EERC
UND UNIVERSITY OF NORTH DAKOTA

HYDROGEN ENERGY ROAD MAP

Hydrogen and North Dakota's Energy Future

ROAD MAP FOR DEVELOPMENT AND IMPLEMENTATION OF HYDROGEN ENERGY

Revised June 30, 2024. With funding from the North Dakota Industrial Commission (NDIC) Oil and Gas Research Program Contract No. G-054-105, this final project report summarizes findings from a study of hydrogen energy development opportunities and challenges in North Dakota.

HYDROGEN IS GAINING NOTICE AS THE WORLD IS SEEKING TO REDUCE THE CARBON INTENSITY OF ENERGY PRODUCTION AND USE.

BASIS FOR HYDROGEN

75% of human-generated GHGs come from CO_2 emitted from combusting carbon-based fuels.

Global greenhouse gas (GHG) emissions are equivalent to roughly 380 million tonnes/year of carbon dioxide (CO_2), of which nearly 30 million tonnes/year come from human activities. Most of the human-caused emissions, nearly 75%, are from combusting carbon-based fuels.[1] **Because hydrogen (H_2) contains no carbon, when it is burned as a fuel or converted directly to electricity in a fuel cell, it generates water—and no CO_2.**

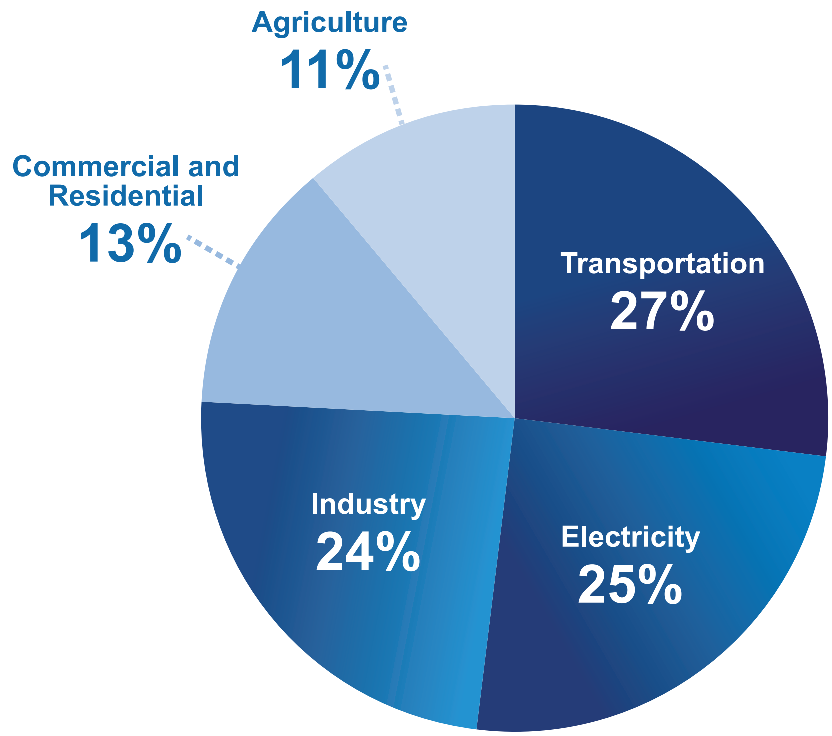
And when hydrogen is produced with few to no CO_2 emissions—by using renewable energy or by using fossil energy with CO_2 capture and storage (CCS)—hydrogen becomes a low-carbon or net-zero energy carrier, meaning that CO_2 emissions are eliminated or greatly reduced from its overall production and use. With increasing awareness of its indispensability in achieving the worldwide goal of affordable decarbonized energy, hydrogen is on track to become a major global energy currency.

The graphs at right show major 2020 U.S. sources of GHG emissions, including CO_2, methane (CH_4), nitrous oxide (N_2O), and fluorine-containing (F) gases. Because each GHG has its own global warming potential (GWP) or "heat-trapping capacity," aggregate GHG emissions are reported as "CO_2 equivalent" in the form of tonnes of CO_2 (1 tonne equals 1000 kilograms or 2205 pounds). This means that 1 tonne of emitted methane—which has a GWP of 27 versus 1 for CO_2—has the global warming impact of 27 tonnes of emitted CO_2. N_2O and the F gases have GWPs of about 273 and 2000–20,000, respectively.

GHG EMISSIONS[2]

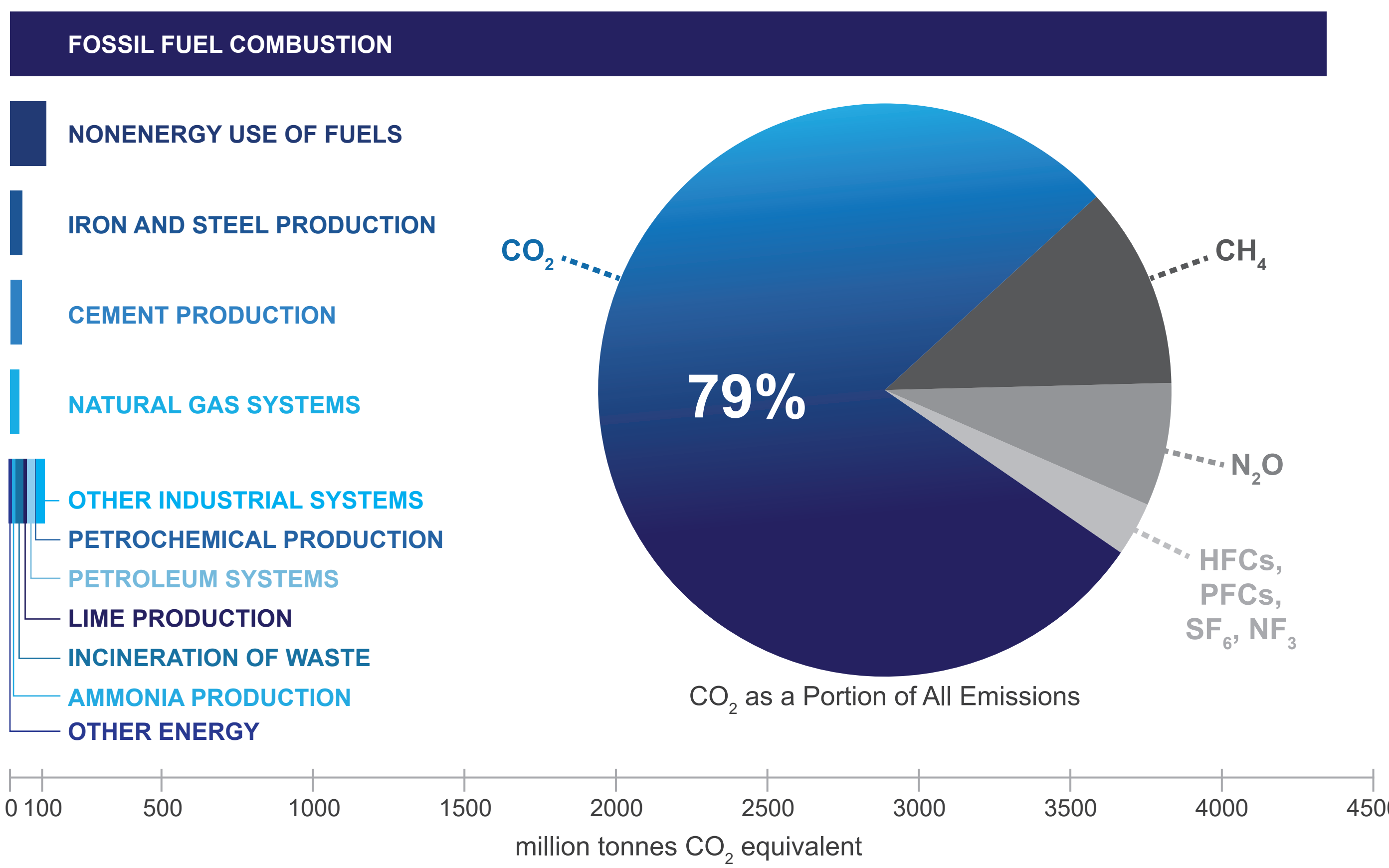
2020 U.S. GHG emissions, 5.98 billion tonnes.

U.S. GHG EMISSIONS IN 2020 TOTALED NEARLY 6 BILLION TONNES.



2020 U.S. GHG EMISSIONS BY ACTIVITY[3]

Hydroflurocarbons (HFCs), perfluorocarbons (PFCs), sulfur hexafluoride (SF_6), nitrogen trifluoride (NF_3)



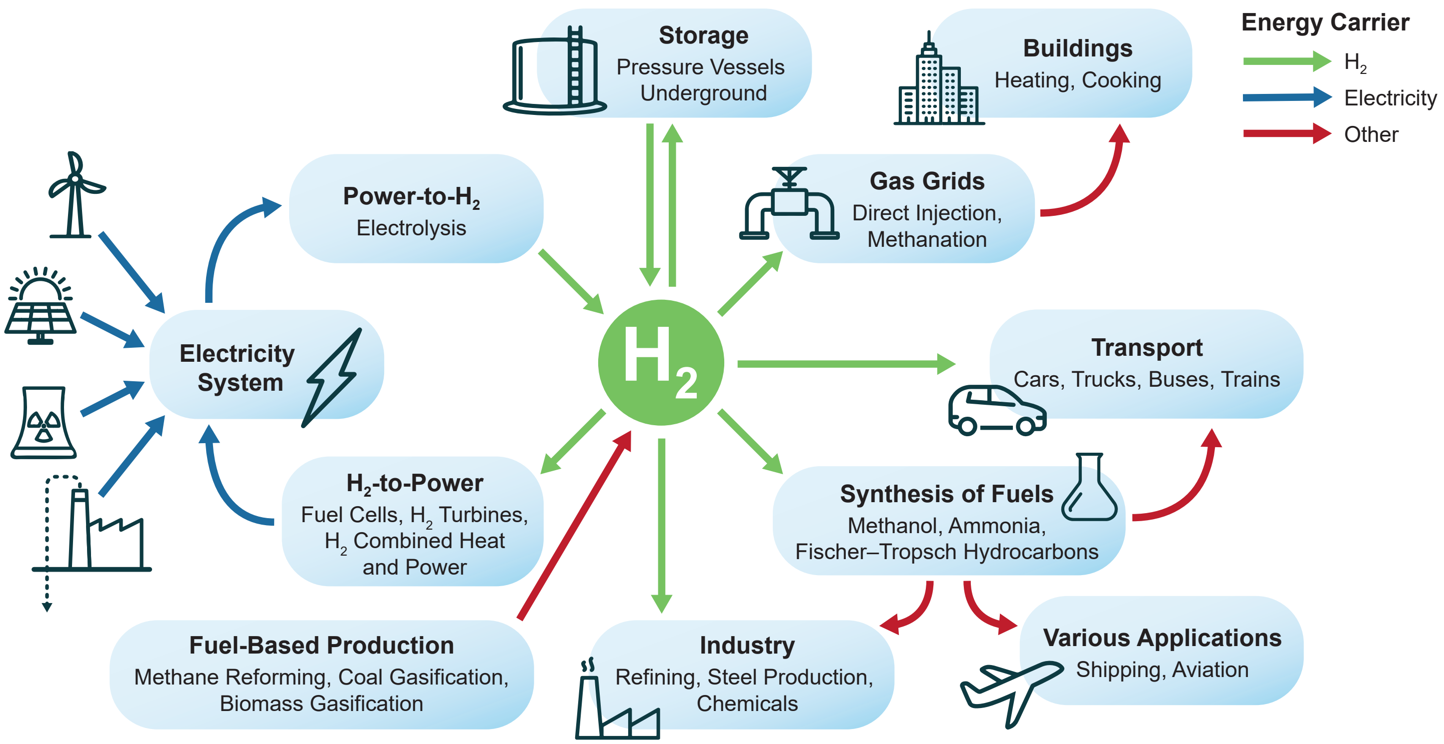
What is hydrogen, and why is it so important?

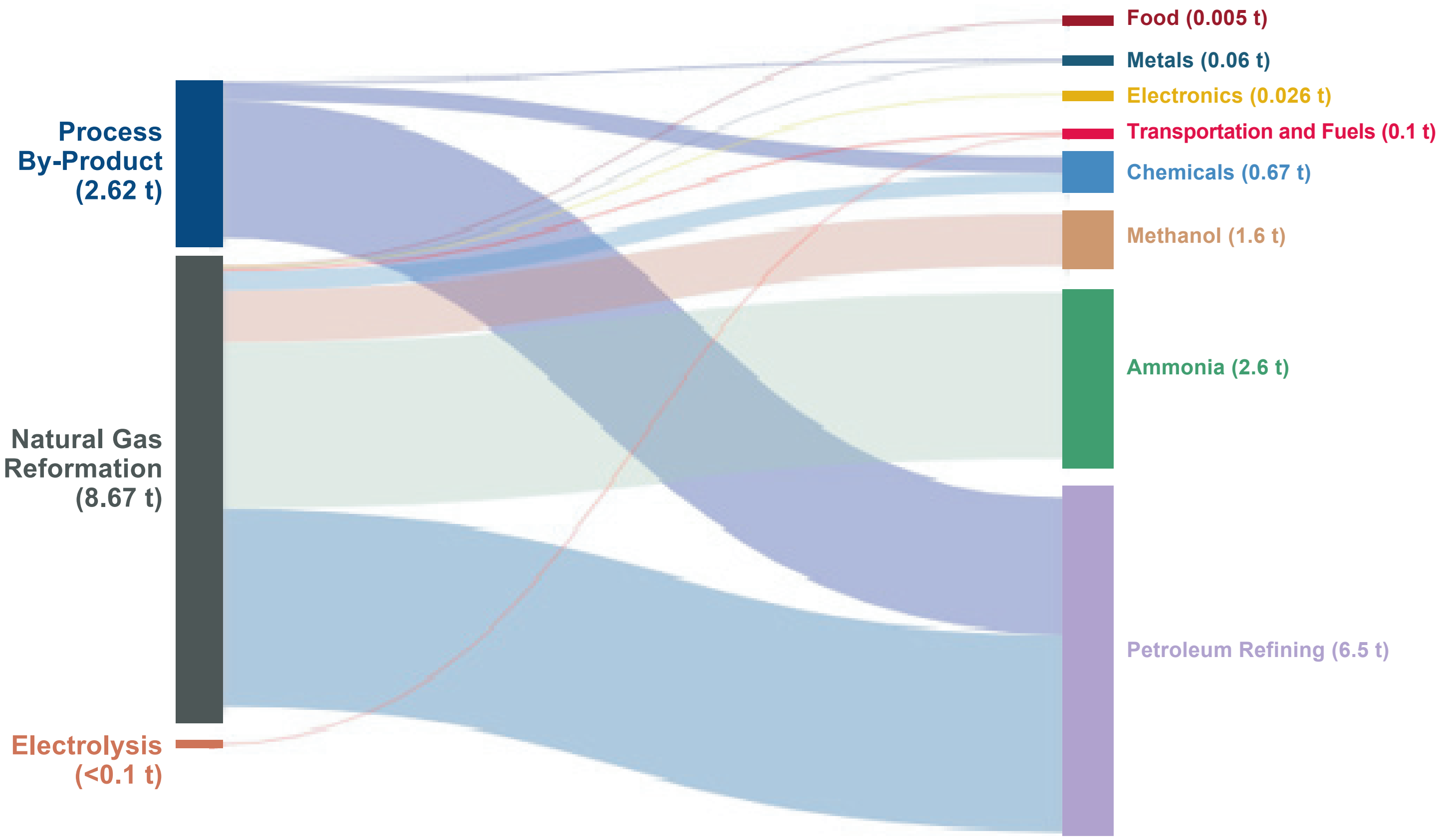
Hydrogen, abbreviated as H, is the lightest and most abundant element in the universe. It is colorless, odorless, and nontoxic. Pure hydrogen exists as two hydrogen atoms bonded together to form a molecule of hydrogen, and pure hydrogen gas comprises only hydrogen molecules.

Although abundant, hydrogen rarely exists as pure hydrogen. Instead, hydrogen atoms are bonded with other atoms in compounds like water, hydrocarbon liquids and gases, alcohols, biomass, minerals, and countless other materials. Because hydrogen cannot normally be extracted from subsurface reservoirs like oil and natural gas, it must be liberated from the compounds in which it naturally exists, which requires energy.

Hydrogen is an essential feedstock in many chemical and fuel manufacturing processes, including petroleum refining and production of renewable diesel/jet fuel, methanol, ammonia, and polymers. As a carbon-free energy carrier, hydrogen can be efficiently converted to zero-carbon electricity using fuel cells, turbines, and other power generation technologies.

HOW HYDROGEN IS USED





U.S. HYDROGEN **SUPPLY AND DEMAND**, 2022 (TONNES)[4]

This diagram showcases the existing sources of hydrogen supply (left) and depicts how proportions of each contribute to existing sources of hydrogen demand (right).

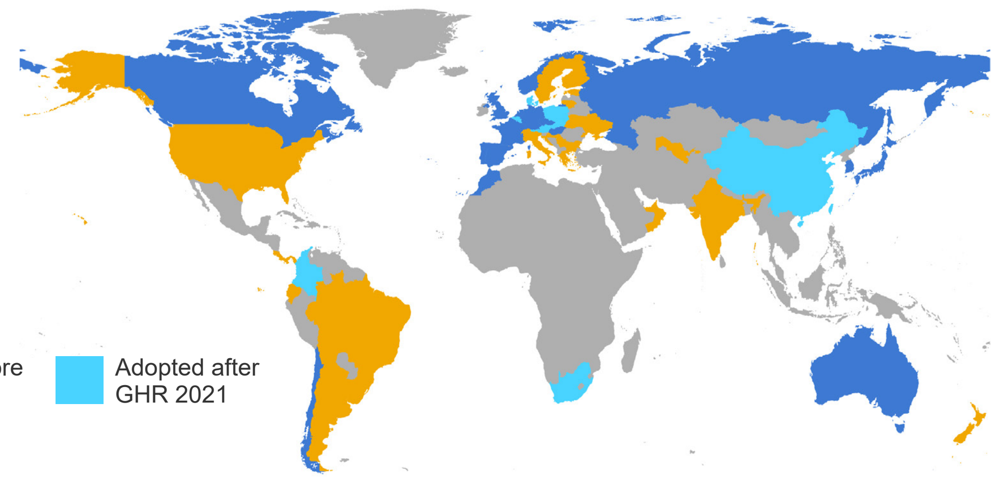
Most U.S. hydrogen use is for **petroleum refining (56%), ammonia production (22%), and methanol production (14%).**[4] About 80% of U.S. hydrogen production is purposely produced—mostly via steam methane reforming (SMR), with smaller contributions by steam reforming of other hydrocarbons and by gasification of coal—while about 20% is made as a by-product of various industrial operations. Major sources of "by-product" hydrogen are production of gasoline blendstocks and polymer feedstocks from oil and natural gas and production of chlorine and sodium hydroxide from brine via the "chlor-alkali" process. Roughly half of current U.S. hydrogen production comes from plants designed specifically to produce hydrogen for sale, while the other half is produced at large facilities designed for integrated hydrogen production and consumption, mainly petroleum refineries and ammonia plants. Hydrogen produced via these two scenarios is referred to as merchant or captive hydrogen, respectively.

BASIS FOR HYDROGEN

Countries accounting for more than 75% of current global hydrogen production have announced national hydrogen strategies.

Development of these national plans shows that hydrogen energy is expected to play a significant role in the future energy economy. Specific policies and approaches vary, but the International Energy Agency (IEA Global Hydrogen Review [GHR], 2022) has identified five policy categories for supporting hydrogen energy.[5] According to IEA's assessment of hydrogen plans, production targets have become more common and ambitious since 2021, partly because of energy disruptions caused by the conflict in Ukraine; however, complementary policies that stimulate demand are considered to be lagging.

COUNTRIES WITH A **NATIONAL HYDROGEN STRATEGY** IN PLACE OR UNDER DEVELOPMENT[5]



IEA HYDROGEN **POLICY CATEGORIES**

- **Establish targets** and/ or long-term policy signals
- Support **demand creation** for low-emission hydrogen
- **Mitigate** investment risks
- Promote **R&D innovation,** strategic demonstrations, and knowledge sharing
- Establish **regulatory frameworks,** standards, and certification systems

Hydrogen policy in the United States is currently guided by the 2021 Infrastructure Investment and Jobs Act (IIJA) and the 2022 Inflation Reduction Act (IRA). Together, these pieces of legislation align with many of the IEA policy categories and specifically include the following provisions:

- Mandate the creation of a Clean Hydrogen Production Standard (IIJA Section 40315).
- Create the Clean Hydrogen Production Tax Credit, Section 45V of the tax code (IRA Section 13204).
- Appropriate $5 billion in loans and grants to support domestic manufacturing of low- or zero-emission vehicles, including hydrogen fuel cell vehicles (IRA Sections 50142 and 50143).
- Authorize appropriations (IIJA Section 40314) of $9.5 billion for:
  - Clean Hydrogen Electrolysis Program.
  - Clean hydrogen manufacturing and recycling.
  - Nationwide network of at least four Regional Clean Hydrogen Hubs.
  - Hydrogen demand-side support initiative.

Globally, over 1418 large-scale clean hydrogen projects have been announced.

Despite the impressive growth in project announcements between 2019 and 2023 shown below, an estimated $430 billion of additional investment will be needed by 2030 to reach net-zero carbon emissions by 2050.[6] Of the $570 billion in announced projects through 2030, roughly 7% (by value) have been committed, meaning they are either already underway or their final investment decision has been made.

Projects for renewable hydrogen lead the total proposed hydrogen production capacity shown below. These projects are most commonly based on using wind or solar electricity to power an electrolyzer, a device that electrochemically splits water into its hydrogen and oxygen constituents.

Low-carbon hydrogen projects include natural gas reforming or coal gasification in combination with CCS. These projects make up a smaller portion of the total announced production capacity below, but they are generally more cost-competitive today compared to renewable hydrogen.

Supply comprises about 75% of clean hydrogen investment, whereas infrastructure and end use account for only about 10% and 15%, respectively.

THOSE PLANNING FOR A 2030 START (1011 PROJECTS) REPRESENT AN INVESTMENT VALUE OF $570 BILLION.

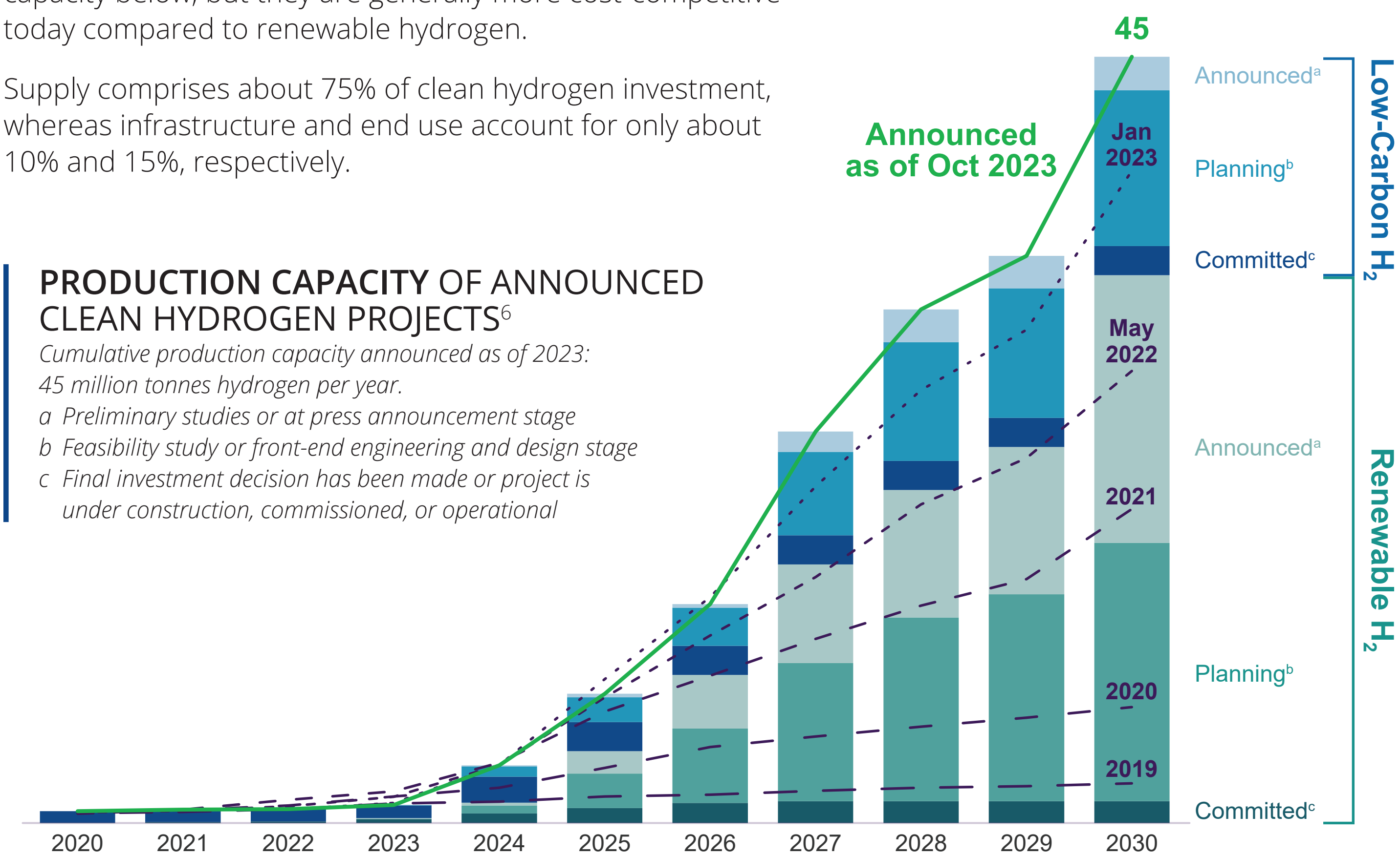
PRODUCTION CAPACITY OF ANNOUNCED CLEAN HYDROGEN PROJECTS[6]

Cumulative production capacity announced as of 2023: 45 million tonnes hydrogen per year.

a Preliminary studies or at press announcement stage

b Feasibility study or front-end engineering and design stage

c Final investment decision has been made or project is under construction, commissioned, or operational



U.S. hydrogen use is expected to grow sixfold by 2050.

Options for emitting less CO_2 to the atmosphere include:

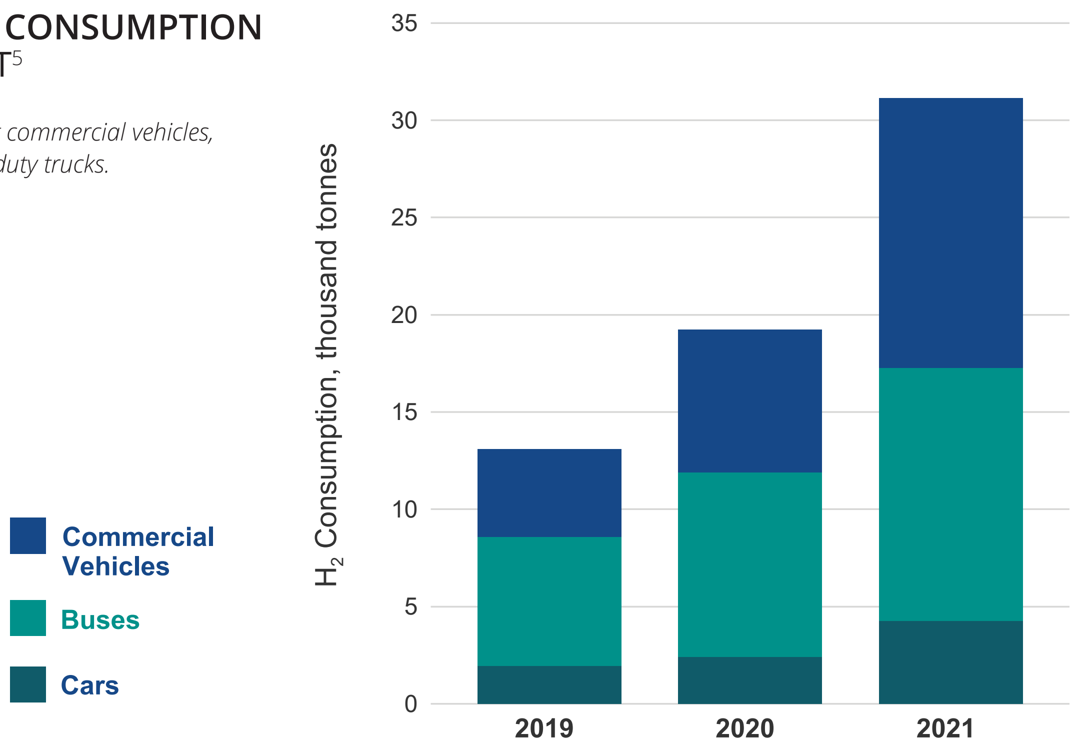
- Using less carbon-derived energy.
- Capturing CO_2 and storing it underground or converting it to durable solids—like concrete.
- Increasing use of renewable, nuclear, and other CO_2 emissions-free energy resources.
- Replacing carbon-based fuels with hydrogen produced with no CO_2 emissions.

Energy services such as light-duty transportation, heating, cooling, and lighting may be relatively straightforward to decarbonize by electrification with electricity generated from renewable energy or "low-carbon" fossil energy produced with CCS. Other energy services essential to modern civilization that will likely be more difficult to decarbonize include aviation, long-distance transport, shipping, production of carbon-intensive structural materials such as steel and cement, natural gas-based production of major industrial chemicals like ammonia and methanol, and provision of a reliable and affordable electricity supply capable of meeting fluctuating demand.[7]

Global hydrogen demand for road transport has increased 60% since 2020. Most of this is consumed in trucks and buses because of their high annual mileage and heavy weight relative to the larger stock of fuel cell electric cars. In 2021, hydrogen demand for commercial vehicles exceeded that from buses for the first time, reaching 45% of total hydrogen demand in the transport sector. The successful trials of hydrogen-fueled passenger trains in Germany led to the deployment of the first fuel cell train fleet (14 trains) in Lower Saxony in August 2022.[5] Hydrogen offers a solution to decarbonizing diesel rail lines where electrification is difficult and distances are too far to be covered by battery electric trains.

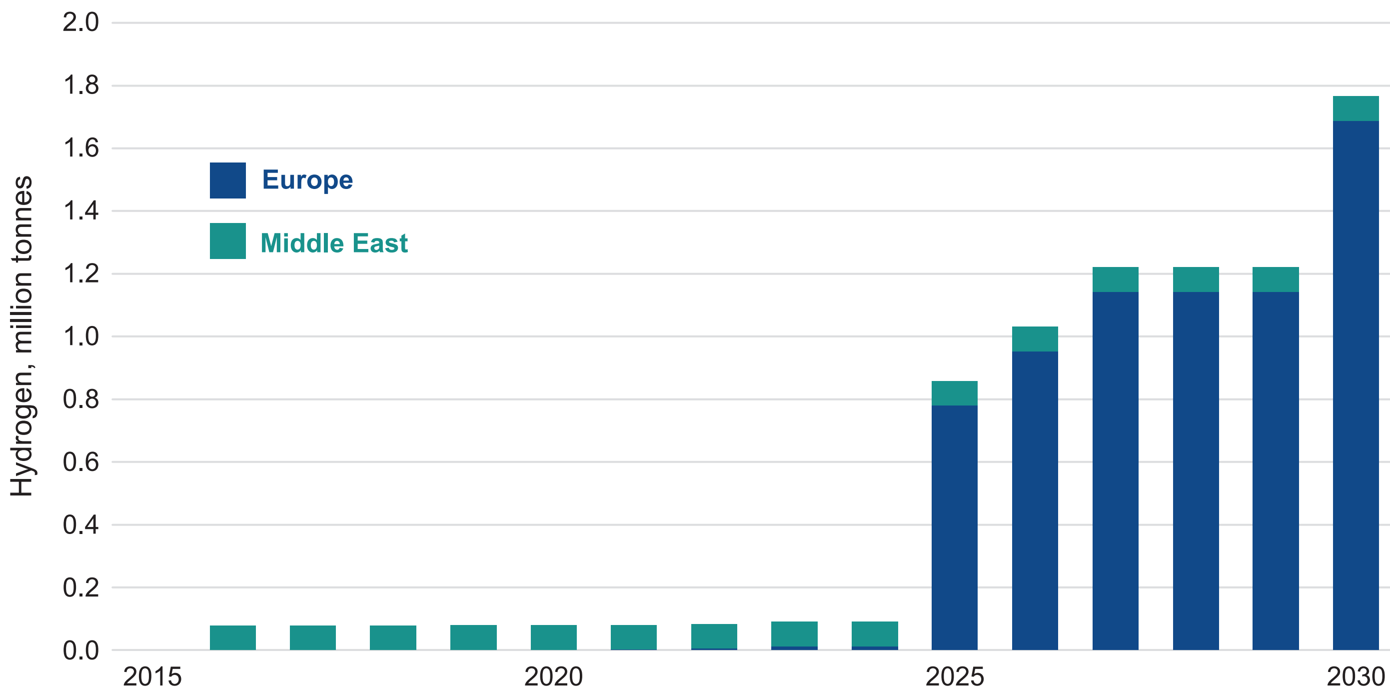
GLOBAL HYDROGEN **CONSUMPTION** IN ROAD TRANSPORT[5]

By vehicle segment, 2019–2021.
Commercial vehicles include light commercial vehicles, medium-duty trucks, and heavy-duty trucks.



LOW-CARBON HYDROGEN PRODUCTION CAPACITY FOR STEELMAKING VIA DIRECT REDUCED IRON (DRI)[5]

Operational and planned low-carbon hydrogen production capacity for DRI steelmaking by region, 2015–2030. All projects produce hydrogen through water electrolysis. Only projects with a disclosed start year of operation are included.



Steelmaking accounts for about 11% of all global CO_2 emissions.[8] Blast furnace steel production accounts for two-thirds of global crude steel output—1.95 billion tonnes in 2021—and typically generates 2 tonnes CO_2/tonne steel.[8] Switching production capacity to DRI technologies that use low-carbon hydrogen offers opportunities for decreasing steelmaking carbon intensity to less than 0.5 tonnes CO_2/tonne steel.[8] Conventional DRI technology uses a fossil fuel-generated mixture of carbon monoxide (CO) and hydrogen to chemically reduce iron ore. In 2021, conventional DRI accounted for about 12% of global steel production,[9] and the hydrogen used for this DRI accounted for about 5 million tonnes of industrial hydrogen demand, meaning that low-carbon-hydrogen DRI represents an opportunity to economically achieve major and meaningful global CO_2 emission reductions. As shown in the above graph, **worldwide investment in low-carbon hydrogen production capacity** (typically based on solar- and/or wind-powered water electrolysis) **for DRI is projected to increase rapidly.**

HYDROGEN PRODUCTION

Natural Gas + Water = 75% of Global Hydrogen Production

Most North American hydrogen production is done by reforming natural gas/methane, with associated CO_2 emissions vented to the atmosphere, yielding "gray" hydrogen. The two major methane-to-hydrogen technologies deployed today are SMR and **autothermal reforming (ATR)**, both of which use steam as feedstock/reactant in addition to methane. In SMR, methane combustion (for process heat) and methane reforming (for hydrogen production) occur in separate chambers of the reactor system, resulting in two separate and distinct output streams:

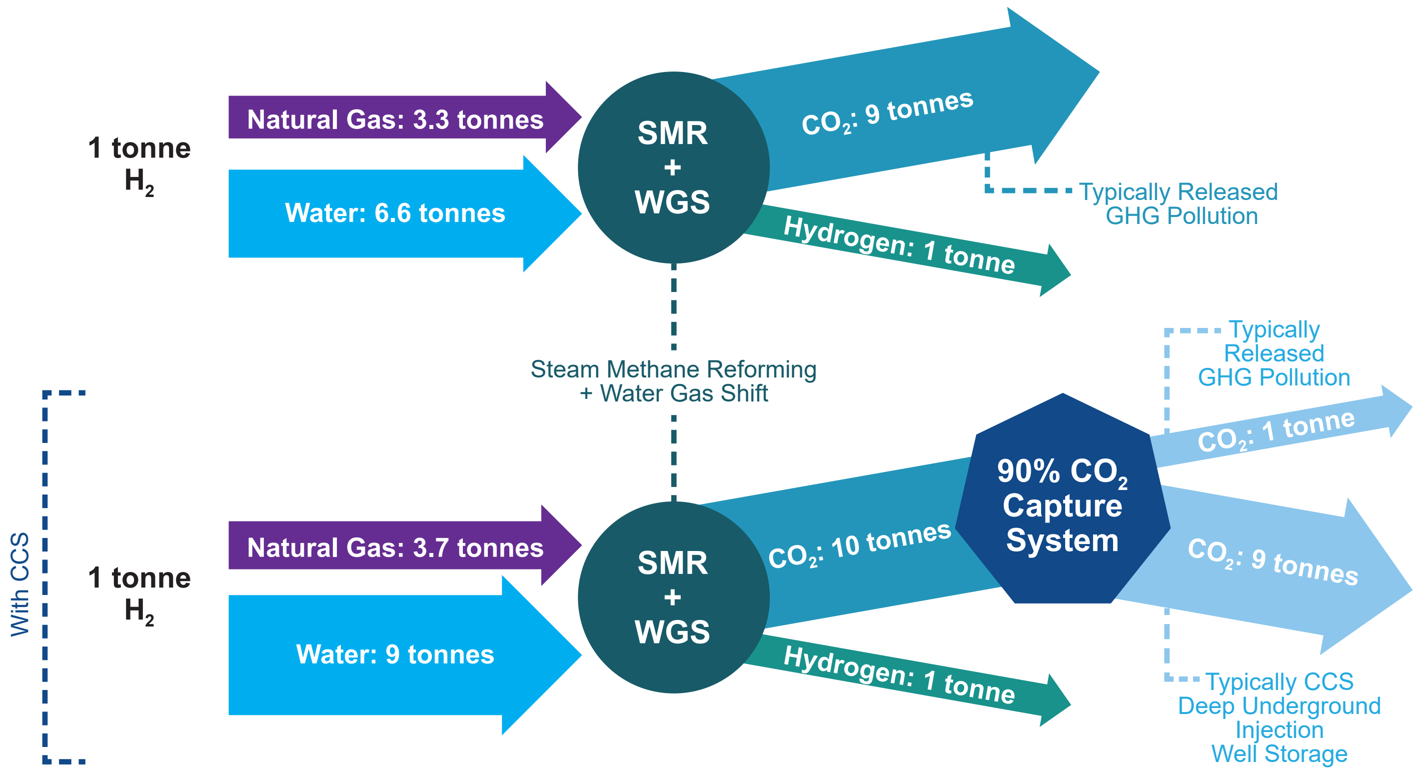
- Flue gas containing water and CO_2
- Product gas containing hydrogen and CO_2

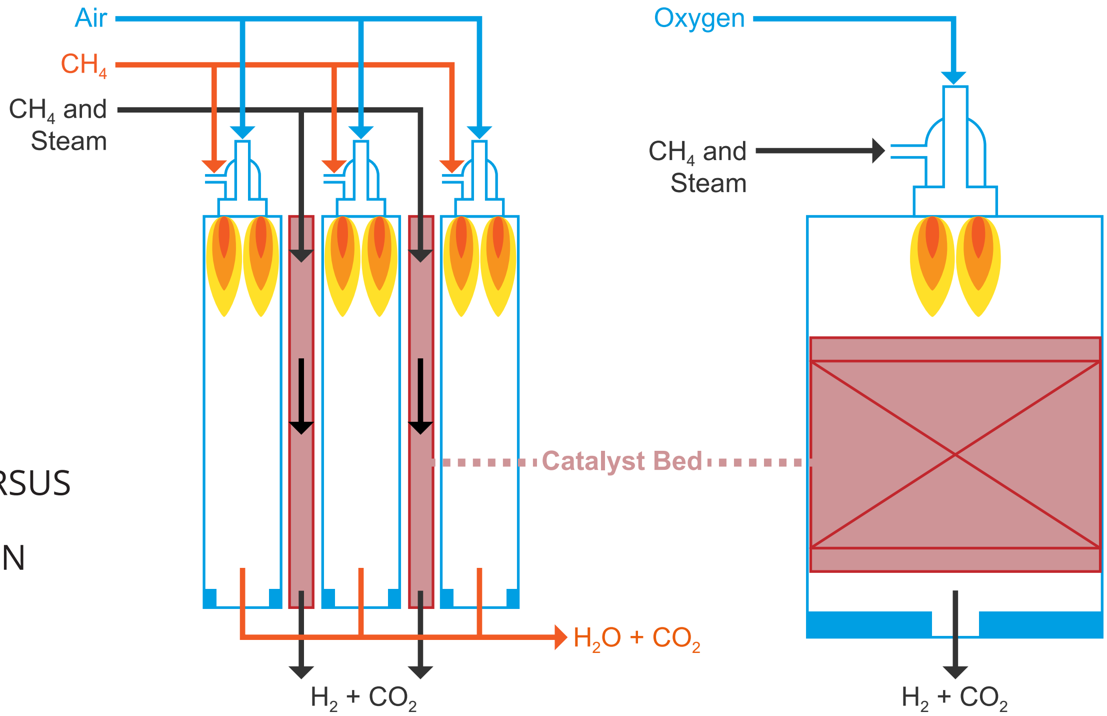
In ATR, methane combustion and reforming occur in the same chamber, resulting in a single output: product gas containing H_2 and CO_2.

Today, SMR is more widely deployed than ATR, primarily because of its use of air rather than more expensive oxygen. However, if CO_2 capture is an objective, the simplicity of dealing with a single output stream is a major advantage of ATR because it translates to lower capital and operating costs, especially at larger scales. For this reason, most underway and recently announced projects to build hydrogen plants with CO_2 capture capability are based on ATR technology.

CO_2 EMISSIONS FROM TODAY'S MOST COMMON HYDROGEN PRODUCTION METHOD[10,11,12]

SMR with CO_2 emitted to atmosphere (top) or CO_2 captured and stored (bottom). The additional natural gas and water inputs in the lower figure enable carbon capture.



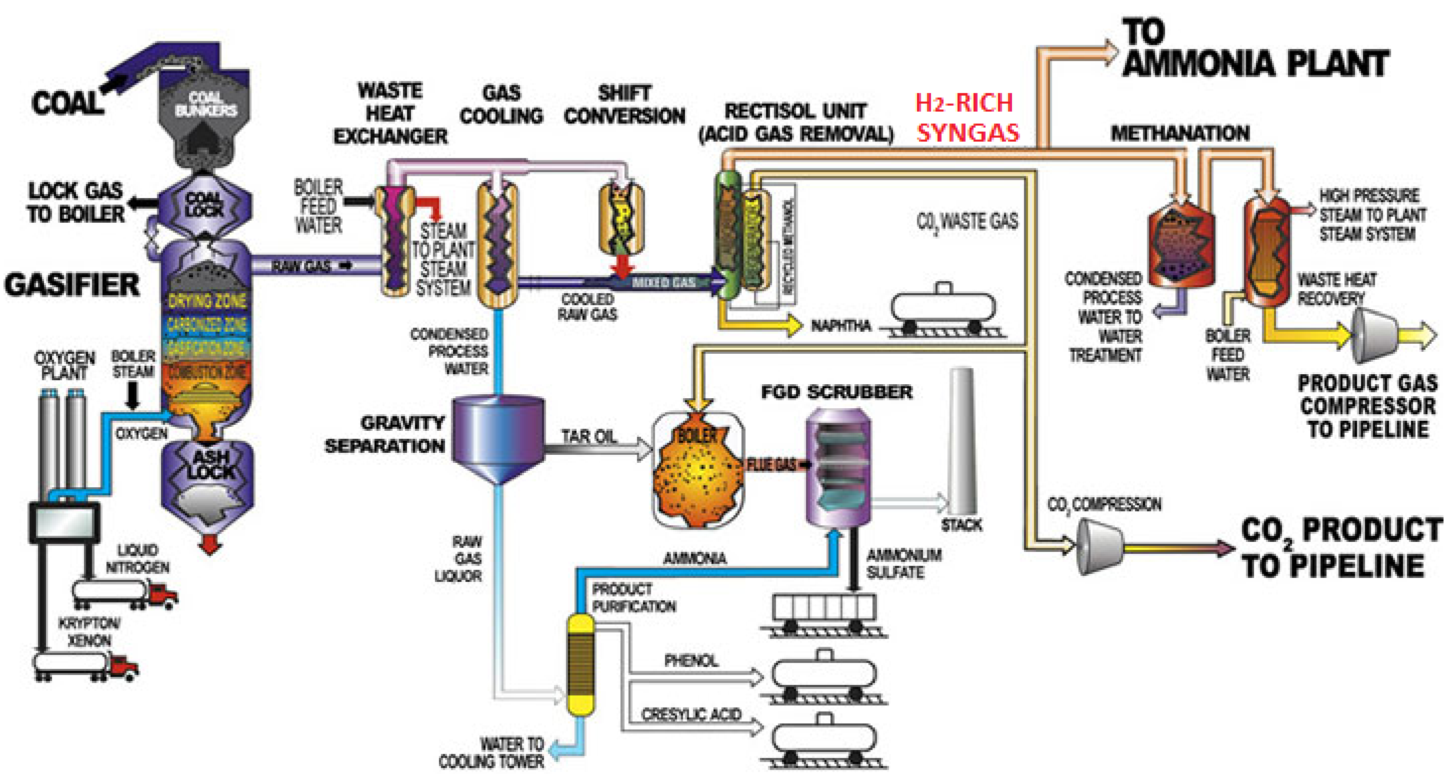


SMR (LEFT) VERSUS **ATR** (RIGHT) FOR HYDROGEN PRODUCTION

Process	SMR	ATR (oxidative steam reforming)
Carbon Feedstock	Natural gas, refinery gas, or naphtha	Natural gas or light gaseous hydrocarbons
Oxygen Feedstock	Air for fuel combustion to heat the process (not used for hydrogen generation in the SMR reactor tubes)	Oxygen from air separation unit (ASU) fed with controlled stoichiometry to limit CO_2 generation
Steam Feedstock	Yes	Yes, often from combined SMR
Catalyst Required	Yes, nickel	Yes, nickel, cobalt, and others
Target Chemical Reactions	$CH_4 + H_2O \rightarrow CO + 3H_2$	$CH_4 + H_2O \rightarrow CO + 3H_2$ $2CH_4 + O_2 \rightarrow 2CO + 4H_2$
Additional Side Reactions	$CO + H_2O \rightarrow CO_2 + H_2$	$CH_4 + O_2 \rightarrow CO_2 + 2H_2$
Energy Required/Released	Endothermic, requires heat input	Balance of endothermic and exothermic
Hydrogen Content in Product Gas	~70%	~65%
Product Gas Pressure	15–40 bar	30–50 bar
Product Gas Temperature	850°C	1000°C

North Dakota: Making Hydrogen from Coal since 1984

With a hydrogen production capacity of over 300,000 tonnes/year, the Dakota Gasification Company (DGC) synfuels plant in Beulah is one of the largest operating (as of 2022) hydrogen plants in North America. With a bank of 14 mammoth-scale gasifiers, the DGC synfuels plant converts about 18,000 tons of North Dakota lignite per day into a hydrogen-rich synthesis gas referred to as "syngas." In addition to hydrogen, syngas contains CO and CO_2. As shown below, the syngas stream is split, with one portion routed to "methanation" for production of pipeline-quality methane/natural gas and the other to ammonia production. When conducted without CO_2 capture, coal gasification yields "brown" hydrogen. If gasification is integrated with CCS, produced hydrogen is classified as "blue" hydrogen. Since 1988, more than $1.3 billion has been invested in the synfuels plant to achieve environmental compliance, improve efficiency, and diversify the product slate. Most recently, about $700 million was invested in a major expansion to produce urea, liquid carbon dioxide, and diesel exhaust fluid.



DGC SYNFUELS PLANT **PROCESS FLOW**

DGC synfuels plant process flow diagram showing unit operations.

DGC SYNFUELS PLANT **COMPLEX**

DGC synfuels plant complex (foreground) collocated with Antelope Valley Power Station (background blue buildings).

DGC CAPTURES MORE CO_2 FROM COAL CONVERSION THAN ANY FACILITY IN THE WORLD

As a global pioneer and leader in CO_2 capture, utilization, and storage (CCUS), DGC captures more CO_2 from coal conversion than any facility in the world, and it transports the captured CO_2 to the world's largest geologic carbon storage project in Weyburn, Saskatchewan.

After compression to convert gaseous CO_2 to a high-density "supercritical fluid," DGC sends the CO_2 through a 205-mile pipeline to Weyburn for use in enhanced oil recovery (EOR) operations that result in permanent CO_2 geologic storage, as monitored by IEA.

DGC has a CCUS capacity of 3 million tonnes of CO_2 per year. According to IEA, current (2022) global CCUS capacity is about 45 million tonnes/year, meaning that DGC represents almost 7%. Since 2000, DGC has captured and transported more than 40 million tonnes of CO_2 for geologic storage.

Renewable Electricity + Water = Zero-Carbon Hydrogen

Natural Gas + Water + CCS = Low-Carbon Hydrogen

Hydrogen can be produced from water by the process of electrolysis, which uses electricity to split/separate water into its elemental ingredients of hydrogen and oxygen. When renewable electricity is used to power an electrolyzer, the produced hydrogen is considered green.

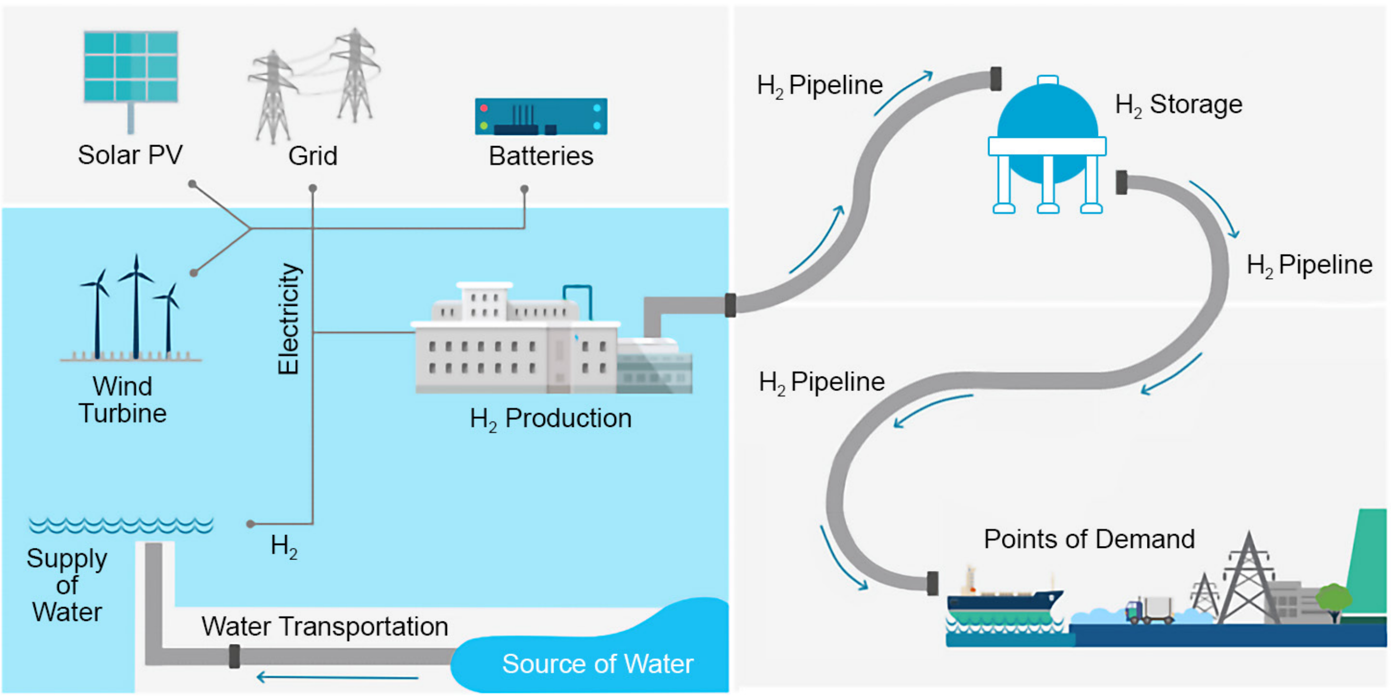
When hydrogen is produced from natural gas and water/steam via SMR or ATR integrated with CCS, it is referred to as blue hydrogen. Because CO_2 capture rates are limited to about 80%–95% because of both technical and economic considerations, blue hydrogen is considered low-carbon as opposed to net-zero carbon. In addition, fugitive emissions of methane during drilling, extraction, and transport are difficult to eliminate, and methane is a more potent GHG than CO_2. According to IEA, 1 tonne of methane is equivalent to 28–36 tonnes of CO_2 in terms of global warming impact. While the table shows a large cost differential between green and blue hydrogen, green hydrogen cost is projected to decrease to $2.50/kg[13] by 2030 because of 1) decreasing costs and increasing deployment of renewable power systems (translating to decreased cost and increased availability of renewable electricity) and 2) decreasing cost, increasing deployment, and a higher utilization factor of electrolyzers.

CHARACTERISTICS OF THREE MAJOR HYDROGEN TYPES[11,12,14]

	Gray	Blue	Green
Production Method	SMR	SMR with CCS	Water electrolysis using renewable electricity
CO_2 Intensity, kg CO_2e/kg H_2	8–12	1–4	0–1
Production Cost, $/kg H_2 (in 2030)	1.30–3.10	1.50–3.20	1.90–4.00
Water Use, kg H_2O/kg H_2	6–13	6–18	9

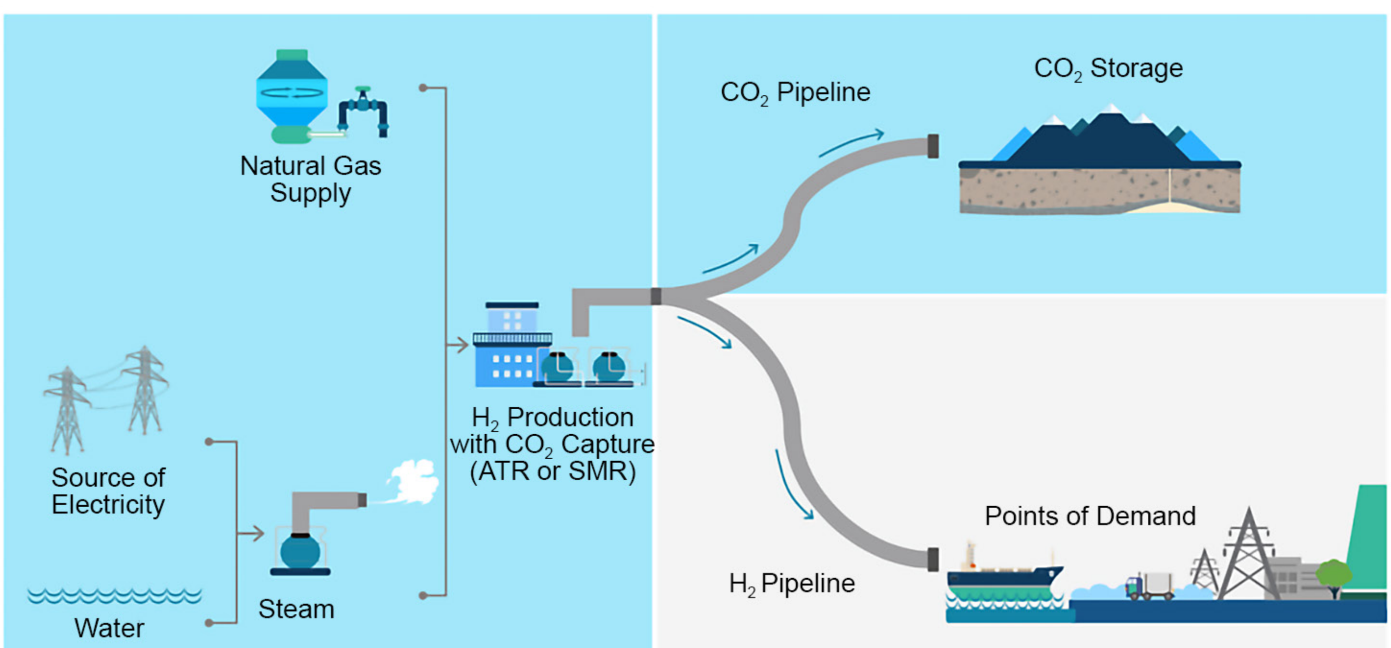
NET-ZERO (GREEN) HYDROGEN FROM RENEWABLE ENERGY

Production of clean hydrogen via renewables-powered electrolysis.



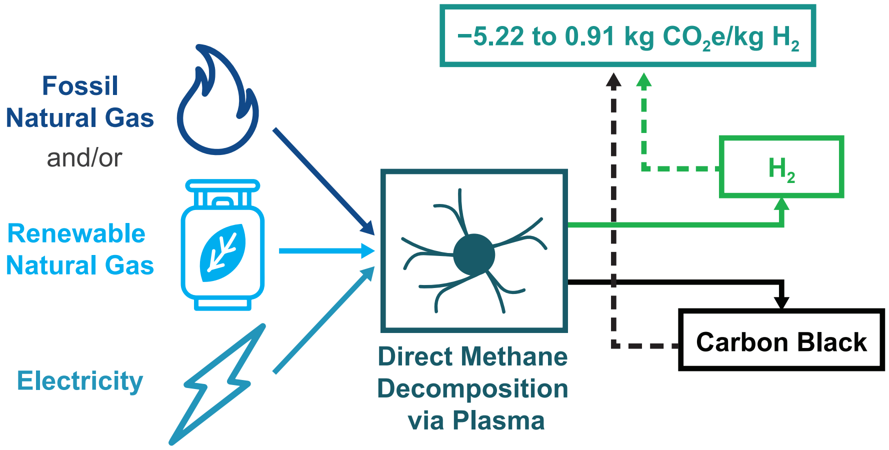
LOW-CARBON (BLUE) HYDROGEN FROM FOSSIL ENERGY WITH CCS

Production of clean hydrogen via SMR or ATR with CCS.



$CH_4 \rightarrow C_{solid} + 2H_2$... and No CO_2

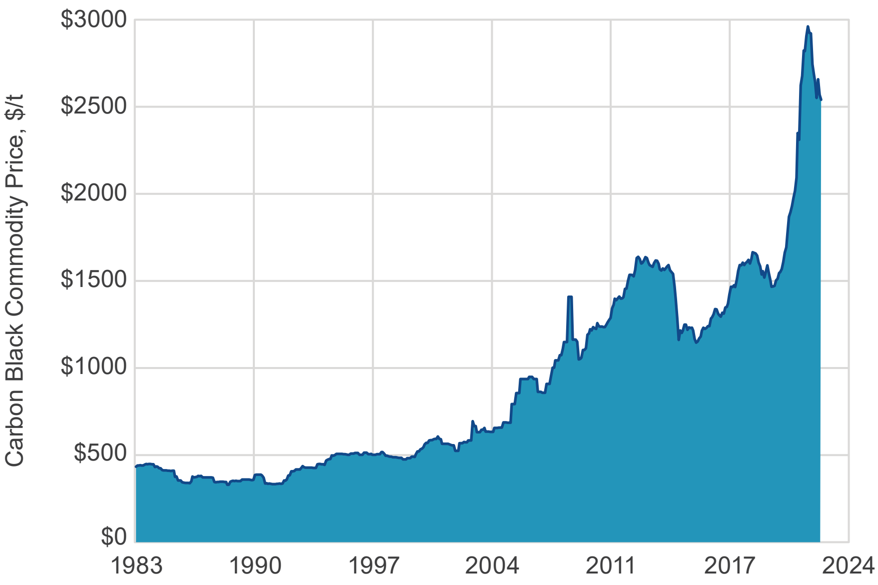
In the above methane pyrolysis reaction, C_{solid} refers to carbon black. The energy for producing hydrogen from methane/natural gas pyrolysis can be provided either electrically or by burning methane, hydrogen, or other fuels. In 2016, Machhammer et al.[15] compared methane pyrolysis against conventional SMR and coal gasification based on hydrogen production cost. They reported that for SMR and coal gasification, the primary cost drivers are natural gas price and the capital expense of building a state-of-the-art gasification plant, respectively, while for methane pyrolysis, the two roughly equal cost drivers are the price of feedstock (natural gas or renewable natural gas) and the price of electrical energy for pyrolysis (in state-of-the-art systems, electricity is used to power a plasma-based methane decomposition reactor). The carbon black by-product is 100% carbon (no CO_2) and represents a valuable revenue stream with wide-ranging industrial and engineering applications (see below). According to Machhammer et al., hydrogen production cost from methane pyrolysis ranges \$2600–\$3200/tonne versus—according to IEA—\$1200–\$2100/tonne for SMR with CCS and \$2100–\$2600/tonne for coal gasification with CCS. The below right graph compares methane pyrolysis to other hydrogen pathways based on CO_2 emissions.[16]



METHANE **PYROLYSIS/ DECOMPOSITION**

Hydrogen production via methane pyrolysis/decomposition using an electrically driven plasma reactor.

CARBON BLACK **COMMODITY PRICE**

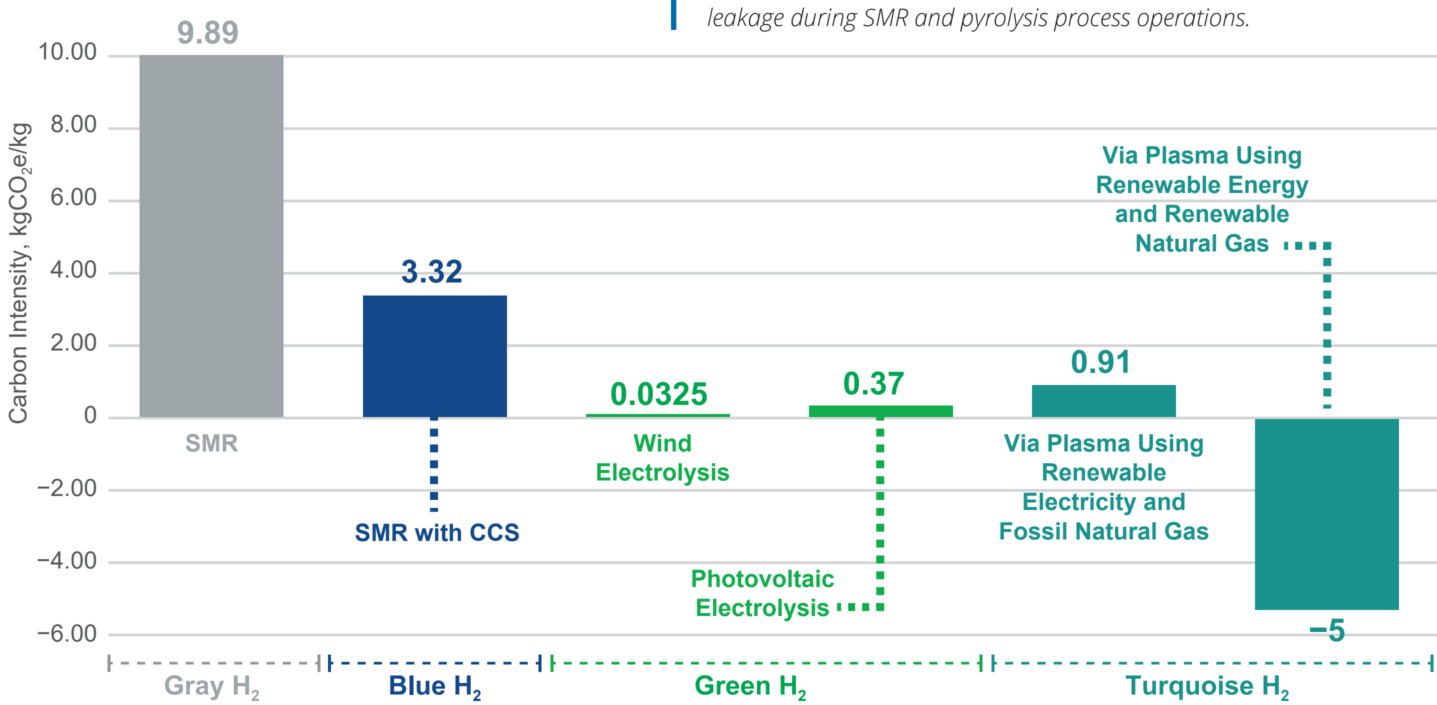


The graph[17,18] illustrates sharply increasing carbon black price in response to increasing demand as new carbon black applications emerge, including batteries, coatings, piping, wire and cable, and tires and other rubber goods. Lower-value, higher-volume applications include agricultural irrigation, mulch films, greenhouse coverings, and soil amendment. Ultrahigh-volume uses include earthworks; road building; and adding strength, flexibility, and durability to concrete, steel, and other structural materials.

MONOLITH™ METHANE PYROLYSIS PLANT UNDER CONSTRUCTION IN HALLAM, NEBRASKA

RENEWABLE METHANE PYROLYSIS USING RENEWABLE ELECTRICITY = **"NEGATIVE" CO_2**[16]

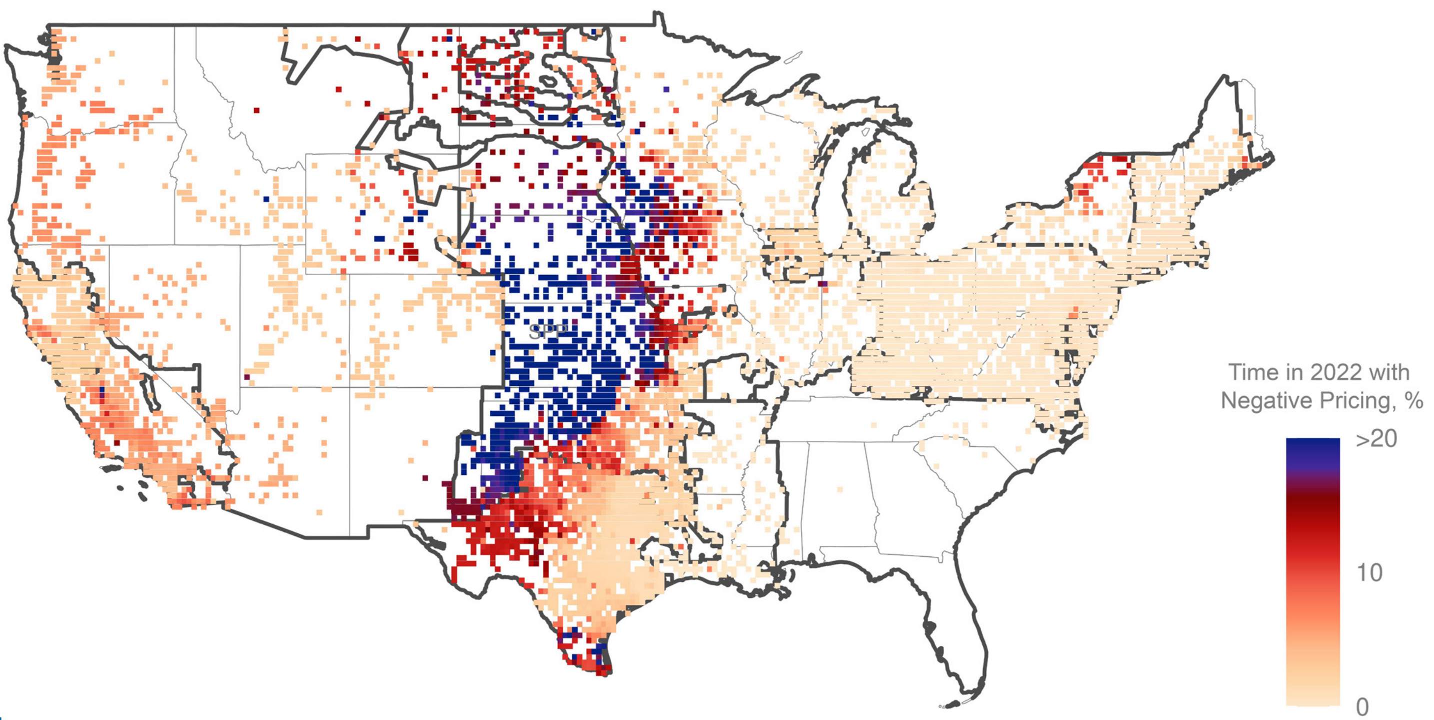
Comparison of hydrogen pathways based on CO_2 emissions. Carbon intensity (CI) calculation includes accounting for 1.5% methane leakage during SMR and pyrolysis process operations.



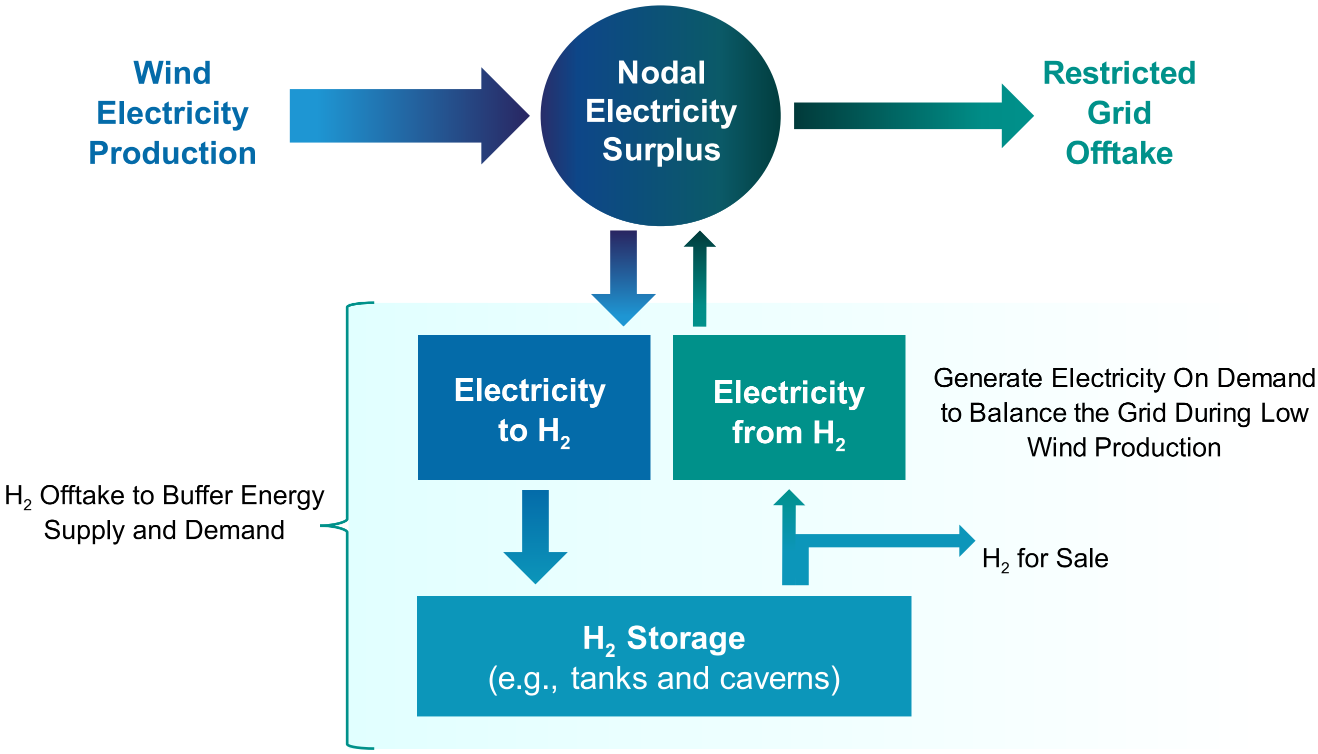
Hydrogen, as a form of energy storage, is complementary to renewables like wind.

The electric grid experiences daily, weekly, and seasonal variation in demand that it traditionally accommodates by adjusting generation. However, as more variable renewable energy generation is added to the grid, the ability of grid operators to match demand with supply diminishes. Adding an option for renewable energy conversion and storage, as diagrammed at right, would give operators the flexibility to maximize renewable production when the resource, e.g., wind, is available without overloading the grid.

Congested grid transmission is one cause of restricted offtake of renewables; another is mismatched timing between when renewable energy is available and when there is demand for power. Either way, restrictions in grid offtake capacity can lead to localized surpluses of electrical power, resulting in low or even negative electricity prices. The figure below presents the percentage of time in 2022 when the wholesale price for electricity was negative at each node cluster on the map. Instances of negative price occurred most frequently in a north–south band across the Great Plains, with many locations having negative pricing up to 20% of the year. This region corresponds to the most intense build-out of wind generation in the United States, an activity that has been driven by demand for renewable energy certificates and a federal wind energy production tax credit.



2022 NEGATIVE WHOLESALE ELECTRICITY
PRICING FREQUENCY AT GRID NODE CLUSTERS[19]
Lines demark electric power regions.



HYDROGEN-BASED OFFTAKE FOR CONSTRAINED WIND GENERATION

WIND TO HYDROGEN: NOT NEW TO NORTH DAKOTA[20]

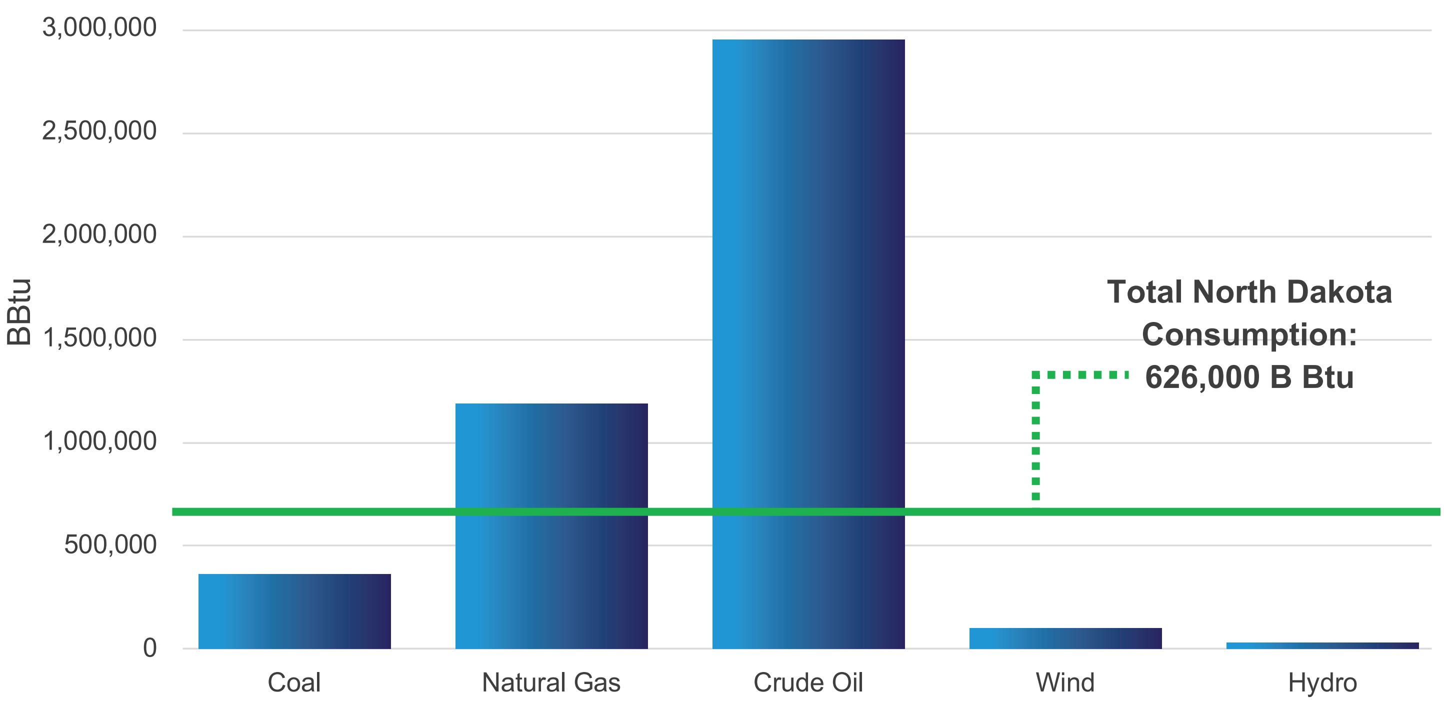
More than a decade ago, Basin Electric Power Cooperative, with support from the Energy & Environmental Research Center (EERC), evaluated the feasibility of dynamically scheduling wind energy to power an **electrolysis-based hydrogen production system.** The demonstration system was constructed near Minot, North Dakota, and included an alkaline electrolyzer, hydrogen compressor, storage tanks, and a compressed hydrogen dispenser. While the evaluation utilized less advanced equipment than available today, it demonstrated that the electrolyzer was sufficiently responsive to input power fluctuations to act as an effective load-balancing tool for a grid- or power plant-integrated wind farm. The demonstration also included **converting several internal combustion vehicles to run on hydrogen.**

North Dakota has abundant natural resources for blue and green hydrogen production.

Low-carbon hydrogen production costs are dependent on location, cost of energy and feedstock, and selected production technology. Regarding location, critically important for green hydrogen viability is access to large-scale, low-cost renewable electricity, whereas blue hydrogen requires low-cost access to large-volume, well-characterized, and safe geologic CO_2 storage capacity. Many locations with access to one or two needed resources lack access to another. For example, Minnesota and Iowa have bountiful wind power resources and dependable (via pipeline) natural gas but lack both in-state CO_2 storage capacity and an affordable means of transporting captured CO_2 to out-of-state storage resources.

North Dakota is advantageously different. **With its coexisting resources of affordable natural gas for hydrogen production, well-characterized subsurface geologic formations ideally suited for CO_2 storage, other geologic formations with high potential for hydrogen storage, and vast renewable energy resources, North Dakota is well-positioned to be a major regional and global supplier of blue and green hydrogen.** Annual North Dakota energy production by sector is shown below. Of significance is that the current installed wind energy capacity of 4847 megawatts (MW) represents only 1.6% of the total estimated North Dakota wind energy potential of 296,000 MW, which means that if wind energy capacity were ramped up to 75% of potential, wind power would rival crude oil on an annual energy output basis.

NORTH DAKOTA'S **ANNUAL ENERGY PRODUCTION**[21]

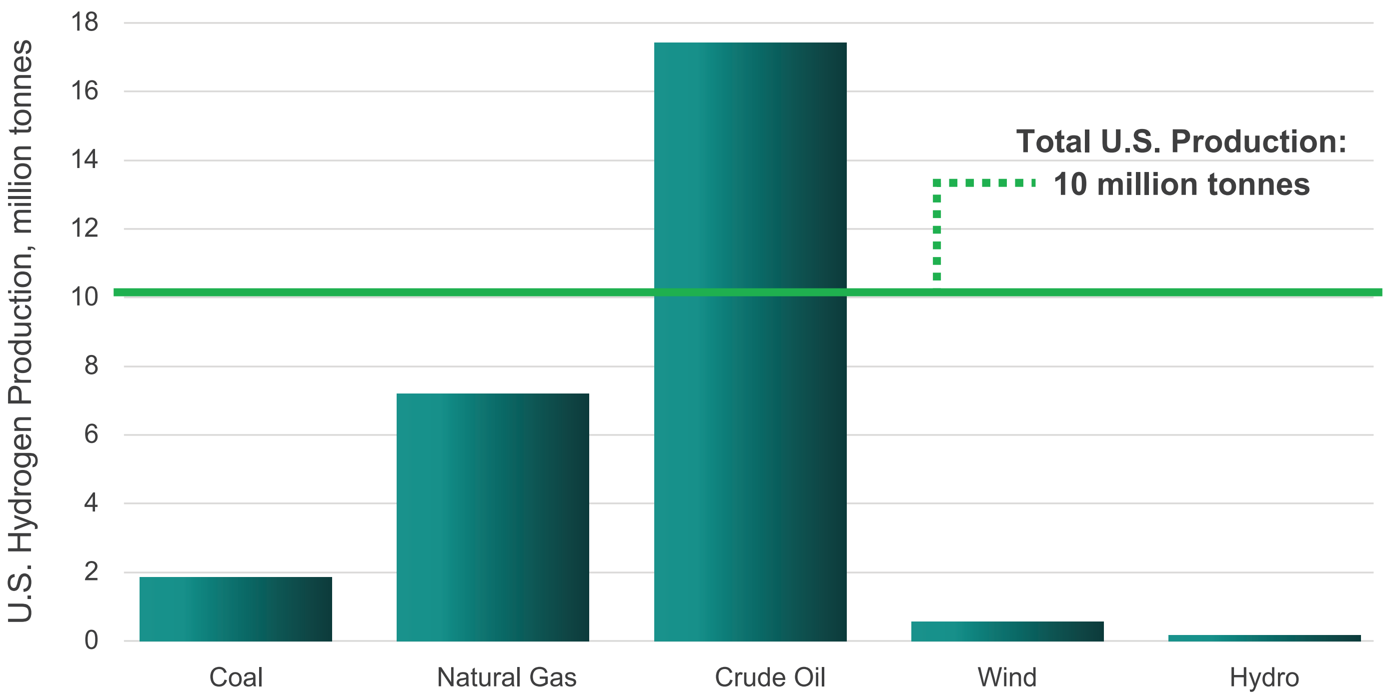


IF CONVERTED TO HYDROGEN, NORTH DAKOTA'S CURRENT SLATE OF ENERGY PRODUCTS WOULD EQUATE TO NEARLY THREE TIMES U.S. HYDROGEN DEMAND.

Annual North Dakota **energy production by sector.**

Approximate hydrogen yields **if each energy product were converted to hydrogen** using state-of-the-art technologies.

ANNUAL EQUIVALENT
HYDROGEN PRODUCTION



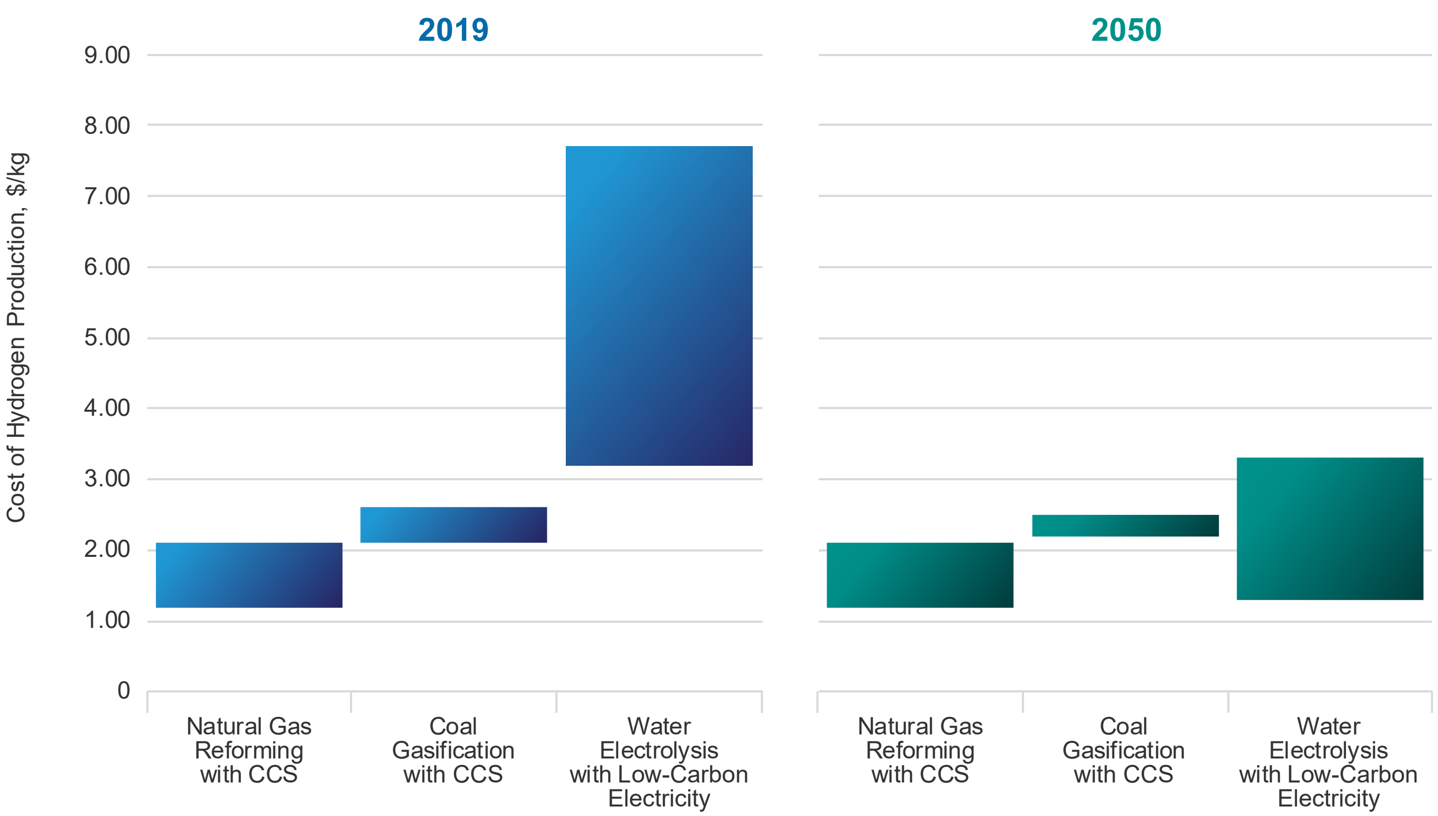
Cost Projections for Low-Carbon Hydrogen

Today, natural gas-based reforming with CCS presents the lowest cost for industrial scale, low-carbon hydrogen production. Coal gasification with CCS is estimated to be slightly more costly than natural gas with CCS, but both carbon-based options are significantly less expensive than renewable-powered electrolysis.

In 2050, all three options are predicted to be within a competitive cost range. Significant future cost reductions for natural gas reforming and coal gasification are unlikely given their mature development status. However, future hydrogen production from zero-carbon electricity is expected to benefit from an assumed reduction in electrolyzer costs—\$872/kWe today to \$269/kWe in 2050—and a reduction in renewable electricity costs that assumed an average value of \$36–\$116/MWh today to \$20–\$60/MWh in 2050.[22]

COST PROJECTIONS FOR LOW-CARBON HYDROGEN[22]

Estimated production cost in 2019 and in 2050 using natural gas reforming, coal gasification, and water electrolysis powered with low-carbon, renewable electricity.



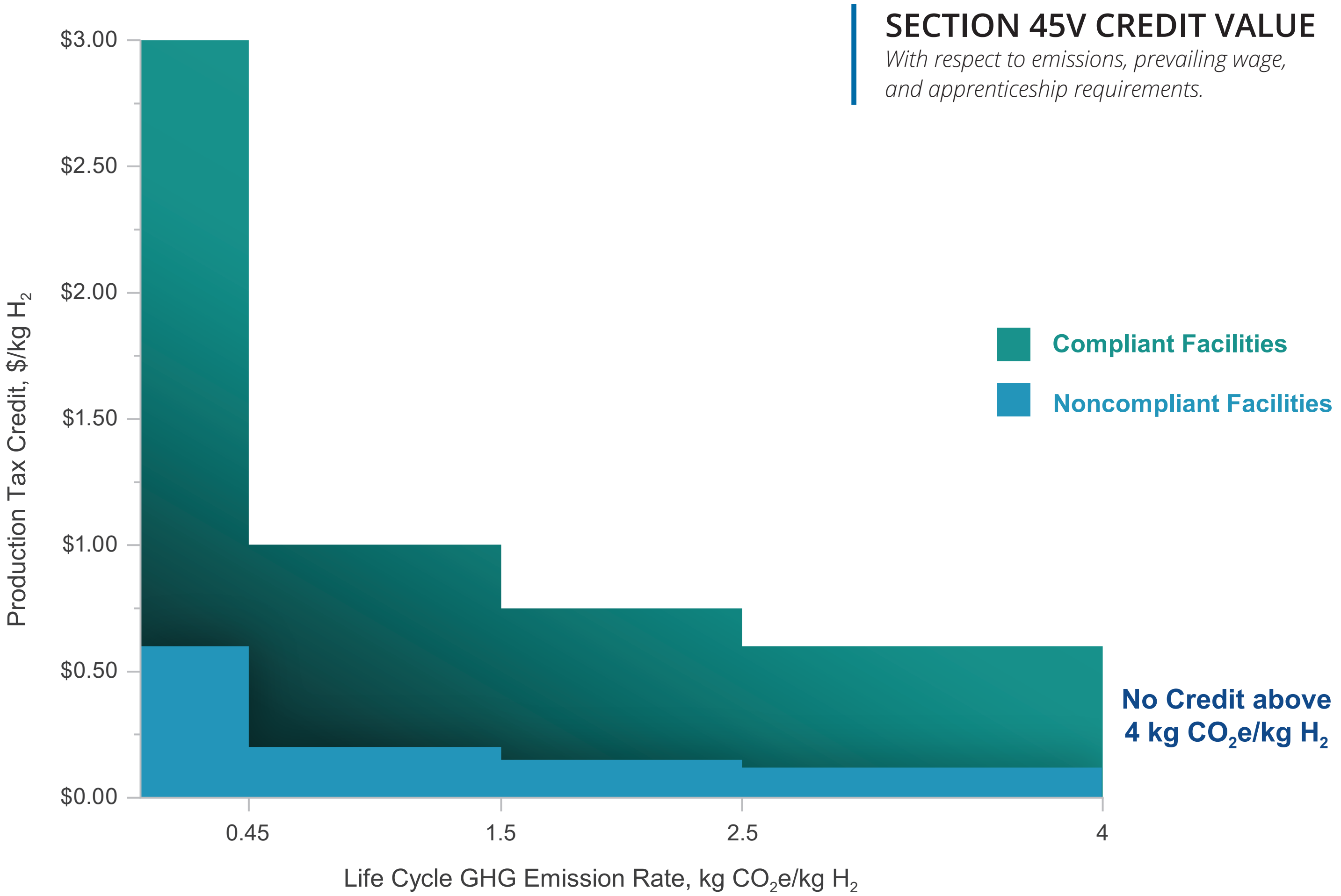
Production Tax Credit for Low-Carbon Hydrogen – Section 45V[23]

The 2022 IRA added Section 45V to the Internal Revenue Code, which is a credit allowable for qualified clean hydrogen produced at a qualified clean hydrogen production facility. The credit is proportional to the mass of qualified clean hydrogen that is produced in accordance with the following provisions:

- Credit applies to hydrogen produced after December 31, 2022, and has a 10-year term beginning on the date a qualified clean hydrogen production facility is placed in service.
- The production facility must begin construction before January 1, 2033.
- To qualify as clean hydrogen, its life cycle GHG emission rate cannot exceed 4 kilograms of CO_2 equivalent per kilogram of hydrogen produced (kg CO_2e/kg H_2).
- Credit value ranges from \$0.12/kg H_2 to \$3.00/kg H_2 and is based on the CI of the production process and the facility's compliance with federal prevailing wage and apprenticeship requirements, as shown below.
- Notably, facilities cannot claim both 45V credits for clean hydrogen production in combination with 45Q credits for CO_2 sequestration.

SECTION 45V CREDIT VALUE

With respect to emissions, prevailing wage, and apprenticeship requirements.



WORKING WITH HYDROGEN

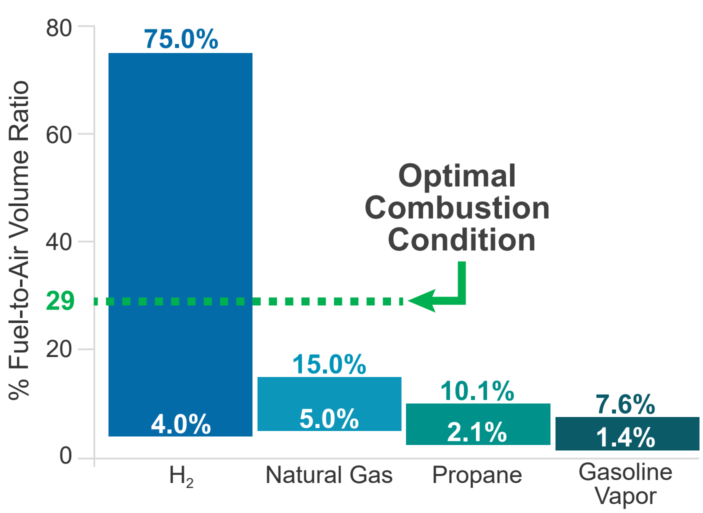
"Hydrogen safety concerns are not cause for alarm; **they simply are different** from those we are accustomed to with gasoline or natural gas."

– Air Products and Chemicals, Inc.

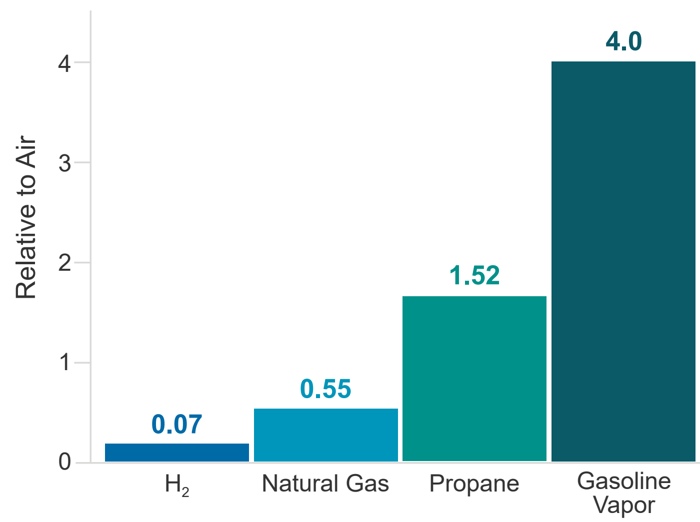
As with any fuel, the chemical energy contained in hydrogen can lead to dangerous situations during its transport, storage, and use. However, also like other fuels in common use, the risks associated with hydrogen are understood, and they can be managed with a high degree of safety. For example, the petroleum-refining and ammonia- and methanol-manufacturing industries have all handled hydrogen safely for decades.

Hydrogen burns with a pale flame that is difficult to see in daylight. However, hydrogen-specific flame sensors have been developed to detect hydrogen flames regardless of the conditions.

Hydrogen is much less dense than other fuel gases and vapors, as shown at right, meaning it will disperse upward into the atmosphere more quickly to form a noncombustible mixture away from ground level—even more so than natural gas. In contrast, liquid fuel vapors like those from gasoline are heavier than air and will collect at ground level, which increases the risk of having them encounter an ignition source and causing harm during a fire.



RELATIVE DENSITY OF HYDROGEN AND OTHER FUELS[24]



The lower flammability limit for hydrogen, 4.0%, is similar to that of natural gas, as shown at left, but its flammability range is much wider than for natural gas. However, from a practical standpoint, high hydrogen concentrations will be difficult to maintain during an accidental release given its low density and fast rate of diffusion in air, which is nearly four times that of natural gas.

Hydrogen requires less energy to ignite compared to other common fuels at its optimal fuel-to-air ratio (29% hydrogen by volume as highlighted at left), although its ignition energy is similar to other fuels at lower concentrations that would be expected in the event of an accidental release.

FLAMMABILITY RANGE OF HYDROGEN AND OTHER FUELS[24]

From about 1900 to 1937, rigid airships/dirigibles buoyed by hydrogen (14 times lighter than air) were the preferred mode of trans-Atlantic travel because of their speed and comfort. Prior to 1937, the Zeppelin Company had a perfect safety record—27 years of civil flight operations with nearly 100 different airships transporting people, animals, goods, and mail without a single fatality. That changed in May 1937 when the Hindenburg caught fire while landing in New York. Over time, many explanations regarding the cause of the incident have appeared, including sabotage, a highly flammable fabric covering, and lightning. The current understanding is gas escaping from a leaking cell encountered a spark of uncertain origin and ignited.[25]

WITH THE RIGHT UTILIZATION PROTOCOLS, HYDROGEN IS AS SAFE AS GASOLINE, DIESEL, NATURAL GAS, AND OTHER TRADITIONAL FUELS.

Eighty years after the Hindenburg, giant airships may be poised for a comeback—not for passenger service, but as a low-carbon means of delivering goods around the globe. As proposed by Julian Hunt of the International Institute for Applied Systems Analysis in Laxenburg, Austria,[26] the new airships would be able to circle the globe in 16 days (versus 77 days for ships) with multiple thousand-tonne cargo loads and generate only a fraction of the pollution—by riding the jet stream. According to Barry Prentice, University of Manitoba professor and president of Buoyant Aircraft Systems International in Winnipeg, using a cargo airship rather than a jet would slash both fuel use and carbon production by 90%, and airships do not need runways.[27]

HYDROGEN- VS. GASOLINE-FUELED FIRE

The photos at right are from video of fires caused by a relief device failure test in a hydrogen-fueled vehicle (left) and a fuel-line leak in a gasoline-fueled vehicle (right). At the time of this photo (60 seconds after ignition), the hydrogen flame has begun to subside, while the gasoline fire is intensifying. After 100 seconds, all of the hydrogen is gone and the car's interior is undamaged. The passenger compartment temperature rose less than 14°F. The gasoline-fueled car continued to burn for several minutes and was destroyed.

Hydrogen Storage and Transport Density

1 kg of hydrogen contains about the same amount of energy as 1 gallon of gasoline.

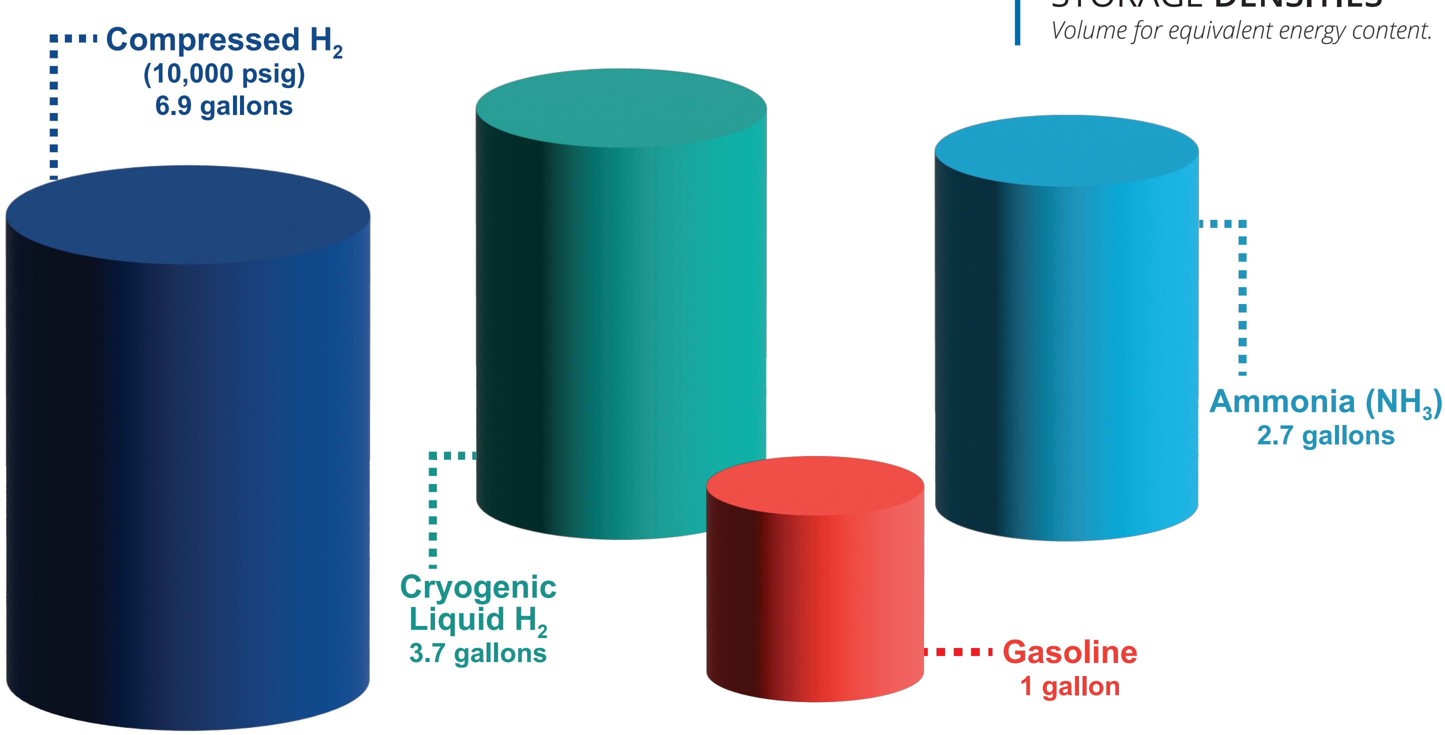
Relative to common gases in the atmosphere, hydrogen molecules are much smaller and generally more reactive. Hydrogen is a low-density gas at room conditions, and this property presents challenges when transporting hydrogen and/or storing it.

Hydrogen contains significant energy content on a mass basis (i.e., based on weight), but as shown below, a conventional liquid fossil fuel like gasoline can contain much more energy per unit volume compared to various forms of stored hydrogen. Gaseous hydrogen at atmospheric pressure is not shown in the comparison since it is such low density that it only has about 1/3000 the energy of hydrocarbon liquid fuels on a volume basis. Hydrogen's energy density does increase under pressure, as shown by the 10,000-psig case below, which is based on the onboard storage pressure in some hydrogen fuel cell vehicles. However, even if hydrogen is liquefied to make it as dense as feasible in its elemental form, the volumetric energy density is still only about one-quarter that of gasoline.

Another feasible approach to store and transport hydrogen is reacting it to create chemical "carriers," like ammonia or methanol. These carriers effectively increase the volumetric density of hydrogen energy storage. Interestingly, liquid ammonia contains more hydrogen atoms per gallon than does cryogenic liquid hydrogen.

STORAGE **DENSITIES**

Volume for equivalent energy content.



Several hydrogen densification methods are available to increase its volumetric density.

GAS COMPRESSION | Method most commonly used today for transport and storage of relatively small quantities of hydrogen. It includes gas cylinders, tube trailers, and lighter-weight tanks designed specifically for fuel cell vehicles. Large quantities of compressed hydrogen can be transported via pipeline.

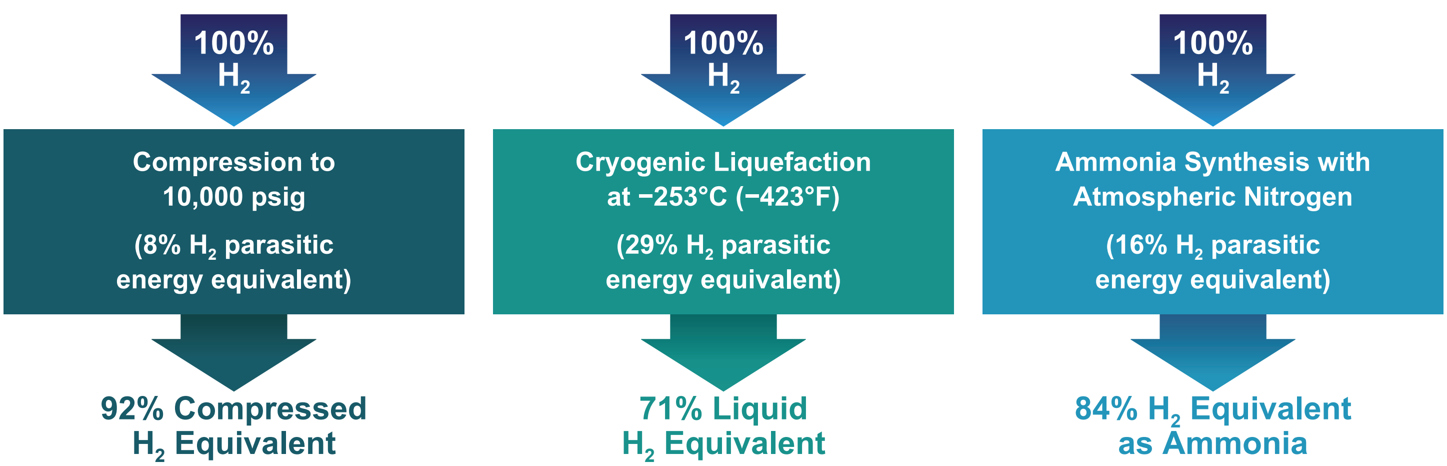
CRYOGENIC LIQUEFACTION | Offers increased energy density compared to compression. Liquefied hydrogen is suitable for large-quantity transport, especially where pipelines are not feasible, e.g., overseas export by ship.

HYDROGEN CARRIERS | Possess volumetric energy densities that can approach and exceed that of liquefied hydrogen. However, carrier production is more complicated than compression or liquefaction; they require other material input streams, e.g., air as a source of nitrogen to make ammonia or CO_2 to make carbon-neutral methanol. Carriers are generally appropriate for intermediate uses where more compact storage is required than is feasible with a compressed gas, but the complications of handling a cryogenic liquid are not justified. Some carriers, like ammonia, might also be transported via pipelines. Research is ongoing into novel materials that attain higher densities with less parasitic losses. Materials such as carbon and various metal powders, bricks, and solid–liquid slurries are being studied.

Each densification approach requires effort and consumes energy that is needed to make hydrogen. For example, compression requires the least amount of densification energy in the comparison below[28] (parasitic energy for compression is shown in terms of the energy content of the starting hydrogen), but it provides the least amount of densification among the three examples shown.

The end use application also affects the choice of hydrogen densification. In the comparison below, ammonia takes less parasitic energy to produce[29] than cryogenic liquid hydrogen,[30] and it is more energy dense compared to liquid hydrogen. However, if the end use application cannot use ammonia directly, it must be "cracked" to release hydrogen which adds additional parasitic losses that may exceed those associated with an alternative densification method.

PARASITIC ENERGY FOR DENSIFICATION EXAMPLES



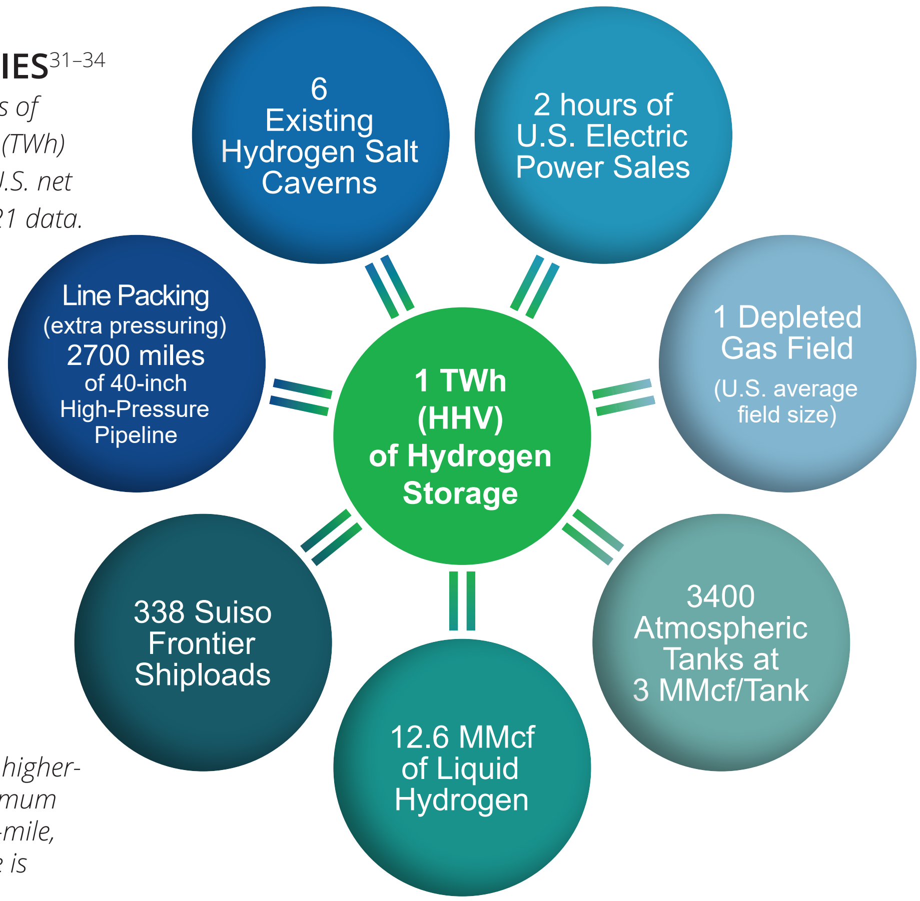
Bulk Hydrogen Storage in North Dakota Subsurface Salt Caverns

Once densified, hydrogen can be stored for long periods of time to capitalize on production surpluses and provide supply during periods of high demand. While hydrogen molecules and chemical carriers are stable, some storage methods have associated losses. For instance, a certain amount of unrecoverable “cushion” gas is permanently trapped in subsurface storage in depleted gas reservoirs.

Liquid hydrogen storage is another example with storage losses since it is a cryogenic liquid and it is not feasible to keep it sealed under pressure. As a result, there is a constant boil-off of hydrogen that must be vented and either consumed or cooled back into liquid form. For example, liquid hydrogen tanker ships have been proposed that would consume the boil-off gas to power the ship, similar to the way liquefied natural gas (LNG) tankers consume boil-off natural gas today. The Suiso Frontier, being the first liquefied hydrogen carrier ship of its kind, does not include this optimization and runs on conventional hydrocarbon fuel.

USABLE STORAGE **EQUIVALENCIES**[31–34]

Diagram compares the logistical requirements of different methods for storing 1 terawatt-hour (TWh) of hydrogen, equivalent to about 2 hours of U.S. net electric power generation based on 2010–2021 data.



NOTES:

***MMcf** = million cubic feet at standard temperature and pressure (60°C and 14.7 psia)*

***1 TWh** = 1 billion kWh*

***HHV** = higher heating value*

***Line packing** | Storing hydrogen in a pipeline at higher-than-normal operating pressure to achieve maximum storage capacity. At $250,000 per inch-diameter-mile, cost of a 40-inch-diameter high-pressure pipeline is about $10 million/mile.*

***The Suiso Frontier** | The world's first liquefied hydrogen carrier ship. Built by Kawasaki Heavy Industries, the ship completed its first international voyage from Kobe, Japan, to Victoria, Australia (where its 1250-cubic-meter tank was filled with 75 tonnes of hydrogen liquefied at −253°C) and back to Kobe in March 2022. Suiso means hydrogen in Japanese.*

The specific hydrogen storage approach will vary according to the application, from portable vehicles to seasonal energy storage.

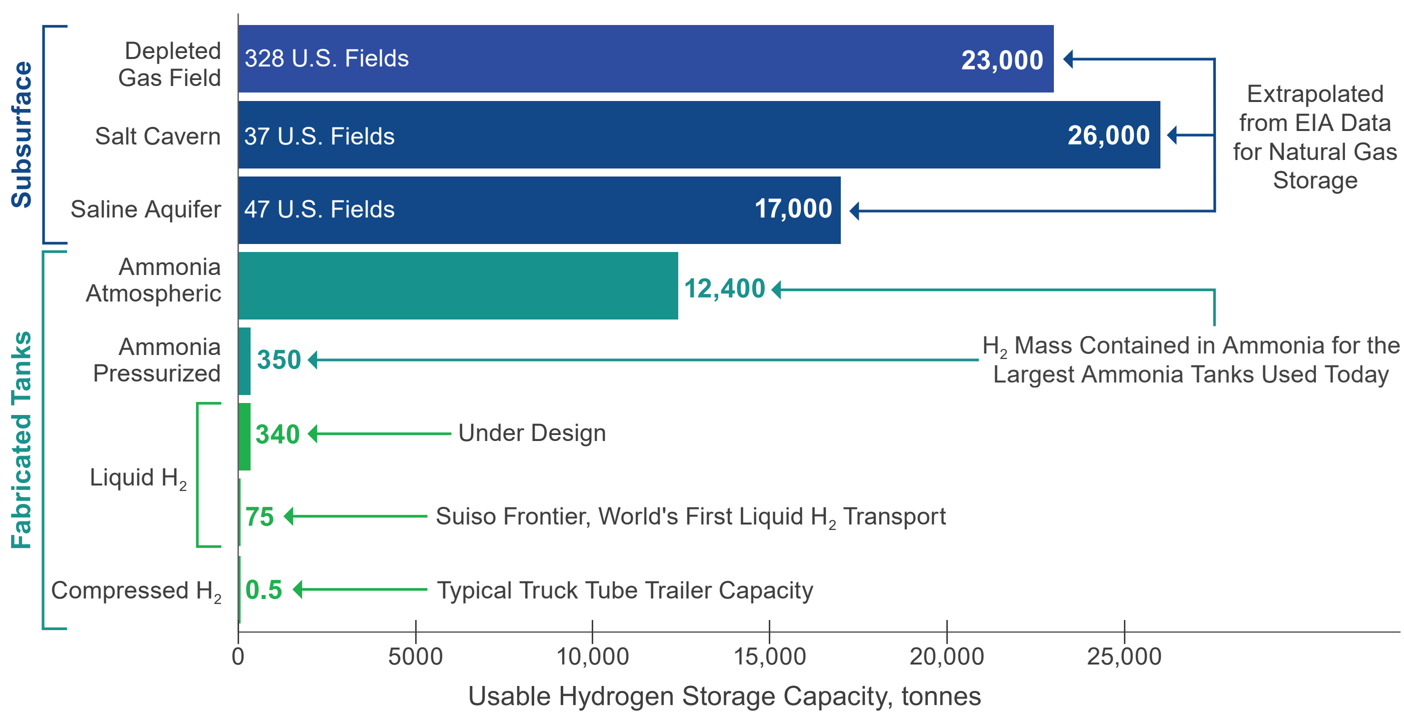
Hydrogen can be stored in both subsurface geologic formations and in specially manufactured tanks. Subsurface storage is generally less expensive than surface tank storage but is limited to locations possessing suitable geology. Consequently, subsurface storage is typically used for larger-volume, longer-term storage needs.

The figure below shows a potential exception to the limited capacity of tank storage: atmospheric-pressure ammonia storage tanks used today for the fertilizer trade, which could also be used to leverage ammonia as a hydrogen carrier.

Fabricated storage tanks are much more expensive than the few-dollars-per-kilogram costs of geologic facilities. Tanks designed for Class 8 long-haul hydrogen-powered trucks (10,000-psi Type IV composite tanks having 30–60-kg capacities) are estimated to cost almost $400/kg hydrogen in mass production, with a U.S. Department of Energy (DOE) target of $300/kg by 2030. Liquid hydrogen tanks with capacities ranging from 20 to 100 kg hydrogen are estimated to cost $100–$800/kg hydrogen depending on configuration.[35]

In contrast to their pressurized tank counterparts, atmospheric-pressure ammonia tanks need to address ammonia boil-off similar to the way liquid hydrogen storage tanks do.[36]

USABLE HYDROGEN STORAGE CAPACITIES BY APPROACH[37,38]



EIA = Energy Information Administration

Subsurface Storage for Hydrogen Hub Development

Large-volume, long-duration (i.e., seasonal), and inexpensive hydrogen storage is a cornerstone to develop a hydrogen-based energy sector. Storage is critical to stabilize hydrogen hub operations in response to variations from renewable power availability, market demand, production plant turnarounds, etc. Large-volume storage options include subsurface injection, large liquid hydrogen tanks, or the storage of a hydrogen carrier like ammonia using existing technology. Of these options, subsurface injection requires the least amount of hydrogen manipulation (i.e., compression only) and is an attractive candidate for regions with the subsurface resources needed to accommodate it.

Three primary types of subsurface hydrogen storage options are relevant for North Dakota: salt caverns (engineered cavities in underground salt deposits formed by injecting water into deposits, dissolving the salt, then recovering the salt-laden water), saline aquifers (water-saturated porous rock that occurs naturally), and depleted oil and gas reservoirs (naturally occurring oil and gas formations that no longer produce economically). Depleted oil and gas reservoirs and saline aquifers are the least costly, but they suffer from the potential 1) to introduce impurities into hydrogen, 2) for hydrogen to chemically or biologically react with its surroundings (e.g., microorgansims converting hydrogen to methane), and 3) for hydrogen to dissolve into and migrate with water. The table below lists other important differences.

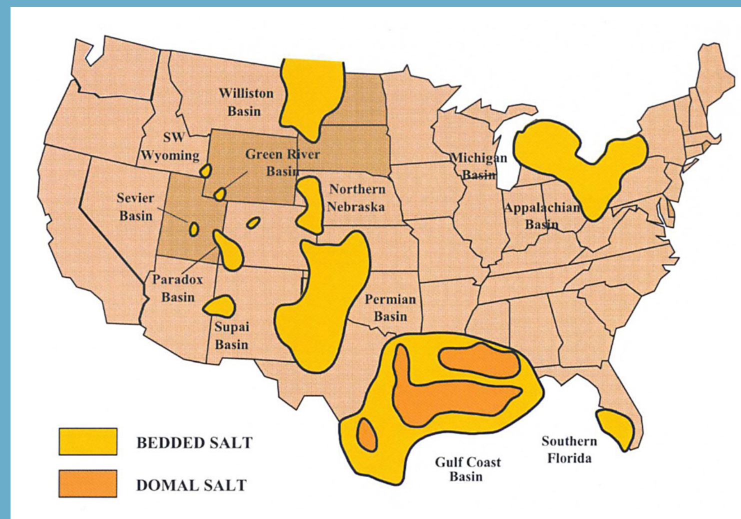
COMPARISON OF SUBSURFACE HYDROGEN STORAGE OPTIONS RELEVANT TO NORTH DAKOTA

	Salt Caverns	Saline Aquifers	Depleted Oil and Gas Reservoirs
Gas Tightness	Very good	Fair	Very good
Stored Gas Contamination	Low	High	High
Ratio of Working Gas to Total Gas Capacity	High	Low	Moderate
Cycles per Year	High	Low	Low
Relative Capital Cost to Construct	Moderate	Low	Low
Relative Operational Cost	Low	Low	Moderate
Hydrogen Readiness	Proven, four commercial sites in operation globally	Demonstration projects in planning stage	Proven for town gas (H_2, CH_4, and CO mixture)

SALT CAVERN STORAGE IN NORTH DAKOTA

At present, only four salt cavern-based hydrogen storage sites are operating in the world, and three are located in the U.S. Gulf Coast region, where extensive, thick domal salt formations exist. North Dakota has thinner subsurface bedded salt formations that may have the potential to accommodate the creation of salt caverns.

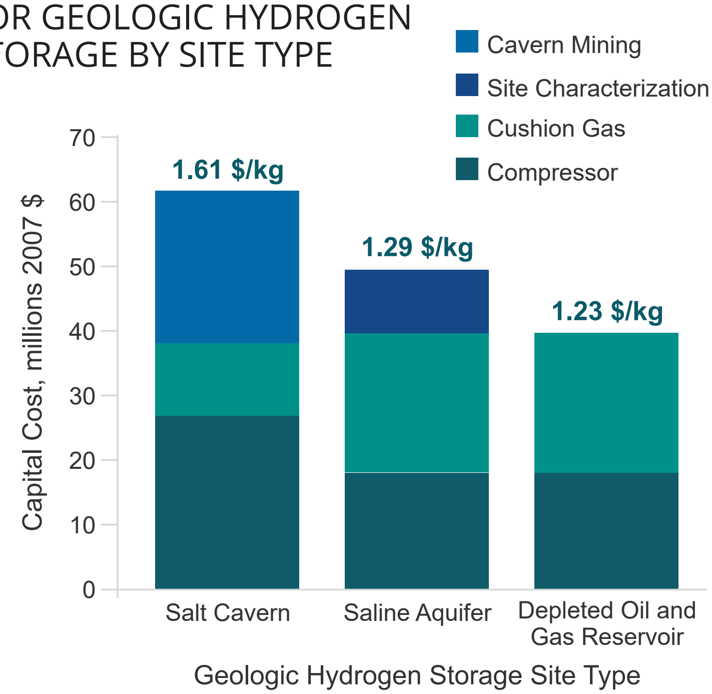
As interest in hydrogen has grown, additional research and study are being performed to evaluate the hydrogen storage viability of the bedded salt formations found in western North Dakota. Initial feasibility studies have been completed by the EERC. Further investigation into engineered salt cavern development and use is ongoing and includes the drilling of a test well intended to collect core and gather data from two bedded salt formations. Results of the study will provide guidance regarding commercial opportunities for hydrogen storage in North Dakota.



U.S. BEDDED AND DOMAL SALT FORMATIONS[39]

Salt cavern storage of natural gas has a long (over a century) history, and salt cavern hydrogen storage has been commercially implemented for over 30 years at U.S. Gulf Coast locations. Existing hydrogen salt caverns offer storage capacities up to several hundreds of GWh and are ideally suited to short- to medium-term energy demand fluctuations, as they allow for multiple injection–reproduction cycles per year and a high ratio of working gas (hydrogen that can be withdrawn) to total gas (which includes "cushion gas," the amount needed to maintain sufficient pressure to enable gas withdrawal).[40] In (highly generalized) summary, salt cavern storage offers maturity/demonstrated commercial viability at higher cost, while porous saline aquifers and depleted hydrocarbon reservoirs offer lower cost (and often higher capacity) but come with some unknowns to address.[41]

2014 CAPITAL COST ESTIMATES FOR GEOLOGIC HYDROGEN STORAGE BY SITE TYPE



No single approach to transporting hydrogen is ideal for all circumstances.

Hydrogen can be transported in a few different forms:

COMPRESSED GAS | Requires compression to high pressures to achieve the energy density required to be economic.

CRYOGENIC LIQUID | Requires compression and cooling to condense the hydrogen gas into a higher-density liquid.

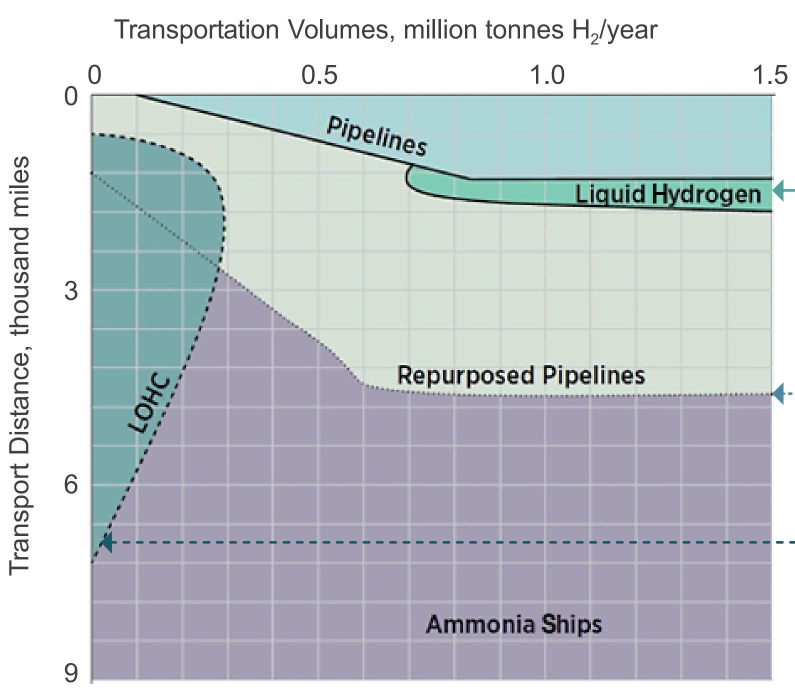
LOHC | Liquid organic hydrogen carrier (LOHC), a compound that can be reversibly hydrogenated and dehydrogenated to transport hydrogen. The LOHC based on toluene and methylcyclohexane chemistry leverages processing and transport experience from the petrochemical industry.

AMMONIA | Similar to an LOHC, ammonia has a high hydrogen density and can be used as a hydrogen carrier. Large-volume transport options include pipelines and ships.

Each of these forms of hydrogen can be transported by a variety of mechanisms (truck or rail tankers, pipeline, or ships) and with varying applicability depending on necessary scale and transport distance.

For large volumes transported 3000 miles, a 2022 study concluded ammonia is less expensive than hydrogen liquefaction, which is less expensive than LOHC for hydrogen transport.[42] Transportation savings depend on factors such as the amount of hydrogen, the distance transported, topography along the route, and cost of transport infrastructure.

In the 2050 projections summarized in the figure below,[42] it is anticipated that pipelines will serve as the principal mode of long-distance terrestrial (intracontinental) transport, although the feasible distance for pipelines might be extended if existing natural gas pipelines can be repurposed. For intercontinental transport, ammonia shipping is predicted to be favored, while liquid hydrogen and LOHCs may be competitive at the margins of ammonia's economy of scale.



PREFERRED HYDROGEN **TRANSPORT REGIMES** ANTICIPATED BY 2050[42]

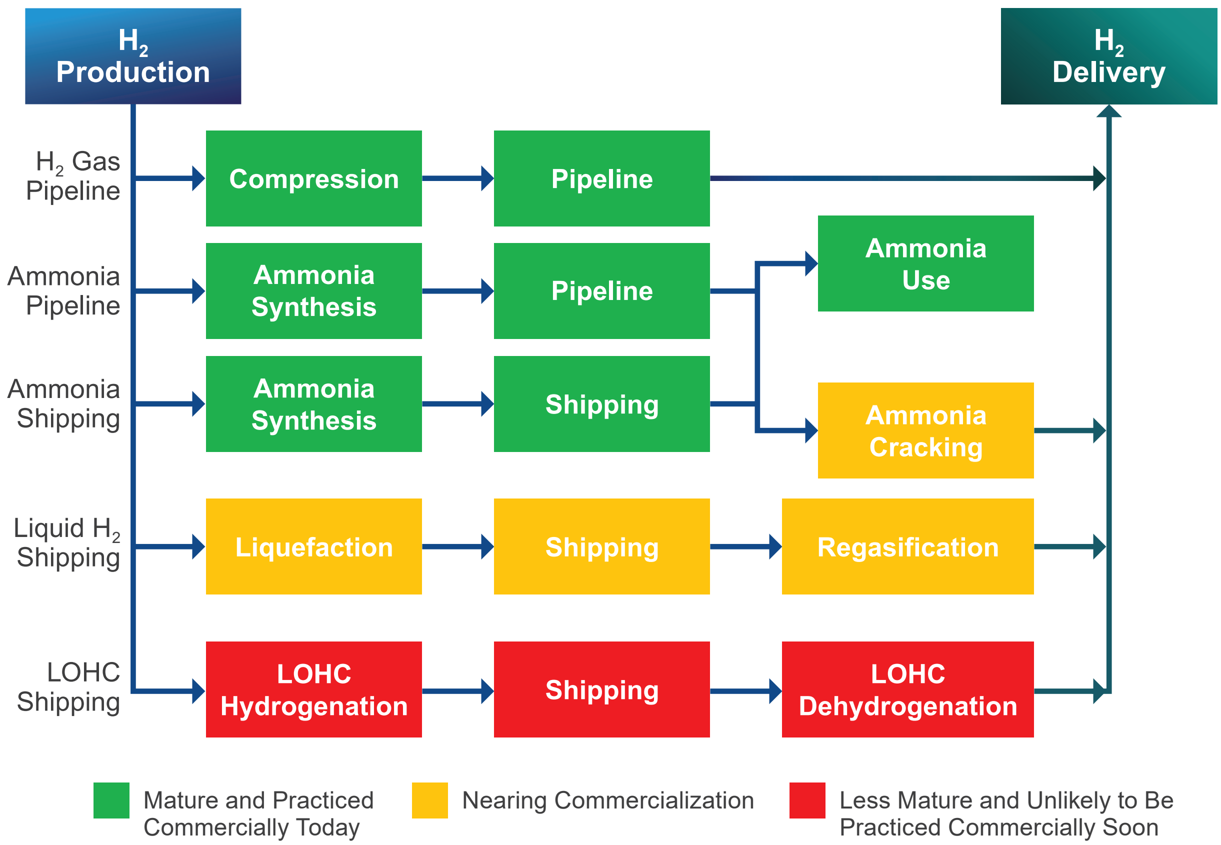
Liquid H_2 by ship may fill a niche for short-distance, offshore transport where pipelines cannot be built.

The "Repurposed Pipelines" region is bounded by a dotted curve because appropriate pipelines are not available in all locations. Without existing infrastructure to leverage, ammonia shipping would likely be recommended.

A dashed curve demarks the LOHC-relevant region because LOHC technology requires significant maturation before it will be commercially deployed for hydrogen transport.

TECHNOLOGY READINESS OF HIGH-VOLUME HYDROGEN TRANSPORT[42]

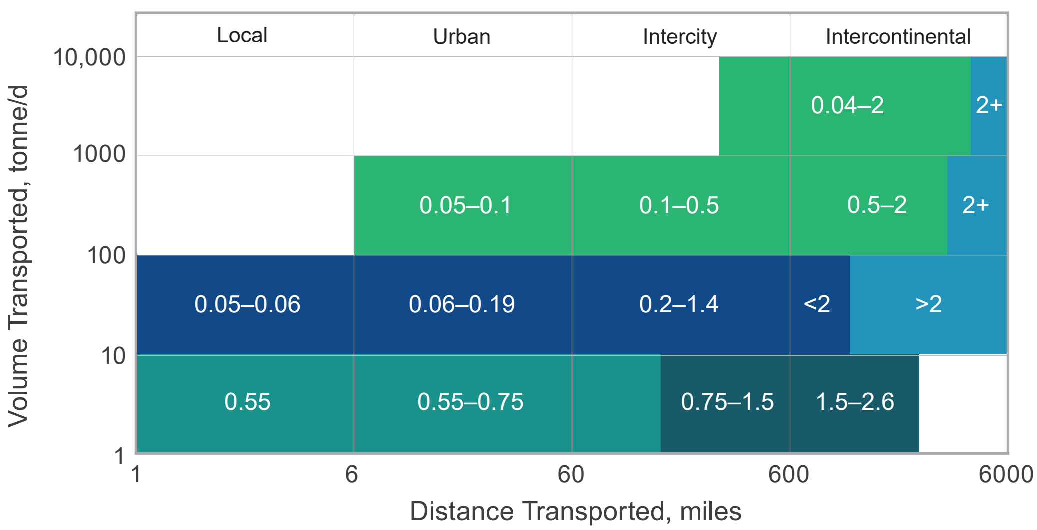
(more than 1000 tonnes per day)



The figure above compares today's technology readiness of hydrogen transport technologies that are expected to be available commercially in 2050. With the exception of LOHC shipping, all of the processes shown above are either practiced commercially today or are near commercialization at scales less than 1000 tonnes per day, but as the diagram shows, further development and commercialization are needed to scale up one or more process steps for nearly all of the transport approaches. Key exceptions include hydrogen compression, ammonia synthesis, gas and ammonia pipeline transmission, and ammonia shipping; these processes are currently practiced at large scale within the petrochemical and fertilizer industries, which are today's largest hydrogen consumers.

Among the transport options above, pipelines and liquid hydrogen deliver hydrogen product directly. Ammonia cracking is required to release hydrogen from an ammonia carrier, similar to the dehydrogenation process required for an LOHC. However, unlike an LOHC, ammonia is itself a valuable commodity and could be used directly as shown to potentially negate the need for large-scale ammonia cracking in some situations.

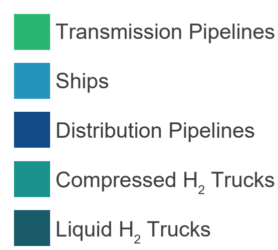
Relative Capacities of Different Modes of Transport



NOTIONAL COST OF HYDROGEN TRANSPORTATION

Notional cost of hydrogen transportation based on distance and volume transported in 2022.[43–45]

All values in $/kg hydrogen.

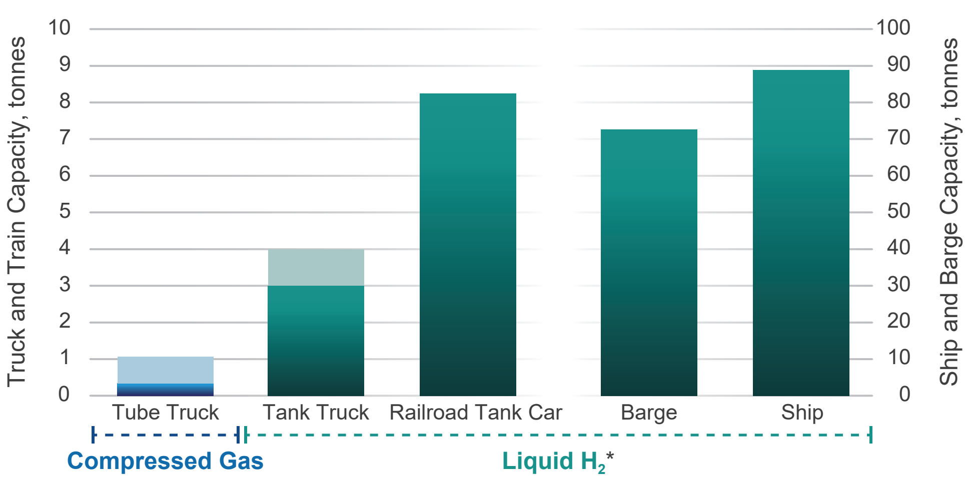


TRUCKS | Preferred when transporting small volumes, such as less than 10 tonnes/day hydrogen. Truck transport is used for both cryogenically liquefied and compressed gaseous hydrogen. Liquefaction gives more hydrogen per volume than compression but also costs more. A trade-off occurs at about 100 miles, above which the cost of liquefaction is more than justified by the lower volume-per-mile transport cost.

PIPELINES AND SHIPS | Predominant above 10 tonnes/day.

RAIL | Transport of liquid hydrogen in rail tank cars is feasible[46] but would require upgrading some of the 85 existing U.S. Department of Transportation (DOT) 113C120 tank cars or spending about $650,000–$750,000 per car to construct a hydrogen version of DOT-113C120W9 tank cars.[47] Assuming a 30,680-gallon capacity, a tank car would transport about 8 tonnes of liquid hydrogen.[45]

BARGE | Only three hydrogen barges operate in the United States; all are owned by NASA, which uses hydrogen as rocket propellant. Each cost about $560,000 in 1964, and each has a capacity of 270,000 gallons (72 tonnes) of liquid hydrogen.[48] The world's only hydrogen carrier, the Suiso Frontier, has a capacity of 330,000 gallons (88 tonnes of hydrogen), but a delivered volume of roughly 75 tonnes for a 5000-mile voyage.[33]



COMPARISON OF HYDROGEN VEHICLE CAPACITIES[43–45,48]

Light color provides an idea of range of capacity depending on tube, tank, and truck construction.

**Liquid hydrogen, which loses 0.06%–2% volume/day because of boil-off.*

Hydrogen transport by pipeline is possible, and leveraging existing infrastructure is a near-term path.

Existing U.S. hydrogen pipeline infrastructure is limited in extent and locale, especially compared to natural gas or even ammonia infrastructure. Even ammonia infrastructure dwarfs hydrogen infrastructure in the United States and globally. Ammonia has twice the length of pipelines; and in terms of ships, there are 170 ammonia transports globally as opposed to only one hydrogen tanker. Because ammonia is arguably the best hydrogen carrier available today (and likely will be into the future), ammonia infrastructure offers near-term utility for hydrogen transport.

U.S. NATURAL GAS INFRASTRUCTURE AS A GUIDE TO HYDROGEN INFRASTRUCTURE

Of existing large energy infrastructure (e.g., electricity, crude oil), the natural gas and LNG system is the most similar to what might be constructed for hydrogen. Natural gas is transported on land predominantly by pipeline and across seas by refrigerated ship. Unfortunately, new pipelines are expensive and time-consuming to construct; on average in the United States, it will cost roughly $250,000 per inch-mile, or $7.5 million per mile, for a 30-inch-diameter transmission pipeline and require minimally 3–4 years.[49] Currently, the United States has about 1600 miles of hydrogen pipelines and more than 300,000 miles of natural gas transmission pipelines.[50] Given that the United States constructed an average of 1200 miles/year of new natural gas transmission pipelines over the past 7 years, at those rates, building a comparable hydrogen transmission network would require more than two centuries and cost $2.3 trillion! This is a prohibitively large investment given the risk involved with constructing a system based on technologies that have not been commercialized or fully demonstrated at this time.[51] A potential obvious solution to new construction would be to adapt the existing natural gas system to accept and use hydrogen blends.

REPURPOSING U.S. NATURAL GAS INFRASTRUCTURE FOR HYDROGEN

Both crude oil and natural gas pipelines have been or are being used for hydrogen transport. In 2005, Air Liquide reported repurposing 65- and 34-mile crude oil pipelines near Corpus Christi and Freeport, Texas, for pure-hydrogen service. At that time, the pipelines had been in service for 7–10 years and were still operating. A downside of repurposing crude oil pipelines is pressure limits of 350–740 psig.[52]

European studies estimate repurposing natural gas pipelines for hydrogen to be 10%–35% of the expense of new construction.[53] Consequently, in 2021, industry members of the European Hydrogen Backbone Initiative estimated that 69% of 123,000 miles of existing major European natural gas pipelines could be converted to hydrogen.[54] Eleven European gas infrastructure companies have proposed a plan to modify 4200 miles by 2030 and 14,000 miles by 2040 of pipeline infrastructure for hydrogen transport, three-quarters of which will consist of converted natural gas pipelines.[55]

THERE ARE CURRENTLY:

More than **300,000 miles of natural gas transmission pipelines** (not including distribution mains).

More than **85,000 miles of crude oil pipelines** dispersed across the United States.

Only about **1600 miles of hydrogen pipelines** concentrated along the U.S. Gulf Coast in Texas and Louisiana, with short stretches in California.[50]

OPPORTUNITIES FOR NORTH DAKOTA

Near-Term Hydrogen Opportunities for North Dakota

Perhaps the greatest impediment to hydrogen commercialization is the "chicken and egg" problem of hydrogen production waiting for demand to appear and demand waiting for production to commence. Near-term applications that minimize this constraint and are possible today include:

- Hydrogen blending into existing natural gas pipelines to decarbonize natural gas use.
- Supplying no- or low-carbon (green or blue) hydrogen to existing demand at petroleum and renewable oil refineries.
- Ammonia production with green or blue hydrogen to decarbonize the agricultural industry.

As fertilizer, ammonia (NH_3) has long been critical to affordable food production. More recently, NH_3 is gaining recognition around the world as an economically, environmentally, and strategically valuable fuel because of its 18% hydrogen content (as a result, 1 gallon of liquid ammonia contains 50% more hydrogen than 1 gallon of liquid hydrogen), carbon-free composition, storage/transport affordability, and near-zero explosion risk. Because it contains no carbon, NH_3 conversion to energy via fuel cell or combustion generates no CO_2 emissions. This means that if NH_3 is produced using renewable energy, nuclear energy, or fossil energy with CCS, NH_3 becomes a "net-zero" fuel, meaning that, essentially, no CO_2 emissions are associated with any aspect of its production and use. NH_3 attributes as a fuel, hydrogen carrier, and energy storage medium are driving global investment in NH_3 technology/infrastructure development and deployment.

LIQUID HYDROGEN **VERSUS AMMONIA**

a Kilograms per cubic meter.
b At 20°C and 10 bar (68°F and 290 psi).
c Gigajoules per cubic meter.
d Megajoules per kilogram.

Property	Units	Hydrogen	Ammonia
Phase		Liquid	Liquid
Density	kg/m^3[a]	70.8	610[b]
Volumetric Hydrogen Content	kg H_2/m^3	70.8	107.7
Volumetric Energy Density	GJ/m^3[c]	8.5	12.9
Gravimetric Hydrogen Content	wt%	100	17.65
Gravimetric Energy Density	MJ/kg[d]	120	21.18
Hydrogen Release		Evaporation	Cracking (425°C)
Explosive Limit in Air	vol%	4–75	15–28
Flammability/Toxicity		Highly flammable	Toxic

MAJOR AMMONIA-AS-ENERGY-CARRIER INITIATIVES ARE UNDERWAY AROUND THE GLOBE.

A highly abbreviated list includes the following:

- To meet national government-prescribed CO_2 mitigation (energy sector decarbonization) objectives, Japanese utilities are currently blending and combusting ammonia with coal (at a Btu ratio of 20% NH_3–80% coal) for grid power production, with the objective of eventually completely replacing coal with NH_3.
- Mitsubishi Heavy Industries (MHI) and other gas turbine manufacturers are developing electricity-generating turbines capable of operating on 100% NH_3. MHI is expecting to have a 40-MW NH_3 turbine ready for commercial sale in 2025.
- Utilities operating in North Dakota and around the world are evaluating NH_3 as an energy storage medium. Deployment of utility-scale energy storage technologies that 1) utilize excess power to make NH_3 and 2) convert stored NH_3 to power when needed would reduce the need for inefficient and expensive power plant "deep cycling" in response to load fluctuations resulting from renewable energy inputs to the grid. Three utilities operating power plants in North Dakota—Basin Electric, Minnkota Power, and Otter Tail Power—are partnered with the EERC on the ongoing DOE- and North Dakota Industrial Commission (NDIC)-funded Ammonia-Based Energy Storage Technology [NH_3-BEST] project.
- The International Maritime Organization—the United Nations body that regulates the global shipping industry—along with industry leaders Maersk, Wärtsilä, MAN Energy Solutions, Samsung Heavy Industries, and others are working to replace sulfur-laden heavy diesel fuel (currently fueling almost 100% of all freighters, tankers, and container ships) with NH_3.
- GE and others are developing ammonia-fueled locomotive engines and/or fuel cells; Nissan, BMW, GM, and others are developing ammonia-fueled engines and fuel cells for cars, trucks, and buses; and Cummins and others are working to develop ammonia-fueled propulsion systems for planes.

NEAR-TERM NORTH DAKOTA OPPORTUNITIES FOR LOW-CARBON HYDROGEN ARE AMMONIA, NATURAL GAS BLENDING, AND OIL REFINING.

ZERO-EMISSION CLASS 8 TRUCK

Freightliner Cascadia zero-emission Class 8 truck with ammonia-to-power system built and installed by Brooklyn, New York-based Amogy.

The global ammonia market is set to expand significantly.

Ammonia use in North Dakota and the surrounding states of Montana, Minnesota, and South Dakota represented approximately 16% of total U.S. consumption in 2021. A summary of ammonia consumption data and the amount of hydrogen contained within that ammonia is presented in the table.[56]

ANNUAL AMMONIA CONSUMPTION BY NORTH DAKOTA AND SURROUNDING STATES[56]

State	2021 Consumption, tonnes ammonia	Hydrogen in Ammonia, tonnes hydrogen
Minnesota	963,000	171,000
Montana	329,000	58,000
North Dakota	937,000	166,000
South Dakota	682,000	121,000
Region	2,911,000	516,000
Regional Fraction of U.S.	16%	
U.S. Total	18,567,000	3,297,000

North Dakota is the only one of these states with an ammonia plant. The DGC plant in Beulah has the capacity to produce 381,000 tonnes/year of ammonia. In 2020, the plant produced about 320,000 tonnes, roughly 84% of capacity.[57] Based on available data, 84% is the approximate ratio of ammonia production capacity to actual production for most U.S. plants—and the U.S. ammonia industry as a whole.

Even though North Dakota ammonia production is only about a third of North Dakota consumption, because ammonia is a globally fungible commodity, building more in-state production capacity would require competing (on price) with imports from other states and Canada. Because Manitoba and Saskatchewan supply lines to North Dakota are short, competing with these established suppliers would be difficult—especially if ammonia consumption is essentially limited to its utilization as fertilizer. However, with increasing recognition of ammonia's utility as a hydrogen-rich energy carrier and fuel, the global ammonia market is set to expand significantly. As one major indicator, the Japan Electricity Infrastructure Division released in February 2022 the "Transition Roadmap for the Power Sector," which calls for utilization of 3 million tonnes of blue or green ammonia/year for power production by 2030 and 30 million tonnes/year by 2050.[58]

Japan's transition represents a potentially significant trend in use of ammonia as a low-carbon fuel for power production. Critically important is that all ammonia sold into the Japanese power market is required to be blue or green. Japan's commitment to transitioning its power sector to hydrogen/ammonia is impacting the global ammonia industry, as evidenced by recently announced agreements between Japanese and U.S., Canadian, Australian, European, and Arab companies to explore options for supplying ammonia to Japan. One example is an agreement between Itochu Corporation (Japan), Petronas Energy Canada, and Inter Pipeline (Canada) to plan development of a 1-million-tonne/year $1.3 billion blue ammonia plant in Alberta.[59] Ammonia product would be railed to Vancouver for shipment to Japan.

As another example, Mitsui & Co., a leading global ammonia marketer, and CF Industries, the world's largest ammonia producer, are collaborating on exploration and development of blue ammonia projects in the United States. Under their

MARINE ENGINE ON ITS WAY TO BE RECONFIGURED FOR AMMONIA

Marine engine on its way to be reconfigured for ammonia at the MAN Energy Solutions Research Center in Copenhagen. The maritime shipping industry currently runs on heavy diesel fuel and generates about 3% of global CO_2 emissions. Switching to ammonia would take this to zero.

WITH AFFORDABLE NATURAL GAS, ACCESSIBLE SUBSURFACE CO_2 STORAGE CAPACITY, VAST RENEWABLE ENERGY RESOURCES, AND RAIL CONNECTIONS TO WEST COAST SHIPPING TERMINALS, **NORTH DAKOTA IS WELL-POSITIONED TO BECOME A GLOBAL SUPPLIER OF BLUE AND GREEN AMMONIA.**

August 2021 memorandum of understanding, CF Industries and Mitsui plan to assess options for establishing blue ammonia supply and supply chain infrastructure, CO_2 transportation and storage, expected environmental impacts, and blue ammonia economics and marketing opportunities in Japan and other countries. Evidence of CF Industries' commitment to decarbonizing its ammonia production network includes a definitive agreement to develop the first commercial-scale green ammonia project in North America (in Donaldsonville, Louisiana), as well as initiatives to develop CCS opportunities and other CO_2 abatement projects to enable blue ammonia production.

With affordable natural gas, easy access to well-characterized and secure subsurface CO_2 storage resources, and rail connections to West Coast shipping terminals, North Dakota is well-positioned to become a global supplier of blue ammonia.

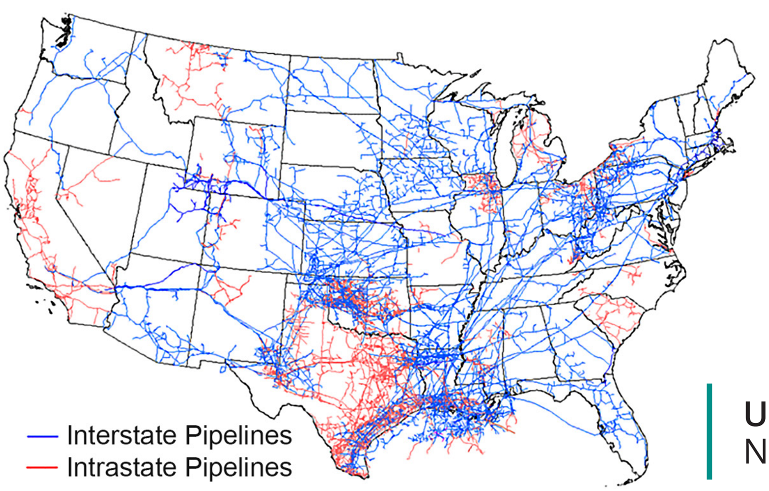
Based on available information regarding an ammonia plant built by Incitec Pivot in Waggaman, Louisiana, and commissioned in 2017, the capital cost of a state-of-the-art 800,000-tonnes/year ammonia plant is about $850 million.[60] Adding infrastructure for CCS would increase capital cost significantly. Siting the plant at a location directly above CO_2 storage capacity would minimize capital and operating costs associated with CO_2 compression and transport. Options for moving North Dakota-produced blue ammonia to near-term markets include railing to West Coast shipping terminals in the United States and/or Canada.

Hydrogen can be blended with natural gas for transport and separation (for pure hydrogen applications) or use as a hydrogen–natural gas blend.

Blending and piping of hydrogen into other gas streams in the United States are not new. More than 200 years ago, Baltimore and successive other U.S. cities produced and piped "town gas," (a coal-derived mixture of 30%–50% hydrogen) to streetlamps, commercial buildings, and residences. By the 1880s, electricity began replacing town gas for lighting, and by the 1960s, natural gas replaced town gas for other uses. Today, except for niche locations, such as Honolulu, Hawaii, natural gas has superseded town gas.[61,62] Blending hydrogen into gas systems is being considered to decarbonize natural gas when burned or for hydrogen transport where the blend is temporary, with the intention to separate and recover hydrogen at its destination for customer hydrogen applications.

Hydrogen blending into the natural gas system offers several potential benefits, including the following:

- Provides across-the-board, incremental decarbonization, including in hard-to-abate sectors
- Leverages a vast existing infrastructure that would be virtually impossible to replicate in the near term
- Maintains the resiliency associated with having parallel gas- and electricity-based networks for energy distribution
- Diversifies the distribution options for constrained renewable electricity generation by using the energy to produce hydrogen
- Creates a significant storage capacity for "line packing" hydrogen
- Opens a large, near-term hydrogen market for states like North Dakota with existing transmission infrastructure



U.S. INTERSTATE AND INTRASTATE NATURAL GAS PIPELINES[63]

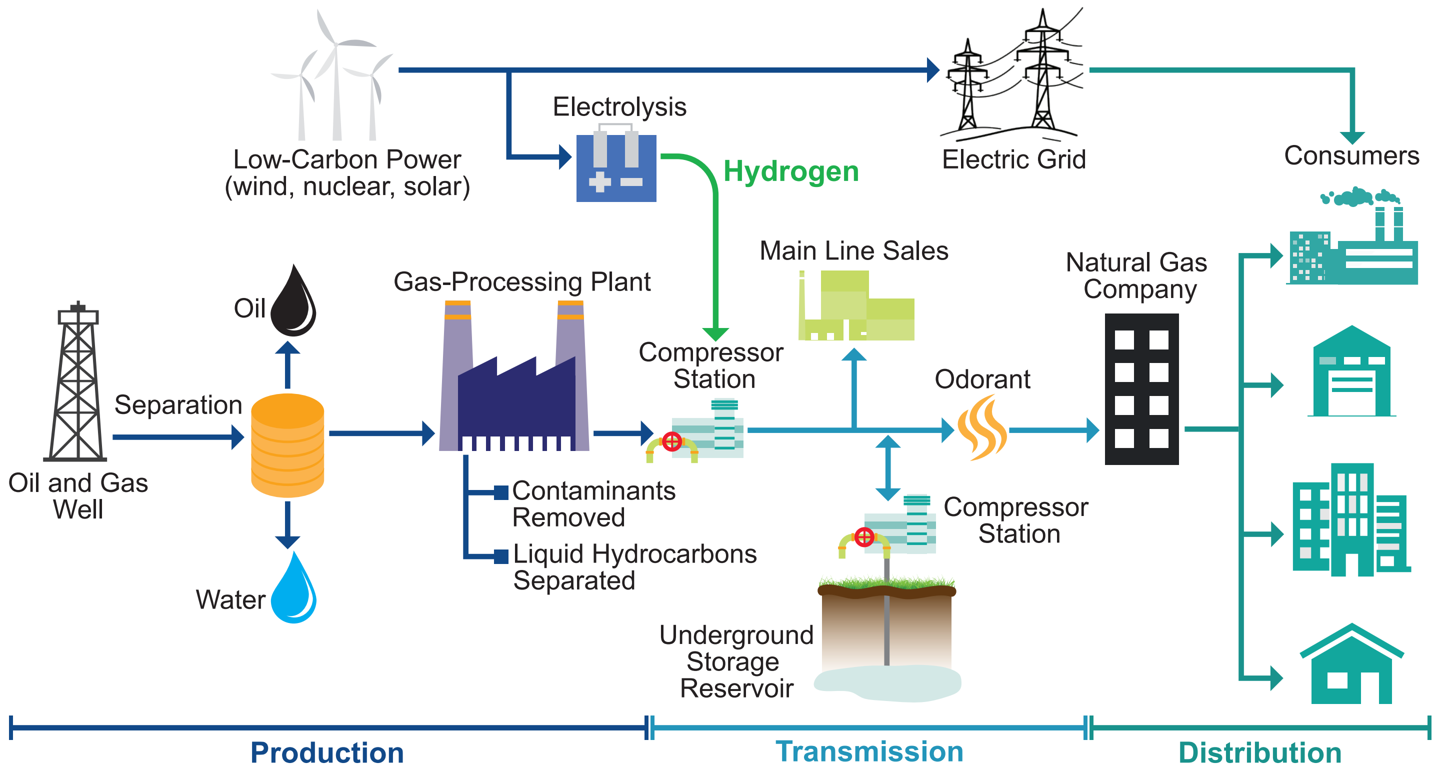
NORTH DAKOTA'S POTENTIAL PIPELINE BLENDING CAPACITY COULD BE A SIZABLE EXPORT MECHANISM FOR HYDROGEN.

Based on North Dakota's existing natural gas interstate pipeline capacities, a comparable hydrogen transmission system would possess a capacity of roughly 4.4 trillion scf/year (10.6 million tonnes/year). The pipeline would transport less energy than the comparable natural gas pipeline, i.e., about 1.4 quadrillion Btu/year hydrogen versus 1.7 quadrillion Btu/year methane, because of the lower volumetric energy density of hydrogen.

A 5% blend of hydrogen into all of North Dakota's transmission pipelines would equate to 90,000 MMscf/year (0.2 million tonnes).

NOTIONAL LOW-CARBON HYDROGEN BLENDING UPSTREAM OF THE NATURAL GAS TRANSMISSION NETWORK[64]

Hydrogen could be introduced into the existing natural gas system to supply all downstream systems and customers with the blend and to provide a parallel pathway for constrained low-carbon power to reach the market.



TECHNOLOGY FOR HYDROGEN BLENDS

Power generation equipment manufacturers such as Mitsubishi, GE, Siemens, and Ansaldo Energia claim to have gas turbines that can operate on at least 20% hydrogen and are diligently working to manufacture 100% hydrogen-capable machines by 2030. This conforms to many countries' goals of clean electric power in the 2030–2035 time frame.[65–69]

Blending for hydrogen transport means the blend is temporary, with the intention, ultimately, to separate and recover hydrogen at its destination for customer hydrogen applications. Conventional applications include use as a chemical (ammonia and methanol production), petroleum or metals refining, and food processing. Nascent applications include use as a fuel for fuel cell vehicles and fuel cell-based power generation or production of synthetic fuels using CO_2 extracted from the atmosphere. Hydrogen's value in these applications ("chemical value" and "motor fuel value") is distinctly different from that in natural gas decarbonization applications, often termed "fuel value."

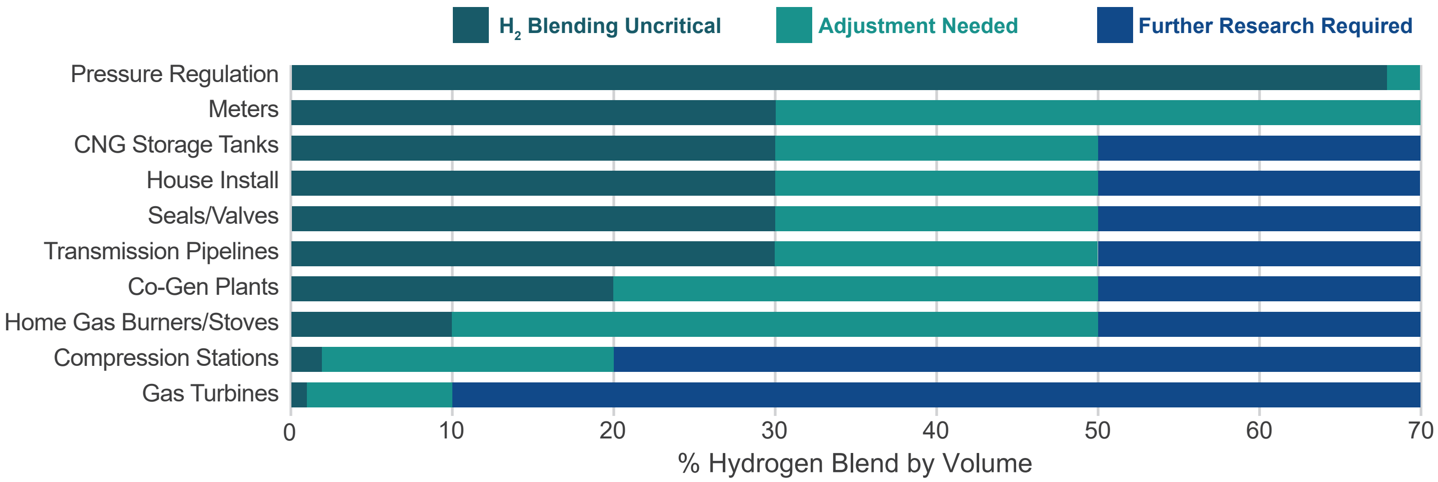
Commercially, hydrogen has been separated and purified for decades, for example, in refinery steam methane reforming-based hydrogen units by pressure swing adsorption (PSA) equipment. PSA equipment vendors today claim that their equipment can reliably provide virtually any degree of purity up to 99.9999% with capacities up to 350 MMscfd.[70,71] Electrochemical separators that can also compress hydrogen are being developed by HyET Group, a Netherlands-based company, for the transportation (i.e., light-duty fuel cell vehicle) market. Units only process up to 2000 kg/day (about 800,000 scfd). SoCalGas has announced that it is interested in demonstrating the technology.[72,73]

Hydrogen blending up to 5% is generally considered to be safe. Higher blend ratios require case-specific analysis to determine compatibility.

RECENT STUDIES ASSESSING HYDROGEN BLENDING IN NATURAL GAS:

- DOE is sponsoring a 2-year, $15 million blend study collaboration entitled **HyBlend**, which commenced in 2021 and involves more than 20 partners, six of which are national labs. The study is investigating economic, environmental, and materials-compatibility aspects of blending hydrogen into natural gas.[74]
- A **California literature review** identified five U.S. and 13 foreign blend studies: 12 of the 18 studies were in progress as of summer 2022. Two of the U.S. projects were unable to test over the intended concentration range because of issues: one project intended to test to 20% and only reached 10% because of combustion issues, and the other intended to get to 5% but only attained 2% because of end-use issues. Two foreign tests failed to achieve desired concentrations: one test observed that hydrogen can permeate through polyamide distribution pipe in less than 24 hours; the other test targeted 15%, but only attained 12% with no explanation. The longest-duration "test" is Hawaii Gas experience over more than 50 years at levels generally between 10% and 12%.[75]
- A 2022 **California Public Utilities Commission Hydrogen-Blending Impact Study** presents marginally more insight than the NATURALHY study of two decades ago.[75,76]

ESTIMATED HYDROGEN **BLEND LIMITS** FOR EXISTING INFRASTRUCTURE[77]



Hydrogen in a pipeline network is only acceptable to the tolerance of its least compatible component. Above is an estimated extent of compatibility and the effort required to increase compatibility of various pipeline components and user equipment with varying hydrogen blends. Identifying the least compatible component and modifying it permits higher concentrations of hydrogen in blends. The effort required to improve compatibility varies significantly: for example, changing materials of construction of compressor components or compressed natural gas (CNG) tanks could be relatively easy, whereas redesigning gas turbine combustors to handle the faster-burning hydrogen requires more effort.

CALIFORNIA BLEND STUDY **CONCLUSIONS**[75]

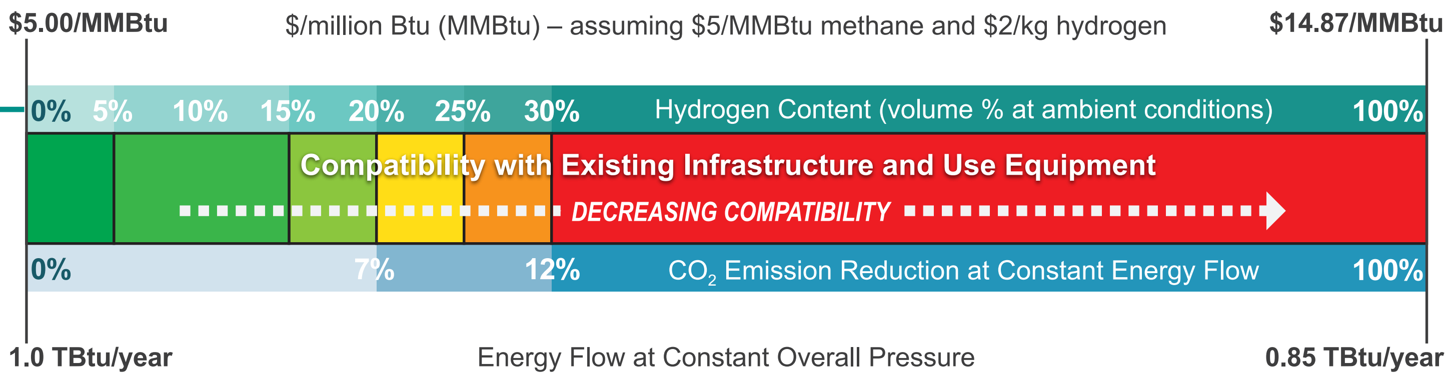
Hydrogen blends of up to 5% in the natural gas stream are generally safe.

Hydrogen blends above 5%:

- Result in a greater chance of pipeline leaks and the embrittlement of steel pipelines.
- Could require modifications of appliances such as stoves and water heaters to avoid leaks and equipment malfunction.

Hydrogen blends of more than 20% present a higher likelihood of permeating plastic pipes, which can increase the risk of gas ignition outside of the pipeline.

Because of the lower energy content of hydrogen gas, more hydrogen-blended natural gas will be needed to deliver the same amount of energy to users compared to pure natural gas.



NOTIONAL BLEND CHARACTERISTICS FOR HYDROGEN–METHANE

DECARBONIZATION POTENTIAL OF BLENDING

While technically feasible in the near term, hydrogen blending into the natural gas distribution system does have limitations with respect to its decarbonization potential. Several factors must be considered as hydrogen blending content is increased from 0% to 100% as shown in the figure above.

Not all components of the natural gas distribution system will be compatible with significant hydrogen blending. Relatively small percentages of hydrogen can be accommodated without modifications, but the compatibility of pipes and downstream equipment declines significantly at blends of 20% hydrogen and higher.

Hydrogen has a lower volumetric energy density than the methane it replaces, thereby derating the energy transport capacity of the distribution system. A full replacement of methane with hydrogen would result in a 15% energy capacity decrease at a constant operating pressure. This decrease could be compensated by increasing the pressure of the distribution system if feasible from safety and technical standpoints, but this solution would require higher operating cost in the form of increased compressor power.

CO_2 emission reductions from hydrogen blending are not directly proportional to the blend ratio while delivering the same energy content. Instead, because of its lower volumetric energy density, hydrogen's effect on CO_2 emissions is blunted relative to its blend ratio. For example, a threshold blending of 20% hydrogen results in approximately a 7% CO_2 emission reduction.

Hydrogen is used for fuel production at North Dakota petroleum refineries and renewable diesel facilities.

Petroleum refining is the largest consumer and, traditionally, the largest producer of hydrogen of all U.S. industries. Petroleum refineries and renewable diesel plants consume hydrogen to remove impurities such as sulfur and oxygen from oil ("hydrotreating") and to break less valuable longer molecules into more valuable shorter molecules ("hydrocracking").

Hydrogen is produced via two basic pathways. "By-product hydrogen" is generated as a by-product of petroleum-refining processes like reforming of naphtha (light/volatile hydrocarbons) to produce high-octane blendstocks for gasoline, whereas "on-purpose hydrogen" is intentionally produced in a purpose-built hydrogen plant—typically a steam methane reformer. When used on-site, hydrogen produced via either of these pathways is referred to as "captive hydrogen." In contrast, "merchant hydrogen" plants produce hydrogen for sale and delivery to external customers via pipeline, rail, or truck. Other less prominent hydrogen production–supply scenarios include by-product hydrogen generated at petrochemical plants and plants that produce chlorine and sodium hydroxide (caustic soda) referred to as chlor-alkali plants.

Facility	H_2 Plant Capacity, tonnes/year	H_2 Plant CO_2 Emissions, tonnes/year
Iowa		
Illinois		
Joliet	N/A	N/A
Robinson	N/A	N/A
Lemont	10,000	100,000
Wood River	170,000	1.5 million
Minnesota		
Koch Industries	180,000	1.6 million
Marathon	10,000	100,000
Montana		
Great Falls*	20,000	200,000
Laurel	60,000	600,000
Exxon Mobil	20,000	200,000
Phillips 66	30,000	300,000
North Dakota		
Mandan	N/A	N/A
Dickinson*	20,000	200,000
Nebraska		
South Dakota		
Wisconsin		
Superior	N/A	N/A
Wyoming		
Newcastle	N/A	N/A
Evansville	N/A	N/A
Evanston	N/A	N/A
Sinclair	50,000	400,000
Total	**570,000**	**5.2 million**

ON-PURPOSE **CAPACITY**[78]

Estimated regional 2021 on-purpose refinery hydrogen production capacity and associated CO_2 emissions.

** Converted from petroleum to renewable oil feedstocks.*

The table at left lists on-purpose hydrogen production capacities of regional facilities. As shown, they cumulatively produce more than 500,000 tonnes of hydrogen and about 5 million tonnes of CO_2 per year. Also shown is that the Mandan refinery does not produce on-purpose hydrogen, since the refinery currently generates sufficient by-product hydrogen for its refining operations.

The table shows that the Dickinson and Exxon Mobil facilities both produce 20,000 tonnes/year of hydrogen. Not shown is that the Dickinson and Exxon facilities have capacities of 20,000 and 60,000 barrels per day, respectively. The difference in hydrogen requirement is due to the difference in feedstocks: renewable oil at Dickinson and petroleum at Exxon. Because renewable oil contains much more oxygen than petroleum, more hydrogen is consumed in oxygen removal.

LOW-CARBON HYDROGEN PRODUCTION COULD SUPPORT IN-STATE REFINING OF REDUCED-CARBON FUELS.

Replacing natural gas with low-carbon hydrogen produced at a central location either based on water and renewable electricity or natural gas with carbon capture has been studied for decades.

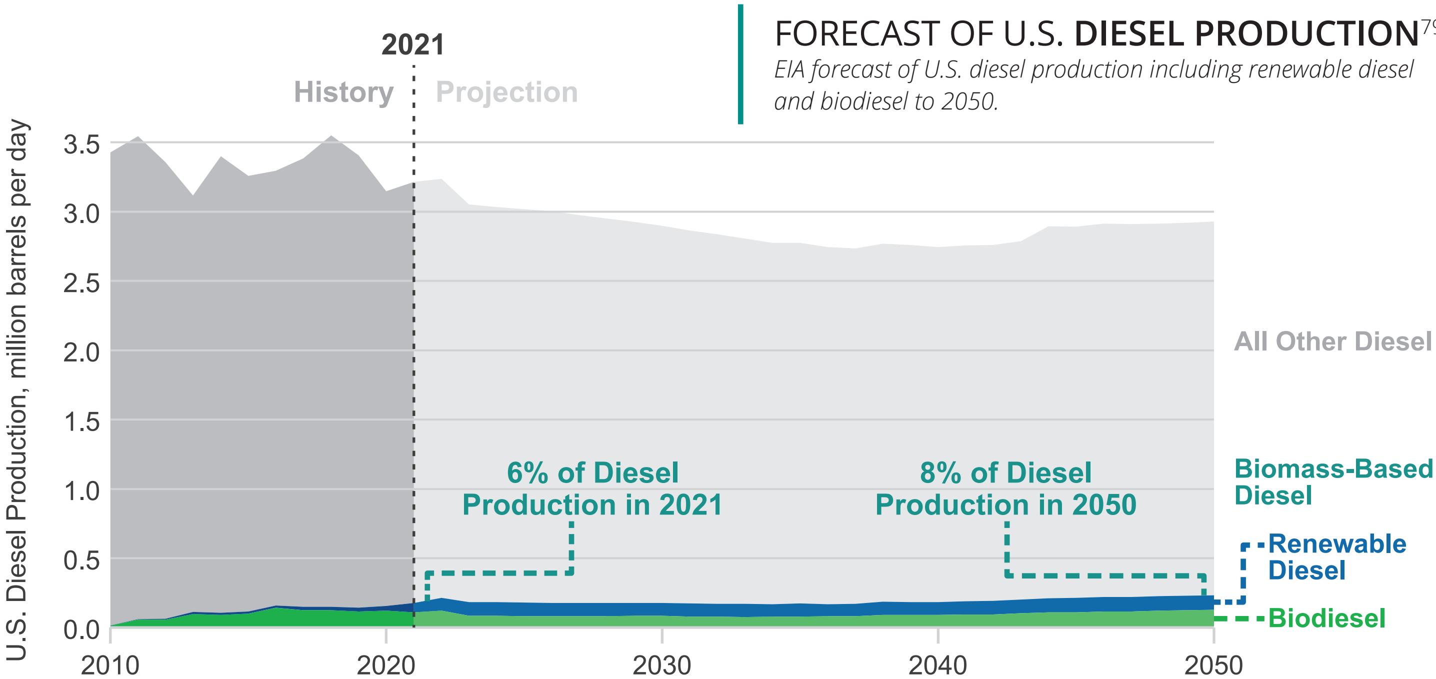
As demand increases for renewable diesel like that produced at Marathon's Dickinson facility (unlike biodiesel produced via transesterification, renewable diesel is chemically similar to petroleum diesel), more clean hydrogen will be needed. The below EIA forecast projects slow growth in bio-based diesel production. However, because the projection accounts for the facts that 1) renewable diesel and biodiesel compete for the same feedstocks and 2) bio-based fuel sales are more policy-driven than market-driven, the forecast could change with changes to policy.

Another refinery use for hydrogen—one not practiced today—is hydrogen as a process fuel, replacing natural gas. CO_2 emission point sources are distributed across refineries, making CO_2 capture difficult. Replacing natural gas with low-carbon hydrogen has been studied for decades.[80] In 2021, U.S. refineries consumed almost 1 trillion cubic feet of natural gas; while some was directed to hydrogen production and chemical uses, most was combusted in fired heaters, boilers, and gas turbines.[81]

This equipment and its 50 million tonnes of CO_2 emissions represent a significant opportunity for low-carbon hydrogen. Replacing natural gas will not eliminate refinery carbon emissions since natural gas represents only about one-quarter of the fuels combusted; about half of refinery fuel is waste gas (i.e., hydrocarbon gas by-products from refinery processes) and another quarter is other fuels, some of which could also be converted to low-carbon hydrogen with CCS.[82]

FORECAST OF U.S. **DIESEL PRODUCTION**[79]

EIA forecast of U.S. diesel production including renewable diesel and biodiesel to 2050.



OPPORTUNITIES FOR NORTH DAKOTA

Continued energy policy leadership will ensure hydrogen is developed as a diversified, value-added energy product to grow North Dakota's economy.

WHAT HAS NORTH DAKOTA DONE?

- In 2021, the North Dakota Legislature funded two efforts to explore hydrogen energy development in North Dakota. The first was Senate Bill 2014, Section 15, which enabled this study of the opportunities for hydrogen energy in North Dakota. The resulting characterization of North Dakota's resources, both natural and engineered; regional hydrogen markets; and critical infrastructure to store, transport, and distribute hydrogen **spotlighted the advantages of hydrogen energy development in the region and attracted industry investment.** The second effort was funded by Senate Bill 2014, Section 14, and is **exploring the feasibility of gas storage** (both clean hydrogen as well as natural gas and NGLs) in North Dakota's geologic salt formations.
- Low-carbon hydrogen is important to a future hydrogen economy, and it can be produced from all of North Dakota's energy resources. Production of low-carbon hydrogen from fossil resources (coal and natural gas) requires the capture and storage of CO_2. **North Dakota's leadership in achieving primacy for carbon sequestration** has positioned the state to expand use of abundant coal and natural gas to produce clean hydrogen, leveraging the enormous carbon sequestration capacity in North Dakota.
- NDIC's Clean Sustainable Energy Authority (CSEA) was created in 2021 "to support research, development, and technological advancements through partnerships and financial support for the large-scale development and commercialization of projects, processes, activities, and technologies that reduce environmental impacts and increase sustainability of energy production and delivery." Several hydrogen energy and carbon capture/sequestration projects have been funded through this program, **expediting the deployment of hydrogen energy technology in North Dakota.**

THE LEGAL, BUSINESS, AND TAX POLICY AND OVERALL BUSINESS CLIMATE IN NORTH DAKOTA CAN POSITION THE STATE TO **LEAD IN HYDROGEN ENERGY DEVELOPMENT.**

LOOKING AHEAD, WHAT CAN NORTH DAKOTA DO?

Continue support for existing energy programs and ensure that hydrogen development is a priority topic:

- CSEA
- Renewable Energy Program
- Oil and Gas Research Program
- Lignite Research Program

Leverage the advantageous regulatory environment in North Dakota for low-carbon hydrogen that is analogous to the state's leadership position in carbon sequestration.

Promote policy to enable geologic storage of gases, including hydrogen, natural gas, NGLs, and CO_2, all of which are necessary to sustain existing natural resource development while expanding opportunities into hydrogen energy use and export.

Support low-carbon hydrogen as a value-added product of North Dakota's energy industry:

- Provide leadership around the value of hydrogen production from all types of North Dakota energy.

Support transparency in all carbon-accounting transactions to facilitate trade.

REFERENCES

1. Prentice, I.C., Farquhar, G.D., Fasham, M.J.R., Goulden, M.L., Heimann, M., Jaramillo, V.J., Kheshgi, H.S., Le Quéré, C., Scholes, R.J., Wallace, D.W.R., and others, 2001. The carbon cycle and atmospheric carbon dioxide, *in* Houghton, J.T., Ding, Y., Griggs, D.J., Noguer, M., van der Linden, P.J., Dai, X., Maskell, K., Johnson, C.A. [eds.], Climate change 2001—the scientific basis: Cambridge: Cambridge University Press, p. 183–237, https://www.ipcc.ch/site/assets/uploads/2018/03/WGI_TAR_full_report.pdf.
2. U.S. Environmental Protection Agency. Sources of Greenhouse Gas Emissions. 2020, https://www.epa.gov/ghgemissions/sources-greenhouse-gas-emissions (accessed 2022).
3. U.S. Environmental Protection Agency. *Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2020*; U.S. Environmental Protection Agency, EPA 430-R-22-003, 2022, https://www.epa.gov/system/files/documents/2022-04/us-ghg-inventory-2022-main-text.pdf (accessed 2022).
4. Energy Futures Initiative. U.S. Hydrogen Demand Action Plan. Feb 2023, energyfuturesinitiative.org (accessed 2023).
5. International Energy Agency. Global Hydrogen Review – 2022. https://iea.blob.core.windows.net/assets/c5bc75b1-9e4d-460d-9056-6e8e626a11c4/GlobalHydrogenReview2022.pdf (accessed 2022).
6. Hydrogen Council; McKinsey & Company. *Hydrogen Insights: The state of the global hydrogen economy, with a deep dive into renewable hydrogen cost evolution.* Hydrogen Council, Dec 2023.
7. Davis, S.J.; Lewis, N.S.; Shaner, M.; Aggarwal, S.; Arent, D.; Azevedo, I.L.; Benson, S.M.; Bradley, T.; et al. Net-Zero Emissions Energy Systems. *Science* **2018**, *360,* 6396.
8. S&P Global Commodity Insights. Direct-Reduced Iron Becomes Steel Decarbonization Winner. Insight Blog: Energy Transition/Metals, Jun 22, 2022.
9. Midrex Technologies, Inc. 2021 World Direct Reduction Statistics. 2022, www.midrex.com (accessed 2023).
10. International Energy Agency. *IEA G20 Hydrogen Report: Assumptions;* https://iea.blob.core.windows.net/assets/29b027e5-fefc-47df-aed0-456b1bb38844/IEA-The-Future-of-Hydrogen-Assumptions-Annex_CORR.pdf (accessed 2023).
11. International Energy Agency. *The Future of Hydrogen: Seizing Today's Opportunities;* Report prepared by the IEA for the G20, Japan; 203 p., https://iea.blob.core.windows.net/assets/9e3a3493-b9a6-4b7d-b499-7ca48e357561/The_Future_of_Hydrogen.pdf (accessed 2023).
12. Saulnier, R.; Minnich, K.; Sturgess, P.K. *Water for the Hydrogen Economy;* Report prepared for WaterSMART Solutions; 2020, https://watersmartsolutions.ca/wp-content/uploads/2020/12/Water-for-the-Hydrogen-Economy_WaterSMART-Whitepaper_November-2020.pdf (accessed 2023).
13. Kakoulak, G.; Kougias, I.; Taylor, N.; Dolci, F.; Moya, J.; Jäger-Waldau, A. Green Hydrogen in Europe – A Regional Assessment: Substituting Existing Production with Electrolysis Powered by Renewables. *Energy Conversion and Management* **2021**, *228,* 113649.
14. Rosa, L.; Sanchez, D.L.; Realmonte, G.; Baldocchi, D.; D'Odorico, P. The Water Footprint of Carbon Capture and Storage Technologies. *Renewable and Sustainable Energy Reviews*. **2021**, *138,* 110511.
15. Machhammer, O.; Bode, A.; Hormuth, W. Financial and Ecological Evaluation of Hydrogen Production Processes on Large Scale. *Chem. Eng. Technol.* **2016**, *39,* 1185–93.
16. Diab, J.; Fulcheri, L.; Hessel, V.; Rohani, V.; Frenklach, M. Why Turquoise Hydrogen Will Be a Game Changer for the Energy Transition. *International Journal of Hydrogen Energy* **2022**, *47*, 25831–25848.
17. U.S. Bureau of Labor Statistics. Producer Price Index by Commodity: Chemicals and Allied Products: Carbon Black, All Processes. Federal Reserve Bank of St. Louis; 2023; https://fred.stlouisfed.org/series/WPU06790918 (accessed Jun 7, 2023).
18. Intratec. Carbon Black Price. https://www.intratec.us/chemical-markets/carbon-black-price (accessed Jun 2023).
19. Millstein, D.; O'Shaughnessy, E.; Wiser, R. 2023. Renewables and Wholesale Electricity Prices (ReWEP) Tool. Version 2023.1; Lawrence Berkeley National Laboratory; https://emp.lbl.gov/news/exploring-wholesale-energy-price (accessed 2023).
20. Rebenitsch, R.; Bush, R.; Boushee, A.; Woeste, J.; Stevens, B.G; Peters, R.R.; Williams, K.D.; Bennett, K. *Wind-to-Hydrogen Energy Pilot Project: Basin Electric Power Cooperative;* Final Report (Sept 1, 2004 – Dec 31, 2008) for Basin Electric Power Cooperative and U.S. Department of Energy Cooperative Agreement No. DE-FG36-04GO14264; EERC Publication 2009-EERC-06-11; Energy & Environmental Research Center: Grand Forks, ND, June 2009.
21. U.S. Energy Information Administration. State Energy Data. 2019.
22. International Energy Agency. Global Average Levelised Cost of Hydrogen Production by Energy Source and Technology, 2019 and 2050, In *CCUS in Clean Energy Transitions;* 2020; 174 p., https://iea.blob.core.windows.net/assets/181b48b4-323f-454d-96fb-0bb1889d96a9/CCUS_in_clean_energy_transitions.pdf (accessed 2023).
23. U.S. Code. Credit for Production of Clean Hydrogen. Section 45V, Title 26, 2023, http://uscode.house.gov/view.xhtml?req=granuleid:USC-prelim-title26-section45V&num=0&edition=prelim (accessed 2023).
24. H_2 Hydrogen Tools. Hydrogen Compared with Other Fuels. Pacific Northwest National Laboratory, https://h2tools.org/bestpractices/hydrogen-compared-other-fuels (accessed 2023).
25. Paone, T. Dealing with the Aftermath of the *Hindenburg* Disaster. *National Air and Space Museum* website, May 6, 2022. https://airandspace.si.edu/stories/editorial/aftermath-hindenburg.
26. Hunt, J.D.; Byers, E.; Balogun, A.; Leal Filho, W.; Colling, A.V.; Nascimento, A.; Wada, Y. Using the Jet Stream for Sustainable Airship and Balloon Transportation of Cargo and Hydrogen. *Energy Conversion and Management: X,* **2019**, *3,* 100016.
27. Phelps, D. Airships and Ice Roads. *Working Draft Magazine* **2021**, April. https://2021.workingdraftmagazine.com/2021/04/12/airships-ice-roads/ (accessed 2023).
28. Gardiner, M. Energy Requirements for Hydrogen Gas Compression and Liquefaction as Related to Vehicle Storage Needs. DOE Hydrogen and Fuel Cells Program Record, Record 9013, Jul 7, 2009, https://www.hydrogen.energy.gov/pdfs/9013_energy_ requirements_for_hydrogen_gas_compression.pdf (accessed 2023).
29. Smith, C.; Hill, A.; Torrente-Murciano, L. Current and Future Role of Haber–Bosch Ammonia in a Carbon-Free Energy Landscape. *Energy Environ Sci.* **2020**, *13,* 331.
30. Al Ghafri, S.; Munro, S.; Cardella, U.; Funke, T.; Notardonato, W.; Trusler, J.M.; Leachman, J.; Span, R.; Kamiya, S.; Pearce, G.; Swanger, A.; Dorador Rodriguez, E.; Bajada, P.; Jiao, F.; Peng, K.; Siahvashi, A.; Johns, M.; May, E. Hydrogen Liquefaction: A Review of the Fundamental Physics, Engineering Practice and Future Opportunities. *Energy Environ. Sci.* **2022**, *15,* 2690.
31. Statista. Net Electricity Generation in the United States from 1950 to 2021. 2021, https://www.statista.com/statistics/188521/total-us-electricity-net-generation/ (accessed 2022).
32. Compton, J. In Utah, Hydrogen and Salt Domes Are Winning the West for Renewable Energy. Mitsubishi Heavy Industries Group, Spectra, 2020, https://spectra.mhi.com/hydrogen-and-salt-domes-are-winning-the-west-for-renewable-energy (accessed 2022).
33. Kawasaki. World's First Liquefied Hydrogen Carrier Suiso Frontier Launches: Building an International Hydrogen Energy Supply Chain Aimed at Carbon-Free Society. 2019, https://global.kawasaki.com/en/corp/newsroom/news/detail/?f=20191211_3487 (accessed 2022).
34. Bellini, E. World's Largest Underground Hydrogen Storage Project. *pv magazine* 2022, https://pv-magazine-usa.com/2022/08/04/worlds-largest-underground-hydrogen-storage-project/ (accessed 2022).
35. Houchins, C.; James, B.D. Hydrogen Storage Cost Analysis. Presented at the 2022 Annual Merit Review and Peer Evaluation Meeting, https://www.hydrogen.energy.gov/pdfs/review22/st235_houchins_2022_p.pdf (accessed 2022).
36. Al Ghafri, S.Z.S.; Swanger, A.; Jusko, V.; Siahvashi, A.; Perez, F.; Johns, M.L.; May, E.F. Modelling of Liquid Hydrogen Boil-Off. *Energies* **2022**, *15,* 1149, https://doi.org/10.3390/en15031149 (accessed 2023).
37. U.S. Energy Information Administration. Natural Gas: Underground Natural Gas Storage Capacity. U.S. Department of Energy, 2023, www.eia.gov/dnav/ng/ng_stor_cap_dcu_NUS_a.htm (accessed 2023).
38. McDermott International, Ltd. McDermott's CB&I Storage Solutions Completes Conceptual Design for World's Largest Liquid Hydrogen Sphere. Press release, 2021, https://www.mcdermott-investors.com/news/press-release-details/2021/McDermotts-CBI-Storage-Solutions-Completes-Conceptual-Design-for-Worlds-Largest-Liquid-Hydrogen-Sphere/default.aspx (accessed 2023).
39. U.S. Department of Energy National Energy Technology Laboratory. Cavern Roof Stability for Natural Gas Storage in Bedded Salt. Work performed by RESPEC Inc., 2005, https://netl.doe.gov/node/2638 (accessed 2023).
40. Epelle, E.I.; Obande, W.; Udourioh, G.A.; Afolabi, I.C.; Desongu, K.S.; Orivri, U.; Gunes, B.; Okolie, J.A. Perspectives and Prospects of Underground Hydrogen Storage and Natural Hydrogen. *Sustainable Energy & Fuels* **2022**, *6,* 3324–3343, https://pubs.rsc.org/en/content/articlelanding/2022/se/d2se00618a (accessed 2022).

41. Lord, A.C.; Kobos, P.H.; Borns, D.J. Geologic Storage of Hydrogen: Scaling up to Meet City Transportation Demands. *International Journal of Hydrogen Energy* **2014,** *39* (28), 15570–15582, https://www.sciencedirect.com/science/article/pii/S0360319914021223#fig3 (accessed 2022).

42. IRENA. *Global Hydrogen Trade to Meet the 1.5°C Climate Goal: Part II – Technology Review of Hydrogen Carriers;* International Renewable Energy Agency, Abu Dhabi, 2022, https://www.irena.org/-/media/Files/IRENA/Agency/Publication/2022/Apr/ IRENA_Global_Trade_Hydrogen_2022.pdf?rev=3d707c37462842ac89246f48add670ba (accessed 2022).

43. Office of Energy Efficiency & Renewable Energy. Hydrogen Tube Trailers. 2022, https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers (accessed 2022).

44. U.S. Drive. *Hydrogen Delivery: Technical Team Roadmap;* 2013; https://www.energy.gov/sites/prod/files/2014/02/f8/hdtt_roadmap_june2013.pdf (accessed 2022).

45. Chart, Inc. LNG Tank Car SR-603: Bulk Transport Unit. 2013, https://files.chartindustries.com/14722936_LNG_Railcars.pdf (accessed 2022).

46. Diermann, R. Hydrogen Can Be Transported by Rail, German Railway Company Says. *pv magazine* Aug 10, 2020. https://www.pv-magazine.com/2020/08/10/hydrogen-can-be-transported-by-rail-german-railway-company-says/ (accessed 2022).

47. Mele, C. LNG Rail Tank Cars: The Few and the Unknown. *Delaware Currents* Feb 12, 2021, https://delawarecurrents.org/2021/02/12/lng-rail-tank-cars-the-few-and-the-unknown/ (accessed 2022).

48. The New York Times. NASA to Purchase Eight Fuel Craft: Altered Barges to Be Used in Rocket Test Work. May 17, 1964, p 283, https://timesmachine.nytimes.com/timesmachine/1964/05/17/106969720.html?pageNumber=283 (accessed 2022).

49. Parfomak, P.W. *Pipeline Transportation of Hydrogen: Regulation, Research, and Policy;* Congressional Research Service, R46700, 2021, https://crsreports.congress.gov/product/pdf/R/R46700 (accessed 2022).

50. Blanton, E.M.; Lott, M.C.; Smith, K.N. *Investing in the U.S. Natural Gas Pipeline System to Support Net-Zero Targets;* Columbia SIPA, Center on Global Energy Policy, 2021, https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/GasPipelines_CGEP_Report_111522.pdf (accessed 2022).

51. U.S. Energy Information Administration. Natural Gas Pipeline Projects. 2022, www.eia.gov/naturalgas/pipelines/EIA-NaturalGasPipelineProjects.xlsx (accessed 2022).

52. Air Liquide. Questions and Issues on Hydrogen Pipelines: Pipeline Transmission of Hydrogen. Presented at the DOE Hydrogen Pipeline Working Group Meeting, Aug 31, 2005, https://www.energy.gov/sites/default/files/2014/03/f10/hpwgw_questissues_campbell.pdf (accessed 2022).

53. ACER. *Transporting Pure Hydrogen by Repurposing Existing Gas Infrastructure: Overview of Existing Studies and Reflections on the Conditions for Repurposing;* European Union Agency for the Cooperation of Energy Regulators, 2021, 23 p., https://acer.europa.eu/Official_documents/Acts_of_the_Agency/Publication/Transporting%20Pure%20Hydrogen%20by%20Repurposing%20Existing%20Gas%20Infrastructure_Overview%20of%20studies.pdf (accessed 2022).

54. Eckert, V.; Jewkes, S.; Binnie, I. Europe's Gas Firms Prime Pipelines for Hydrogen Highway. *Reuters* Nov 18, 2021, https://www.reuters.com/business/cop/europes-gas-firms-prime-pipelines-hydrogen-highway-2021-11-18/ (accessed 2022).

55. Baker, D.R.; Dezem, V.; Freitas, G., Jr. Pipeline Owners Look to Hydrogen as Natural Gas Comes under Attack. *World Oil* Jan 29, 2021, https://www.worldoil.com/news/2021/1/29/pipeline-owners-look-to-hydrogen-as-natural-gas-comes-under-attack (accessed 2022).

56. U.S. Environmental Protection Agency. Commercial Fertilizer Purchased. 2017, https://www.epa.gov/nutrient-policy-data/commercial-fertilizer-purchased (accessed 2023).

57. Dakota Gasification Company. Website. dakotagas.com (accessed 2023).

58. METI: Ministry of Economy, Trade and Industry, Japan, Electricity Infrastructure Division, Agency for Natural Resources and Energy. Transition Roadmap for Power Sector. 2022, https://www.meti.go.jp/policy/energy_environment/global_warming/transition/transition_finance_technology_roadmap_power_eng.pdf (accessed 2022).

59. Government of Alberta. Hydrogen Development: Hydrogen Economic Opportunities. https://www.alberta.ca/economic-opportunities.aspx (accessed 2023).

60. Incitec Pivot Limited. *Annual Report* 2017; https://www.annualreports.com/HostedData/AnnualReportArchive/i/ASX_IPL_2017.pdf (accessed 2022).

61. Rasmussen, F.N. City's Gaslight Glow Dimmed in 1957 Progress: The American Gas Industry Was Born in Baltimore in 1816, When an Artist Wanted a Clean, Smoke-Free Way to Illuminate a Roomful of Paintings. *The Baltimore Sun* Oct 9, 1998, https://www.baltimoresun.com/news/bs-xpm-1998-10-10-1998283099-story.html (accessed 2022).

62. Melaina, M.W.; Antonia, O.; Penev, M. *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues;* National Renewable Energy Laboratory, NREL/TP-5600-51995, Mar 2013, https://www.nrel.gov/docs/fy13osti/51995.pdf (accessed 2022).

63. US Energy Information Administration. Natural Gas Explained: About U.S. Natural Gas Pipelines. 2008, https://www.eia.gov/naturalgas/archive/analysis_publications/ngpipeline/index.html (accessed 2023).

64. U.S. Energy Information Administration. Natural Gas Explained: Delivery and Storage of Natural Gas. 2022, https://www.eia.gov/energyexplained/natural-gas/delivery-and-storage.php (accessed 2022).

65. Patel, S. High-Volume Hydrogen Gas Turbines Take Shape. *POWER* May 1, 2019, https://www.powermag.com/high-volume-hydrogen-gas-turbines-take-shape/ (accessed 2022).

66. Mitsubishi Power. The Hydrogen Gas Turbine, Successfully Fired with a 30% Fuel Mix, Is a Major Step Towards a Carbon-Free Society. Apr 26, 2018, https://power.mhi.com/special/hydrogen/article_1 (accessed 2022).

67. Patel, S. The POWER Interview: GE Unleashing a Hydrogen Gas Power Future. *POWER* May 30, 2019, https://www.powermag.com/the-power-interview-ge-unleashing-a-hydrogen-gas-power-future/ (accessed 2022).

68. Siemens Energy. Zero Emission Hydrogen Turbine Center: On the Path to Decarbonization. 2021, https://www.siemens-energy.com/global/en/priorities/future-technologies/hydrogen/zehtc.html (accessed 2022).

69. Ansaldo Energia. Solutions for the Energy Transition. 2022, https://www.ansaldoenergia.com/offering/solutions-for-the-transition (accessed 2022).

70. Air Liquide. Low-Carbon Hydrogen: A Portfolio of Technologies for Low-Carbon Hydrogen Production, Purification and Recovery. 2022, https://engineering.airliquide.com/technologies/low-carbon-hydrogen (accessed 2022).

71. The Linde Group. Hydrogen Recovery by Pressure Swing Adsorption. 2016, https://www.linde-engineering.com/en/images/HA_H_1_1_e_09_150dpi_NB_tcm19-6130.pdf (accessed 2022).

72. HyET Hydrogen. HyET HCS100 Hydrogen Compressor Stack. 2020, https://hyethydrogen.com/hcs100/ (accessed 2022).

73. SEMPRA. SoCalGas among First Utilities in the Nation to Transition Its Over-the-Road Fleet with Hydrogen Fuel Cell Electric Vehicles. Jan 20, 2022, https://www.sempra.com/socalgas-among-first-utilities-nation-transition-its-over-road-fleet-hydrogen-fuel-cell-electric (accessed 2022).

74. U.S. Department of Energy Office of Energy Efficiency & Renewable Energy. HyBlend. 2021, https://www.energy.gov/sites/default/files/2021-08/hyblend-tech-summary.pdf (accessed 2022).

75. Raju, A.S.K.; Martinez-Morales, A. *Hydrogen Blending Impacts Study;* California Public Utilities Commission Final Report R.13-02-008; 2022; 180 p., https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF (accessed 2022).

76. California Public Utilities Commission. CPUC Issues Independent Study on Injecting Hydrogen into Natural Gas Systems. 2022, https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-issues-independent-study-on-injecting-hydrogen-into-natural-gas-systems (accessed 2022).

77. S&P Global. Commodity Insights: Estimated Hydrogen Blend Limits. 2020, https://www.spglobal.com/commodityinsights/en/market-insights/topics/energy-price-crisis (accessed 2022).

78. U.S. Energy Information Administration. Refinery Capacity. 2021, https://www.eia.gov/petroleum/refinerycapacity/archive/2021/refcap21.xls (accessed 2022).

79. U.S. Energy Information Administration. EIA Projects U.S. Renewable Diesel Supply to Surpass Biodiesel in AEO2022. *Today in Energy* Mar 24, 2022, https://www.eia.gov/todayinenergy/detail.php?id=51778 (accessed 2022).

80. Thomas, D. *Carbon Dioxide Capture for Storage in Deep Geologic Formations – Results from CO_2 Capture Project Capture: Capture and Separation of Carbon Dioxide from Combustion Sources;* Vol. 1; Elsevier, Amsterdam; 2005; p. 203–211.

81. U.S. Energy Information Administration. Fuel Consumed at Refineries. 2022, https://www.eia.gov/dnav/pet/pet_pnp_capfuel_dcu_nus_a.htm (accessed 2022).

82. NAICS (North American Industry Classification System). Petroleum Refining Sector (NAICS 324110). Energy and GHG Combustion Emissions Profile, Nov 2012, 15 p., https://www.energy.gov/sites/prod/files/2013/11/f4/energy_use_and_loss_and_emissions_petroleum.pdf (accessed 2022).

HYDROGEN IS WORTH THE INVESTMENT, AND NORTH DAKOTA HAS THE RESOURCES.

The growth of hydrogen as an energy carrier has the potential to grow and diversify North Dakota's economy. Hydrogen provides a low-carbon tool that can enable continued growth of our fossil and renewable resources, provides a new raw material for existing and new industries including fuel manufacture and ammonia synthesis, and represents a new export product with growing global demand. Hydrogen is an important part of the energy economy of tomorrow and is **worth the investment.**

For more information contact:

John Harju, Ph.D.
VP for Strategic Partnerships
701.777.5157 | jharju@undeerc.org

Brian Kalk, Ph.D.
Chief Research Officer
701.777.5455 | bkalk@undeerc.org

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018
701.777.5000 | eercinfo@undeerc.org
www.undeerc.org