EPRI ELECTRIC POWER RESEARCH INSTITUTE

LCRI LOW-CARBON RESOURCES INITIATIVE

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An Introduction to Low-Carbon Fuels

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Introduction

In the near term, substantial greenhouse gas (GHG) emissions reductions for much of the economy are projected to be driven by cleaner sources of electricity generation, advances in energy efficiency, the electrification of transportation, and where possible, other sectors. However, additional solutions are needed for the estimated 40% or more of end uses that cannot be easily or cost-effectively decarbonized through electrification [1].

"Low-carbon fuels" and "energy carriers,"[1] such as hydrogen, ammonia, synthetic hydrocarbon fuels, and biofuels, along with the technologies that enable their application, could provide solutions for these difficult-to-decarbonize sectors. When produced with zero or low GHG emissions—from clean electricity, renewable feedstocks, or fossil resources with carbon capture, utilization, and storage (CCUS)—these low-carbon resources could provide pathways to decarbonization for end-use applications including:

- Maritime shipping and aviation
- Long haul and heavy-duty transport
- Provision of high-temperature heat for industry
- Provision of heat for certain segments of the building heating market

In some cases, low-carbon fuels can be delivered, stored, and used in a similar fashion as fossil fuels. This may present opportunities to repurpose existing power generation assets and fossil fuel infrastructure for the transition to a deeply decarbonized energy system.

Many low-carbon fuels can be produced from electricity, making them a promising source of large-scale energy storage for the electric grid. These fuels (hydrogen, ammonia, etc.) can be transported and stored in bulk for subsequent use in electric power generation. This, in turn, provides an option for temporally and geographically balancing electricity supply and demand.

This white paper provides an introduction to the production, transport, storage, and use of hydrogen, ammonia, electricity-based synthetic fuels, and biofuels. This overview of the current low-carbon fuels landscape complements a series of technical reports the Low-Carbon Resources Initiative (LCRI) is developing to explore each of these topics in more depth.[2]

Hydrogen

Hydrogen is the lightest element on the periodic table and is currently widely used for industrial applications. Pure hydrogen exists at a relatively low concentration as a "free gas" in the atmosphere, but it readily combines with carbon, nitrogen, oxygen, and other elements to form common compounds such as water, ammonia, and methane. Therefore, production of hydrogen generally involves its extraction from hydrogen-containing compounds[3]—typically fossil fuels, water, or biomass (organic material that originates from plants or animals).

[1] In this paper, "fuels" refers to the role that low-carbon resources can serve in producing heat or power for a wide range of applications. The term "energy carriers" is also used, which characterizes these resources as intermediates between primary energy sources and end-use applications that allow energy to be transported or stored in a usable form. In related work as part of the EPRI and Gas Technology Institute (GTI) Low-Carbon Resources Initiative (LCRI), these are sometimes called "alternative energy carriers".

[2] To view recent publications or for more information, visit www.lowcarbonlcri.com.

[3] Although not widely exploited today as a source of hydrogen, naturally occurring hydrogen has been detected in high concentrations in certain geologic environments.

Production

Current global demand for pure hydrogen is approximately 70 million metric tons (MMT) per year [2]. Hydrogen can be used as a fuel with no CO_2 or particulate emissions at the point of use. However, the majority of hydrogen produced today originates from fossil-fuel feedstocks, with global hydrogen production accounting for 6% of natural gas and 2% of coal consumption [3].

Almost no fossil-based hydrogen production employs CO_2 capture. This production accounts for 830 MMT of CO_2 emissions per year [3], which is more than the annual CO_2 equivalent (CO_2-eq) emissions of all U.S. passenger cars in 2018 [4].

However, several low-carbon processes[4] can produce hydrogen. These processes use a variety of energy sources and/or feedstocks, including nuclear and renewable electricity, biomass, and fossil fuels with CCUS. Figure 1 summarizes these hydrogen production processes, which are detailed below.

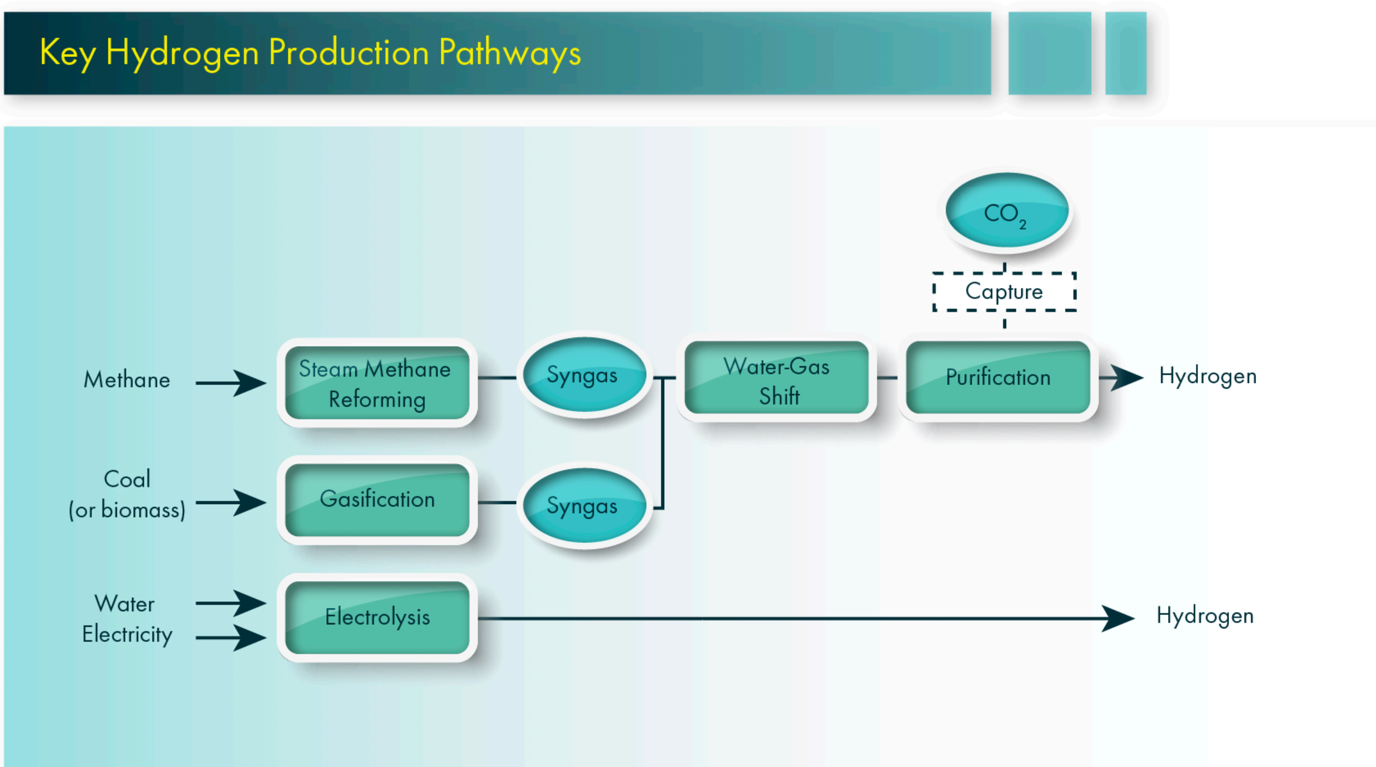

Figure 1. Simplified hydrogen production pathways.

NATURAL GAS REFORMING

A process known as steam methane reforming (SMR) dominates hydrogen production today. SMR is a mature process that the petrochemical industry has widely practiced for decades. SMR heats methane and steam in the presence of a catalyst to produce a synthetic gas (syngas), which primarily consists of carbon monoxide (CO) and hydrogen. This syngas then undergoes an additional conversion step, the water-gas shift reaction, to produce CO_2 and more hydrogen.

[4] While numerous hydrogen production processes exist, this section covers only the four primary routes for the sake of brevity. LCRI's upcoming series of technical reports will cover hydrogen production methods in more detail, including processes not included in this report.

On average, this process emits 10 metric tons of CO_2 for every metric ton of hydrogen produced [3]. Although less widespread than SMR, other mature pathways for production of hydrogen from natural gas include partial oxidation and autothermal reforming.

COAL GASIFICATION

Production of hydrogen from coal is a mature process that has been practiced for decades, primarily as a precursor for ammonia production. Today, most coal gasification-based hydrogen production facilities are located in China. This process reacts coal with steam and oxygen under high temperatures and pressures to produce syngas, which then undergoes a water-gas shift reaction to produce CO_2 and more hydrogen. On average, this process is nearly twice as CO_2-intensive as SMR [3].

Fossil-Based Hydrogen Production with CCUS

Because SMR and coal gasification account for the vast majority of hydrogen production today, CO_2 capture retrofits are an attractive option to decarbonize existing production capacity. Current commercial technologies can enable the capture of approximately 90% or more of CO_2 emissions. In recent years, CCUS systems have been deployed at several fossil-based hydrogen production facilities, with several more deployments planned.

ELECTROLYSIS

Electrolysis is an electrochemical process that splits water into hydrogen and oxygen using electricity. This process takes place within an electrolyzer, which consists of an anode and a cathode that are separated by an electrolyte material.

- Alkaline electrolysis is a mature electrolyzer technology that has been widely used for decades in certain specialized markets.
- Proton exchange membrane (PEM) electrolyzers, which offer more flexible operation and a smaller footprint, are in earlier stages of commercial development.
- Solid oxide electrolysis cells (SOECs) are a pre-commercial technology that operates at high temperatures (requiring a heat source) but with a relatively high electrical efficiency. SOECs are also capable of operating in a reverse mode by converting hydrogen back into electricity, enhancing their potential value as grid balancing resources.

The electrolysis process produces no direct CO_2 emissions. When the electricity used to power electrolysis originates from a low- or no-carbon source, the resulting hydrogen is considered a low- or no-carbon fuel. While less than 1% of dedicated hydrogen production today originates from electrolysis [3], the number and scale of electrolysis projects has increased significantly in recent years (see Figure 2 on page 6). Drivers of this trend include:

- The increasing availability of low-cost renewable electricity to power the process
- The potential for electrolytic hydrogen to contribute to dynamic balancing, seasonal-scale energy storage, and other grid services that support further integration of renewables into the electricity system

HYDROGEN PRODUCTION FROM BIOMASS

In a process not widely used today, hydrogen can be produced from biomass sources via gasification, similarly to coal, or via biological conversion processes such as fermentation. When CCUS is included, these systems can—in some cases—be considered net-CO_2 negative, as the carbon in the biomass feedstocks was recently absorbed from the atmosphere.[5]

[5] However, the CO_2 footprint of biomass-derived products depends on a range of factors including feedstock production methods and land-use impacts (see box on page 20 for more information).

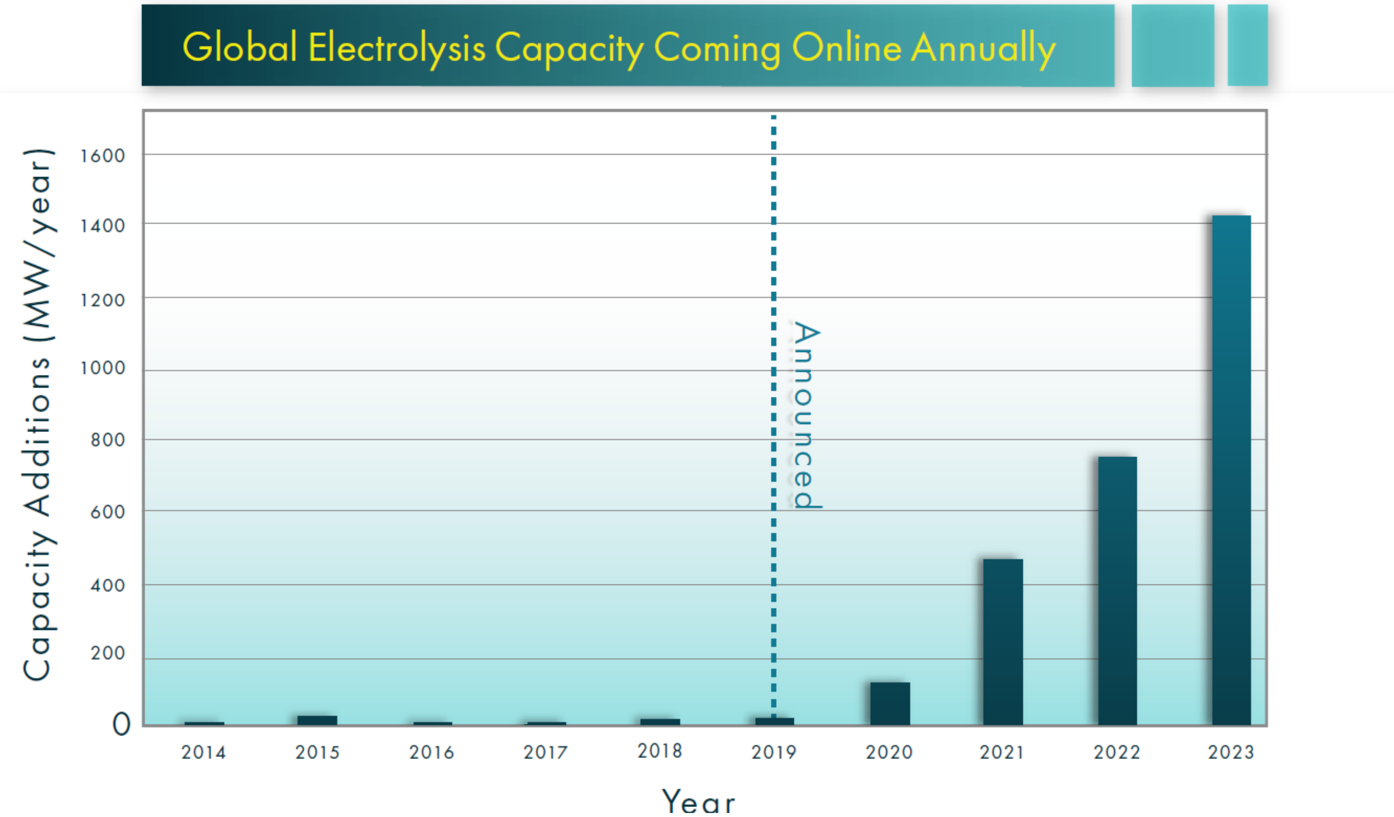

Figure 2. Electrolytic hydrogen production capacity additions by deployment year, historical and announced [5].

Transport, Storage, and Handling

HANDLING

Some key considerations for the handling of hydrogen include:

- **Experience**. As a widely used feedstock for the oil refining and the chemical industries, the distribution system and handling practices for hydrogen are well-established for existing applications.
- **Energy density**. The low volumetric energy density of hydrogen complicates and increases the cost of storage and transport relative to conventional fossil fuels, as larger volumes and compression or liquefaction are needed.
- **Ease of liquefaction**. Hydrogen must be cooled to cryogenic temperatures to liquify it, which is energy-intensive. Depending on the method and duration of storage, a substantial amount of stored liquid hydrogen can be lost through evaporation (also known as "boil off").
- **Small molecular size**. Hydrogen leakage can be higher, compared to natural gas, particularly through joints and seals, due to the small molecular size of hydrogen.
- **Absorption of hydrogen atoms or molecules by many materials**. Absorption of hydrogen embrittles steel, accelerates fatigue crack growth, and permeates through and can degrade plastics.
- **Lack of odor, invisible flame, broad ignition range, and low ignition energy**. These hydrogen properties exacerbate the risk of explosion in the event of a leak, so the safety-related requirements for handling of hydrogen are generally more stringent than for natural gas.
- **Nontoxic**. While exposure to many common fuels (and their vapors) can lead to negative health consequences, hydrogen is non-toxic. Additionally, combustion of pure hydrogen does not produce poisonous CO gas.

STORAGE

Hydrogen can be stored underground as a gas given the right geologic conditions (e.g., in salt caverns, depleted oil and gas fields, or saline aquifers) or above ground in a compressed gas or liquified state in tanks.

Alternatively, hydrogen can be converted to other easier-to-transport and easier-to-store compounds and then reconverted to hydrogen at the point of use (or in some cases, used directly—see Ammonia Applications subsection, page 12). Examples include ammonia (see sidebar on page 12) and liquid organic hydrogen carriers. Unlike hydrogen, these do not require cryogenic cooling or highly specialized equipment for transport and storage as liquids. However, these carrier-based approaches will likely only be competitive in select applications. These include applications in which the logistical challenges and energy/evaporative losses of liquid hydrogen storage and transport outweigh the energy losses incurred during conversion/reconversion.[6] If transported via pipeline, line packing—a technique widely employed for natural gas storage today—could also be used to manage daily swings in hydrogen demand.

TRANSPORT

Pure hydrogen can be transported under pressure in dedicated or repurposed pipelines. In fact, approximately 1,600 miles of dedicated pipelines are currently operating in the U.S. [6].

Liquified hydrogen (or a carrier such as ammonia) can be transported by truck, which is typically employed for low-volume or short- distance transport, or by ship or rail.

Hydrogen can also be blended into existing natural gas pipelines, which could be retrofitted to handle higher concentrations of hydrogen. The degree of tolerance to hydrogen blends is highly dependent on the widely varying characteristics of local and regional gas networks. However, recent studies suggest that with appropriate modifications, low concentrations (less than approximately 5 to 15% by volume) could be accommodated without significantly increasing the risks of using these blends in end-use devices, or the integrity and durability of existing pipeline network [7].

Applications

Today, oil refining, ammonia production, and methanol production dominate hydrogen use, accounting for 33%, 27%, and 11% of hydrogen demand, respectively [3]. Transitioning these existing applications to low-carbon hydrogen sources (e.g., from electrolysis, biomass, or fossil fuels with CCS) offers substantial CO_2 reduction potential for the oil refining and chemical sectors.

Low-carbon hydrogen's emerging applications include use as a fuel for power generation, transportation applications, or heat provision for industry and buildings. It can also be used as a feedstock for materials manufacturing or to produce chemicals. For example, hydrogen can be used as a chemical building block for other hydrogen-based molecules, such as ammonia, methanol, dimethyl ether (DME), methane, and other hydrocarbons, which in turn can be used as fuels or chemical feedstocks themselves.

STEEL PRODUCTION

Direct reduction of iron (DRI) is a method for producing steel that currently accounts for approximately 5% of steel production [8]. Conventional DRI uses a natural-gas-derived syngas of hydrogen and CO as a reducing agent in the process. Using larger proportions of hydrogen as a reducing agent (up to 100%)—and replacing natural gas and coal-

[6] Potential applications of hydrogen carriers include long-distance, overseas shipping, as well as bulk, long-term storage in regions without underground storage options.

coal-based hydrogen sources with electrolytic hydrogen—is one of several pathways considered for decarbonization of steel production. With appropriate technology modifications, hydrogen could also substitute fossil fuels to provide the process heat used in the steel-making process. In Europe, initiatives and industry consortia have been formed to advance prospects for substitution of low-carbon hydrogen for fossil fuels in steelmaking processes.

INDUSTRIAL HEAT

Today, fossil fuels service almost all industrial heat applications. Although electrification is commercially competitive for many of these applications in temperature regimes below 400°C (750°F), hydrogen is a potential source of high-temperature (more than 400°C/750°F) heat for industry. For certain large-scale processes in industries, including cement, aluminum, and glass, use of hydrogen alone or blended with natural gas could decarbonize high-temperature heat supplies [9].

TRANSPORT

Electrification and hydrogen fuels have the potential to play complementary roles in decarbonization of the transport sector. Hydrogen-fueled vehicles could be better suited than battery electric vehicles (BEVs) in more energy-intensive (e.g., heavier duty, long distance) and/or high utilization transport applications because of their faster refueling times and potentially longer ranges. Table 1 summarizes hydrogen's current and potential applications in the transport sector.

Table 1. Hydrogen-fueled transport by market segment.

Segment	Summary
Light-duty transport	Fuel cell electric vehicles (FCEVs) have been deployed in light-duty form in many regions of the world and have the potential to contribute to the decarbonization of personal transport modes. FCEVs feature fast refueling times (similar to conventional internal combustion engine vehicles). In 2018, the total stock of FCEVs reached 11,200 [3].
Medium- and heavy-duty trucks and vans	More than 1000 fuel cell electric trucks and delivery vehicles are currently deployed in China, and several logistics companies are testing fuel cell range extenders for their delivery BEVs [3]. A few auto manufacturers have announced plans for FCEV tractor trailers.
Buses	The longer range of FCEV buses makes them suited to higher daily mileage operation and/or more flexible routing relative to BEV buses. For example, intercity buses and regional coach transit are potentially promising use cases.
Maritime	There are some early maritime applications today of fuel-cell-powered auxiliary power units on ferries (a shorter-distance use case) and for port operations (e.g., forklifts, trucks, and other cargo-handling equipment/vehicles). Liquified hydrogen is being explored as a potential fuel option for international shipping, but more energy-dense alternatives, such as ammonia, methanol, or biofuels, could be more competitive low-carbon fuel options (see the Shipping subsections of sections Ammonia, Electricity-Based Synthetic Fuels, and Biofuels for more information). As the international supply chain for hydrogen scales and hydrogen internal combustion engine technologies matures, hydrogen boiled off from onboard storage tanks may also be used as a fuel for purpose-designed tanker ships transporting liquefied hydrogen (similar to some liquified natural gas [LNG] tankers today).
Rail	Hydrogen fuel cells are an option to displace nonelectric rail operations and may be more competitive in longer-distance regional rail freight applications with low utilization rates [10] (since electrification is typically the more cost-effective option for higher-utilization routes). A handful of hydrogen trains currently operate in Europe, and several countries plan to develop and deploy hydrogen-fueled rail.
Aviation	Hydrogen's low volumetric energy density and complex storage requirements present challenges relative to other low-carbon fuel options for aviation. However, its application has achieved some traction in the sector. Hydrogen has been demonstrated on a limited basis as a fuel for smaller planes, and a major aircraft manufacturer has announced plans to develop hydrogen-fueled large commercial airliners.
Non-road mobile equipment	Fuel-cell-powered forklifts are commercially mature, with approximately 25,000 deployed in the United States alone [11]. Indoor air quality regulations drive adoption of fuel-cell-powered electric drivetrains in warehouse materials handling applications. Hydrogen fuels are also one of several CO_2-mitigation technology options being explored for construction equipment, such as backhoes and bulldozers, as well as equipment used in forestry, mining, and agriculture.

BUILDINGS

Delivering hydrogen blended with natural gas via existing gas pipeline networks could play an important role in certain regions where building space and water heating is more difficult or costly to electrify. These applications include certain colder climates where electricity system buildout to serve sharp winter load peaks and deployment of high-capacity variable-speed heat pumps may be prohibitively expensive.

However, blending is only an incremental step to full decarbonization of building heating applications. Using a 20% blend of zero-carbon hydrogen (by volume) would reduce CO_2 emissions by only approximately 7% due to the lower volumetric energy density of hydrogen relative to natural gas (see Figure 3). Repurposing existing gas networks to supply 100% hydrogen would require extensive infrastructure and end-use appliance modification or replacement.

According to the IEA, more than 30 demonstration projects worldwide focus on hydrogen blending in gas networks [12]. Delivering mixed gases containing both hydrogen and methane via pipeline has a long history. In fact, use of town gas, a manufactured gas product derived from coal that typically contained 30-50% hydrogen, to power streetlights, households, and commercial buildings dates back to the Gaslight Era of the early and mid-1800's [7].

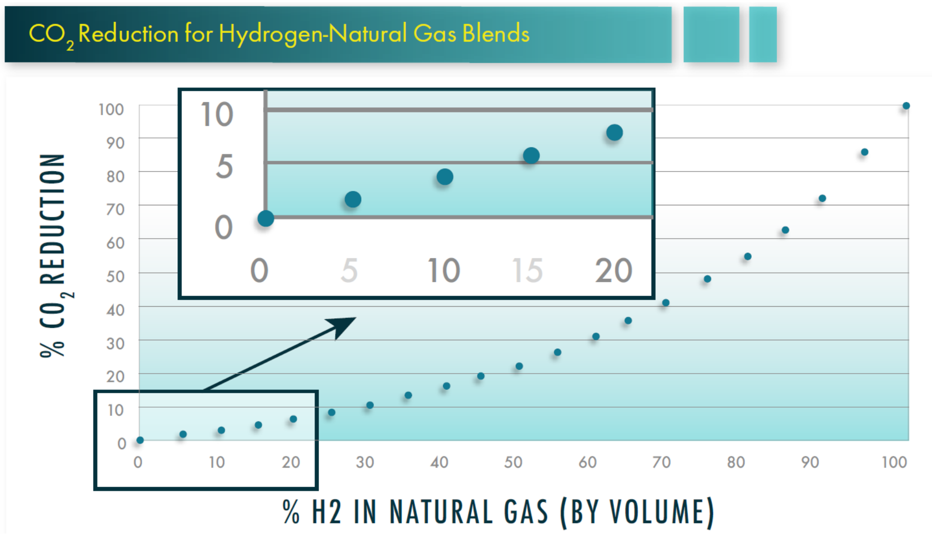

Figure 3. CO_2 reduction potential for blends of hydrogen and natural gas relative to use of 100% natural gas.

In addition to delivery and use of natural gas-hydrogen blends by existing infrastructure and end-use equipment, fuel cells can be deployed at residential or commercial buildings to generate electricity from hydrogen, and by-product heat can be recovered for water heating and space conditioning. Projects in Europe and Japan have demonstrated large-scale deployment of fuel cell micro-combined heat and power configurations at residential and commercial buildings [13,14,15].

POWER GENERATION

Several electricity generation technologies can use hydrogen as a fuel. Table 2 on page 10 summarizes key technologies for power production from hydrogen.

Hydrogen could become an important source of long-term or large-scale energy storage for the following reasons:

- Hydrogen produced from electricity can be stored underground in bulk (i.e., geologic storage) and then used to generate electricity.
- Hydrogen (or other hydrogen-based fuels) could be transported from one region to another to balance regional variations in renewable generation and/or seasonal variations in demand.

However, the round-trip efficiency losses of a power-to-hydrogen-to-power system are estimated at 56-66% [16]—or even higher, depending on the methods (and duration or distance) of storage and transport. These losses are substantially higher than those associated with pumped hydroelectric storage, which is the conventional technology for long-duration, grid-scale energy storage.

Table 2. Hydrogen-fueled electricity generation technologies.

Technology	Scale/Application	Comments
Gas turbines	Large-scale generation (small-scale "microturbine" configurations also exist)	Many commercial gas turbines in industrial settings use hydrogen-rich gas, and efforts are underway by turbine manufacturers to develop robust, large-scale gas turbines capable of operating on up to 100% hydrogen[7] [17].
Engines	Distributed generation	Original equipment manufacturers (OEMs) report that current spark ignition engines designed for natural gas can accommodate hydrogen blends of 20-25 vol% without requiring hardware modifications. Operation on 100% hydrogen is also being explored [18]. Two-stroke engines also have the potential to use liquid hydrogen, which could simplify on-site delivery and storage.
Fuel cells	Distributed generation	The largest stationary fuel cell deployments today are approximately 50 MW. This is a suitable scale for addressing distributed generation needs, such as back-up, off-grid, or smaller-scale flexible power. Approximately 70 MW of stationary hydrogen fuel cell units are currently deployed [3].

Ammonia

A compound consisting of nitrogen and hydrogen, ammonia is the chemical building block for all nitrogen-based fertilizers. At ambient conditions, it is a colorless gas with a pungent smell. Like hydrogen, ammonia produces no direct CO_2 emissions when combusted and can be produced with a low carbon footprint. This motivates interest in its application as a carbon-free energy carrier.

Production

Figure 4 (page 11) summarizes ammonia production pathways. Ammonia is produced by combining hydrogen with nitrogen (separated from air), typically in a thermochemical process in the presence of a catalyst. Ammonia production uses 31 MMT of hydrogen per year [3], representing the second largest source of demand for hydrogen. Globally, 72% of ammonia is produced from natural-gas-derived hydrogen and 22% is produced from coal [19]. Coal-based production is widespread only in China.

The most prevalent way to produce ammonia is the Haber-Bosch process, which uses an iron-based catalyst and operates at high temperatures and pressures. However, other novel processes in development can operate at lower temperatures and pressures, and in some cases, without a catalyst. Ammonia production is responsible for approximately 500 MMT of CO_2 emissions per year, and approximately 90% of these emissions result from the production of hydrogen [20]. Therefore, replacing the carbon-intensive hydrogen feedstock with low-carbon hydrogen is the primary measure under consideration for decarbonization of ammonia production.

Although the process is not widely used today, ammonia can be produced from electrolytic hydrogen with relatively low technical barriers. In fact, many commercial ammonia plants used electrolysis to produce hydrogen from hydroelectric power throughout the 20th century. Several pilot and commercial-scale projects are planned and underway globally to produce low-carbon ammonia from electrolytic hydrogen [19].

[7] For more information on the status and challenges of using hydrogen as a gas turbine fuel, see EPRI's "Technology Insights Brief: Hydrogen-Capable Gas Turbines for Deep Decarbonization" [17].

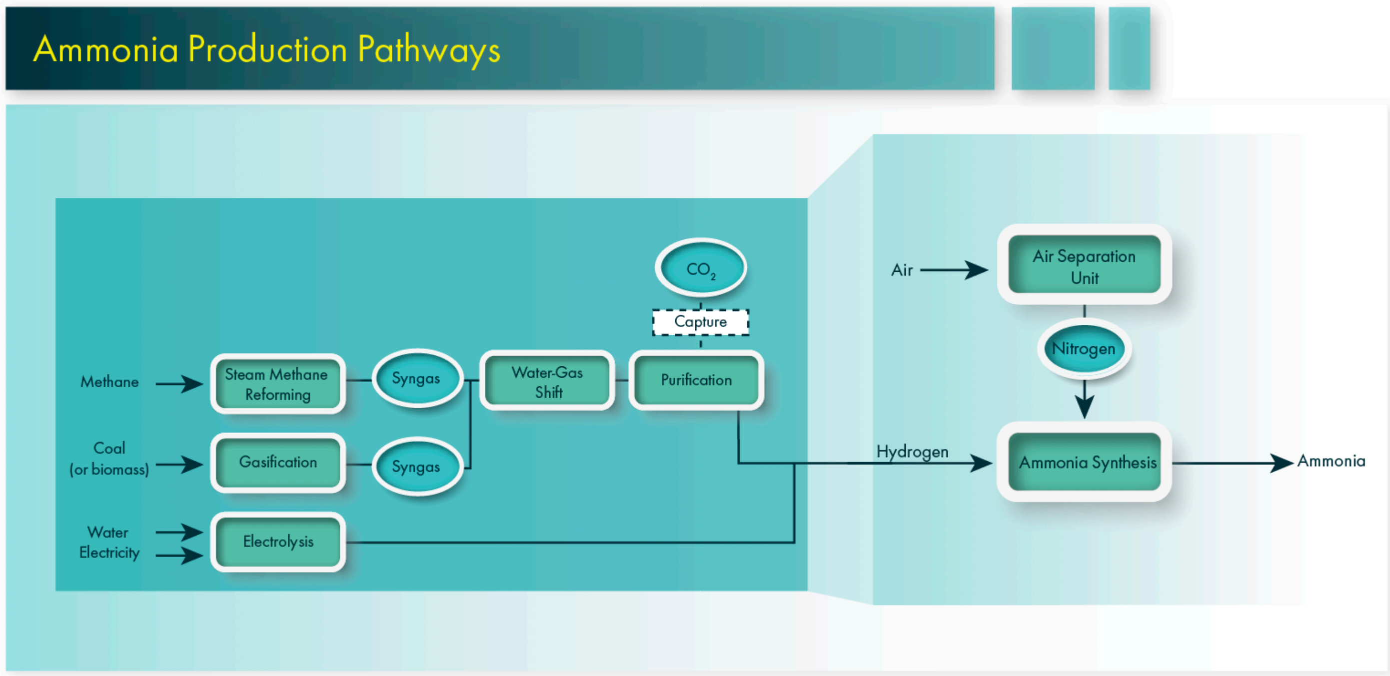

Figure 4. Ammonia production pathways.

Alternative routes to low-carbon ammonia involve pairing conventional fossil-based production routes with CCUS. Process CO_2 emissions consist of CO_2 produced as a by-product of the chemical reactions used to transform the hydrocarbon feedstocks into input hydrogen. Methods of capturing these process emissions are commercially-available and widely practiced for ammonia production. The reason is that by-product CO_2 from ammonia plants is commonly used as a chemical feedstock for production of urea, which is an ammonia-based fertilizer that accounts for more than one-half of ammonia demand. In fact, CO_2 utilization in urea production is by far the largest carbon capture and utilization application today [21]. Although capture of concentrated process CO_2 streams is technically mature, a majority of the CO_2 emissions associated with the energy-intensive ammonia production process are related to the combustion of hydrocarbon fuels to provide the plant with energy and process heat. Capture of these more dilute flue gas CO_2 streams is more costly and is not currently widely practiced. However, this capture would be needed to achieve deep decarbonization of existing fossil-fuel-based ammonia production capacity.

Transport, Storage, and Handling

HANDLING

Following are key considerations for the handling of ammonia:

- **Energy density**. As an energy storage medium, liquid ammonia has a potential advantage in that its volumetric energy density is nearly three times higher than compressed hydrogen.
- **Ease of compression and liquefaction**. Ammonia, which is a gas at room temperature, liquifies at a much higher temperature and lower pressure than hydrogen, which reduces the cost and technical challenges of its transport and storage.
- **Toxicity**. Ammonia is toxic, is a precursor to air pollution, and has a high vapor pressure in the liquid state. Handlers must take precautions to avoid escape of hazardous ammonia gas.

- **Corrosivity.** Ammonia is mildly corrosive and is known to cause stress corrosion cracking, especially when oxygen is present as an impurity.
- **Flammability.** Ammonia has a much narrower flammability range than hydrogen, meaning it has a lower probability of unintentional ignition in its handling (e.g., if leakage occurs).
- **Experience.** Because ammonia is a globally-traded chemical commodity, its distribution system is well-established. Safety practices and regulations for its handling are also relatively mature and established.

STORAGE

Ammonia is most commonly stored in a liquid state in pressurized tanks (approximately 10 bar at 25°C/77°F [22]). For bulk storage (e.g., at shipping terminals), ammonia is refrigerated to -28°F (-33°C) and stored in low pressure (<0.1 bar) tanks [23].

Ammonia as a "Hydrogen Carrier"

Ammonia is being explored as a "hydrogen carrier" because of its higher volumetric energy density and greater ease of compression and liquefaction relative to hydrogen. This means hydrogen would be converted to ammonia for transport and storage before being converted back to hydrogen at or near the point of use. Reconverting ammonia to hydrogen via a commercially-mature process known as "ammonia cracking" incurs efficiency losses of approximately 15%. Transporting hydrogen as ammonia would likely be the most cost-effective option (relative to transport as liquified/ compressed hydrogen) for longer-distance transport modes, such as ocean shipping.

TRANSPORT

Liquid ammonia is often transported by truck and pipeline. Approximately 3000 miles of ammonia pipelines currently operate in the United States [24]. New ammonia pipelines would be less costly than new hydrogen pipelines, in part because of the higher compression requirements for piped hydrogen relative to ammonia [3]. Overseas shipping of ammonia is common today, and standard liquified petroleum gas (LPG) tankers are widely used for intercontinental transport (see Figure 5).

Figure 5. Standard LPG tankers can be used to ship ammonia.

Applications

Approximately 176 MMT of ammonia is produced annually [20], with agricultural uses accounting for approximately 80% of demand [21]. Ammonia is widely used as a chemical feedstock in various industrial applications and explosives manufacturing, as well as in cleaning products. Low-carbon ammonia could serve these existing applications.

Although combustion of ammonia produces no CO_2, emissions of nitrogen oxides (NOx), an air pollutant, must be mitigated. Emerging uses of ammonia include its application as a fuel to power engines, boilers, turbines, and solid oxide fuel cells [25], as well as its application as a "hydrogen carrier."

SHIPPING

Fuel switching to ammonia is an option being explored for decarbonization of the maritime sector. Due to its higher energy density and relative ease of liquification, onboard storage of ammonia would be technically simpler and less capital-intensive than hydrogen [26]. However, with an energy density approximately one-half that of conventional marine fuels, ammonia would require more on-board fuel storage space or more frequent refueling. Although multiple manufacturers are developing 100% ammonia-fueled maritime engines, dual-fuel configurations (ammonia blended with fuel oil) may offer nearer-term commercial viability [27]. Existing maritime engines need modifications to burn ammonia.

POWER GENERATION

Like hydrogen, ammonia can be used as a fuel for power generation:

- **Boilers**. Ammonia can be used in blends for coal-fired boilers and is being investigated for use at existing coal power plants. Low blends of ammonia have already been demonstrated, and blending up to 20% on an energy basis may be feasible with only minor modifications to coal power plants [3]. With more significant modifications, boilers have the potential to be retrofitted to utilize higher concentrations of ammonia.
- **Engines**. Ammonia can fuel existing reciprocating engines with relatively minor modifications [28]. Efforts underway to develop engines optimized for operation on 100% ammonia largely focus on their application for maritime shipping propulsion.
- **Gas turbines**. In addition to hydrogen, ammonia (blended with natural gas and/or hydrogen, or used on its own) is another potential fuel for gas turbines. However, existing fuel supply and combustion systems would require modification. Micro-scale (less than 500 kW) ammonia-fueled gas turbines have been demonstrated on a limited basis.

Electricity-Based Synthetic Fuels[8]

Hydrogen produced from electricity can be combined with CO_2 to produce a wide variety of synthetic fuels and feedstocks, such as methane, methanol, dimethyl ether, gasoline, diesel, and aviation fuels. These synthetic fuels can be more easily handled, transported, stored, and used than hydrogen.

Terminology for Synthetic Fuels

When electrolysis produces the hydrogen input for synthetic fuels, the products are commonly called "electrofuels" or "e-fuels." The conversion schemes are referred to as "power-to-gas," "power-to-liquid," or more generally, "power-to-X," depending on the end product.

Certain synthetic hydrocarbons can be employed as direct substitutes for their conventional fossil-fuel counterparts (e.g., synthetic gasoline and diesel). The majority of activity to date in the area of electrolytic hydrogen-based synthetic fuels has focused on producing synthetic methane and, to a lesser extent, methanol.

Production

Synthetic fuel production is energy intensive because each conversion step involves sizeable energy losses. According to the IEA, energy losses account for approximately 45-60% of the electricity used to produce electricity-derived synthetic fuels (by mature conversion processes) [29]. If no concentrated source of CO_2 is available, the additional electricity required to separate CO_2 from the air via direct air capture (DAC) lowers the process energy efficiency by approximately 10% for power-to-liquids [30]. Improving conversion efficiencies is a central research and development focus in the synthetic fuels arena. However, even with considerable gains, synthetic fuels will likely not be a competitive decarbonization option in applications where direct use of electricity is feasible.

[8] Although this section focuses on synthetic hydrocarbons produced from electrolytic hydrogen and "sustainable" sources of CO_2, synthetic fuels can also be produced with hydrocarbon feedstocks, such as biomass (often called biofuels—covered in the Biofuels Production subsection, page 17), and fossil fuels, such as coal and natural gas. Conventional production of synthetic fuels from fossil-fuel feedstocks does not offer the potential for emissions reductions relative to conventional fuels. However, producing synthetic fuels from fossil feedstocks with emission reduction benefits is technically possible if low-carbon, fossil-derived hydrogen (i.e., if the hydrogen production employs CCS) and "sustainable" sources of CO_2 are feedstocks. This section does not cover these pathways.

Figure 6 summarizes select pathways for production of synthetic fuels from electrolytic hydrogen, which are detailed below.

Key Electricity-Based Synthetic Fuel Production Pathways

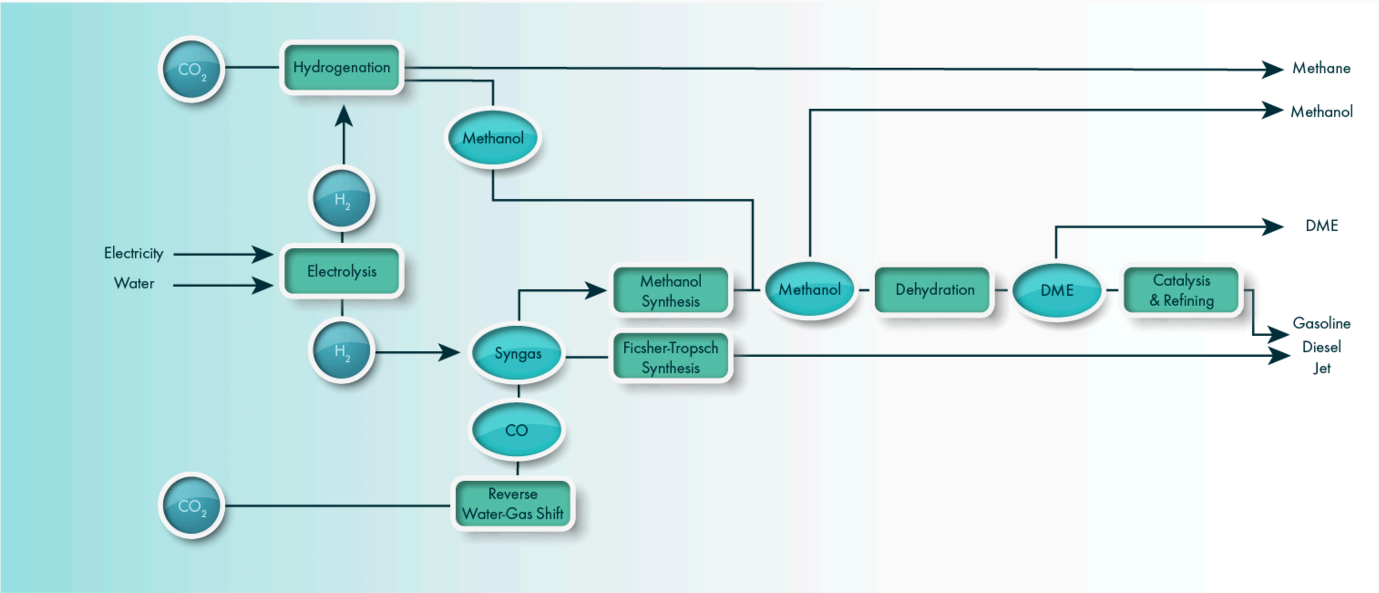

Figure 6. Primary pathways for production of synthetic fuels from electricity.

HYDROGENATION

The CO_2 hydrogenation process produces methanol and methane directly from hydrogen and CO_2. Known as methanation when methane is the product, this process is a technically mature and in the early commercialization stage [29]. Methanol can then also be catalytically converted to produce synthetic liquid fuels, or undergo a dehydration reaction to produce DME. There are approximately 70 demonstration projects for the production of synthetic methane from electrolytic hydrogen, with most located in Germany and Europe [3], along with a few projects for production of methanol from electrolytic hydrogen via this process.

METHANOL SYNTHESIS

In addition to direct production from hydrogen and CO_2 via hydrogenation, synthetic methanol can be produced via a mature process similar to conventional production processes from fossil fuels. CO and hydrogen are the primary inputs to this process, but because a CO source is typically not available, CO_2 is first converted to CO via the reverse water-gas shift process. Then, syngas consisting of CO and hydrogen is catalytically converted to methanol via methanol synthesis. The resulting methanol can be catalytically converted to produce gasoline (via the methanol-to-gasoline process) or dehydrated to produce DME.

Low-Carbon Methanol as a Feedstock for Plastic Production

Methanol, like ammonia, is an important feedstock for the chemical industry. Methanol is a basic ingredient for the manufacture of many products, including plastics. Methanol demand for plastics production has grown substantially in recent years, so "green" methanol produced from electrolytic hydrogen or biomass feedstocks (see the Biofuels Production subsection, page 17) could play an important role in decarbonization of the plastic production industry.

FISCHER-TROPSCH SYNTHESIS

CO and hydrogen are the primary inputs to this process, but because a CO source is typically not available, CO_2 is first converted to CO via the reverse water-gas shift process. Fischer-Tropsch synthesis then converts a syngas consisting of CO and hydrogen to raw liquid fuels (known as "synthetic crude") which can then be upgraded to synthetic diesel, gasoline, or jet fuels. Although Fischer-Tropsch synthesis is a commercially-mature process for production of liquid fuels from natural gas and coal, its application for power-to-liquids production is at an earlier stage of development.

Sources of CO_2 for Electricity-Based Synthetic Fuels

Potential CO_2 sources for production of synthetic fuels include:

- Captured CO_2 from fossil-fuel usage for power generation or industrial processes
- CO_2 obtained through DAC
- Biogenic sources (e.g., biogas and bioethanol production)

The cost of CO_2 feedstocks for synthetic hydrocarbons is highly dependent on available source. Using more concentrated process CO_2 streams from nearby industrial operations (e.g., ammonia production facilities) is much lower cost than using post-combustion capture at a power plant or DAC.

Fuels synthesized with captured carbon and the fossil fuels they displace have similar point-of-use CO_2 emissions. However, emissions savings derive from reusing CO_2 that otherwise may have been emitted from a previous process, displacing new CO_2 emissions from fossil-derived hydrocarbon use. The CO_2 savings associated with using electricity-based synthetic fuels is highly dependent on the emissions intensity of their production processes, including the source of energy input. Although these fuels contain carbon and emit CO_2 when used, certain synthetic hydrocarbons produced with "recycled" CO_2 and low-carbon energy inputs (such as low-carbon electricity) are considered "low-carbon" when their lifecycle emissions are substantially lower than the fossil fuels they displace.

Transport, Storage, and Handling

By definition, "drop-in" fuels are chemically and functionally identical to their petroleum-derived counterparts. Therefore, drop-in synthetic fuels, such as synthetic methane, gasoline, diesel, and jet fuel, are in principle fully compatible with existing transport and storage infrastructure and can be blended with their fossil fuel counterparts in concentrations of up to 100%.

Following are key handling considerations and transport and storage methods for methanol and DME, which are not considered drop-in compatible:

- Methanol is a stable liquid at ambient conditions. With extensive applications as a chemical feedstock, it is a widely traded chemical with a well-established distribution and storage infrastructure. Methanol is shipped overseas in dedicated ocean tankers, and bulk inland transport commonly occurs by rail or barge. Methanol is stored in large tanks similarly to petroleum-based liquid fuels, and tanker trucks typically locally distribute or transport smaller volumes of the chemical [31].

- DME is a gas at ambient conditions, but is handled under pressure as a liquefied gas similarly to LPG. LPG storage, transport, and handling infrastructure could be leveraged for DME, but replacement of some seals and gaskets with DME-compatible materials may be necessary) [32].

Applications

AVIATION

Although some aviation biofuel production routes are more mature, production of synthetic drop-in jet fuels from electricity may play a role in the long-term decarbonization of the aviation sector. Current aviation industry standards allow for blending of up to 50% synthetic jet fuels produced via Fischer-Tropsch synthesis, but integrated power-to-kerosene production has not yet been demonstrated [30].

LAND TRANSPORT

Synthetic diesel, gasoline, and methane are drop-in fuels that, in principle, can directly replace their fossil fuel counterparts for transport applications. Multiple power-to-gas projects are producing synthetic methane for application in compressed natural gas (CNG) vehicles. Production of synthetic gasoline and diesel from electricity is at earlier development stages.

Methanol and DME can be blended with gasoline and diesel, respectively, for use in the transport sector to reduce local emissions, such as particulate matter. However, the limitations of end-use equipment constrain the blending ratio of these fuels. Higher concentration methanol-gasoline blends can be used in specially-designed flexible fuel vehicles, which are most common in China. Methanol has been explored more broadly as an alternative transportation fuel in the past in the United States (principally in California), but ethanol has largely displaced it as an oxygenate for gasoline blends in this market [33]. Pure DME can also be used as a vehicle fuel in purpose-designed compression ignition engines. DME vehicle demonstrations have operated in North America, Europe, and Asia (mainly for buses and heavy-duty vehicle fleets) [34,35].

GAS GRID INJECTION

Synthetic methane can be injected into the natural gas grid, theoretically at quantities of up to 100%, for blended use in home heating, CNG vehicle fueling, and other traditional natural gas applications. According to IEA, over 50 projects injecting synthetic methane produced from electrolytic hydrogen into gas grids are recently completed, underway, or planned [12].

SHIPPING

Methanol is being investigated as a clean replacement for bunker fuel for maritime applications. Methanol can be used in marine diesel engines with minor system modifications using a small amount of pilot fuel for ignition. Because methanol is a liquid, its associated distribution, handling, and bunkering approaches are similar to those of conventional marine fuels.

However, methanol's energy density is approximately one-half that of conventional marine fuels, so more on-board fuel storage space or more frequent refueling would be required. A retrofitted passenger ship (see Figure 7) and a small fleet of new-build chemical tankers now operate on methanol fuel.

DME is also being investigated as a diesel substitute for marine engines. At least one OEM has developed DME-capable engines for marine applications [36].

Figure 7. The Stena Germanica, a ferry converted to operate on methanol fuel (photo courtesy of Stena Line).

Biofuels

The term "biofuels" typically refers to biomass-derived liquid—and sometimes gaseous—fuels often used for transport applications. (This section discusses biomass-derived liquids and gases.) Biofuels can be produced from a variety of organic feedstocks, including plants, or from agricultural, forestry, domestic, and industrial wastes. Because the plants and soils that are used to produce biofuels absorb CO_2 from the atmosphere as they grow, biofuels may offer substantial CO_2 emissions savings and carbon sequestration benefits relative to the fossil fuels they substitute[9], despite the release of much of this CO_2 back into the atmosphere at the point of use. Biofuels produced from waste feedstocks can in general lead to avoided GHG emissions—for example, biogas production by anerobic digestion of organic waste enables avoided methane emissions.

The most prevalent conventional biofuels in use today are ethanol ("bioethanol") and biodiesel, which are most often blended (although at relatively low levels) with their fossil-fuel counterparts for transport applications. Today, policies that mandate blending at low levels with their fossil-fuel counterparts primarily drive the global biofuel market [37].

Differentiating Between Conventional and Advanced Biofuels

Conventional biofuels—principally ethanol and biodiesel—are produced from sugar- and oil-based crops using fully commercialized processes. Although no industry consensus definition exists, "advanced biofuels" typically refers to biomass-derived fuels produced from lignocellulosic feedstocks (e.g., organic waste streams, agricultural and forestry residues, and dedicated energy crops in some cases) that may provide net GHG emissions benefits relative to the fuels they replace. Many advanced biofuels can function as "drop-in" fuels, meaning they are chemically similar enough to the fossil fuels they replace (i.e., they meet fuel specifications) that they can be blended in high concentrations or used "neat" in conventional end-use systems (e.g., engines, appliances) without modifications.

Production

Processes for ethanol production from sugar- and starch-based feedstocks and biodiesel production from lipid-based feedstocks are technically mature and widely deployed. These processes provide the vast majority of today's transport biofuels [37]. This section will not detail these conventional biofuel production processes. Instead, it focuses on production processes for advanced biofuels.

Figure 8 on page 18 summarizes key advanced biofuel production pathways. Tables 3 (page 18) and 4 (page 19) list key biological and biochemical routes, and thermochemical routes, respectively, for advanced biofuel production.

[9] Biofuels' GHG implications vary widely and are highly dependent on a range of factors, including land-use impacts and feedstock conversion methods. Therefore, emissions implications relative to incumbent fuels must be assessed (see the box on page 20 for more information).

Key Advanced Biofuel Production Pathways

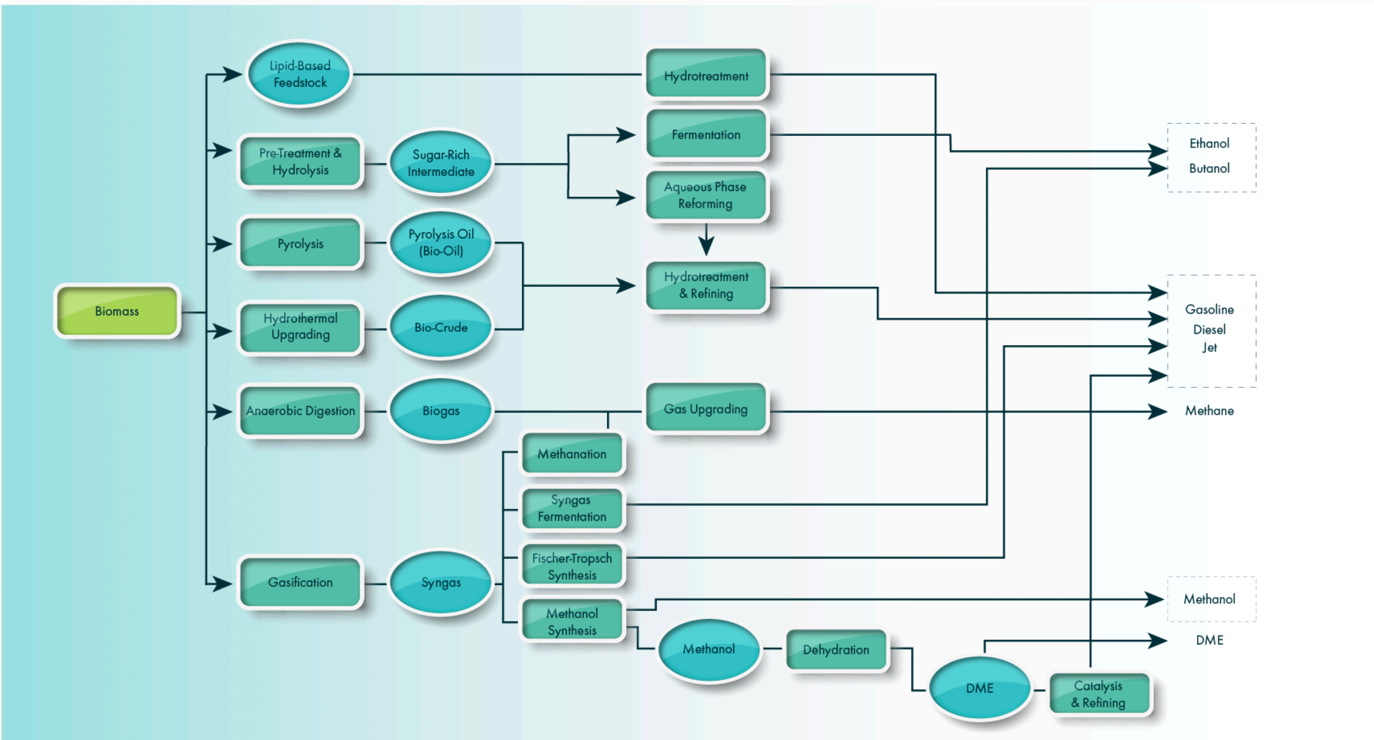

Figure 8. Simplified diagram of primary advanced biofuel production pathways.

Table 3. Key biological and biochemical routes for advanced biofuel production.

Primary Conversion Process	Process Summary	Maturity
Anaerobic digestion	The biological decomposition of biomass materials in the absence of air produces a mixture of methane and CO_2 (referred to as "biogas"), which can be used directly or upgraded (by removing CO_2 and impurities) to produce pipeline-quality biomethane.	Biogas production through anaerobic digestion and biogas upgrading to biomethane are mature processes [37] widely deployed at wastewater treatment facilities, landfills, and large animal farms.
Fermentation	Lignocellulosic biomass (dry plant matter such as agricultural residues) is first pretreated to separate the cellulose and hemicellulose from other components. The cellulose and hemicellulose then undergo hydrolysis for conversion into simple sugars suitable for fermentation. Yeast or bacteria then ferment these simple sugars, producing ethanol and butanol (a feedstock for the chemical industry).	Several first-of-a-kind fermentation-based lignocellulosic ethanol plants are in operation or in commissioning/final construction phases globally [38].
Syngas fermentation	First, biomass feedstocks undergo gasification to produce syngas. Microorganisms then ferment the syngas, producing ethanol and butanol.	This technology is in relatively early stages of development.

Table 4. Key thermochemical routes for advanced biofuel production.

Primary Conversion Process	Process Summary	Maturity
Pyrolysis	Dry biomass feedstocks are heated in the absence of oxygen, producing pyrolysis oil (as well as solid charcoal and by-product gasses) that can be used directly or upgraded by hydro-treating to produce high-quality liquid fuels that can substitute gasoline, diesel, or jet fuel. The upgrading steps can take place at a dedicated plant, or the pyrolysis oil could be blended with conventional crude for co-processing at oil refineries. Fast pyrolysis, which is characterized by rapid heating rates and short residence times, maximizes the production of pyrolysis oil.	A handful of fast pyrolysis plants in the demonstration to early commercial phase currently are in operation [38].
Fischer-Tropsch synthesis	First, a syngas is produced through gasification of biomass feedstocks. This syngas is then converted to intermediate hydrocarbons via Fischer-Tropsch synthesis, a catalytic process, which are subsequently upgraded to diesel, kerosene, or gasoline.	While the Fischer-Tropsch process itself is technically and commercially mature, application to biomass feedstocks is relatively new, with a few pilot and demonstration plants in operation.
Hydrothermal upgrading	Also known as hydrothermal liquefaction, hydrothermal upgrading is a process in which biomass with high water content is heated and pressurized to convert it to liquid “bio-crude”. This bio-crude can act as a substitute for heavy fuel oil or be upgraded to gasoline and diesel via hydrotreating [38], a similar process to that used at conventional oil refineries. Co-processing of bio-crude at existing oil refineries may be possible.	Hydrothermal upgrading for advanced biofuel production has been developed and tested only at pilot scale.
Hydrotreatment	Widely used in petroleum refineries, hydrotreatment involves reaction of lipid-based feedstocks (e.g., waste oils) with added hydrogen under high temperatures and pressures in the presence of a catalyst. The intermediate hydrocarbon liquid then undergoes a hydrocracking and isomerization step, which also involves the addition of hydrogen, producing jet fuel (known as HEFA-SPK), diesel (known as HVO or renewable diesel), and gasoline.	This process is commercially mature, with most production capacity today focused on production of renewable diesel.
Methanol synthesis	First, biomass is gasified. The resulting syngas is reacted with CO_2 over a catalyst and is refined to produce methanol. The resulting methanol can be catalytically converted and refined to produce gasoline (via the methanol-to-gasoline process) or be dehydrated to produce DME.	Methanol synthesis from conventional fossil fuel feedstocks is a technically and commercially mature process, but only a few commercial-scale methanol synthesis projects with biomass feedstocks are currently in operation [38].
Methanation	First, biomass is gasified. The resulting syngas is cleaned/conditioned, then undergoes a catalytic methanation step before being upgraded to produce biomethane (known as bio-synthetic natural gas, or bio-SNG).	While biogas upgrading is a more mature pathway for production of biomethane, there are several demonstration-scale bio-SNG plants in operation.
Aqueous phase reforming	Biomass feedstock first undergoes pretreatment and hydrolysis to produce an aqueous solution of sugars. Then, this aqueous solution of sugars is converted via a multi-step catalytic reforming process that requires hydrogen as an input.	Current applications of aqueous phase reforming are primarily focused on hydrogen production, and application of the process for production of liquid biofuels (which requires additional processing steps) is in earlier stages of development.

Bioenergy's Potential for Net GHG Emissions Reductions

Pairing biofuel production with CCS, which removes CO_2 from the atmosphere and sequesters it below ground, has long been discussed as a potential route to "negative emissions." The direct CO_2 emissions that result from burning biofuels without carbon capture are typically considered carbon neutral because the CO_2 absorbed by the growing feedstock plants offsets the CO_2 emitted at the point of use. However, this is an over-simplification, because of possible GHG changes due to land-use and market implications. Comprehensive carbon accounting for biofuels that accounts for these indirect impacts and long-run climate dynamics is needed.

Transport, Storage, and Handling

Following are key considerations for the handling of biomass feedstocks:

- **Variable production**. Many biomass feedstocks are harvested seasonally, so adequate storage is key to enabling year-round biofuel production. Furthermore, storage vessels must be adequately sealed to maintain biomass dryness and avoid degradation.
- **Moisture content**. Untreated biomass typically contains significant moisture, so drying or pretreatment is helpful.
- **Flammability**. Bulk storage of biomass also poses fire and dust explosion risks, potentially limiting storage time and requiring storage designs that account for dust hazards (e.g., by protecting against spark sources).
- **Energy density**. The higher weight and lower energy density of untreated biomass feedstocks compared with fossil fuels complicates and increases the cost of transport, potentially limiting the geographic areas in which biomass for fuels production can be sourced. Fuel preparation techniques, such as drying, size reduction, and other forms of densification, can facilitate handling, transport, and storage, while also increasing feedstock homogeneity and improving conversion logistics.

Transport, delivery, and storage considerations for biofuels are detailed below.

CONVENTIONAL BIOFUELS

Conventional biofuels, such as ethanol and biodiesel (also known as fatty acid methyl ester [FAME] biodiesel), are typically blended with gasoline and diesel, respectively, for transport applications. However, their physical properties differ from those of petroleum-derived fuels with which they are blended, complicating handling and distribution:

- For example, ethanol's higher water solubility can cause it to separate from gasoline during distribution and can contribute to corrosion of pipeline materials.
- FAME biodiesel has poor flow properties under colder conditions and an affinity for attracting dirt and other contaminants in transport.

For these reasons, ethanol and FAME biodiesel are typically not transported via existing petroleum pipeline infrastructure. Instead, they are usually blended with gasoline or diesel at distribution terminals, and the blends are then transported via truck to fueling stations [39].

DROP-IN BIOFUELS

Drop-in biofuels are chemically and functionally indistinguishable from their petroleum-derived counterparts and, in principle, are fully compatible with existing distribution and storage infrastructure. The most mature drop-in biofuels are methane from upgrading of biogas, and diesel and jet fuels from hydrotreatment. Other pathways under development for fully infrastructure-compatible biofuels include Fischer-Tropsch synthesis, pyrolysis, and hydrothermal upgrading.

BUTANOL

Most development efforts for bio-derived butanol focus on blending it with gasoline, similarly to ethanol. However, unlike ethanol, butanol is immiscible in water, potentially decreasing barriers to its transport in existing pipelines (although this has not yet been demonstrated). Distribution by tanker truck or rail is also possible.

METHANOL AND DME

See Electricity-Based Synthetic Fuels, Transport, Storage, and Handling subsection, page 15.

PYROLYSIS OIL AND BIOCRUDE

Many properties of these biofuel intermediates differ from properties of crude oil. For example, pyrolysis oil and biocrude have higher water and oxygen content and tend to be more corrosive. Their transport and storage via existing crude oil pipelines and infrastructure is likely unfeasible without additional upgrading steps.

BIOGAS

Because biogas is a low-grade, low-value fuel, its transport is rarely economically feasible [40], so it is almost always consumed on-site (e.g., for heat and power production at landfills, livestock operations, and wastewater treatment plants). Because biogas is typically used as it is produced, most storage is temporary, smaller scale, and lower pressure in nature. For example, digesters may be equipped with an integrated flexible, inflatable fabric top to accommodate smaller volumes of excess biogas.

BIOMETHANE

Biogas can be upgraded to pipeline-quality biomethane that is fully interchangeable with conventional natural gas, and is typically stored similarly to conventional natural gas in a compressed or liquified form. However, storage in a liquified form is typically limited to relatively short periods to minimize evaporative losses. If consumed on-site or near the point of use, biomethane is most commonly transported via dedicated pipeline. If transported longer distances, distribution in a bulk liquified form in LNG tanker trucks is common, but transport in a compressed form (in tube trailers) is also practiced [40]. Similar to synthetic methane produced from electricity, biomass-derived methane may also be blended into conventional natural gas pipeline networks.

Applications

LAND TRANSPORT

Biofuels accounted for approximately 4% of global on-road transport fuels (by energy) in 2016 [37]. Existing biofuels demand is dominated by on-road transport applications of ethanol and biodiesel, which are first generation biofuels that are most often blended at low levels with conventional gasoline and diesel for performance and environmental benefits.

Transport applications of drop-in biofuels are detailed below.

- Renewable diesel is a class of advanced biofuel drop-in diesel replacements produced through various processes (including hydrotreatment, Fischer-Tropsch synthesis, and pyrolysis). It is approved for use in existing engines and infrastructure in the United States and Europe. Renewable diesel production through hydrotreatment is commercially mature. The United States alone consumed nearly 1 billion gallons of renewable diesel in 2019 [41], mostly in California because of the state's Low-Carbon Fuel Standard.

- Renewable gasoline is suitable for use in spark ignition [41] and is approved for use in existing infrastructure and engines in the United States and Europe.

- Today, natural gas powers approximately 23 million vehicles worldwide [42]. Pipeline-quality biomethane can replace conventional natural gas for use in CNG or LNG vehicles. This opportunity is greatest in regions with substantial natural gas vehicle fleets and existing fueling infrastructure. Several European cities (including Stockholm, Lille, and Berlin) use sizable biomethane vehicle fleets for public transport and waste collection [43].

Transport applications of methanol, DME, butanol, and biodiesel, which are not fully drop-in compatible, are detailed below.

- Methanol and DME are considered gasoline and diesel substitutes, respectively. Bio-derived DME has been successfully demonstrated as a fuel for heavy-duty vehicle applications, with OEMs continuing development [44].
- Butanol blends of up to 16% with gasoline are approved for use in the United States, and biobutanol-gasoline blends are sold at a limited number of U.S. locations [45].
- In the rail transport sector, diesel is the dominant fuel for routes that have not been electrified. Biodiesel is a potential diesel substitute for rail transport, but experience in use of 100% biodiesel and biodiesel-diesel blends as rail fuels has been relatively limited.

AVIATION

More than 150,000 flights have used biofuel blends, and a handful of major international airports currently support regular biofuel distribution (see Figure 9) [46]. Several aviation biofuel production processes are already certified to industry standards (i.e., approved for blending with fossil jet kerosene). However, only one pathway (HEFA-SPK fuel) is technically mature and commercialized (with current industry standards allowing blends of up to 50%) [44]. Although biofuels accounted for less than 0.1% of aviation fuel consumption in 2018, biofuels have potential for growth. For example, the IEA's Sustainable Development Scenario projects a future with biofuels representing approximately 10% of aviation fuel demand by 2030, growing to nearly 20% by 2040. As the number of long-term fuel off-take agreements between airlines and biofuel producers grows, biofuels are positioned to play a central role in the aviation industry's long-term decarbonization plans [46].

Figure 9. Aircraft biofuel fueling on airport tarmac (photo courtesy of United Airlines).

SHIPPING

According to a 2017 Lloyd's Register and UMAS assessment, advanced liquid biofuels could represent the most cost-competitive low-carbon option for the shipping industry. Because they can be used in a way that closely mirrors current technology, capital cost implications for machinery and storage may be relatively low compared to alternatives, such as ammonia and hydrogen [26]. Early adoption of biofuels has occurred in certain niche markets, such as ferries operating near densely populated coastal areas (requiring higher fuel quality than for deep-ocean shipping) and charter boats in the eco-tourism industry (e.g., whale-watching cruises). The U.S. Navy and Coast Guard have also tested and deployed biofuels and biofuel blends on ships, including conventional biodiesel, hydrotreated renewable diesel, and bio-butanol [47]. Several marine engine manufacturers have certified their engines to operate on conventional (FAME) biodiesel or biodiesel-diesel blends.

Biofuel intermediates, such as bio-crude (from hydrothermal upgrading) and pyrolysis oil, are also being explored as substitute fuels for marine engines that use low-quality heavy fuel oil.

While the existing LNG fleet size is relatively small but growing, biomethane can act as a drop-in fuel for LNG vessels. Methanol and DME are also being explored as marine fuels (see Electricity-Based Synthetic Fuels, Applications: Shipping subsection, page 16) and can both be produced from biomass.

POWER AND HEAT

Production of biogas from landfills (known as landfill gas), wastewater treatment processes, and livestock operations for direct thermal use on-site or for electricity generation (typically via engines) are commercially mature processes. Thousands of biogas installations are in operation, and most producers use the biogas for on-site electricity, process heat, or combined heat and power (CHP) production. Today, nearly 20 GW of biogas-based power generation capacity is available, mostly in Europe and the United States [48]. Biogas co-generation is a potential area for growth, particularly in locations with local demand for heat off-take or in certain industrial applications where biogas production can provide both waste treatment and on-site electricity and heat.

In China, a major biogas-producing country, most biogas is produced from small-scale biodigesters and used for domestic cooking [43]. Such small-scale domestic biogas applications are common in rural areas that lack connection to the gas and/or electric grid throughout the developing world.

Liquid biofuels can also be used for heat and power production as a substitute for diesel fuel, but these applications are not expected to be a major driver of biofuel deployment.

Although direct use of biomass (as opposed to gaseous or liquid biomass-derived fuels) is outside this report's scope, mature biomass applications include the following:

- Co-firing with coal in large-scale power plants
- Fuel for smaller-scale CHP plants
- Heat production for district heating networks
- Provision of process heat for a range of industries
- Fuel for traditional heat production for cooking and space heating

There is also potential for future large-scale dedicated biopower facilities, particularly with CCS.

GAS GRID INJECTION

Biogas that has been upgraded and purified to produce biomethane (also known as renewable natural gas [RNG]) that meets specifications for pipeline-quality gas can be injected into existing natural gas pipeline networks. The gas can then be distributed and broadly utilized in a blended form with conventional natural gas.

However, integration with natural gas networks has traditionally been far less common than direct use on-site because of the costs associated with upgrading the biogas to specifications for pipeline-quality gas and the high cost of interconnecting the RNG facility with the natural gas distribution network. The more-centralized gas cleaning, upgrading, and grid injection operations associated with larger-scale RNG projects, which have grown in recent years, can mitigate these barriers.

Conclusion

The global energy system is transforming rapidly, and the emerging consensus surrounding the urgency of decarbonization has driven unprecedented momentum in low-carbon fuels. No single "silver bullet" technology or fuel is capable of providing substantial, widespread emissions reductions and energy services. Economy-wide, deep decarbonization requires a robust portfolio of low-carbon fuels in combination with other measures, including electrification and energy efficiency. When produced via low-carbon means, fuels such as hydrogen, ammonia, methanol, and synthetic drop-in fuels can provide pathways to decarbonization for a wide variety of end uses that currently rely on fossil fuels. In some cases, these fuels can be delivered, stored, and utilized similarly to fossil fuels, enabling existing assets and infrastructure to be leveraged in the transition to a low-carbon energy system. Where existing infrastructure cannot be used, new infrastructure development can play a critical role in the timing and feasibility of low-carbon fuel adoption.

Next Steps

Many technologies across the low-carbon fuel value chains remain pre-commercial. Large-scale and low- or no-carbon production, delivery, and utilization of these resources requires significant additional research. Key research needs to accelerate development and deployment of these technologies include the following:

- Assess the technical and economic uncertainty, feasibility, and value of low-carbon energy carrier applications relative to, or in tandem with, alternative decarbonization approaches, such as electrification
- Assess various low-carbon fuel pathways' cost, performance, and GHG emissions
- Identify optimal approaches to integrate fuel production with various low-carbon electricity sources; and assess the energy system impact of energy carrier adoption (e.g., evaluation of any required changes to the generation mix)
- Model and analyze end-to-end energy production and long-term energy storage opportunities
- Evaluate and test the ability of existing infrastructure (e.g., natural gas pipelines) to support low-carbon fuels and fuel blends; and assess the new infrastructure needed to support delivery, storage, and utilization of low-carbon fuels
- Analyze feedstock supply for low-carbon fuels, including resource requirements, environmental impacts, and land use challenges
- Develop safety protocols, operations and maintenance strategies, and long-term management approaches for equipment across the energy carrier value chain
- Research and develop ways to enable improvements in energy-conversion efficiency for production of synthetic fuels (e.g., identify new catalysts, and improve process heat utilization)
- Develop and optimize end-use technologies in the transportation, buildings, and industrial sectors to accommodate a range of potential low-carbon fuels

EPRI and the Gas Technology Institute (GTI) have created the Low-Carbon Resources Initiative (LCRI) to help address these research gaps in order to accelerate the development and demonstration of low-carbon energy technologies for large-scale deployment by 2030 and beyond. This five-year initiative will focus on a variety of low-carbon energy carriers, including hydrogen, ammonia, synthetic fuels, and biofuels. It will provide a centralized, collaborative platform to accelerate development of key technologies through fundamental research, demonstration, and deployment.

Acronyms and Abbreviations

Abbreviation	Meaning
BEV	battery electric vehicle
CCS	carbon capture and storage
CCUS	carbon capture, utilization, and storage
CHP	combined heat and power
CNG	compressed natural gas
CO	carbon monoxide
CO_2	carbon dioxide
CO_2-eq	carbon dioxide equivalent
DAC	direct air capture
DME	dimethyl ether
EPRI	Electric Power Research Institute
FAME	fatty acid methyl ester
FCEV	fuel cell electric vehicle
GHG	greenhouse gas

Abbreviation	Meaning
GTI	Gas Technology Institute
HVO	hydrotreated vegetable oil
LCRI	Low-Carbon Resources Initiative
LNG	liquefied natural gas
LPG	liquified petroleum gas
MMT	million metric tons
NOx	nitrogen oxides
OEM	original equipment manufacturer
PEM	proton exchange membrane
RNG	renewable natural gas
SMR	steam methane reforming
SNG	synthetic natural gas
SOEC	solid oxide electrolysis cell

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