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How the Midwest Can Lead the Hydrogen Economy: Matching Generation Assets to Distribution Markets in Planning Hydrogen Refueling Infrastructure for Trucking and Transit

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How the Midwest Can Lead the Hydrogen Economy: Matching Generation Assets to Distribution Markets in Planning Hydrogen Refueling Infrastructure for Trucking and Transit

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Executive Summary

The transition away from carbon-based energy consumption is underway in response to climate change. This is evident in the transportation sector, where vehicles with electric drive systems will be needed to replace fossil fuel powertrains and to significantly increase market share over the coming decades. Hydrogen-powered fuel cell electric vehicles provide one important path to decarbonization in transportation, particularly for heavy-duty applications such as transit and trucking. This study explores the regional assets along a major freight corridor from Pittsburgh to Minneapolis (hereinafter, the "Interstate Corridor") that could enable a hydrogen refueling infrastructure for transit agencies and long-haul trucking, the likely early adopters of hydrogen fuel cell electric vehicles.

 For the foreseeable future, Midwestern states are not expected to adopt California-style incentives, such as Zero Emission Medium- or Heavy-Duty Vehicle Programs which fund the early commercial implementation of zero emission trucks and buses.[1] Hydrogen adoption for Midwestern transit will instead depend on identifying the barriers and pathways to commercial viability. Transit and trucking fleets operating in the Midwest face identical challenges in transitioning to low emission fuels: how to support one-to-one replacement of conventional diesel vehicles, especially with regard to range and refueling time. Hydrogen fuel cell technology addresses some of these challenges in ways that battery electric vehicles have yet to. As a result, this study focuses on the economic factors that affect both the transit and trucking industries as early adopters of hydrogen.

Fundamental issues that have previously constrained fuel cell adoption, especially for vehicle applications, have to a great extent been resolved. For example, fuel cell manufacturers have successfully commercialized their product as evidenced by the 60% decrease in the cost of fuel cell systems for transportation on a $/kW basis since the mid-2000s.[2] Additionally, shale development in the Midwest[3] has brought about an abundant supply of cheap natural gas, the primary feedstock for hydrogen generation, through steam methane reforming. Moreover, improvements in electrolyzer technologies have lowered considerably the cost of producing hydrogen through electricity, promising a commercially viable zero-emissions hydrogen pathway.

While resolving hydrogen generation issues has led to solutions in *producing* hydrogen more inexpensively, the matter of how to *deliver* hydrogen cost-effectively remains an outstanding

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[1] *See* Alternative Fuels Data Center. "Hydrogen Laws and Incentives in California."
https://afdc.energy.gov/fuels/laws/HY?state=CA

[2] "DOE Fuel Cell Technologies Office Record 17007: Fell Cell System Cost." *U.S. Department of Energy.* (2017). https://www.hydrogen.energy.gov/pdfs/17007_fuel_cell_system_cost_2017.pdf. *See also* "Fact of the Month April 2018: Fuel Cell Cost Decreased by 60% Since 2006." *U.S. Department of Energy.* (2018). https://www.energy.gov/eere/fuelcells/fact-month-april-2018-fuel-cell-cost-decreased-60-2006

[3] The Midwest here defined includes the states of Illinois, Indiana, Michigan, Minnesota, Ohio, Pennsylvania, and Wisconsin.

problem. In California, where early stage public hydrogen refueling stations have been installed, the combined cost of transporting the hydrogen to the station along with the hardware for storing and dispensing the fuel can represent more than 80% of the price at the pump,[4] which averaged nearly $16 per gasoline gallon equivalent in 2019.[5] Figure 1 shows the projected cost breakdown for hydrogen used in early fuel cell electric vehicle markets by 2025 based on research conducted for the U.S. Department of Energy's Fuel Cells Program.[6] While factors such as technological improvements, increased station utilization, and economies of scale in component manufacturing are expected to drive down the cost to deliver and dispense hydrogen for vehicles, the cost of getting hydrogen to the refueling station and making it available to dispense will likely still be more than twice the cost of actually producing the hydrogen via electrolysis by the middle of the decade.[7] Accordingly, developing strategies that reduce the cost of hydrogen distribution will be critical to the early adoption of fuel cell electric transportation.

Figure 1. Projected Cost of Hydrogen from Electrolysis for Early Market Fuel Cell Vehicles

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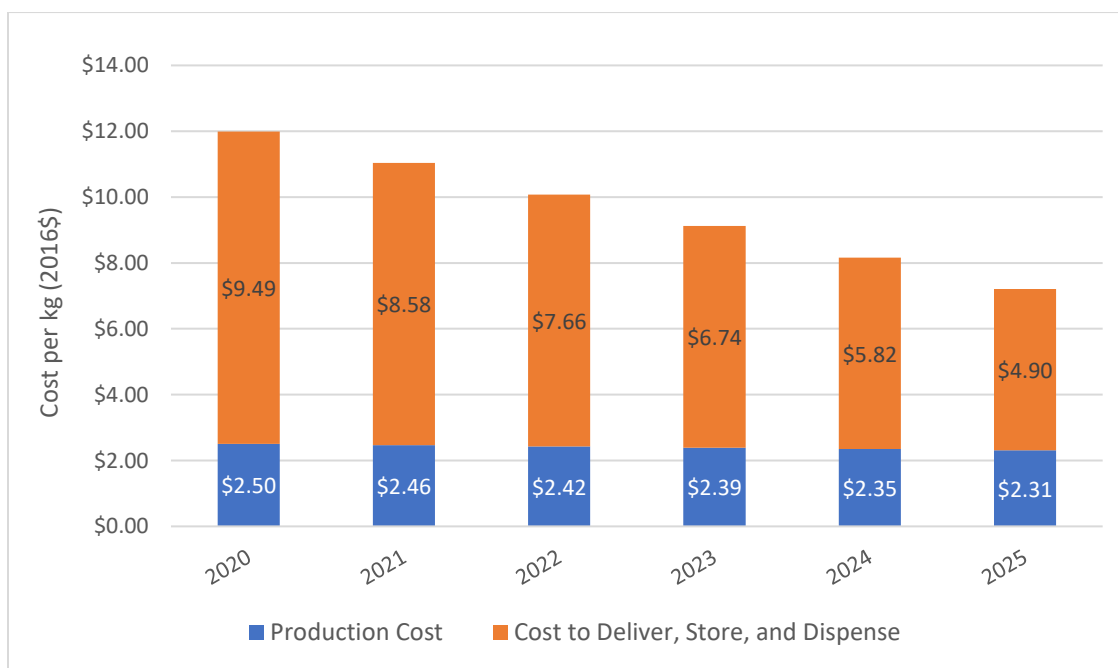
[4] *See* Reddi, K., Elgowainy, A., Rustagi, N., & Gupta, E. (2017). Impact of hydrogen refueling configurations and market parameters on the refueling cost of hydrogen. *International Journal of Hydrogen Energy*, 42(34), 21855-21865.

[5] *See* U.S. Department of Energy, Alternative Fuels Data Center. *Clean Cities Alternative Fuel Price Report* [April-October, 2019]. https://afdc.energy.gov/publications/search/keyword/?q=alternative%20fuel%20price%20report

[6] *See* DOE Hydrogen and Fuel Cells Program Record #18003 (*Current Status of Hydrogen Delivery and Dispensing Costs and Pathways to Future Cost Reductions*) and #19009 (*Hydrogen Production Cost From PEM Electrolysis – 2019*). https://www.hydrogen.energy.gov/program_records.html#prod_delivery.

[7] Projections are based on Argonne National Laboratory's Hydrogen Production Analysis (H2A) and Hydrogen Delivery Scenario Analysis (HDSAM) models. Centralized production of 1,500 kg per day and delivery via gaseous tube trailers and liquid tankers were assumed for these projections, which represent feasible targets if state-of-the-art laboratory-scale R&D achievements are scaled up and commercially adopted.

This study reviews the assets and markets along the Interstate Corridor that might make a hydrogen refueling infrastructure feasible in the near future by minimizing the cost of distributing and dispensing hydrogen. Initial demand for hydrogen in transportation will likely not be sufficient to justify large capital investments such as pipelines that could deliver hydrogen from large centralized production plants that take advantage of economies of scale. Distributed production at the point of consumption will therefore likely be the most viable approach for introducing hydrogen as an energy carrier for transportation in the near term. However, as demand for hydrogen intensifies the avoided distribution cost of onsite production will be counterbalanced by the economies of scale that could otherwise be achieved using centralized production. One option for negotiating this point of production tradeoff is to have semi-central production. Such intermediate facilities could realize limited economies of scale while reducing the cost of infrastructure required for delivery by being closer to the point of consumption.

Nuclear plants in the Midwest along the Interstate Corridor are candidate sites for such semi-central production as they are located near both major freight corridors and industrial centers, areas where potential high-volume users of hydrogen are concentrated, including transit agencies. The U.S. Department of Energy (DOE), through its Light Water Reactor Sustainability Program, has already announced funding for pilot projects in Ohio and Minnesota to demonstrate the technical and economic feasibility of hydrogen production by splitting water using electricity generated at nuclear power plants.[8] The proximity of these plants to current and future hydrogen consumers in transportation and industry could minimize delivery costs and help smooth the balance between supply and demand. Figure 2 illustrates the nearness of the Midwest nuclear fleet to high-volume hydrogen demanders, both in the present and potentially in the future with the transition of trucks that deliver freight along the Interstate Corridor to fuel cell powertrains. Additionally, Figure 2 includes the location of current and planned metal processing facilities that use more hydrogen-intensive processes to convert iron ore to iron.

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[8] *See* "INL Selected to Partner with Three Utilities on First-of-a-Kind Integrated Energy Systems." (2019). *Idaho National Laboratory.* https://inl.gov/article/inl-selected-to-partner-with-three-utilities-on-first-of-a-kind-integrated-energy-systems/

Figure 2. Potential Demanders and Nuclear Supply of Hydrogen[9]
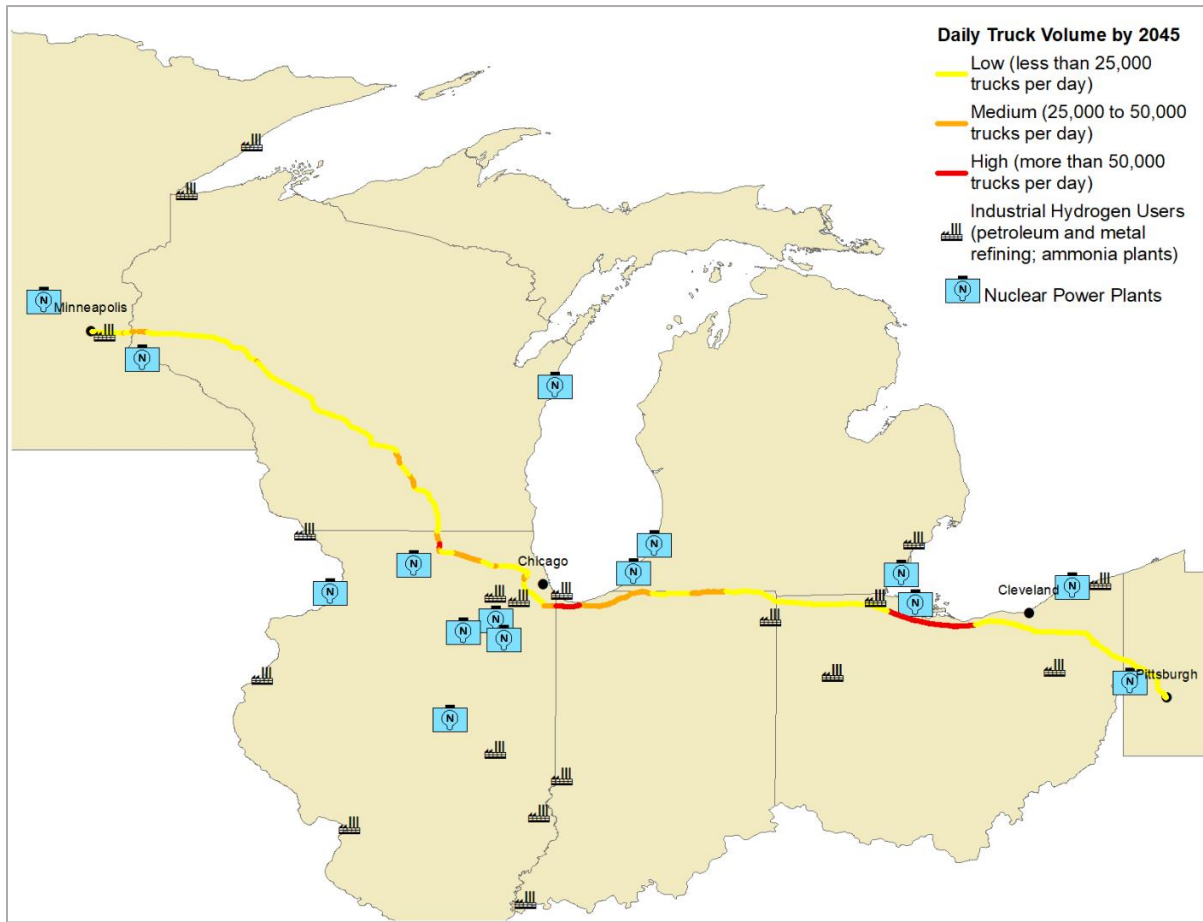
For hydrogen use in heavy-duty transportation, siting refueling stations to maximize capacity utilization will be critical to realizing the lowest possible price at the pump that could in turn increase FCEV adoption. Refueling station capacity utilization strongly influences hydrogen refueling cost.[10] Full capacity utilization is most likely to occur where the demand for fuel by heavy-duty vehicles is highest. The most promising sites for economical hydrogen refueling stations in this context are areas that have a history of high fuel demand, such as traditional truck stops along major freight corridors, and large transit facilities with dense ridership.

Hydrogen will likely play a prominent role in decarbonizing the transportation sector. Given that hydrogen can store more energy in less weight than most common transportation fuels, fuel cells

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[9] Truck volume forecasts are derived from the most recent Freight Analysis Framework (FAF) produced through a partnership between the Bureau of Transportation Statistics (BTS) and Federal Highway Administration (FHWA); *see* https://ops.fhwa.dot.gov/freight/freight_analysis/faf/. Petroleum refinery and nuclear plant locations are available through the U.S. Energy Information Administration; *see* https://www.eia.gov/maps/layer_info-m.php. Locations for Midwest ammonia plants and direct reduced iron (DRI) facilities were identified using Google search queries.

[10] *See* https://www.sciencedirect.com/science/article/pii/S0360319917320311

are well-suited for vehicles with heavy payloads and long ranges. While there are still challenges to meeting the DOE's cost target for hydrogen at the pump of $4 per gasoline gallon equivalent, the goal of achieving $2 production within that target has been met by fossil resource pathways and is nearing realization for zero-emissions methods such as electrolysis. With increased demand, the price at the pump for hydrogen can converge with the DOE's $4 target and be competitive with other transportations fuels. By planning deployment of Midwest refueling infrastructure in a manner that exploits existing assets for producing hydrogen, demand could be fostered while realizing competitive prices.

The Interstate Corridor running from Minneapolis to Pittsburgh is particularly well positioned to provide both the market for and the supply of hydrogen. This can be readily seen by comparing the existing and projected hydrogen generation capacity to the industrial hydrogen markets in the Midwest, as set forth in Table 1:

Table 1. Current and Projected Midwest Hydrogen Consumption and Production (metric tons)

		Current[11]	2030	2040
Hydrogen Consumption	iron processing	1,699	2,086	2,696
	ammonia plants	9,144	10,714	13,060
	petroleum refining	2,707	2,990	3,385
	Total	**13,549**	**15,789**	**19,141**
Hydrogen Production	ethane crackers	763	1,516	3,572
	chlor-alkali plants	59	90	152
	on-purpose production at dedicated hydrogen plants	2,287	4,232	9,137
	Total	**3,109**	**5,838**	**12,861**
	Surplus (Shortage)	**(10,440)**	**(9,951)**	**(6,280)**

 note: 1 metric ton = 1,000 kg

Inexpensive electricity from nuclear plants located near industrial hydrogen consumers and heavy-duty vehicle hubs could provide the early impetus for a hydrogen refueling infrastructure in the Midwest. This combination of proximately located hydrogen generation and markets suggests that careful infrastructure planning along the Interstate Corridor could significantly reduce early adoption distribution costs.   Figure 3 provides one strategy for optimizing station location based upon the density of existing refueling stations for heavy duty trucks and the anticipated fuel economy of heavy-duty fuel cell electric vehicles over the next two decades. Midwest nuclear plants are also included in Figure 3 to illustrate their potential to supply these proposed stations with hydrogen.

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[11] Includes consumption and production of hydrogen at plants planned for completion in the early 2020s.

Figure 3. Optimized Hydrogen Refueling Station Siting and Midwest Nuclear Plants
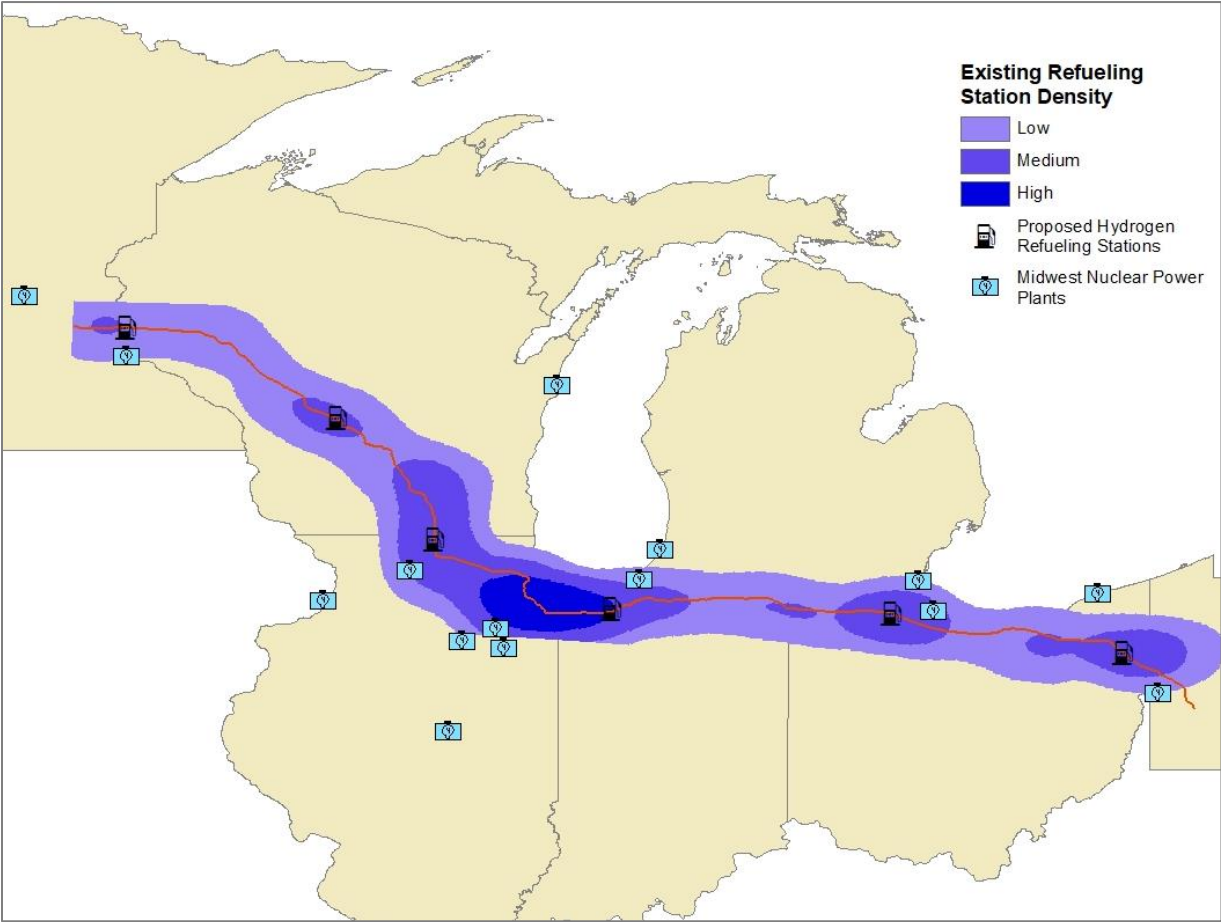
1. Introduction

This study was undertaken in response to fundamental changes that have occurred in the last decade in the Midwestern[12] and United States energy economy. Structural changes in energy markets, together with an increasingly imminent crisis in climate change, have together put the hydrogen economy in the forefront of regional planning. The study examines the regional assets along the major freight corridor from Pittsburgh to Minneapolis that could trigger a hydrogen refueling infrastructure for transit agencies and long-haul trucking. Such fleets are the most likely early markets for hydrogen electric vehicles.

Hydrogen generation, transportation and storage systems provide both a challenge and an opportunity for the Midwest economy. This has been understood for many years, especially in the Midwest, which will feel keenly the disruptive effects of the transition from internal combustion engines to elective drive engines. Manufacturing automobiles and trucks have long comprised a major part of the Ohio and Michigan economies.

The transition has been deemed necessary by threats to both climate from carbon dioxide emissions and to national security, as world oil reserves have increasingly been concentrated within rogue states. By the early 2000s, falling oil supplies were threatening the world economy: prices had risen to as much as $150/barrel, and oil imports made up over half of the US trade deficit. This accelerated planning for the transition. Ohio responded with the Third Frontier program, which in 2002 began to invest heavily into the development of fuel cell technologies.[13]

Yet the transition from internal combustion engines to fuel cells slowed. In 2020, almost 20 years later, only a handful of hydrogen refueling stations exist in the Midwest. Fuel cell automobiles or trucks cannot be purchased except in California, where refueling infrastructure is available, mostly in and around Los Angeles.

There have been two reasons for this lack of progress. First, fuel cell technology was not yet ready for commercial applications in the 2000s. And second, the only way to commercially generate hydrogen has been through the process of steam methane reformation. With the wholesale price of natural gas regularly over $8.00 per million British thermal units (MMBtu),[14] hydrogen manufacturing through steam reformation, while less expensive than alternatives, was still very expensive. But by the 2000s, an important third reason for lack of progress in the adoption of fuel cell technology had emerged: the steam reformation process was not emission free. For these reasons, in 2009, Department of Energy Secretary Stephen Chu decided to focus federal energy funding into "shovel ready" renewable generation, vehicle efficiency and plug in

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[12] The Midwest here defined includes the states of Illinois, Indiana, Michigan, Minnesota, Ohio, Pennsylvania, and Wisconsin.

[13] https://www.energytechnologiesinc.com/pressRelease/news/Press_Release_3rd_TFFC_Grant.php

[14] Henry Hub prices for natural gas peaked at $13.42/mmbtu in 2005. By November 2019, it was at $2.65/mmbtu. *See*: https://www.eia.gov/dnav/ng/hist/rngwhhdm.htm

hybrid cars rather than into hydrogen fuel cells.[15] Secretary Chu argued that it was unlikely that a hydrogen refueling infrastructure could be built in the next 20-30 years that would reduce US dependence on oil.   Further, he noted, using natural gas for transportation (which hydrogen requires) would "put a strain on natural gas for industrial uses and heating."[16]

In the ten years since Secretary Chu made this decision, however, these fundamental issues have largely been resolved.   First, fuel cell manufacturers have achieved commercial status.   Fuel cells are sufficiently durable, and costs have come down. Fuel cell electric forklifts are today in common use in warehouses. Honda offers an 8-year warranty on its fuel cell Clarity model, which sells for under $60,000.[17]   Other fuel cell vehicles are readily available — subject to refueling availability. Second, natural gas today is cheap, making hydrogen generation cheap. The advent of shale development in the Appalachian Basin beginning around 2005 has been so successful that by 2014, natural gas prices crashed to below $2.00 per million cubic feet. In 2020, it remains below $3.00, and the US Energy Information Agency does not forecast a major change in price for the next 20 years.[18] The result is that generating hydrogen from steam methane reformation in 2020 costs a fraction of what it cost in 2009.

A third new development, however, may be the most important to the hydrogen economy: cost reductions in generation of hydrogen through electrolysis.   Cost reductions in electricity generation and improvements in electrolyzer technology have combined to promise a near-term source of zero emission hydrogen that could power the transportation sector in the 21st century. Wholesale electricity costs in 2020 are particularly attractive for wind and nuclear power, and off-peak power from these sources can be repurposed from the grid to hydrogen generation.

The first adopters of hydrogen transportation in the Midwest will likely be transit agencies, pushed by the availability of federal funding for zero-emission vehicles in public transportation and also by California mandates to deploy more zero-emission buses that will likely drive down vehicle costs for agencies in all states. Hydrogen fuel cell buses are likely to also be a popular choice among agencies along the Interstate Corridor because of their range in cold weather.[19] Large haul commercial truck fleets are likely to follow. However, transportation systems will not be the only use for hydrogen in the Midwest. Industrial use is already significant and growing, as can be seen from the new steel plant being built in Toledo, Ohio, where hydrogen is being used as a reducing agent. Further, hydrogen will increasingly be used for grid storage. Modern models for the grid require increased reliability, while depending increasingly on renewable, intermittent power sources. In a data driven economy, grids in the 21st century will need to provide 99.999%

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[15] S. Power, "Energy Secretary, Congress, Collide Over Hydrogen Car Funds," *Wall Street Journal*, July 28, 2009, https://www.wsj.com/articles/SB124874456766585605
[16] *Id.*
[17] Honda Clarity fuel cell price based on Kelly Blue Book Value. *See* https://www.kbb.com/honda/clarity-fuel-cell/2019/base-style/?vehicleid=443592&intent=buy-new
[18] For reference case forecasts of natural gas prices, see the Energy Information Administration's Annual Energy Outlook 2019. *Energy Prices by Sector and Source* (table). https://www.eia.gov/outlooks/aeo/data/browser
[19] Henning, Mark; Thomas, Andrew R.; and Smyth, Alison, "An Analysis of the Association between Changes in Ambient Temperature, Fuel Economy, and Vehicle Range for Battery Electric and Fuel Cell Electric Buses" (2019). Urban Publications. 0 1 2 3 1630. https://engagedscholarship.csuohio.edu/urban_facpub/1630

uptime.[20] This will make energy storage an increasingly important part of the grid, and hydrogen will likely make up a significant part of the storage mix.

Changes to energy markets and delivery systems, together with mandates to reduce carbon emissions and foreign oil dependency, all point to a developing hydrogen economy in the next 20 years. Many assets already exist in the Midwest that could catalyze a nascent hydrogen economy. Accordingly, the study team has undertaken this review of assets and markets along the Interstate Corridor that might make a hydrogen refueling infrastructure feasible in the near future. This review includes an analysis of potential strategies for how the Midwest can develop a viable hydrogen refueling infrastructure.

2. Hydrogen Production Pathways in the Midwest

The U.S. Department of Energy's Fuel Cell Technology Office (FCTO) outlines three major categories of technology pathways for hydrogen production: fossil resources, biomass resources and direct water splitting.[21] Each category consists of multiple production pathways at different stages of technological and commercial readiness. Most hydrogen produced today comes from fossil resources, with 95% of current production derived from natural gas.[22]

The viability of a hydrogen production pathway is geographically variable and driven by context-specific economic factors. One of these factors is the point of production, where central, semi-central, and distributed production facilities are all possibilities while hydrogen develops as an energy carrier for transportation applications, with each potential production point having its own set of advantages and disadvantages.[23] Nearly all of the hydrogen produced in the United States is made in large central plants that take advantage of economies of scale to lower the average cost of production.[24]

This point of production, however, relies on an underdeveloped distribution and delivery infrastructure to satisfy a dispersed hydrogen demand. For example, a survey by the Study Team of the 43 counties containing segments of the 878-mile Interstate Corridor from Pittsburgh to

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[20] The operational performance of information technology (IT) systems is generally evaluated according to "uptime," the percentage of time a particular system is operational. In IT, it is one of the most vital metrics associated with the performance of mission-critical systems. The higher the uptime, the more available and better performing the system. Uptime is traditionally measured in nines, which correlates to an expected amount of downtime over a given period. Five nines, or 99.999%, corresponds to approximately 5 minutes of downtime per year and is a highly valued level of system availability often recommended for mission-critical applications and in performance-sensitive industries like finance and ecommerce. *See* https://www.nefiber.com/blog/five-nines-uptime-sla-mean/

[21] *See* https://www.energy.gov/eere/vehicles/downloads/us-drive-hydrogen-production-technical-team-roadmap

[22] *Id*.

[23] *See* U.S. Department of Energy, Fuel Cell Technologies Office. (2015). "Fuel Cell Technologies Office Multi-Year Research, Development, and Demonstration Plan." *Hydrogen Production* (section 3.1). https://www.energy.gov/sites/prod/files/2015/06/f23/fcto_myrdd_production.pdf

[24] *See* two prior footnotes.

Minneapolis identified the presence of only around 17 total miles of hydrogen gas pipelines.[25] The high capital cost associated with installing hydrogen gas pipeline, as much as 68% more than the cost of installing natural gas pipeline of similar diameter and operating pressure according to researchers at the National Institute of Standards and Technology, ,[26] presents a challenge to the expansion of centralized hydrogen production.

The substantial delivery infrastructure and large capital investments required to move hydrogen from central production plants to points of use can be avoided by producing hydrogen onsite at refueling stations, a scenario known as distributed or forecourt production. Hydrogen distribution cost are generally greater than production costs. For this reason, distributed production will likely be the most viable approach for introducing hydrogen as an energy carrier for transportation in the near term because of what is anticipated to be low initial demand.[27] However, as demand for hydrogen intensifies the avoided distribution cost of onsite production will be counterbalanced by the economies of scale that could otherwise be achieved using centralized production. One option for negotiating this point of production tradeoff is to have semi-central production on the edge of urban areas. Such intermediate facilities could realize economies of scale—albeit limited—while reducing the cost of infrastructure required for delivery by being closer to the point of consumption.[28]

The different points of hydrogen production for transportation described herein correspond with varying production scales. As envisioned by the U.S. Department of Energy's *U.S. Drive* partnership in conjunction with the transportation and energy industries, small-scale distributed production would yield 100 to 1,500 kilograms of hydrogen per day, medium-scale semi-central facilities would produce 1,500 to 50,000 kilograms per day, and large-scale centralized facilities would generate greater than 50,000 kilograms of hydrogen per day. Figure 4 illustrates the number of heavy-duty class 8 trucks (also known as 18-wheelers) that varying hydrogen production volumes might support. Figure 5 illustrates this potential for fixed-route transit buses.

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[25] Hydrogen gas pipeline lengths for these counties were estimated using the U.S. Department of Transportation's National Pipeline Mapping System (NPMS) Public Viewer. *See* https://pvnpms.phmsa.dot.gov/PublicViewer/

[26] *See* Fekete, J. R., Sowards, J. W., & Amaro, R. L. (2015). Economic impact of applying high strength steels in hydrogen gas pipelines. *International Journal of Hydrogen Energy*, 40(33), 10547-10558. https://doi.org/10.1016/j.ijhydene.2015.06.090

[27] https://www.energy.gov/eere/fuelcells/central-versus-distributed-hydrogen-production

[28] *See* U.S. Department of Energy, Fuel Cell Technologies Office. (2015). "Fuel Cell Technologies Office Multi-Year Research, Development, and Demonstration Plan." *Hydrogen Production* (section 3.1). https://www.energy.gov/sites/prod/files/2015/06/f23/fcto_myrdd_production.pdf

Figure 4. Projected Daily Hydrogen Requirement for
Heavy-Duty Class 8 Fuel Cell Trucks (2019)[29]

Image Source: Kenworth

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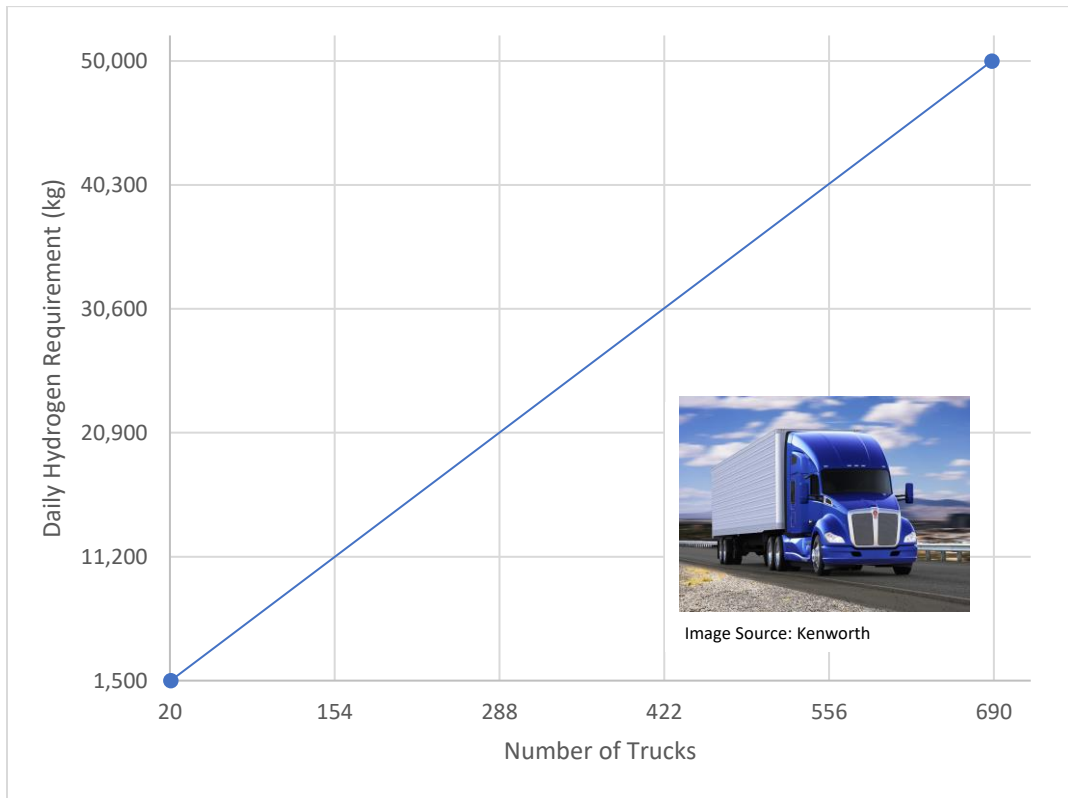
[29] Based on a fuel requirement of 64 diesel-gallons equivalent (comparable to approximately 73 kg of hydrogen) per vehicle to travel 500 miles given current technology for class 8 fuel cell trucks. *See* https://www.hydrogen.energy.gov/pdfs/review19/ta024_vijayagopal_2019_o.pdf. *See also* https://epact.energy.gov/fuel-conversion-factors

Figure 5. Projected Daily Hydrogen Requirement for Fuel Cell Electric Buses (2019)[30]

Image Source: FTA
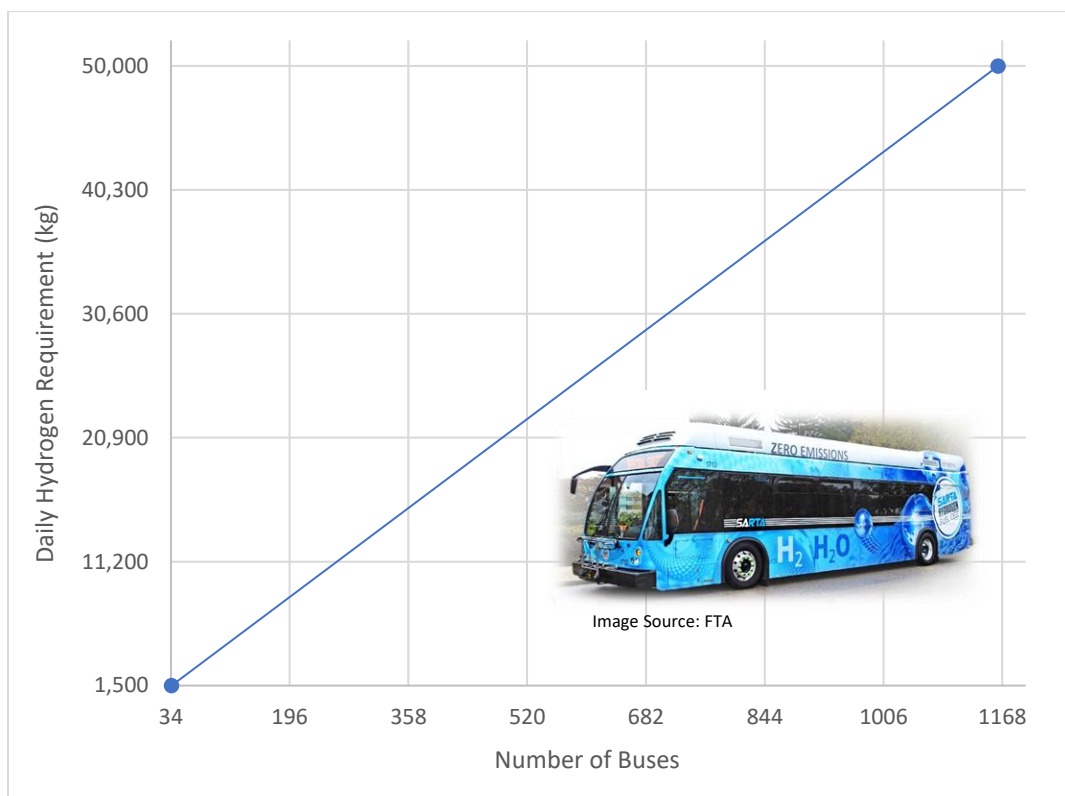
Another determinant of a hydrogen production pathway's viability for transportation applications is the number of market participants in other industries either vying for available hydrogen or producing it as a byproduct of their industrial process and the amount of hydrogen these participants demand or supply. Some of the more significant industrial consumers of hydrogen include petroleum refineries, ammonia plants, and newer iron processing plants.[31] These users of hydrogen produce some of what they need internally—known as *captive* hydrogen—and receive the balance, if necessary, from *merchant* suppliers who are distinct companies producing hydrogen at separate central production facilities that is then delivered via pipeline, bulk tank, or cylinder truck delivery. Industrial-scale consumers of hydrogen in the Midwest have historically not been as reliant on merchant suppliers because of a lack of dedicated hydrogen pipelines.[32] However, hydrogen pipeline buildout could lead to greater

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[30] Based on a fuel requirement of 38 diesel-gallons equivalent (comparable to approximately 43 kg of hydrogen) per vehicle to travel 266 miles given current technology and daily range for fuel cell electric buses. *See* https://www.nrel.gov/docs/fy19osti/72208.pdf

[31] The majority of ammonia produced by plants through the United State is for fertilizer used in agriculture. Direct reduction of iron ore (DRI) in the steel production process uses hydrogen to reduce iron ore to iron without melting. *See* https://www.hydrogen.energy.gov/pdfs/review19/sa172_elgowainy_2019_o.pdf. *See also* https://www.energy.gov/sites/prod/files/2018/08/f54/fcto-h2-scale-kickoff-2018-19-green.pdf

[32] *See* "U.S. Gulf Coast refinery demand for hydrogen increasingly met by merchant suppliers." *U.S. Energy Information Administration. (2019).* https://www.eia.gov/todayinenergy/detail.php?id=38712

reliance on merchant suppliers to meet demand among industrial consumers, which has been the case in the Gulf Coast region, where the hydrogen pipeline network is the most robust in the country.[33] This may lead to greater competition with transportation applications for hydrogen in the merchant market.

These competitive pressures could potentially be alleviated, and the hydrogen fuel supply for transportation secured, by industries that produce by-product hydrogen that can be recovered from waste streams of existing chemical production processes. Two such processes being closely examined for the techno-economic viability of hydrogen recovery are ethane cracking, an enabling technology for making plastics derived from natural gas liquids such as ethane, and chlor-alkali production where chlorine is made by passing an electrical current through salt brine.[34] For processes such as these, by-product hydrogen is generally utilized inefficiently. While some of this hydrogen is either combusted to generate process heat energy required for manufacturing or sold externally as a commodity, the rest is very likely vented to the atmosphere or flared.[35] In the case of chlor-alkali plants in Europe, it has been estimated that as much as 10% of the by-product hydrogen is either vented or flared.[36] The cost of hydrogen production by recovering it from waste streams is conceivably quite low (around $1 per kg according to Argonne National Laboratory) and is composed primarily of the cost of the natural gas that must be substituted for the by-product hydrogen that otherwise would be routed into the combustion fuel stream and burned to generate the heat energy required for manufacturing.[37]

The hydrogen production pathways described herein can be deployed at different points of production, although not all are equally techno-economically viable across all scales.[38] The U.S. Department of Energy has an ultimate cost target for hydrogen production of no more than $2/kg (no more than $4/kg for delivered and dispensed hydrogen), independent of the technology

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[33] *Id.*

[34] *See* H2@Scale Workshop Report. *National Renewable Energy Laboratory.* (2016). https://www.nrel.gov/docs/fy17osti/68244.pdf

[35] Lee, D. Y., Elgowainy, A. A., & Dai, Q. (2017). *Life Cycle Greenhouse Gas Emissions of By-product Hydrogen from Chlor-Alkali Plants* (No. ANL/ESD-17/27). Argonne National Lab.(ANL), Argonne, IL. https://greet.es.anl.gov/publication-chlor_alkali_h2

[36] *Id*.

[37] Lee, D. Y., & Elgowainy, A. (2018). By-product hydrogen from steam cracking of natural gas liquids (NGLs): Potential for large-scale hydrogen fuel production, life-cycle air emissions reduction, and economic benefit. *International Journal of Hydrogen Energy*, *43*(43), 20143-20160.

[38] The hydrogen production technology pathways seen here are those outlined in the U.S. Department of Energy's *US Drive Hydrogen Production Technical Team Roadmap. See* https://www.energy.gov/sites/prod/files/2017/11/f46/HPTT%20Roadmap%20FY17%20Final_Nov%202017.pdf

pathway.[39]   This unit fuel cost is viewed as the threshold at which fuel cell electric vehicles become competitive with alternatives in the marketplace.[40]

A. Fossil resources pathways

i. Steam Methane Reforming

Currently, the most widespread process for producing hydrogen gas is Steam Methane Reformation (SMR). SMR is the process of taking a natural gas, such as methane, and applying heated steam with a nickel catalyst to separate the hydrogen molecules from the rest of the compound.[41] This process is already being used on an industrial scale. The hydrogen it produces is economically competitive, although the costs associated with SMR correlate directly to the cost of the natural gas that is used as a feedstock. Further, SMR is a carbon-intensive process, producing excess CO_2 or other carbon compounds as the hydrogen is separated from the rest of the methane input. In order to negate the carbon footprint of SMR, carbon capture technologies will need to be implemented at an industrially competitive price scale. The potential for this is discussed further below. In the context of the Midwest, SMR is an appealing option due to the widespread availability of natural gas in the region as well as the high level of already-existing production facilities.[42] Today, 95% of Hydrogen produced for industrial use is made through the SMR process, generally without being paired with Carbon Capture technologies.

ii. Coal Gasification

Coal gasification uses high temperature steam and oxygen gas to convert solid coal into gaseous hydrogen and carbon monoxide. The process is technologically mature but is less efficient than SMR, and it produces large amounts of solid waste in the form of slag and ash. The high capital costs of the coal gasification process (between 1.4 and 2.5 times higher than SMR) and the necessities of waste disposal make it efficient only at larger scales, although future developments may make scalability of this technology more feasible. Coal gasification also releases CO2 as a byproduct.[43]

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[39] DOE Hydrogen and Fuel Cells Program: 2018 Annual Progress Report. *U.S. Department of Energy.* (2019). https://www.hydrogen.energy.gov/annual_progress18.html

[40] *See* U.S. Department of Energy, Fuel Cell Technologies Office. (2015). "Fuel Cell Technologies Office Multi-Year Research, Development, and Demonstration Plan." *Hydrogen Production* (section 3.1).

[41] Information summarized from Air Products and Chemicals' *Steam Methane Reformer Overview, see* http://www.airproducts.com/~/media/Files/PDF/industries/energy/energy-hydrogen-steam-methane-reformer-datasheet.pdf

[42] *See* Thomas, Andrew R. and Henning, Mark, "Shale Investment Dashboard in Ohio Q3 and Q4 2018" (2019). Urban Publications. 0 1 2 3 1628. https://engagedscholarship.csuohio.edu/urban_facpub/1628

[43] U.S. DRIVE Partnership, *Hydrogen Production Tech Team Roadmap*, (2017)

iii. SMR and Coal gasification with Carbon Capture

The carbon footprints of both SMR and coal gasification could be reduced or even negated through the application of Carbon Capture technologies. The concept behind carbon capture involves preventing the carbon produced by industrial processes from entering the atmosphere, either by storing it or finding marketable uses for it. This can involve simply storing excess CO_2 in underground geological caverns or storage wells drilled for this purpose. However, in order to become truly economically viable, new marketable uses for that excess carbon will need to be explored and developed.

For processes involving high concentrations of CO_2 production (such as SMR or coal gasification) the CO_2 can be physically absorbed and separated using solvents such as Selexol™. Recent research has suggested that a large SMR facility (producing 314 t/d of hydrogen) using Carbon Capture via Selexol™ could produce hydrogen at a cost of $0.99/kg. At a medium scale (50 t/d) this figure is still only $1.47/kg, while at a small scale (1.5t/d) this cost increases to $3.24/kg.[44] This indicates that hydrogen production via SMR with Carbon Capture can be economically competitive, although not yet at the scale of an individual hydrogen fuel pumping station.

Developing and implementing these carbon capture technologies will require further investment and policy prioritization. Carbon capture could become economically competitive if either an incentive is placed on the removal of CO_2 (via a carbon tax or cap-and-trade policy) or if a profitable use for reclaimed carbon can be developed.[45] Those potential uses might include the production of carbonate building materials and aviation fuels that have carbon-based components. Another potential market for captured carbon particularly applicable to the Midwest would be the production of fertilizers for use in large-scale agriculture. It is possible that state or federal policy might prioritize the purchasing of CO_2 based fuel for aviation or other large-scale purposes, which would increase the market demand for these resources.

B. Biomass resources pathways

Another avenue for hydrogen production that is considered to be potentially cost-competitive is the sourcing of hydrogen from organic biomass. This can be accomplished through various production pathways. Biomass gasification uses a similar process to the coal gasification procedure noted above, differing mainly in that it uses organic material such as energy crops (trees or grasses grown specifically for energy-production purposes) as an input rather than coal. Additionally, biomass-derived liquid reforming processes can be used to refine organic material into liquids which can then be converted to hydrogen via some of the same chemical procedures as SMR. The current state of this biomass liquid reforming technology allows for hydrogen to be

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[44] Research conducted by authors
[45] Research conducted by authors

produced at around $6.60/gge,[46] with the cost of the biomass input making up 83% of production costs.[47] These processes share several of the same challenges as SMR, but are less well-developed, more capital-intensive, and have limitations to their durability.[48] There are also processes such as dark fermentation and microbial electrolysis that use the biological metabolic processes of microbes to convert certain organic waste products directly into hydrogen gas. However, the organic feedstocks for these processes are expensive to refine, and hydrogen-specific fermentation processes still need to be further developed.[49] The high relative costs of biomass feedstocks make it difficult to scale these processes down for decentralized production.

C. Direct water splitting pathways

i. Water electrolysis

Water electrolysis is the process of using electrical currents to break down the bonds connecting the hydrogen and oxygen atoms in water molecules. This allows for the production of H_2 gas at large scales with minimal carbon output, releasing only oxygen in the form of O_2 gas as a byproduct. The main production pathways for water electrolysis involve either low-temperature reactions (using a polymer-electrolyte membrane or alkaline solution) or high temperature production using solid oxide electrolyzers. If the electricity used in electrolysis is generated by a zero-carbon energy source, such as a nuclear power plant or a wind farm, there is no carbon footprint directly associated with the process.[50] Electrolysis technologies are receiving increased attention and investment from both private enterprises and from federal agencies and state governments as a potential clean source for industrial-scale hydrogen production. For example, what has been called the "largest hydrogen electrolyzer for transportation in the United States," a plant capable of producing 900 kg of hydrogen per day, will likely be in service by mid-2020 at the SunLine Transit Agency in Southern California.[51] Part of a larger $17.8 million project that included two fueling station modules and five fuel cell buses, funding for procurement and installation of this industrial-scale electrolyzer came primarily from the California Air Resources Board.[52]

The most common types of electrolyzers are discussed below.

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[46] DOE Hydrogen and Fuel Cells Program Record #14005. October 7, 2014.
https://www.hydrogen.energy.gov/pdfs/14005_hydrogen_production_status_2006-2013.pdf
[47] U.S. DRIVE Partnership, *Hydrogen Production Tech Team Roadmap*, (2017)
[48] U.S. DRIVE Partnership, *Hydrogen Production Tech Team Roadmap*, (2017)
[49] *Id.*
[50] U.S. Department of Energy, Office of Nuclear Energy, *Evaluation of Non-electric Market Options for a Light-water Reactor in the Midwest* (August 2019)
[51] *See* the following: https://www.palmspringslife.com/50-influential-people-palm-springs/;
https://ww3.arb.ca.gov/msprog/lct/pdfs/sunline.pdf; https://www.sunline.org/hydrogen-cng-construction-project
[52] fhttps://ww3.arb.ca.gov/msprog/lct/pdfs/sunline.pdf

- **PEM electrolyzer**

In PEM electrolysis, a polymer electrolyte membrane (PEM) helps separate the water molecules into stable H_2 and O_2. Through the help of a DOE-funded project, PEM electrolyzers are being installed at the Davis-Besse nuclear reactor facility in Ohio as well as in two nuclear reactor facilities in Minnesota. These PEM electrolyzers will be able to produce hydrogen at a commercial scale beginning in 2020-2021 and may serve as proof-of-concept for large-scale electrolysis-based hydrogen production in the Midwest. PEM electrolyzers have the ability to turn on and off quickly and efficiently, allowing for a high level of responsiveness to the needs of power grids. That is, in an emergency situation or sudden increase in grid demand, the energy being used for hydrogen production can be quickly redirected back to the general grid, minimizing disruption.[53] This makes them particularly appealing for integration into existing power grid infrastructure. Studies conducted by Strategic Analysis, Inc. report that by 2025, hydrogen could be produced for the gas/gallon equivalent cost of $4.20 through centralized production and $4.23 through forecourt production.[54] This indicates a high level of potential scalability for decentralized use. Since electrical energy costs make up 78% of the total production cost of hydrogen via PEM electrolysis,[55] the costs associated with this process could be further reduced if PEM electrolyzers could be paired with dedicated low-cost electrical energy sources. This would likely be the case with off-peak wind and nuclear reactor production.

- **Alkaline electrolyzer**

Alkaline electrolysis is currently the most well-developed and cost-effective electrolysis pathway, although it is still generally more expensive than SMR in most circumstances.[56] This process uses an alkaline solution to catalyze the separation of hydrogen and oxygen. As with PEM electrolysis, the alkaline process operates at relatively low temperatures and generates no direct CO_2 emissions. If electricity can be generated relatively inexpensively (as in the case of nuclear plants during off-peak hours), alkaline electrolysis can be economically competitive with Carbon-Capture-equipped SMR production.[57] Recent research has shown that if capital costs for electricity can be reduced to as low as $500/KW, the production cost of hydrogen through alkaline electrolysis could fall within the $1.97 – $2.13/kg range.[58] With the lower costs that might be available from off-peak nuclear reactors, alkaline electrolysis could be an economically competitive, carbon-minimal production option.

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[53] Strategic Analysis Inc., *Techno-economic Analysis of PEM Electrolysis for Hydrogen Production* (2014), *see* https://www.energy.gov/sites/prod/files/2014/08/f18/fcto_2014_electrolytic_h2_wkshp_colella1.pdf
[54] *Id.*
[55] U.S. DRIVE Partnership, *Hydrogen Production Tech Team Roadmap*, (2017)
[56] U.S. Department of Energy, Office of Nuclear Energy, *Evaluation of Non-electric Market Options for a Light-water Reactor in the Midwest* (August 2019
[57] Research by authors
[58]Research by authors

- **Solid oxide electrolyzer**

Solid oxide electrolysis requires temperatures of 700°—800° C to separate hydrogen from water molecules. Through this process, water in the form of high-temperature steam is run through a solid ceramic electrolyte that breaks the bond between the hydrogen and oxygen atoms. The higher temperatures involved in solid oxide electrolysis also mean that less electrical energy is required for the process. Like PEM and alkaline electrolysis, the solid oxide process does not directly generate CO_2. Both the high-temperature steam and the electricity necessary for the high-temperature solid oxide electrolysis process could be sourced from off-peak nuclear power reactor facilities.

ii. Solar-Based Water-Splitting Hydrogen Production

There are also hydrogen production pathways that directly use solar energy to separate water molecules into oxygen and hydrogen. These include photoelectrochemical processes and thermochemical processes – both of which could eventually be advantageous production routes, but which are currently being researched and developed for further efficiency. Through photoelectrochemical processes, hydrogen can be produced using devices similar to solar-panels consisting of semiconductors and water-based electrolytes.

Hydrogen can also be generated cleanly via Solar Thermochemical Hydrogen Production, which uses high temperatures generated by concentrated solar rays to stimulate reactions with cerium oxide or copper chloride, separating hydrogen from water. These high temperatures can be achieved through large arrays of mirrors or mirrored parabolic dishes that would concentrate solar energy on a single focal chemical reactor. When fully mature, this technology has the potential to be entirely carbon-neutral, as the chemicals involved in the process are completely reused (with the exception of the hydrogen and oxygen outputs). However, this process is still considered to be a long-term option for future development.[59] Both Photoelectrochemical and solar thermochemical processes have the potential to become a valuable part of the future hydrogen production landscape of the United States, but may be more competitive in areas such as the southwest United States where solar resources are more prominent.[60]

3. Hydrogen Storage, Delivery and Dispensing

One of the primary challenges to wider fuel cell electric vehicle adoption (FCEV), for heavy duty trucks and buses as well as passenger cars, is often posed as a "chicken-or-egg" problem: potential investors in refueling infrastructure want to wait for hydrogen vehicles to emerge on the market before risking their capital, but potential vehicle buyers want to wait until fuel is

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[59] U.S. DRIVE Partnership, *Hydrogen Production Tech Team Roadmap*, (2017)
[60] *See* map of Global Horizontal Solar Irradiance, NREL National Solar Radiation Database Physical Solar Model, available at: https://www.nrel.gov/gis/images/solar/solar_ghi_2018_usa_scale_01.jpg

widely available before committing to a purchase.[61] The vehicles themselves are approaching cost parity with alternatives in the marketplace, driven not only by economies of scale in production but also by technological improvements to the proton-exchange membrane (PEM) fuel cells supplying the power. As highlighted by DOE's Fuel Cell Technology Office, the cost of fuel cells for transportation decreased by more than 60% from 2006 through 2017 (see Figure 6).[62] This has translated into similar cost reductions for completed FCEVs, including for heavy duty applications. AC Transit in northern California, for example, saw per bus procurement costs for its fleet of 40-foot fuel cell vehicles fall around 62.5% during this period, from $3.2 million to $1.2 million.[63] Base prices for comparable fuel cell buses are projected to fall below $1 million by 2020 according to the Center for Transportation and the Environment.[64] The base price for similarly sized battery-electric and CNG buses is currently around $750,000 and $500,000, respectively.[65]

Figure 6. Modeled Cost of Fuel Cell System for Transportation 2006-2017

Note: Based on production volume of 500,000 80-kW$_{net}$ PEM fuel cell systems per year.
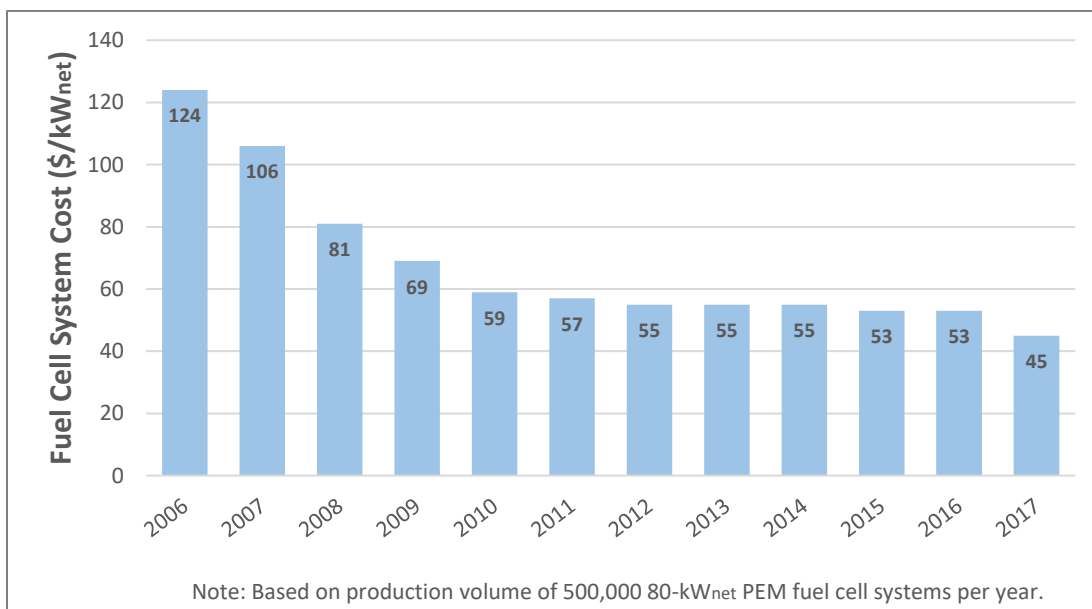
Source: U.S. Department of Energy

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[61] DOE Hydrogen and Fuel Cells Program: 2006 Annual Progress Report. *U.S. Department of Energy.* (2007). https://www.hydrogen.energy.gov/pdfs/progress06/viii_11_jones.pdf

[62] "DOE Fuel Cell Technologies Office Record 17007: Fell Cell System Cost." *U.S. Department of Energy.* (2017). https://www.hydrogen.energy.gov/pdfs/17007_fuel_cell_system_cost_2017.pdf. *See also* "Fact of the Month April 2018: Fuel Cell Cost Decreased by 60% Since 2006." *U.S. Department of Energy.* (2018). https://www.energy.gov/eere/fuelcells/fact-month-april-2018-fuel-cell-cost-decreased-60-2006

[63] Pocard, N. (2017). Interview with AC Transit's Chris Peeples on Hydrogen Powered Buses." https://blog.ballard.com/interview-ac-transit-chris-peeples-hydrogen-powered-buses. *See also* Chandler, K., & Eudy, L. (2007). *Alameda-Contra Costa Transit District (AC Transit) Fuel Cell Transit Buses: Preliminary Evaluation Results* (No. NREL/TP-560-41041). National Renewable Energy Lab. (NREL), Golden, CO (United States).

[64] https://coloradotransit.com/wp-content/uploads/2019/04/CDOT-Full-Slide-Deck-small-copy.pdf

[65] *Id. See also* Wisconsin Department of Transportation Heavy Duty Bus Price Sheet, June 2019 – May 2020. https://wisconsindot.gov/Documents/doing-bus/local-gov/astnce-pgms/transit/procurement/hdb-price.xlsx

The downward trend for fuel cell vehicle costs suggests that upfront costs will not be an impediment to FCEV adoption.[66] Rather, it is the presence (or absence) of a framework for distributing and dispensing hydrogen that will likely be an important, if not predominant, factor that determines the intensity of FCEV adoption for heavy duty applications. Indeed, a 2018 survey of truck fleets found that the most prevalent reason why operators would not consider replacing their class 8 truck with a fuel cell vehicle, as indicated by 4 out of 10 respondents, was due to limited fueling infrastructure.[67]

Dealing with this chicken-or-egg aspect of transitioning to FCEVs is not just a matter of having enough refueling stations and pipeline (or tanker trucks) in place to ensure adequate on-time delivery and dispensing of hydrogen. One of the key roadblocks to the commercialization of fuel cell technologies for transportation is the lack of cost-effective hydrogen storage.[68] A large part of this storage problem stems from the basic material properties of transportation fuels, as illustrated in Figure 7.[69] While the energy per mass of hydrogen is considerably greater than other transportation fuels, its energy per unit volume is much less than other fuels used in heavy duty applications such as diesel, propane (LPG), and compressed natural gas (CNG). For an 18-wheeler fuel cell truck to travel 100 miles using a 10,000-psi gaseous storage system, it would need about 4-5 times the tank volume used by a diesel truck to go the same distance.[70] For a fuel cell electric bus to travel 100 miles using a 5,000-psi gaseous storage system, which is a typical pressure level for this application, it would need about 7-8 times the tank volume used by a comparable diesel-powered transit bus to go the same distance.[71]

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[66] Similarly, evaluations performed by the National Renewable Energy Laboratory on fuel cell buses operated by U.S. transit agencies indicate maintenance costs that are on target to be competitive with conventional propulsion technologies in the near- to mid-term. *See* Eudy, L., & Post, M. B. (2018). *Fuel cell buses in us transit fleets: Current status 2018* (No. REL/TP-5400-72208). National Renewable Energy Lab. (NREL), Golden, CO. https://www.nrel.gov/docs/fy19osti/72208.pdf. *See also* Eudy, L., Post, M., & Jeffers, M. (2017). *American Fuel Cell Bus Project Evaluation: Third Report* (No. NREL/TP-5400-67209). National Renewable Energy Lab. (NREL), Golden, CO. https://www.nrel.gov/docs/fy17osti/67209.pdf

[67] "Fleet Advantage 2018 Survey Reveals Fleet Operators Pulse About Rising Fuel, Maintenance, and Electric Trucks." (2018). *Fleet Advantage.* https://www.fleetadvantage.com/press-releases/fleet-advantage-2018-survey-reveals-fleet-operators-pulse-about-rising-fuel-maintenance-and-electric-trucks

[68] Fuel Cells Technology Fact Sheet. https://www.energy.gov/sites/prod/files/2017/03/f34/fcto-h2-storage-fact-sheet.pdf

[69] https://www.energy.gov/eere/fuelcells/hydrogen-storage

[70] Based on the following assumptions: 1) fuel economy of approximately 0.145 kg per mile for fuel cell class 8 trucks; 2) fuel economy of approximately 0.189 gallons per mile for diesel class 8 trucks; 3) energy content for hydrogen of 52,217 btu per pound; 4) energy content per unit volume for hydrogen gas of 1.3 kWh per Liter at 10,000-psi. *See* the following corresponding sources: 1) https://www.hydrogen.energy.gov/pdfs/review19/ta024_vijayagopal_2019_o.pdf; 2) https://afdc.energy.gov/data/10310; 3) https://www.nrel.gov/docs/gen/fy08/43061.pdf; 4) https://www.energy.gov/eere/fuelcells/hydrogen-storage

[71] *Id*. Based on the following assumptions: 1) fuel economy of approximately 0.162 kg per mile for fuel cell electric buses; 2) fuel economy of approximately 0.307 gallons per mile for diesel transit buses; 3) energy content for hydrogen of 52,217 btu per pound; 4) energy content per unit volume for hydrogen gas of 0.6 kWh per Liter at

Whether in the context of onboard vehicle storage or large-scale bulk storage, solving the problem of how to economically store adequate volumes of hydrogen given existing space constraints will be a key enabler of fuel cell technologies and the hydrogen economy in general.[72] As such, planning for hydrogen distribution and delivery infrastructure should take into consideration the state of the practice for hydrogen storage.

Figure 7. Energy per Liter Versus Energy per Kilogram for Common Transportation Fuels
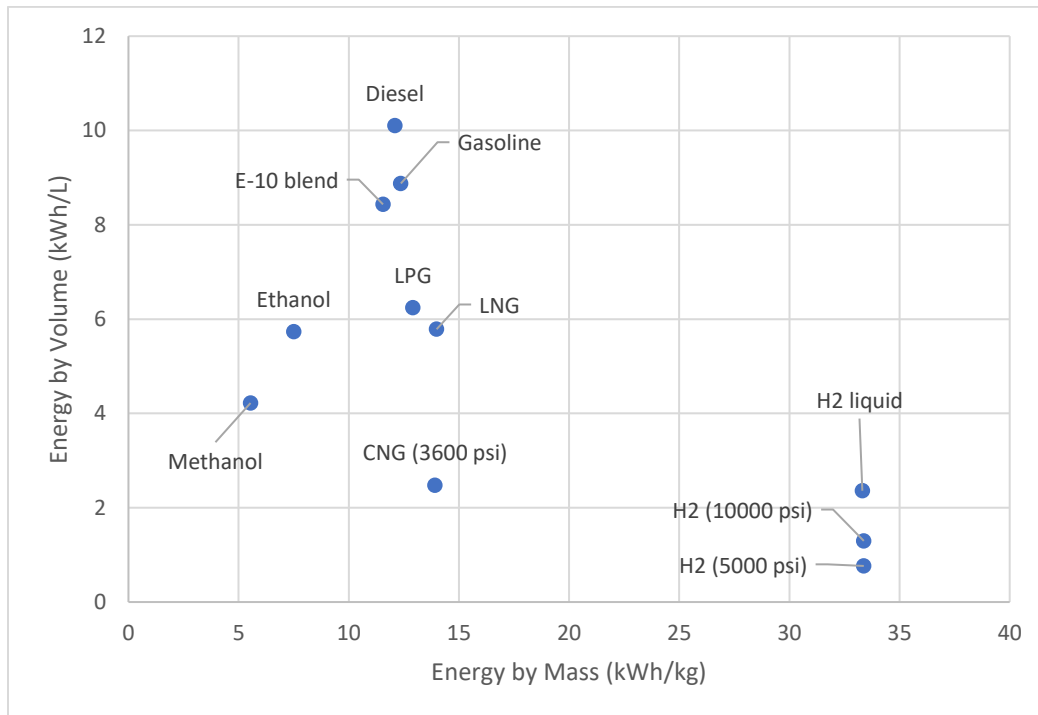
Source: DOE Fuel Cells Technologies Office

A. Hydrogen Storage.

The large-scale storage of pure hydrogen presents a number of challenges due to the physical properties of H_2 gas, which tends to be more diffuse and less dense than hydrocarbons such as fossil fuels. As noted above, the relatively low energy density by volume of H_2 gas will necessitate larger storage volumes, although several potentially viable strategies exist to reduce those storage volumes to a practical, economically manageable scale.[73] In order to avoid overly large storage volumes, hydrogen could either be stored as highly-pressurized gas in reinforced vessels,

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5,000-psi. *See also* https://www.osti.gov/biblio/1462741-supercritical-cryo-compressed-hydrogen-storage-fuel-cell-electric-buses

[72] *See* https://www.energy.gov/sites/prod/files/2015/05/f22/fcto_myrdd_storage.pdf. *See also* http://www.fsec.ucf.edu/en/consumer/hydrogen/basics/storage.htm

[73] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis,* International Journal of Hydrogen Energy vol. 44 (2019)

in the form of cryogenically cooled liquid, or chemically bound to material sorbents as a means of increasing its density. Hydrogen gas can also be stored at relatively larger volumes in several types of underground caverns. Each of these options will be summarized below.

i. Physical-based hydrogen storage

Physical-based hydrogen storage refers to the storage of pure hydrogen either as compressed H_2 gas or in liquefied, cold form. The simplest way to store pure hydrogen gas for short-term storage or transport is in the form of compressed gas held in a pressure vessel or tank. These tanks are generally cylindrical, usually made from aluminum or steel, and can be linked together for increased storage. [74] They range from 135 bar to 930 bar in pressure and vary in cost of storage from approximately \$600 per kg to \$1,450 per kg depending on the pressurization.[75] Fully metallic pressure vessels (known as type I vessels) are the most common and least costly option for gaseous storage, although type II vessels (which are reinforced with a fiberglass overlap) are typically used at high pressure refueling sites. The high costs of physical storage vessels is a significant contributor to the cost of hydrogen storage and delivery at all stages of the hydrogen production process.[76] However, further technological developments, such as new cylinder designs that decrease the use of steel, are expected to lower the costs of storage vessels.[77]

In addition to storage in high-pressure tanks, hydrogen can also be stored at lower densities in large underground geologic formations such as salt caverns, depleted oil and gas fields, hard rock caverns, or deep saline aquifers. The underground storage of hydrogen has the potential to be an advantageous option due to the large volumes of hydrogen gas it might accommodate. Underground storage of hydrogen also carries significant advantages in terms of safety precautions, smaller surface facilities, and lower cost of materials.[78] Currently-existing underground natural gas and hydrogen storage caverns can accommodate an average of approximately 700,000 m^3 of gas, a significantly larger scale than would be economical through steel vessel storage.[79] While the storage of hydrogen in geologic formations will be subject to some degree of imperfections and potential seepage losses through fractures and seismic activity, further development and implementation could allow for the storage of H_2 gas at large industrial scales.

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[74] *Id.*

[75] See pg 23 of U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017)

[76] See pg. 24 of U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017)

[77] See pg. 23 of U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017)

[78] Alexander Lemieux, Karen Sharp, & Alexi Shkarupin, *Preliminary Assessment of Underground Storage Sites for Hydrogen in Ontario, Canada*, International Journal of Hydrogen Energy vol. 44 (2019)

[79] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis,* International Journal of Hydrogen Energy vol. 44 (2019)

Salt caverns are considered to have particularly high potential to be used as underground hydrogen storage systems.[80] The physical properties of salt allow for a relative impermeability of cavern linings compared to other substances, as well as a low likelihood of biological activity that might create potential impurities. In addition, salt caverns can be drilled into with relative facility through high-pressure water drilling.[81] A 2014 analysis found the levelized cost of storing hydrogen in underground salt caverns to be approximately $1.61 per kg of H_2 stored[82] -- making salt cavern storage potentially less cost-effective than storing hydrogen in depleted oil and gas wells or hard rock caverns. However, the intrinsic advantages of salt formations and their relative availability in the Midwest region make salt caverns an appealing option for underground hydrogen storage. The majority of research conducted on the potential of underground hydrogen storage has focused on salt caverns – and the four presently existing underground hydrogen storage facilities (three in the United States and one in Great Britain) all utilize salt caverns.[83]

Similar in concept to salt-cavern-based storage, caverns that have been excavated in hard rock have been used for natural gas storage in several locations in Europe – and this strategy could potentially be used for the storage of hydrogen as well.[84] Research has indicated that the levelized cost of storing hydrogen in hard rock caverns is estimated to be $1.29 per kg.[85] Hydrogen gas is lighter, more diffuse, and less dense than natural gas, so further research will need to be conducted to investigate what adjustments might need to be made to apply this natural gas storage strategy to hydrogen gas.

Other potential underground storage sites for hydrogen could include depleted and repurposed oil and natural gas wells.[86] Significant natural gas extraction has taken place in the shale deposits of the Midwest, creating a potential network of large-scale hydrogen storage options. After the hydrocarbon resources have been fully extracted from a well, the drained pores could then serve as a reservoir for H_2 gas. In such a case, the relatively impermeable underground cavern and the underground gaseous extraction infrastructure would already be in place and could in principle be repurposed for hydrogen storage and re-extraction. The levelized cost of hydrogen storage in repurposed hydrocarbon wells was estimated in 2014 to be $1.23 per kg, making it relatively less

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[80] Alexander Lemieux, Karen Sharp, & Alexi Shkarupin, *Preliminary Assessment of Underground Storage Sites for Hydrogen in Ontario, Canada*, International Journal of Hydrogen Energy 4vol. 4 (2019)
[81] *Id*.
[82] Anna S. Lord, Peter H. Kobos, & David J. Borns, *Geologic Storage of Hydrogen: Scaling Up to Meet City Transportation Demands,* International Journal of Hydrogen Energy vol. 39 (2014)
[83] Alexander Lemieux, Karen Sharp, & Alexi Shkarupin, *Preliminary Assessment of Underground Storage Sites for Hydrogen in Ontario, Canada*, International Journal of Hydrogen Energy 4vol. 4 (2019)
[84] Alexander Lemieux, Karen Sharp, & Alexi Shkarupin, *Preliminary Assessment of Underground Storage Sites for Hydrogen in Ontario, Canada*, International Journal of Hydrogen Energy vol. 44 (2019)
[85] Anna S. Lord, Peter H. Kobos, & David J. Borns, *Geologic Storage of Hydrogen: Scaling Up to Meet City Transportation Demands,* International Journal of Hydrogen Energy vol. 39 (2014)
[86] Alexander Lemieux, Karen Sharp, & Alexi Shkarupin, *Preliminary Assessment of Underground Storage Sites for Hydrogen in Ontario, Canada*, International Journal of Hydrogen Energy vol. 44 (2019)

costly than salt cavern storage.[87] However, much of the research conducted around the strategy of repurposing empty hydrocarbon wells for gaseous storage has centered on their potential as storage reservoirs for recaptured CO_2 emissions, and it remains to be seen how much of that analysis is transferable to hydrogen storage. Unlike with salt cavern storage, repurposed hydrogen wells have a greater potential for microbial activity or the presence of impurities that could react with or seep away from the hydrogen reservoir.[88]

Another way to reduce the volume of hydrogen for storage or transport is to compress and liquefy it into a compressed form at extremely low temperatures. This process reduces the temperature of the hydrogen to around -253° C in order to allow tankers to transport approximately five times the capacity of pressurized gas vessels.[89] However, the liquefaction of hydrogen adds to both the cost and energy consumption of the hydrogen storage process, increasing the cost of hydrogen by more than $1.00 per kg.[90] Liquefied hydrogen is also susceptible to boil-off losses if kept for extended periods of time, despite insulation precautions. For these reasons, liquefied hydrogen is typically stored in double-walled spherical containers.[91] Liquefaction is a technologically mature and well-established process, although liquefied hydrogen is generally more economical if used for large-scale transport rather than small-scale deliveries.[92]

ii. Material-based.

In addition to storing hydrogen in the form of pure gas, hydrogen can be chemically or physically bound to a material sorbent to allow for higher transport densities. These are considered to be long-term options and are not yet technologically mature, but significant research is being done into their potential role in the future of hydrogen storage.

Hydrogen can bond to metal hydrides or other compounds in a way that would then allow the hydrogen to be released if the molecular bonds are separated with high temperatures. These storage compounds exist at significantly higher densities than H_2 gas and can therefore be

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[87] Anna S. Lord, Peter H. Kobos, & David J. Borns, *Geologic Storage of Hydrogen: Scaling Up to Meet City Transportation Demands,* International Journal of Hydrogen Energy vol. 39 (2014)

[88] Alexander Lemieux, Karen Sharp, & Alexi Shkarupin, *Preliminary Assessment of Underground Storage Sites for Hydrogen in Ontario, Canada*, International Journal of Hydrogen Energy vol. 44 (2019).

[89] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis,* International Journal of Hydrogen Energy vol. 44 (2019).

[90] See pg. 16 of U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017).

[91] Joakim Andersson & Stefan Grönkvist, *Large-Scale Storage of Hydrogen,* International Journal of Hydrogen Energy vol. 44 (2019).

[92] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis,* International Journal of Hydrogen Energy vol. 44 (2019). There may also be benefits to liquid hydrogen in terms of fueling time and not needing pre-cooling equipment that are particularly relevant to fleets.

transported more efficiently and at lower pressures than gaseous hydrogen.[93] These storage chemicals can be solid or liquid in form, and are generally reusable for the purposes of hydrogen storage and transport, minimizing waste products and environmental footprint.[94] Hydrogen can also be physically absorbed into metal-organic frameworks or carbon nanotubes which have a large surface area on the molecular level, allowing them to temporarily capture hydrogen atoms for storage.[95] Despite the potential advantages of these methods, much of the technology behind chemical and physical sorption is still being developed, and has yet to be used outside of laboratory settings. Among the challenges these technologies face is the high energy cost of heating and cooling the sorption materials in order to facilitate the storage and release of hydrogen.[96]

B. Hydrogen Delivery.

Rising demand for hydrogen fuel will also necessitate the development of a significant infrastructure for the transportation and delivery of hydrogen. As with the storage of hydrogen, several different pathways for hydrogen transportation and distribution are currently in use or in development. A fully realized hydrogen infrastructure may incorporate all of these options for both the transmission of hydrogen from production centers to centers of demand as well as distribution within those demand centers. (It is worth noting that the on-site production of hydrogen which may become economically feasible would negate transportation costs but may incur the cost of transporting natural gas to the production and distribution site if SMR is used). The prevailing strategies for transporting hydrogen at present include pipeline distribution and the trucking of pure hydrogen in either pressurized gas or liquefied forms. These pathways are elaborated below.

i. Gas Pipelines

At present, approximately 1,600 miles of steel hydrogen pipelines exist in the United States.[97] These are generally used to supply hydrogen for large-scale industrial purposes where demand is significant and concentrated (in the order of hundreds of thousands of kilograms per day). These pipelines allow for regular delivery of H_2 gas at lower operating costs than trucking. The corrosive properties of hydrogen gas make steel pipelines vulnerable to embrittlement over time, although research and development is currently being conducted to determine the feasibility of using materials such as fiber-reinforced polymer or high-strength steel to increase pipeline

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[93] Joakim Andersson & Stefan Grönkvist, *Large-Scale Storage of Hydrogen,* International Journal of Hydrogen Energy vol. 44 (2019).
[94] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis,* International Journal of Hydrogen Energy vol. 44 (2019).
[95] *Id.*
[96] U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017)
[97] *Id.*

resistance to corrosion.[98] The deployment of pipelines at a large scale is also subject to high initial capital costs: the costs of the materials, installation, and rights-of-way are presently around $600,000 per kilometer in urban areas.[99] An analysis of potential hydrogen infrastructure deployment in Ohio conducted at UC Davis determined that as the market penetration of hydrogen fuel cell vehicles increases beyond 10%, pipelines become the most cost-effective infrastructure investments.[100] This is because pipeline infrastructure, once established, allows for significant economies of scale. However, the high initial capital costs of pipeline deployment make pipelines less economically appealing during the transitional phases of hydrogen infrastructure deployment unless significant, concentrated, stable demand already exists (as in the case of industrial petrochemical uses). The extensive network of onshore natural gas pipelines (approximately 300,000 miles of which are currently in use in the United States)[101] can serve as a model for a potential hydrogen pipeline infrastructure, although there may be technical challenges to directly converting natural gas pipeline infrastructure into pipelines for gaseous hydrogen.

ii. Trucking of Pressurized Hydrogen Gas

The transportation of pressurized hydrogen gas cylinders via trucks is considered to be a technologically simple and economically available option.[102] Tube trailers carrying approximately 800 kg of gaseous hydrogen (compressed to 250 bar) are currently used for deliveries to sites within 200 miles of production.[103] While transportation in gaseous form allows for lower payloads than liquefied hydrogen deliveries and higher operating costs than pipelines,[104] the principles behind the delivery of pressurized gas are well understood and technologically mature. Hydrogen loss during transport is less of a factor with pressurized gas than with liquefied hydrogen, since the gas is not subject to the boil-off losses associated with liquid storage.[105] However, the compressors required to fill the storage vessels for transport currently suffer from frequent mechanical issues due to intermittent use, and maintenance and capital costs throughout the compression and transportation remain high.[106] The physical requirements of compressing H_2 gas for transport are different from the more developed process of compressing natural gas, and hydrogen-specific compressors still need to be fully optimized.[107] Importantly,

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[98] See pg. 10 of U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017)

[99] Nils Johnson, Christopher Yang, & Joan Ogden, *A GIS-Based Assessment of Coal-Based Hydrogen Infrastructure Deployment in the State of Ohio*, International Journal of Hydrogen Energy vol. 33 (2008)

[100] *Id.*

[101] See pg. 12 of U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017).

[102] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis,* International Journal of Hydrogen Energy vol. 44 (2019).

[103] U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017).

[104] *Id.*

[105] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis,* International Journal of Hydrogen Energy vol. 44 (2019).

[106] See pg. 14 of U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017).

[107] *Id.*

however, the transportation of hydrogen gas via trucking is especially viable at small, initial scales over shorter distances as it requires less initial infrastructure investment than other avenues of distribution.[108]

iii. Liquid Hydrogen Tanker Trucks

Transporting hydrogen in the form of low-temperature liquid H_2 is currently economically viable for high-demand, mid-range transport.[109] As noted above, liquefaction allows for a greater density of hydrogen to be stored and transported, resulting in vehicle payloads of approximately five times the amount that might be carried by a single truck in pressurized gaseous form.[110] Trucks carrying 4,000 to 5,000 kg of liquefied hydrogen are therefore an economically competitive option for high-demand purchasers within 600 miles of production sites.[111] Eight liquefaction plants currently exist in North America, and liquefied hydrogen transport is cost-effective at mid-range distances if demand is more than 500 kg per day.[112] However, the electricity demands of the liquefaction process add to both the cost and the potential carbon footprint of liquefied hydrogen transport. As noted in the section on liquid hydrogen storage, the liquefaction process adds more than $1.00 to the cost of each kilogram of hydrogen produced and transported.[113] The energy required to liquefy a mass of hydrogen can equate to approximately 35% of the total energy contained in that hydrogen, making it an extremely energy-inefficient process. Additionally, liquefied hydrogen is subject to significant boil-off losses during transportation and storage – the longer hydrogen is kept in liquefied form, the more is lost to evaporation. In order for liquefied hydrogen transport to expand as part of the potential hydrogen delivery infrastructure, further development of more efficient methods of liquefaction is necessary.[114]

C. Hydrogen Dispensing and Refueling Stations.

During the transition to wider FCEV adoption, while demand for fuel is relatively low, the high capital costs associated with dispensing hydrogen to vehicles will be a limiting factor that constrains widespread development of hydrogen refueling stations.[115] While the costs of production and delivery to the refueling station must indeed decline for dispensed hydrogen to

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[108] Nils Johnson, Christopher Yang, & Joan Ogden, *A GIS-Based Assessment of Coal-Based Hydrogen Infrastructure Deployment in the State of Ohio*, International Journal of Hydrogen Energy vol. 33 (2008).

[109] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis,* International Journal of Hydrogen Energy vol. 44 (2019).

[110] *Id.*

[111] *See* pg. 20 of U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017).

[112] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis, supra*, note 109.

[113] *See* pg. 16 of U.S. DRIVE Partnership, *Hydrogen Delivery Technical Team Roadmap*, (2017).

[114] Ramin Moradi & Katrina M Goth, *Hydrogen Storage and Delivery: Review of the State of the Art Technologies and Risk and Reliability Analysis, supra*, note 109.

[115] *See US Drive Hydrogen Delivery Technical Team Roadmap*. (2017).

be competitive with other fuels, neither of these is currently the largest cost driver. Rather, the cost of hydrogen in early FCEV markets is dominated by the cost of building and operating refueling stations, due mainly to the high cost of refueling equipment, small station capacities, lack of economies of scale, and low utilization of the installed refueling capacity.[116] In California, where the early-stage market for hydrogen in transportation has started to develop and the price at the pump reaches upwards of $15/kg, around half of the cost to customers comes from the refueling station cost.[117]

One of the largest cost components for hydrogen refueling stations is the dispensing unit itself. A complete hydrogen dispenser unit costs at least $100,000; comparable units for dispensing gasoline cost around $15,000.[118] Other major cost items, as seen in Figure 8 illustrating the equipment needed for a conventional hydrogen fueling station, include compressors and chillers to ensure that hydrogen is dispensed at the appropriate pressure and flow consistency without overheating the vehicle's tank.[119]

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[116] Reddi, K., Elgowainy, A., Rustagi, N., & Gupta, E. (2017). Impact of hydrogen refueling configurations and market parameters on the refueling cost of hydrogen. *International Journal of Hydrogen Energy*, 42(34), 21855-21865.
[117] *Id.* Note that $15/kg of hydrogen is equivalent on a price per energy basis of around $6.00 per gallon of gasoline. *See* "Cost to refill." *California Fuel Cell Partnership.* (2015). https://cafcp.org/content/cost-refill
[118] *US Drive Hydrogen Delivery Technical Team Roadmap*. (2017).
[119] *See* Reddi, K., Elgowainy, A., Rustagi, N., & Gupta, E. (2017). Impact of hydrogen refueling configurations and market parameters on the refueling cost of hydrogen. *International Journal of Hydrogen Energy*, 42(34), 21855-21865. *See also* Staffell, I., Scamman, D., Abad, A. V., Balcombe, P., Dodds, P. E., Ekins, P., ... & Ward, K. R. (2019). The role of hydrogen and fuel cells in the global energy system. *Energy & Environmental Science*, 12(2), 463-491.

Figure 8. Cost of Equipment Needed for a Conventional Hydrogen Fueling Station

description	quantity	cost	total
tanks [13 kg each, 945 bar MAWP, Type II]	3	$45,633	$136,899
pressure transducer and indicator	6	$1,141	$6,845
block and bleed valve	6	$570	$3,422
air operated valve	6	$2,282	$13,690
pilot solenoid valve	7	$57	$399
isolation hand valve	12	$570	$6,845
check valve	3	$456	$1,369
coolant pump	1	$1,369	$1,369
water chiller	2	$4,563	$9,127
coolant filter	1	$57	$57
instrument air compressor	1	$1,141	$1,141
instrument air dryer and filter	1	$2,909	$2,909
hydrogen compressor [2-stage, 950 bar outlet]			
100 kg/day station - 6 kg/hr, 25 kW		$189,827	$189,827
200 kg/day station - 14 kg/hr, 60 kW	1	$328,774	$328,774
300 kg/day station - 23 kg/hr, 100 kW		$453,010	$453,010
hydrogen dispenser [(1) 350 bar and (1) 700 bar hose]	1	$250,000	$250,000
hydrogen chiller and cooling block	1	$150,000	$150,000
IR flame detector	2	$1,711	$3,422
hydrogen filter	1	$2,852	$2,852
PLC	1	$5,704	$5,704
tubing	-	$22,817	$22,817
fittings	-	$17,112	$17,112
electrical upgrades	-	$57,041	$57,041
fencing	-	$5,704	$5,704
bollards	-	$5,704	$5,704
total (100 kg/day station)			$894,256
total (200 kg/day station)			$1,033,203
total (300 kg/day station)			$1,157,439

Source: Sandia National Laboratories[120]

Note: Costs are in 2016 dollars.

Higher volume production driven by greater market penetration of FCEVs would likely reduce station costs. Cost modeling of hydrogen fueling stations by Argonne National Laboratory and the U.S. Department of Energy indicate a reduction in component costs of between 45 and 60% for compressors and chillers in going from current (low) production volumes to equip the roughly 200 stations worldwide to a "high" market volume scenario representing about 10,000 hydrogen refueling stations. Of course, these capital costs would also be spread out across a larger customer base with increased market penetration of FCEVs. The list of equipment costs seen above in Figure 8 suggests that a conventional hydrogen fueling station can supply little more than the equivalent of 300 gallons of gasoline to customers daily.[121] In contrast, an average U.S. gas station sells around 3,000 gallons of gasoline per month, indicating a cost of capital that is spread out over ten times as much sales volume.[122]

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[120] Hecht, E., & Pratt, J. W. (2017). *Comparison of conventional vs. modular hydrogen refueling stations, and on-site production vs. delivery* (No. SAND2017-2832). Sandia National Laboratory. (SNL-NM), Albuquerque, NM (United States); National Renewable Energy Laboratory, Golden, CO.

[121] 1 gallon of gasoline has the equivalent Btu energy content of approximately 1 kg of hydrogen.

[122] http://blog.opisnet.com/retail-gasoline-price-margins

4. Transit and Trucking Markets for Hydrogen in the Midwest

Among possible modes of transportation, fuel cells seem particularly well-suited to heavy-duty applications. Cost modeling by the National Renewable Energy Laboratory for class 8 trucks indicates a total cost of ownership in 2020 of $1.70 per mile for FCEVs compared to $5.10 per mile for battery-electric vehicles (and $0.7 per mile for diesel trucks).[123] By 2040, class 8 FCEVs are projected to operate at a total cost of ownership that is down from $1.00 per mile greater to 50-cents per mile greater than diesel trucks ($1.3 per mile for FCEVs compared to $0.80 for diesel trucks); battery-electric class 8 trucks are projected to operate at a total cost of $3 per mile by this time.[124]   Fuel cells also offer improvements in performance: current deployments at the ports of Long Beach and Los Angeles have shown fuel cell class 8 trucks to provide a "substantial increase in torque" compared to diesel and natural gas variants.[125]

For transit applications, FCEBs are considered a near one-to-one replacement for conventional buses in that they have a similar range as conventional buses and do not need to be refueled as often as battery electric buses, which generally require charges during scheduled routes.[126] While FCEBs currently have higher startup costs than battery electric buses, adding FCEBs to an established FCEB fleet may not require adding additional refueling infrastructure, which is often required when adding battery electric buses to a fleet.[127] Additionally, maintenances costs for FCEBs in early deployments have become competitive over time with diesel buses as transit agency staff gain more experience.[128]   Furthermore, among agencies deploying both conventional and novel propulsion technologies, the cost per mile related to replacement parts has been lowest for FCEBs in evaluations performed by the National Renewable Energy Laboratory.[129]

Based on the potential for fuel cells in heavy-duty transportation applications, the Study Team undertook a high-level analysis that could inform future planning for hydrogen refueling infrastructure for transit buses and class 8 trucks in the Midwest. Given that heavy duty trucking will be a key enabler for the hydrogen fuel market, the Study Team focused geographically on the Interstate Corridor from Pittsburgh, PA to Minneapolis, MN that includes parts of interstate highways I-76, I-80, I-90, and I-94. The study team investigated possible future demand to 2030 and 2040 for hydrogen among class 8 trucks operating along this corridor as well as transit agencies with service areas in proximity (within 100 miles) of this route. Additionally, the Study Team identified existing and future regional resources available to satisfy this demand.

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[123] https://www.hydrogen.energy.gov/pdfs/review19/sa169_hunter_2019_o.pdf
[124] *Id.*
[125] https://www.energy.gov/sites/prod/files/2018/08/f54/fcto-h2-scale-kickoff-2018-18-williamson.pdf
[126] https://www.nrel.gov/state-local-tribal/blog/posts/fuel-cell-electric-buses-in-the-usa.html
[127] *Id.*
[128] *See* https://www.hydrogen.energy.gov/pdfs/review19/ta013_eudy_2019_o.pdf
[129] *Id.*

A. Heavy Duty Fuel Cell Market Penetration

According to the U.S. Energy Information Administration (EIA), hydrogen use by transit buses and freight trucks is projected to be around 0.01% of total transportation energy use (within each mode) in 2020.[130] By 2050, hydrogen-powered fuel cell vehicles are forecast by the CEOs of leading energy and transport companies to compose 35% market share and 22% market share for buses and trucks, respectively.[131] This represents a compound annual growth rate in market share between now and 2050 of about 29.5% for buses and 28% for heavy-duty trucks. Given these figures, the Study Team projected market penetration in 2030 and 2040 for fuel cell vehicles in the two heavy duty modes, seen below in Table 2. Market-wide adoption of a new technology does of course not generally increase evenly from year to year. Business gains can accelerate rapidly in a single period during the growth phase of an innovative technology's life cycle.

Table 2. Projected Market Penetration of Fuel Cell Vehicles by Mode

Mode	2030	2040
Transit buses	0.20%	2.64%
Class 8 trucks	0.15%	1.85%

B. Daily Demand for Hydrogen

The above market penetration rates were applied to projections for daily vehicle miles traveled (VMT) by class 8 trucks on the Interstate Corridor from Pittsburgh to Minneapolis and transit buses operating in proximity.   The Freight Analysis Framework (FAF), produced through a partnership between the Bureau of Transportation Statistics and Federal Highway Administration (FHWA), was used to estimate the VMT for heavy duty trucks on this route.[132] The FAF models the flow of freight and vehicles along major roads, with the current version including a forecast of average daily movements by vehicle class through 2045. The FAF models this flow by granular highway segments. The interstate route from Minneapolis to Pittsburgh, for example, is composed of more than 1,300 FAF highway segments.

There is no travel analysis framework that similarly models current and future VMT for transit buses. As the FHWA explains, "Forecasting bus VMT is difficult due to the fact that buses serve several distinct markets, each with different influences on demand…. As a result, a bus VMT forecasting model is not part of (any) FHWA VMT forecast model."[133] However, historical VMT

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[130] On a Btu basis. *See* Annual Energy Outlook 2019. Transportation Sector Energy Use by Fuel Type Within a Mode (table). https://www.eia.gov/outlooks/aeo/data/browser

[131] https://www.mckinsey.com/industries/automotive-and-assembly/our-insights/hydrogen-the-next-wave-for-electric-vehicles

[132] *See* https://ops.fhwa.dot.gov/freight/freight_analysis/faf/

[133] https://www.fhwa.dot.gov/policyinformation/tables/vmt/vmt_model_dev.pdf

data for every transit agency on an annual basis can be collected from the Federal Transit Administration's (FTA) National Transit Database.[134] Using the average of historical data as the forecast for all future values is a commonly employed method for establishing benchmark forecasts. [135] This method was used by the Study Team to project future VMT for transit buses. Forecasts of transit bus VMT were based on FTA data for all buses, including rapid transit and commuter buses, for each agency over the last 5 years, during both revenue and non-revenue (i.e. "deadhead") travel time.

Multiplying the expected market penetration in 2030 and 2040 by the overall VMT for transit buses and class 8 trucks in those years along the corridor of interest resulted in projections for daily vehicle miles traveled by fuel cell vehicles for these heavy-duty transportation modes. The resulting projections were in turn multiplied by the expected future fuel consumption for heavy duty vehicles in 2030 and 2040. Current hydrogen consumption for fuel cell buses in the U.S. is around 0.157 kg per mile.[136] For class 8 fuel cell trucks, current hydrogen consumption is around 0.151 kg per mile.[137] Under a conservative, business-as-usual framework for improvements in fuel economy, heavy-duty fuel cell vehicles are projected to consume around 2% less hydrogen per-mile each year between 2020 and 2030, and 0.5% less hydrogen per-mile each year from 2030 to 2040.[138] Tables 3 and 4 show forecasts of daily hydrogen consumption for heavy-duty fuel cell vehicles by state for transit buses and by road segment along the interstate corridor for class 8 trucks given the projections for market penetration, vehicle miles traveled, and fuel economy. Additionally, Figures 9 and 10 forecast the spatial distribution of hydrogen consumption by fuel cell-powered transit buses and class 8 trucks in 2030 and 2040.

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[134] *See* https://www.transit.dot.gov/ntd

[135] *See* https://otexts.com/fpp2/simple-methods.html.

[136] Based on average fuel economy of 7.01 miles per diesel gallon equivalent. *See* https://www.nrel.gov/docs/fy19osti/72208.pdf. *See also* https://epact.energy.gov/fuel-conversion-factors

[137] *See* p. 7 of https://www.hydrogen.energy.gov/pdfs/review19/ta024_vijayagopal_2019_o.pdf

[138] *Id.* Fuel economy data was gleaned from the graphs of interest using WebPlotDigitizer. *See* https://automeris.io/WebPlotDigitizer/

Table 3. Forecast of Daily Hydrogen Demand (in kg) for Transit Buses[139]

State	2030	2040
Illinois	364	1165
Indiana	6	69
Michigan	32	407
Minnesota	38	484
Ohio	536	927
Pennsylvania	29	371
Wisconsin	27	342
Total	**1032**	**3765**

Table 4. Forecast of Daily Hydrogen Demand (in kg) for Class 8 Trucks

Route Segment	2030	2040
Pittsburgh to Cleveland	132	1593
Cleveland to Chicago	1070	18200
Chicago to Minneapolis	940	13004
Total	**2142**	**32797**

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[139] Higher forecasts for hydrogen demand in Ohio and Illinois are due to existing and planned fuel cell bus deployments at the Stark Area Regional Transit Authority (SARTA) in Canton, OH and Champaign-Urbana Mass Transit District (CUMTD). Vehicle miles traveled by fuel cell vehicle for SARTA and CUMTD of 50% and 25%, respectively, of the total miles traveled for each agency's buses were assumed based on fleet composition in the near term. These assumptions may underestimate projected hydrogen consumption by these agencies given evolving vehicle procurement plans.

Figure 9. Forecast of Daily Hydrogen Demand for Transit Buses and Class 8 Trucks in 2030
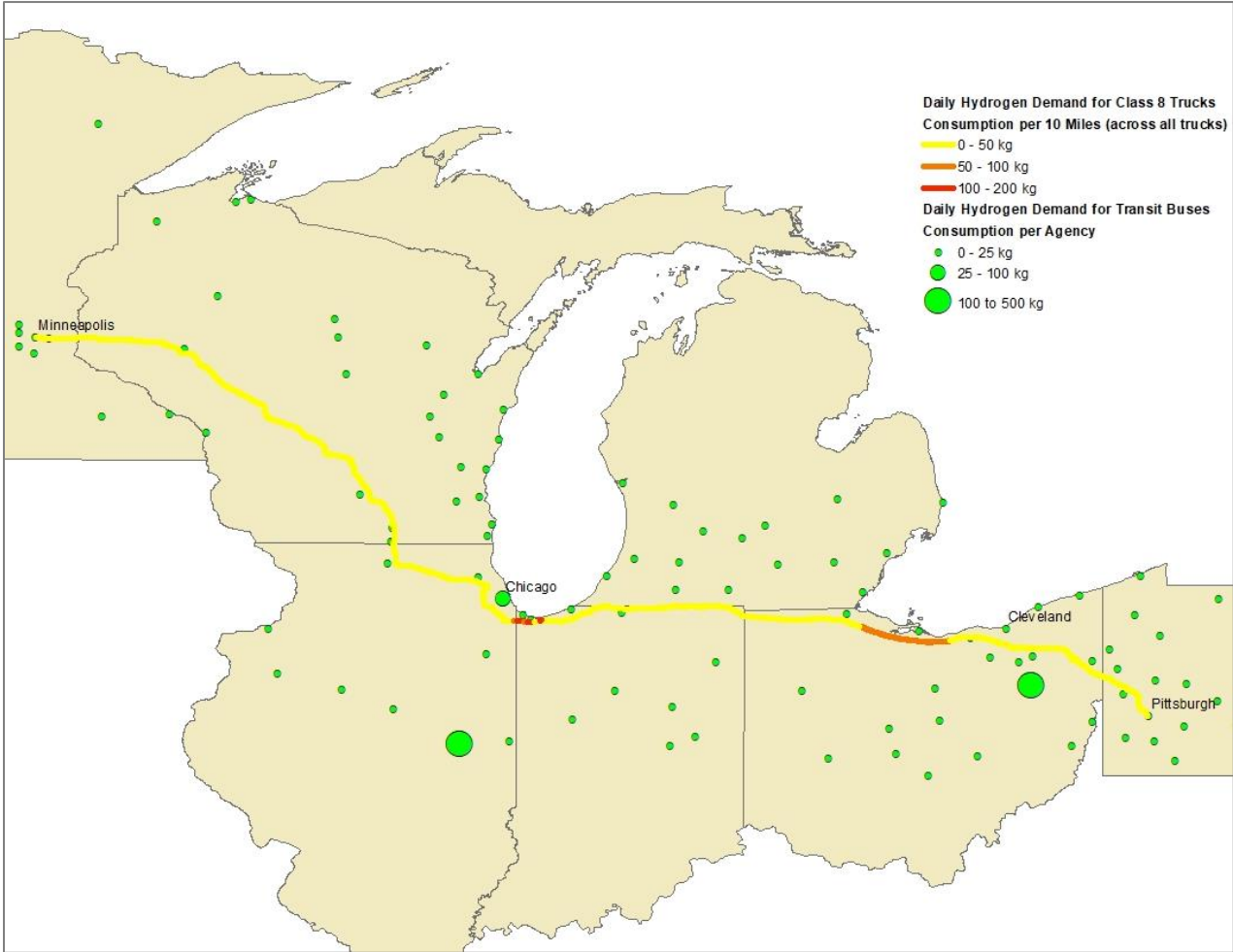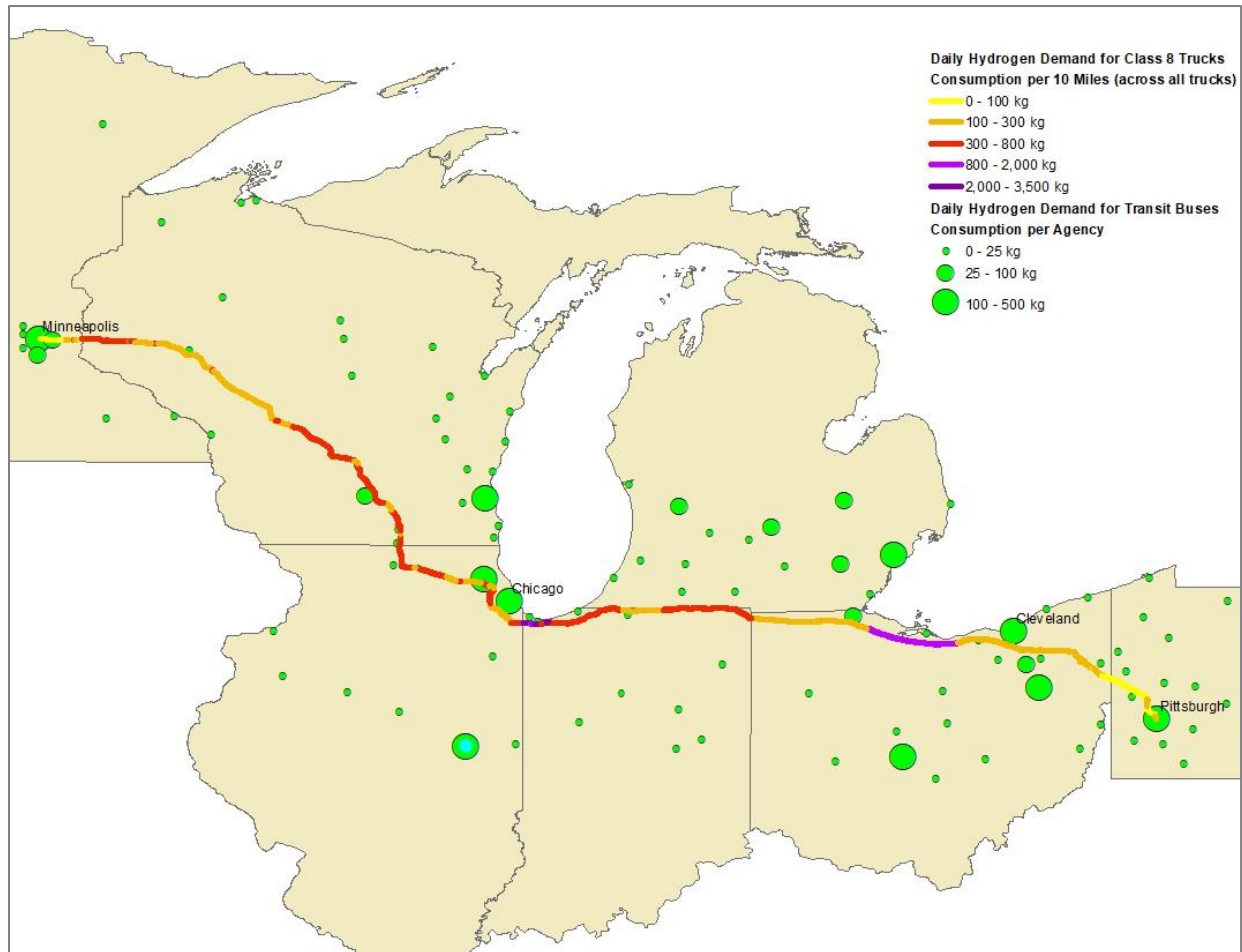
Figure 10. Forecast of Daily Hydrogen Demand for Transit Buses and Class 8 Trucks in 2040

5. Strategies for Infrastructure Buildout

There is widespread agreement that an early hydrogen infrastructure must offer the following: 1) enough stations to provide convenient fuel accessibility for early vehicles; 2) enough capacity to meet hydrogen demand as the FCEB fleets grow; and 3) hydrogen fuel at a price that is competitive with alternatives.[140] There are many options for hydrogen production and delivery; no one supply option will be preferred in all cases. This general examination is a first step in planning for what is an admittedly complex design problem.

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[140] https://steps.ucdavis.edu/wp-content/uploads/2017/05/2017-UCD-ITS-RR-17-04-1.pdf. A fourth requirement, that early hydrogen infrastructure must offer positive cash flow for individual station owners and for network-wide supply, will be explored in future work.

A. Station Coverage

Adequate station coverage for heavy-duty fleet vehicles is arguably easier to determine than optimal siting of refueling stations for passenger vehicles. Class 8 trucks and buses generally have predictable routes. In the case of transit buses, it is assumed that fueling would occur in the vicinity of an agency's central office or service garage. Planning hydrogen refueling stations for class 8 trucks incorporates slightly more uncertainty, though less than for passenger cars, given the fixed path that heavy-duty freight vehicles are assumed to follow -- in this instance the Interstate Corridor from Pittsburgh to Minneapolis.

The main considerations for siting public hydrogen refueling stations are to provide fuel conveniently, quickly, and cost effectively.[141] With this in mind, the Study Team assumed that existing truck stops represent convenient, economical locations for class 8 trucks to refuel, and that the presence of multiple fuel stations for class 8 trucks within close proximity to each other (i.e. clusters) indicate the most convenient locations for drivers to refuel. A mobile software application marketed to class 8 truck drivers was used to identify and geocode all refueling stations for heavy-duty vehicles along the interstate corridor of interest within a geographic information system (GIS).[142] A density map was generated for stations along the interstate corridor and the underlying measure of stations per square mile was used as a proxy for refueling station demand. Candidate locations for further analysis of adequate station coverage were the 50% of highway exits with the greatest number of associated fueling stations per square mile that can accommodate 18-wheeler trucks.

Vehicle range is also certainly important in planning station coverage. The current generation of class 8 fuel cell trucks have a hydrogen storage capacity of around 30 kg of hydrogen.[143] Given the projected improvements in fuel economy for fuel cell trucks described in Section 4, this sort of tank capacity could enable a maximum range of around 240 miles by 2030 and 250 miles by 2040. However, maximum driving range can also be limited by range anxiety, the fear that a vehicle has insufficient range to reach its destination.[144] For electric vehicles in general, early research indicates that drivers prefer maintaining a minimum range capacity of 15 to 20% as a safety buffer.[145] This suggests a conservative estimate for maximum vehicle range of about 190 miles for class 8 FCEVs by 2030 and 200 miles by 2040.

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[141] https://steps.ucdavis.edu/wp-content/uploads/2017/05/2017-UCD-ITS-RR-17-04-1.pdf
[142] *See* https://www.findtruckservice.com
[143] *See* profile of fuel cell drayage truck at https://www.energy.gov/sites/prod/files/2018/08/f54/fcto-truck-workshop-2018-6-hanlin.pdf.
[144] https://www.nrel.gov/docs/fy19osti/73010.pdfps://www.nrel.gov/docs/fy19osti/73010.pdf
[145] https://www.caranddriver.com/news/a15346575/placebo-on-wheels-aaa-charging-trucks-seek-to-remedy-ev-range-anxiety-prove-mostly-unneeded/

The GIS software ArcMap was used with the Network Analyst extension to identify the minimum number of stations that could be situated in areas of high density for existing refueling stations while being no farther than 190 miles from the next nearest refueling cluster for trucking. Figure 11 shows the distribution of refueling locations resulting from this optimization routine.[146]

Figure 11. Optimized Hydrogen Refueling Station Siting
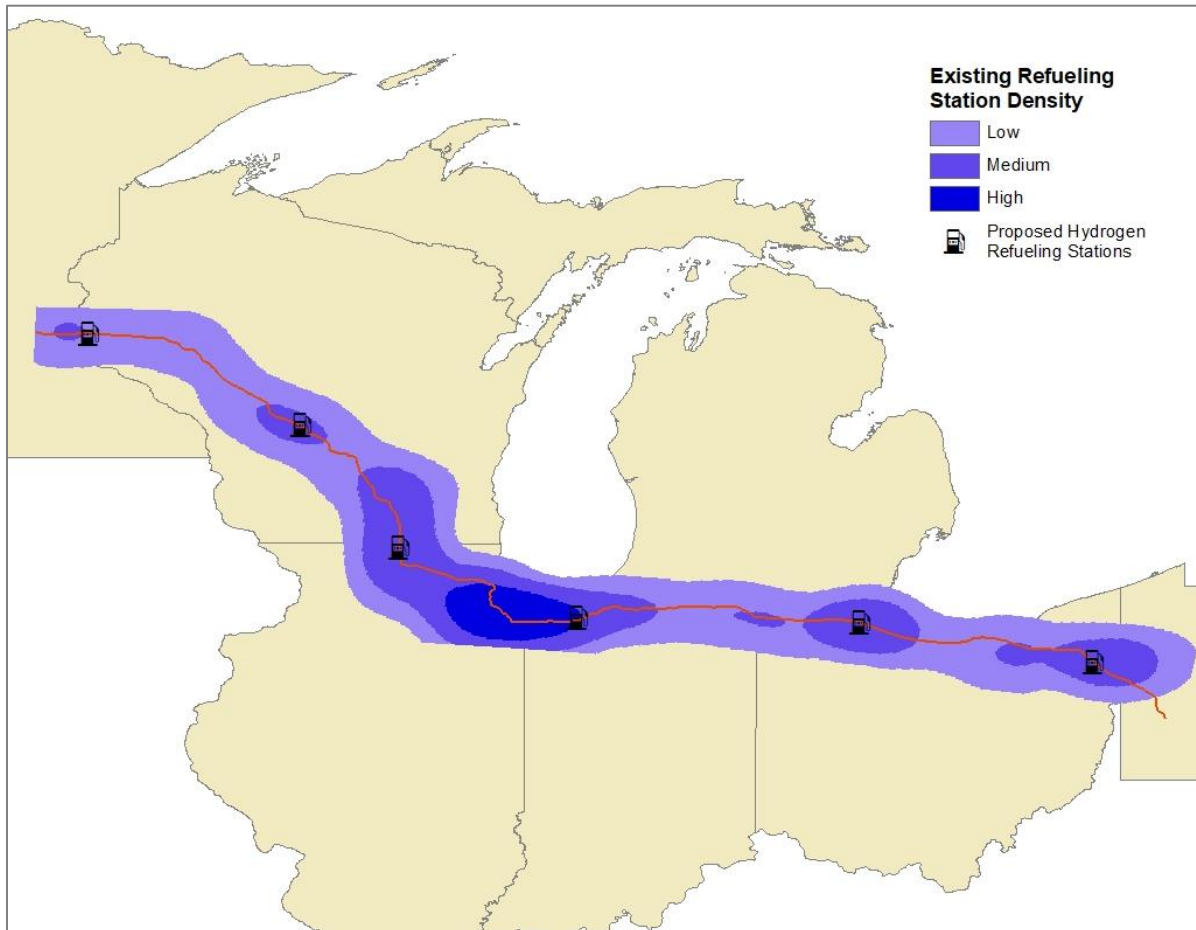
B. Supply Capacity

An analysis of large consumers and producers of hydrogen in the Midwest was undertaken by the Study Team to determine whether the supply of hydrogen is sufficient to keep pace with FCEV adoption. As described previously, significant industrial consumers of hydrogen include petroleum refineries, ammonia plants, and iron processing plants. Major producers of hydrogen, on the other hand, include chlor-alkali plants and ethane crackers, where the hydrogen is a by-

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[146] The "Minimize Facilities" problem type was solved for this location-allocation application. *See* https://desktop.arcgis.com/en/arcmap/latest/extensions/network-analyst/location-allocation.htm#GUID-FB837835-6DA2-4693-B51F-C14285A8BCAF

product of the production process. Additionally, some large consumers of hydrogen such as petroleum refiners have internal *captive* hydrogen production capacity that is generally based on reforming natural gas, and those facilities may have excess capacity. Merchant suppliers of hydrogen provide the balance of what large consumers of hydrogen cannot produce themselves.

The Study Team surveyed publications by the U.S. Department of Energy, the National Laboratories, and local and regional newspapers to ascertain current and future production capacity in the Midwest among these hydrogen market participants.[147] Additionally, conversion factors based on research by the national laboratories, including NREL and Sandia National Laboratory, were relied upon to determine the amount of hydrogen input associated with the amount of commodity output in the case of hydrogen consumers, and the amount of by-product hydrogen output associated with manufacturing output in the case of hydrogen producers.[148] We relied on forecasts of growth by industry in terms of compound annual growth rates (CAGR) as published by market research firms to make projections about future production levels.[149] To ensure we did not overstate the disparity between consumption and production, we assumed conservative growth rates for hydrogen consumption (no more than 2.6% CAGR) and more aggressive growth rates for hydrogen production (no less than 5.4%).

Table 5 shows the results of this analysis in terms of the metric tons of hydrogen forecast to be consumed and produced per day regionally in 2030 and by 2040. The table suggests that a large volume of hydrogen is currently imported from outside the region and will continue to be imported absent significant new generation infrastructure. The results also cast uncertainty on whether regional hydrogen supply will be sufficient to keep pace with growth in the market for FCEVs.

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[147] For example, *see* the following: https://www.usgs.gov/centers/nmic/nitrogen-statistics-and-information; EIA: https://www.eia.gov/petroleum/refinerycapacity/refcap19.xls; https://www.energy.gov/sites/prod/files/2018/07/f54/NGL_Primer.pdf; https://greet.es.anl.gov/publication-chlor_alkali_h2; and https://h2tools.org/hyarc/hydrogen-production.

[148] *See* https://www.hydrogen.energy.gov/pdfs/review19/sa172_elgowainy_2019_o.pdf

[149] *See* www.marketwatch.com, www.mordorintelligence.com, and www.busineswire.com, and www.reportsnreports.com.

Table 5. Projected Midwest Hydrogen Consumption and Production (metric tons)[150]

		2030	*2040*
Hydrogen Consumption	iron processing	2,086	2,696
	ammonia plants	10,714	13,060
	petroleum refining	2,990	3,385
	Total	**15,789**	**19,141**
Hydrogen Production	ethane crackers	1,516	3,572
	chlor-alkali plants	90	152
	merchant production	1,740	3,757
	captive production	2,492	5,380
	Total	**5,838**	**12,861**
	Surplus (Shortage)	**(9,951)**	**(6,280)**

note: 1 metric ton = 1,000 kg

C. Price Competitiveness

Members of the Study Team built and adapted a full technoeconomic model to convey 2018 USD costs of hydrogen production in the functional cost of $/kg H_2 for three separate pathways:

1. Steam methane reforming (SMR) of natural gas with solvent-based carbon capture using Selexol™ (SMR – CC),
2. Electrolytic hydrogen generation from water using alkaline water electrolysis (AEC), and
3. Electrolytic hydrogen generation from water proton exchange membrane electrolysis (PEM).

These technologies were evaluated for three production capacities with unique input parameters and plant properties, as described below in Table 6.

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[150] Derived by the authors based on current hydrogen production and consumption for these industries and their projected market growth rates. *See* notes 147-149, *supra,* and accompanying text. The states included in the analysis are Illinois, Indiana, Michigan, Minnesota, Ohio, Pennsylvania, and Wisconsin.

Table 6. Parameters and Input Costs for Three Scales of Hydrogen Production Facilities

Type	Capacity (kg H_2 / day)	Price of NG[151] ($/MSCF)	Price of electricity[152] ($/MWh)	Plant economic lifetime (yrs)	Capital recovery factor (%)
Refueling Station	1500	7.66	92.9	20	0.0802
Mid-sized	50000	3.78	60.0	40	0.0583
Centralized	314000	2.43	30.0	40	0.0583

A literature review reveals that steam methane reforming is currently the most cost-effective approach for making hydrogen ($1.00 – $2.14/kg H_2), while the addition of carbon capture increases the levelized cost of hydrogen by $ 0.50 to $1.02 per kg H_2.[153] Importantly, however, this cost does not include storage and use of the captured carbon, such as for beverage carbonation or as a refrigerant in large supermarkets. The economics of electrolysis of water is constrained by relatively high energy consumption, lower overall efficiencies and high capital costs—leading to a higher best case cost projection of $2.80/kg.[154] A case-study of electrolysis used in a hybrid system in Texas showed that electrolysis can be paired with intermittent, renewable sources, while yielding a hydrogen breakeven cost of $3.53/kg H_2.[155] Hydrogen generation from biogas is shown to be highly dependent on the feedstock cost, with one study yielding a cost of $2.69 and $4.27/kg H_2 for 150000 and 1500 kg H_2 / day production capacities, respectively.[156]

[151] The natural gas price for hydrogen production at refueling stations and mid-sized production facilities reflect EIA commercial and city-gate prices, respectively, for Ohio. The natural gas price for centralized production reflects Dominion Transmission's Appalachian hub price. *See* https://www.eia.gov/dnav/ng/NG_PRI_SUM_DCU_SOH_M.htm. *See also* https://www.ooga.org/page/MarketReport.

[152] Electricity prices for hydrogen production via electrolysis at refueling stations, mid-sized, and central facilities reflect current commercial, industrial, and wholesale prices, respectively, in Ohio. *See* https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_06_a. *See also* https://www.pjm.com/about-pjm/learning-center/price-ticker.aspx

[153] Dincer, I., & Acar, C., Innovation in Hydrogen Production. *Int. J. Hydrogen Energy* 2017, *42*, 14843-14864. *See also* IEA. The Future of Hydrogen; IEA, Paris, 2019.

[154] Bartels, J. R.; Pate, M. B.; Olson, N. K., An Economic Survey of Hydrogen Production from Conventional and Alternative Energy Sources. *Int. J. Hydrogen Energy* 2010, *35*, 8371-8384.

[155] Glenk, G.; Reichelstein, S., Economics of Converting Renewable Power to Hydrogen. *Nature Energy* 2019, *4*, 216.

[156] Kaiwen, L.; Bin, Y.; Tao, Z., Economic Analysis of Hydrogen Production from Steam Reforming Process: A Literature Review. *Energy Sources, Part B: Economics, Planning, and Policy* 2018, *13*, 109-115.

Technoeconomic models were adjusted from the literature for SMR with carbon capture,[157] electrolysis using AEC,[158] and electrolysis using PEM,[159] using constant 2018 USD and adjusting inputs to reflect current retail, city-gate and hub pricing. Results from our technoeconomic analysis are set forth in Table 7. Our findings show that SMR with carbon capture is the least-cost option of those considered at every scale. For this technology, the dominant capital expense is the steam methane reformer (47% of total capital) followed by the pressure swing adsorption unit (11%) and the Selexol™ capture unit (10%). *See* Figure 12. The total capital investment for a 1500 kg H_2/day production plant is estimated as $4.7 million (2018), whereas the mid-sized and centralized production facilities will command roughly $77 million and $337 million (2018), respectively. The dominant operational expense is the cost of natural gas (32%) followed by overhead (22%) and labor and maintenance (17% each). Included in this analysis is an estimated transportation and storage cost of $22/tCO2. With capture, the anticipated cost of CO2 fully delivered is $39/tCO2.

Table 7. Cost Projections for Hydrogen Generation from SMR with Carbon Capture and Competitive Electrolysis Technologies.

	Hydrogen production cost (2018$ / kg H_2)		
Type	SMR – CC	AEC	PEM
Refueling Station	3.24	6.21	6.64
Mid-sized	1.47	4.16	4.60
Centralized	0.99	2.54	2.97

Both electrolysis technologies are currently considered non-competitive with SMR-CC and are highly dependent on the cost of electricity. The major difference between cost estimates comes down to a difference in the capital cost ($1000/kW and $1200/kW for AEC and PEM, respectively) and the greater stack lifetime (*ca.* 1.5 x) for AEC, leading to lower equipment replacement costs over the lifetime of the plant. However, both systems were modeled at a consistent plant availability of 97%. It is known that PEM technology is more flexible and thus suited for pairing with intermittent sources; thus, a PEM system is likely to operate at a higher capacity factor when compared with an AEC linked to an intermittent power source, leading to a greater cost parity between the two technologies. It is important to note, however, that this analysis assumes that

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[157] DOE INL *Htgr-Integrated Hydrogen Production Via Steam Methane Reforming (Smr) Economic Analysis*; accessed from: https://art.inl.gov/NGNP/INL%20Documents/Year%202010/HTGR-Integrated%20Hydrogen%20Production%20via%20Steam%20Methane%20Reforming%20-SMR-%20Economic%20Analysis.pdf, 2010.

[158] Eichman, J.; Townsend, A.; Melaina, M. *Economic Assessment of Hydrogen Technologies Participating in California Electricity Markets*; National Renewable Energy Lab.(NREL), Golden, CO (United States): 2016. *See also* Guerra, O.; Eichman, J.; Hodge, B.-M.; Kurtz, J. *Cost-Competitive Electrolysis-Based Hydrogen under Current U.S. Electric Utility Rates*; National Renewable Energy Lab.(NREL), Golden, CO (United States): 2018.

[159] James, B.; Colella, W.; Moton, J.; Saur, G.; Ramsden, T. *Pem Electrolysis H2a Production Case Study Documentation*; National Renewable Energy Lab. (NREL), Golden, CO (United States): 2013.

sequestration of carbon is revenue neutral. As of 2020, sequestration has only been solved on a case by case basis. Injection of carbon dioxide into a subsurface reservoir is generally not cost effective, so instead focus has been on developing uses for carbon dioxide, such as for beverages or greenhouses. Without sequestration, however, the SMR-CC approach may not be viable. Since the economics of sequestration is likely to be controlled by local use of carbon, this will be the subject of future analysis on a case-by-case basis.

Figure 12. Capital and operating expense breakdown for a steam methane reformation facility equipped with carbon capture (Selexol™).
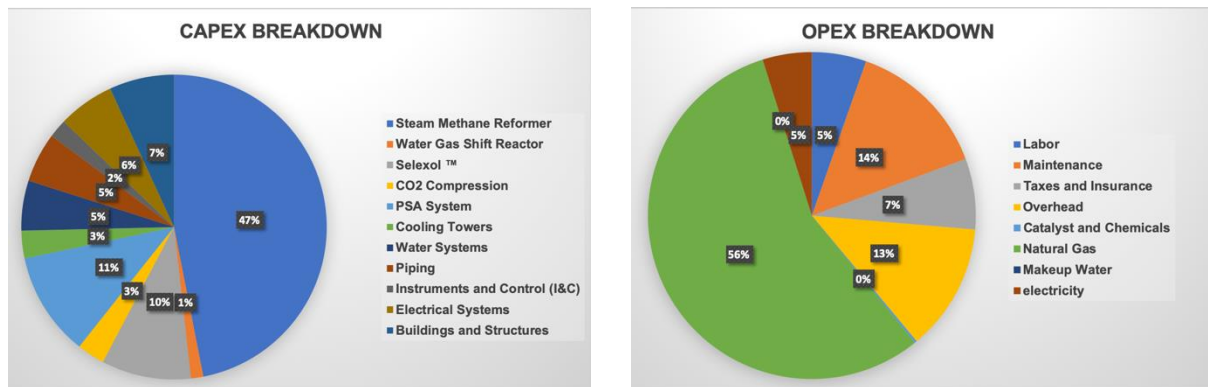

The Study Team used the Hydrogen Delivery Scenario Analysis Model (HDSAM) and the Heavy-Duty Refueling Station Analysis Model (HDRSAM), both developed by Argonne National Lab, [160] to estimate the intermediate-term[161] cost per kilogram to deliver and dispense hydrogen at the proposed refueling stations displayed above in Figure 11. One strategy for hydrogen generation under close examination by the U.S. Department of Energy is production via water electrolysis using electricity supplied by nuclear power plants.[162] As illustrated in Figure 13, these hydrogen production sources would be relatively close to the proposed refueling stations along the interstate corridor from Pittsburgh to Minneapolis.

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[160] *See* Argonne National Laboratory. *Hydrogen Delivery Infrastructure Analysis*. https://hdsam.es.anl.gov/index.php

[161] Future intermediate-term costs were estimated by selecting the "Mid" production volume option within HDSAM and HDRSAM.

[162] *See* Office of Nuclear Energy, U.S. Department of Energy. (2019). "Evaluation of Non-electric Market Options for a Light-water Reactor in the Midwest." https://inldigitallibrary.inl.gov/sites/sti/sti/Sort_19807.pdf

Figure 13. Midwest Nuclear Power Plants
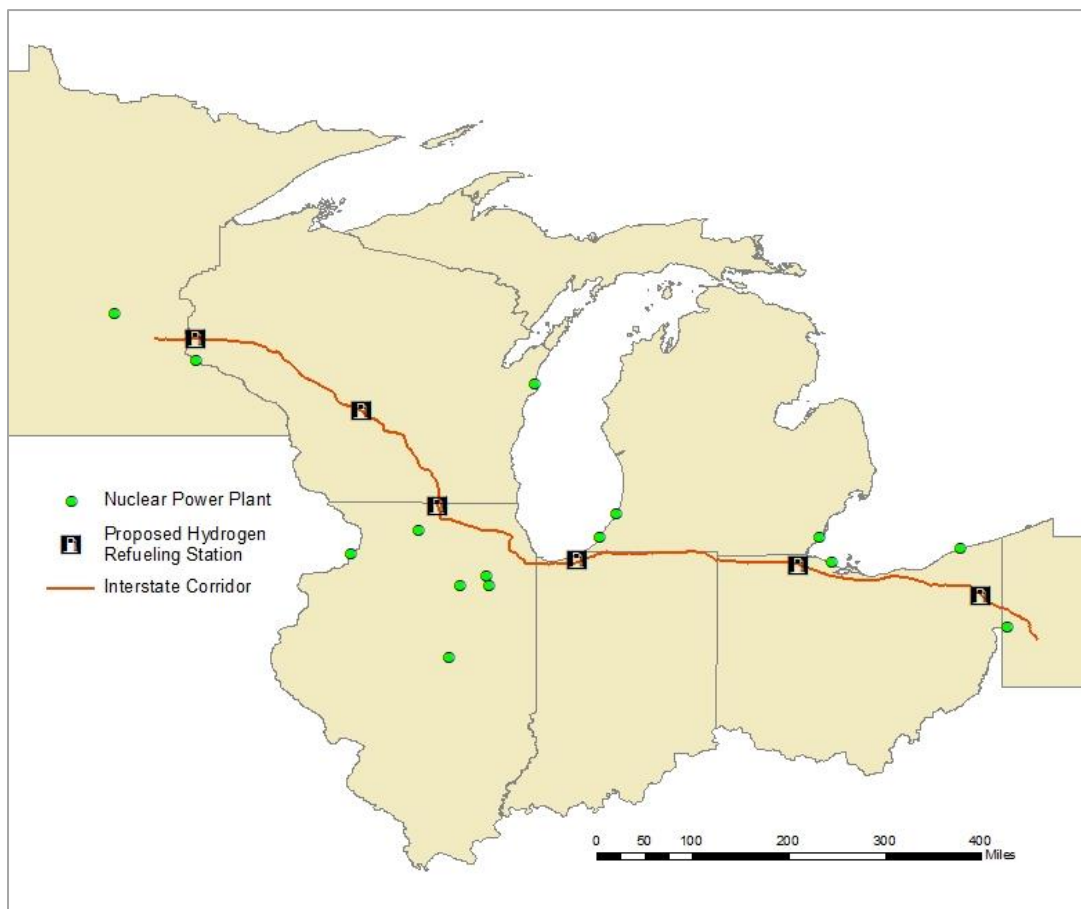
Given the scope of initial pilot projects being developed under the DOE's Light Water Reactor Sustainability Program, early-stage hydrogen production from water electrolysis via nuclear power could yield around 1,000 kg per day per plant.[163] This figure was one of the key assumptions used to estimate the future cost of hydrogen distribution using the HDSAM and HDRSAM models. Other important assumptions included delivery of gaseous hydrogen via tube trailer and a combined urban and rural hydrogen market.[164] It was also assumed that hydrogen supply for each refueling station would come from the nearest nuclear power plant and that the station would consume all of the plant's production. Default financial parameters were used for cost modeling, including an inflation rate of 1.9% and a real after-tax discount rate of 10%.

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[163] This assessment is based on the installation of a 2 MW containerized PEM electrolyzer with a production capacity of 1,000 kg per day. *See* https://www.energycentral.com/c/ec/idaho-national-lab-steps-gas-projects-hydrogen-production-three-us-nuclear. *See also* https://www.meetmax.com/upload/event_47809/Nel%20Hydrogen.pdf

[164] Tube trailers were found to be the lowest cost distribution pathway at this scope and scale compared to the delivery of liquid hydrogen via tanker truck or gaseous hydrogen via pipeline.

Table 8 shows the results of using the HDSAM and HDRSAM models given the described scenario and also what total distribution costs might be should there be a doubling of production (assuming all production would then be consumed by the nearest refueling station). Costs are broken down into four areas. In addition to over-the-road transportation costs, distribution costs include geologic storage and storage on-site at the terminal where hydrogen is compressed after production, components of the distribution pathway that allow for plant outages and seasonal variation in fueling demand.[165] Projected costs are in 2018 dollars.

Table 8. Intermediate-term Hydrogen Distribution Costs for Transportation

Hydrogen Dispensed Per Day Per Station (kg)	Terminal Cost ($/kg)	Geologic Storage Cost ($/kg)	Compressed H2 Truck-Tube Cost ($/kg)	Refueling Station Cost ($/kg)	Total Cost ($/kg)
1,000	$2.90	$0.79	$2.80	$1.20	$7.69
2,000	$1.98	$0.60	$1.70	$0.63	$4.92

6. Conclusions

The demand for low and zero-emissions heavy duty vehicles will only accelerate in the coming decades as both governments and market participants respond to the spectrum of risks (social and political as well as economic and financial) that will continue to intensify due to climate change and related environmental issues.[166] Fuel cell electric vehicles will likely constitute an appreciable portion of the transit bus and long-haul trucking fleet by the middle of the century as part of a strategy to lower greenhouse gas emissions in transportation. For moving large volumes of goods and people, especially over longer distances, FCEVs may indeed end up over the long term being the primary zero-emissions power train replacement for conventional propulsion technologies that use fossil fuels.[167]

However, other industries are also likely to increase their relative demand for hydrogen during this timeframe as it similarly offers the promise of enabling lower greenhouse gas emissions for a diverse set of production processes at comparable costs when scaled up. This has the potential to constrain the supply of hydrogen available for transportation applications and hinder the growth of FCEV deployment. The Midwest region, though, has a distinctive combination of assets

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[165] *See* Argonne National Laboratory. *Hydrogen Delivery Scenario Analysis Model (HDSAM) User Guide*. https://hdsam.es.anl.gov/files/hdsam-guide. *See also* http://ieahydrogen.org/Activities/Task-28/Task-28-report_final_v2_ECN_12_2_v3.aspx

[166] *See* World Economic Forum. (2020). *The Global Risks Report 2020*. http://www3.weforum.org/docs/WEF_Global_Risk_Report_2020.pdf

[167] *See* Borst, M. (2019). "Is hydrogen the future for trucking?" SAE International. https://saemobilus.sae.org/power/feature/2019/06/hydrogen-fuel-cell-trucks

related to hydrogen production that could allow it to provide more adequate supply and facilitate competitive prices.

A excess supply of natural gas is projected to flow out of Appalachia into the Midwestern states for many years to come.[168] Steam methane reforming of this abundant resource is likely to provide a cost-competitive means of producing hydrogen sufficient to satisfy the projected demand for potential markets. To realize economical hydrogen production via natural gas that minimizes negative externalities from emissions, a carbon capture and sequestration strategy must be implemented. But such a strategy does not have to merely depend on the available capacity of tank containers and geological storage, a scarce resource for which multiple industrial gases compete. Instead, captured carbon could become a revenue-generating commodity sold to manufacture high-value products such as synthetic jet fuel that have net-zero emissions across the lifecycle of production and consumption.[169]

The Midwest's nuclear power plants are another unique asset that could be used to satisfy a growing demand for hydrogen. During off-peak hours, the price of wholesale electricity from nuclear power in the Midwest can fall below $0.02 per kWh.[170] This presents an opportunity to produce hydrogen inexpensively from water through electrolysis.[171] Hydrogen generated from nuclear power is emission free, and accordingly there are no costs for carbon capture or sequestration. Repurposing off peak nuclear power to make hydrogen would put downward pressure on the price of hydrogen at the pump when used to fuel vehicles.

While the cost to *produce* hydrogen, through either steam methane reforming or through electrolysis, has declined to the point where it will soon be competitive with conventional transportation fuels, the cost to *deliver* hydrogen remains a barrier to its wider use. For early stage refueling stations in California, the cost to transport hydrogen from the point of production combined with the cost of the station itself represents around 80% of the price at the pump.[172] Technological improvements and economies of scale will of course eventually lower the cost of transporting and dispensing hydrogen. But in the early stages of FCEV adoption, the cost of transportation will likely be best constrained by locating hydrogen production closer to the point of consumption. Near-site gaseous hydrogen generation through steam reformation will likely be the more economical production pathway for initial station deployments, until such time that higher volumes justify the capital costs for hydrogen pipelines or liquefaction units.

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[168] U.S. Energy Information Administration. (2019). *Annual Energy Outlook 2019*.
https://www.eia.gov/outlooks/aeo/

[169] *See* The Royal Society [UK Academy of Sciences]. (2019). *Sustainable synthetic carbon-based fuels for transport* [policy briefing]. https://royalsociety.org/-/media/policy/projects/synthetic-fuels/synthetic-fuels-briefing.pdf

[170] *See* PJM and MISO regional wholesale prices at https://www.pjm.com/about-pjm/learning-center/price-ticker.aspx, and also at http://www.energyonline.com/Data/GenericData.aspx?DataId=8.

[171] The cost to the power plant in this case would be the foregone revenue of selling the electricity on the wholesale market.

[172] *See* https://www.sciencedirect.com/science/article/pii/S0360319917320311

In the Midwest, especially along the Interstate Corridor, transportation costs could also be mitigated by locating refueling stations near nuclear power plants that are able to repurpose off peak power from the grid to hydrogen generation. A number of nuclear plants in the Midwest are located near both major freight corridors and industrial centers where there are high concentrations of potential hydrogen off-takers. The proximity of these market participants could minimize delivery costs and help smooth the balance between supply and demand.

Siting refueling stations to maximize capacity utilization will be critical to realizing the lowest possible price at the pump. Refueling station capacity utilization strongly influences hydrogen refueling cost.[173] For example, the underutilization of station capacity in early California FCEV markets has resulted in levelized station costs that are approximately 40% higher than they would be under full utilization.[174] Going forward, full capacity utilization seems most likely to occur where the demand for fuel by heavy-duty vehicles is highest. It therefore seems reasonable that the most promising sites for economical hydrogen refueling stations in this context are areas that have a history of high fuel demand such as traditional truck stops along major freight corridors and large transit facilities with dense ridership.

Hydrogen has an increasingly wide range of applications across multiple industries, with its role in decarbonizing the transportation sector being especially prominent. Hydrogen can store more energy in less weight than most common transportation fuels, making fuel cells well-suited for vehicles with heavy payloads and long ranges. Challenges certainly exist in realizing the U.S. Department of Energy's long-term cost target for hydrogen of $4/kg at the dispenser, inclusive of production, transportation and refueling station costs. Hydrogen generation at $2/kg (a key DOE objective within the overall $4/kg target) has essentially already been achieved by fossil resource pathways. With increased demand, the cumulative dispensed cost of hydrogen can converge with the DOE's target for hydrogen to be competitive with other transportations fuels. By combining the carefully planned deployment of refueling infrastructure for heavy-duty FCEVs with existing assets for producing hydrogen in the Midwest, this demand could be fostered while realizing competitive prices. The best opportunity to accomplish this is likely along the Interstate Corridor, which not only has significant heavy load traffic, but also has a number of nuclear power plants located therewith.

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[173] *Id.*
[174] *Id*.