requiring stronger safety measures and inspections.[84,85] PHSMA is currently working with several organizations to manage the problem, but it is still in the study phase.[86] These problems will be lessened and then overcome with time, but they still represent a hurdle for centralized hydrogen production in the near term.

This paper is not intended to discount or dissuade hydrogen pipeline projects and infrastructure investments, but it highlights multiple infrastructure dependencies that industry leaders and policymakers must understand and plan strategically to overcome. An immense investment of both resources and time will be needed to realize the great potential of a hydrogen economy. Both blue and green hydrogen are highly innovative, but constructing the necessary infrastructure will take time and careful planning.

Leveraging the existing natural gas network for hydrogen gas delivery is not currently the silver bullet decisionmakers are looking for, but it can still play a part in the near-future of hydrogen. However, if industry leaders can reframe what it means to leverage existing infrastructure and place hydrogen production itself downstream, many new possibilities arise that can boost low-cost production of hydrogen that avoids many of the constraints and obstacles discussed above.

Accessing the Highway Directly

Existing natural gas pipelines have been labeled as the on-ramp to jumpstart hydrogen production.[87] As presented above, retrofitting, blending, or other considerations needed to put hydrogen into natural gas pipelines generates new challenges that will take time to process. But policymakers and industry decisionmakers can reframe their thinking and shift the view of natural gas pipelines from being *on-ramp* to being *the highway* itself.

The commercial and industrial consumers of natural gas can continue using the existing natural gas infrastructure how they do today: moving natural gas. Utilizing the infrastructure for its intended purpose makes sense. Centralized production of hydrogen will take years to design and construct, so immediate investment in distributed hydrogen production is best positioned to jumpstart demand.

Distributed hydrogen production, or producing hydrogen directly where it will be used, is not a new concept. About half of hydrogen production is already in integrated facilities.[88] By producing hydrogen on-site, the need for dedicated pipelines, storage facilities, compressors, and transport trucks is largely avoided or strongly mitigated. Many potential hydrogen-users are not ready to transition immediately. By introducing scalable on-site hydrogen production, an operation can be tailored to the needs of the business.

To go hand in hand with distributed production, there is a hydrogen production process that requires almost no expansion of infrastructure, namely *turquoise hydrogen*. Methane pyrolysis, a technique for producing turquoise hydrogen, uses a different process to separate natural gas than SMR or ATR, and produces solid carbon as a co-product instead of CO_2.[89] Carbon black, graphite, and other pyrolysis co-products are solid material and can be safe and more convenient to handle and store than CO_2. Solid powder carbon even has industrial applications, and research is being conducted to study various ways to utilize and sequester it.[90] This product can also be sold to offset the slightly higher energy needs of methane pyrolysis compared to SMR.[91]

Several first-generation methane pyrolysis plants are already operating, using the hydrogen for ammonia in fertilizer.[92] Depending on the process, some carbon dioxide may be released, but as technology develops it may become even more efficient, and it produces fewer emissions than blue hydrogen. Some versions of the technology utilize a thermal methane pyrolysis that uses heat to break the methane molecule (CH_4) into its C and $2H_2$ components, then sustaining the heat reaction with its own clean hydrogen. This model produces almost no carbon dioxide at all after an initial startup. When using renewable natural gas, methane pyrolysis can even yield a carbon negative balance.

Furthermore, turquoise hydrogen requires much less new infrastructure, because the solid byproduct does not require pipelines, and can be sold again. It is also cost effective as well, with studies showing it could be very competitive with standard SMR in the near future or with a carbon tax.[93]

Monolith Inc., the current largest methane pyrolysis producer, has recently opened multiple industrial-scale plants and uses hydrogen for fertilizer production. Other companies are still in the research and pilot phase. One company is working on a hydrogen production process that creates graphite as a useful byproduct instead of carbon black.[94] Graphite has many potential uses, including being a major component of EV batteries. Another notable innovation in turquoise hydrogen belongs to Modern Hydrogen, which offers a modular methane pyrolysis hydrogen unit that can be easily attached to existing industrial natural gas infrastructure.[95] This bypasses the need for any significant hydrogen infrastructure completely, reducing costs and speeding up utilization.

Certain infrastructure requirements for centralized hydrogen production are unnecessary with distributed production, which leverages existing natural gas infrastructure. Added challenges from green and blue production methods can also be avoided with methane pyrolysis. In particular, the need for new hydrogen transportation and storage solutions – retrofitted or entirely new pipelines, trucks, geologic storage – is entirely obviated. Existing natural gas storage tanks and facilities can hold natural gas until hydrogen is demanded. Significant new energy capacity is not required, reducing the potential for strain on the grid. Additionally, new capture, transportation, or storage solutions for CO_2 are avoided. The resulting carbon can become an asset built directly into new technology and infrastructure, including EV batteries or asphalt.

Unfortunately, methane pyrolysis and distributed production seems to be an afterthought to some hydrogen advocates. The hydrogen Roadmap makes a cursory mention of methane pyrolysis, but the report focuses mostly on electrolysis and SMR with CCS. Solid carbon has broader applications and is easier to handle than CO_2 gas from CCS, yet it receives no tax credit from the Bipartisan Infrastructure Law or Inflation Reduction Act. Over 80 percent of funding from the Bipartisan Infrastructure Law is for regional hydrogen hubs, potentially suppressing innovation for smaller distributed operations.[96]

Right now, methane pyrolysis represents a timely strategy for hydrogen deployment moving forward, but other methods may be deployed in areas where conditions are favorable. Industrial applications with appropriate geography that already utilize a well-developed SMR or ATR system could install CCS technology to reduce emissions. Blue hydrogen plants can be used as integrated facilities in areas where CO_2 is easy to utilize, such as in oil recovery or agriculture.[97] Electrolysis may be a viable option for smaller operations in areas where renewable electricity is abundant. However, true and large-scale centralized production of hydrogen is years away. Policymakers and industry leaders should be aware of this timeframe and make appropriate design and policy decisions.

A common assumption is that scale will make hydrogen production less expensive overall, but expanded production will need to develop a market to supply. Decentralized production allows for a flexible deployment of hydrogen without the need for drastic and costly infrastructure additions, helping speed up the otherwise lengthy timeline for hydrogen adoption. This flexibility positions distributed hydrogen production – through methane pyrolysis or other techniques – as a key partner to other production methods by building up demand and creating immediate hydrogen uses cases that will attract the needed investment and help shape the policy framework needed to realize a more robust hydrogen economy.

Distributed Production Limitations

While the distributed production method allows for a more rapid integration of hydrogen into the economy, it still requires its own critical analysis. Ultimately, to fully reap the benefits of hydrogen production of every type, significant technological advancement and strategic infrastructure will be required.

While this report details how hydrogen can be delivered for use in industrial processes, the industry itself will need to adapt to move away from natural gas. Process heating was presented in a separate Aii report, ultimately concluding that any decarbonization transition will entail considerable logistical, legal, and cost challenges.[98]

Several companies have shown promise and capability when it comes to methane pyrolysis, but ultimately the technology is first generation. Many turquoise hydrogen start-ups are still in the laboratory or pilot-scale phase. While there are operational blue, green, and turquoise hydrogen production facilities in 2024, the IEA has marked hydrogen produced through methane pyrolysis as in the "demonstration" phase, while blue and green hydrogen as in the "market uptake" phase.[99] Decisionmakers who are aware of the real-world application and demonstrated results of the technology will need to help combat sluggish demand by dispelling the misconception that it is too nascent or unscalable. Perception should not be a barrier to proven solutions.

Not every potential user of hydrogen has a natural gas connection to take advantage of, like coal users or even electric-arc furnaces in steelmaking. Newly built industrial plants may also need to add a connection to the natural gas network, ultimately undermining the advantages of a distributed production strategy, or limiting the immediate pool of users to those with natural gas distribution directly to their facilities. The cost of natural gas will also influence prices of methane pyrolysis, as well as blue hydrogen. In fact, depending on the production process, methane pyrolysis may require more natural gas than a facility had used prior, adding fuel costs that must be balanced against the environmental tradeoff of a lower carbon footprint.

Methane pyrolysis, along with electrolysis and SMR with CCS, are more expensive than simply using natural gas. It makes sense that any decarbonization strategy costs more than traditional uncontrolled emissions, but ultimately it would be beneficial to be more competitive. Regular SMR costs around $1 per kg of hydrogen, while SMR with CCS and methane pyrolysis usually cost at least $1.7 per kilogram, often more.[100,101] Distributed production costs may also be slightly higher than those produced at scale.[102] While centralized production is a challenging approach to hydrogen, especially in the short term, building at scale generally increases efficiency, and distributed production will require increased innovation for modularity and size.

Although methane pyrolysis is very different from SMR or ATR with CCS, ultimately it still results in a carbon byproduct, albeit a solid instead of CO_2 gas. Carbon black, graphite, or other solid carbon is a useful byproduct of methane pyrolysis. It is used in tires and other industrial applications, and work is underway to utilize it in asphalt.[103] The added cost from pyrolysis can potentially be offset by the sale of carbon black.[104] However, to fully utilize this method, the demand for solid carbon must scale with the demand for hydrogen. This is a similar constraint to hydrogen itself discussed above.

Current worldwide production of carbon black is approximately 8.1 MMT.[105] Methane pyrolysis produces three times as much carbon black as hydrogen by weight, meaning that if methane pyrolysis was adopted at scale, it would quickly exceed global demand. Therefore, more useful applications to utilize carbon black must be evaluated.[106,107] Simple sequestration of carbon black is also possible by burying it in the ground, but this diminishes its potential utility. As a solid, carbon is far easier to store than gaseous CO_2, but the dust can contain harmful chemicals and must be properly contained.[108] Carbon black has significant potential, but without a sizable market it could still become a liability rather than an asset.

Distributed hydrogen production requires virtually no new infrastructure build outs, but scalability generally increases efficiency, and technology developed for at-scale use is generally easier than specialized smaller applications. On-site distributed production of hydrogen means that mechanical issues or repairs may be more difficult to solve quickly, especially in small operations. It will require additional training and resources to monitor and maintain hydrogen production facilities.

Public policy can also present limitations to the immediate adoption of a distributed hydrogen production market. In some regulations, emissions are calculated from the fuel-consumption data.[109] Even though methane pyrolysis is a clean and effective way to produce hydrogen, by measuring natural gas at the meter to calculate emissions, regulations may hamper the adoption and development of the technology – falsely penalizing a facility for its natural gas meter tallying higher consumption when behind the meter the natural gas is fully decarbonized. Regulations for hydrogen and natural gas pipelines also will require modification for all production methods, with particular care to avoid impeding blue and turquoise hydrogen.

Both innovation and policy reforms (in particular permitting reforms) will be required. Potential consumers will have to be incentivized to move away from inexpensive hydrocarbons. Currently over 5.6 million businesses have a natural gas connection.[110] This requirement may dissuade other potential hydrogen users from methane pyrolysis or require additional steps that undermine the strength of a distributed model.

Conclusion

Hydrogen is a unique energy and chemical resource with broad applicability. It is not surprising that interest in hydrogen has accelerated in recent years in both private industry and public policy. There is great potential for hydrogen to serve as a clean resource to decarbonize elements of the economy, but there are challenges relating to how to produce, transport, store, and utilize hydrogen. At each stage, a detailed analysis reveals great infrastructure dependency. Much of the infrastructure needed for wide-scale hydrogen adoption simply is not yet in place.

To overcome infrastructure obstacles and promote faster hydrogen production, existing infrastructure can be utilized. However, a reframing of both that infrastructure and hydrogen production may be called for. Because blue and green hydrogen each have significant front and back end challenges, the use of existing infrastructure must streamline many challenges at once.

Distributed production is a cost effective and economical option for a flexible adoption of hydrogen. Rather than centrally producing hydrogen and transporting it to end users, a distributed production model allows the hydrogen gas to be produced onsite, avoiding new and specialized hydrogen transportation and storage infrastructure. Natural gas pipelines can facilitate this by bringing natural gas directly to facilities, which can then utilize methane pyrolysis or a similar distributed technique to produce hydrogen on site and on demand.

Methane pyrolysis – designated as turquoise hydrogen – also avoids other key structural limitations. Depending on the particular method and design, turquoise hydrogen requires far less energy while avoiding carbon capture needs and simplifying carbon management. As these challenges for blue and green hydrogen are being resolved, the primary constraint is time and infrastructure.

Distributed turquoise hydrogen requires little or no new infrastructure, presenting fewer short-term constraints. This method provides the potential to jumpstart hydrogen demand quickly to help facilitate greater investment and reform that will also benefit blue and green hydrogen, hydrogen hubs, and ultimately commercial and industrial energy users in search of low-cost and low-carbon solutions to energy and chemical needs.

Decarbonization can begin more quickly, and strategies can be developed for large-scale future markets once hydrogen demand is well-established and supply is reliable. While different production techniques of hydrogen have their own challenges to overcome, they each have a place in the hydrogen economy. If implemented correctly, diverse methods of production can strengthen the energy supply. By leveraging existing infrastructure to its fullest, capitalizing on geographic advantages, and harnessing the nation's technological strength, hydrogen can be realized as the fuel of the future.

Appendix A: List of Acronyms

ATR	Autothermal Reforming
CCS	Carbon Capture and Storage
CO_2	Carbon Dioxide
DOE	U.S. Department of Energy
EIA	Energy Information Administration
EOR	Enhanced Oil Recovery
EPA	Environmental Protection Agency
EV	Electric Vehicle
H_2	Hydrogen
IEA	International Energy Agency
MMT	Million Metric Tons
PEM	Proton Exchange Membrane
PHSMA	Pipeline and Hazardous Materials Administration
SMR	Steam Methane Reforming

Appendix B: Discussion of Hydrogen Color and Public Policy Implication

Black hydrogen is produced from coal, and therefore unlikely to be adopted in an effort to decarbonize. It has high emissions, but low cost. It is uncommon in the United States.

Gray hydrogen uses Steam Methane Reforming (SMR) to produce hydrogen by mixing methane (natural gas) and steam in the presence of a catalyst. The resulting products are hydrogen and CO_2. This is currently the status quo for hydrogen, accounting for about 95 percent of domestic production.[111]

Blue hydrogen is virtually the same as gray hydrogen, except it utilizes Carbon Capture and Storage (CCS). CCS technology is currently in relatively early widescale adoption.[112, 113] Blue hydrogen may use autothermal reforming (ATR) instead of SMR, which is more energy efficient and concentrates the CO_2 for more easy capture.

Green hydrogen is produced through electrolysis of water and has no direct carbon emissions. It takes around 50 kWh of electricity to manufacture a single kilogram of hydrogen, and electrolyzers are expensive to manufacture.[114] Proton-exchange membrane (PEM) cells and alkaline cells are the two main technologies used for electrolysis, though other types are in early stages of development.[115]

Turquoise hydrogen is the name sometimes given to hydrogen produced through methane pyrolysis. Similar to SMR, hydrogen produced through methane pyrolysis uses natural gas as the primary input but produces solid carbon byproduct instead of carbon dioxide. Carbon black, graphite, or other solid carbon, is much easier to store than CO_2, and has some industrial and product applications. The process may be slightly less energy efficient than SMR.

Pink hydrogen is produced from electrolysis using nuclear power. Sometimes it is included within the umbrella of green hydrogen. It is also called purple hydrogen in some papers.

White hydrogen refers to the harvest of naturally occurring hydrogen, formed through geochemical reactions underground. Deposits have only recently been discovered, and there are no large operations yet. White hydrogen is still in the very early stages of discovery and development, but if harnessed, it could produce cheap hydrogen without high energy costs.[116]

Significant research has been conducted into using biomass to produce hydrogen, but inefficiencies mean this option will not be economical without substantial improvements to technology and incentives.[117] There are many different types of biomass production and processes, all with varying energy and CO_2 emissions results.[118] It has the potential to become cheaper, but currently hydrogen production using biomass is at the “large prototype” phase according to the IEA.[119] A benefit of biomass is that many chemicals and products from the process can be useful in other applications, but the variety of chemicals produced also adds its own challenges.

Appendix C: Pipeline Cost and Commentary

The timescales for pipeline construction can be stretched out further by challenges ranging from land acquisition to environmental permitting.[120] Specific hydrogen pipeline costs are difficult to determine and vary significantly by region and length. The average cost of a natural gas pipeline according to the Argonne National Laboratory was around $113,000 per inch-mile in 2018, while a 2021 EPA report found large natural gas pipelines to cost $228,000 per inch-mile.[121,122] The Argonne National Laboratory report found that levelized hydrogen delivery cost varies significantly by region, ranging between $0.04 to over $1.80 per kilogram.

Appendix D: Electrolysis Additional Challenges Discussion

Electrolysis works by running water over a catalyst, but the materials needed for the catalyst and membrane are rare. In particular, Iridium is an extremely rare element that is needed for electrolysis, and it could be a bottleneck for green hydrogen expansion.[123,124] Although very little is needed in each electrolyzer membrane, the global production of Iridium was approximately 6,400 kg in 2023.[125] Platinum is also a rare element needed in electrolyzer membranes, with global production around 190 metric tons in 2022.[126]

Water is another constraint. The chemical reaction to create hydrogen (H_2) from water (H_2O) requires at least 9 L of water for every kg of hydrogen. However, in real applications it takes a cumulative 20 – 30 L of water due to purification and cooling.[127] The need for water is a problem that can be effectively managed with efficient design and proper planning, but it still represents a hurdle for electrolysis.

Citations and Notes

[1] "Carbon emissions" is used broadly to include carbon monoxide (CO), carbon dioxide (CO_2), methane (CH_4), which vary in concentration and impact. Outside of carbon-based emissions are nitrous oxides (NO) and (N_2O), sulfur dioxide (SO_2), and others, including noxious particular matter. Hydrogen largely avoids each of these during combustion, depending on the specific conditions.

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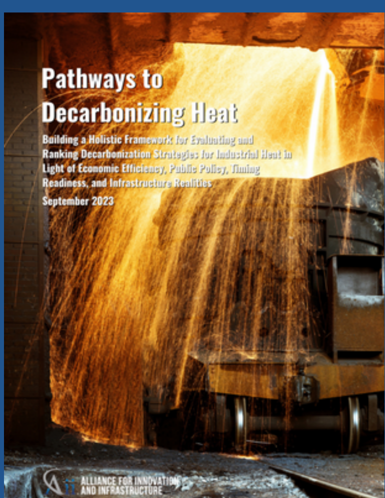

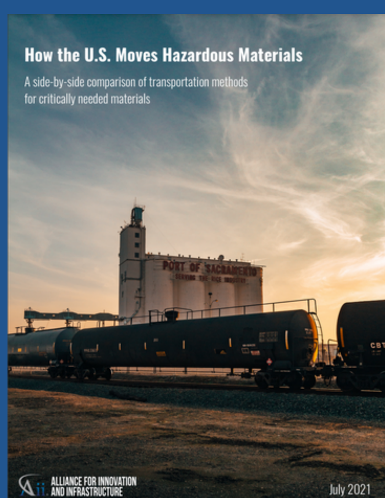

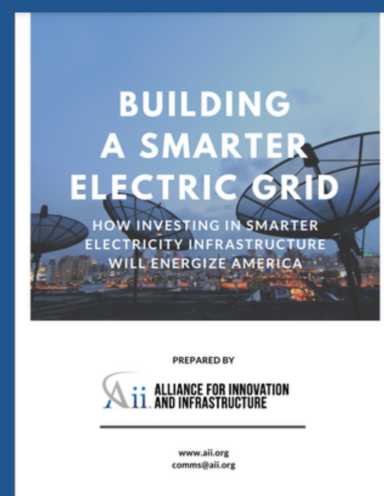

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