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Emerging Technologies Review: Hydrogen Production and Storage

March 2024

Candace D. Briggs
Kendall M. Parker
Gerad M. Freeman
Marcy Whitfield (Project Manager)

Prepared for the Air Force Civil Engineer Center
under a Work-For-Others Agreement with the U.S. Department of Energy

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Pacific Northwest National Laboratory
Richland, Washington 99354

Executive Summary

Most missions in the Air Force depend on both water and energy. The 2021 Air Force Installation Energy Strategic Plan embraces this dependency and outlines a path to greater mission assurance through the realization of more resilient energy and water systems. The previous energy strategic plan placed equal weight on resilience, cost-effectiveness, and cleaner energy technologies. The new plan emphasizes a focus on resilience and mission-centric efforts, while also highlighting the importance of water: "Resilience has become central to Air Force efforts."[1] The 2022 Air Force Climate Action Plan[2] aligns with the Energy Strategic Plan in its third priority, where it calls on the Air Force to optimize energy use and pursue alternative energy sources. The Air Force Civil Engineer Center has tasked Pacific Northwest National Laboratory with investigating emerging technologies to inform the Air Force's understanding of the technology and to guide key considerations for implementing technologies that are resilient and alternative sources to the traditional methods used in the Air Force today.

This report explores the concept of hydrogen production and storage at Air Force installations. Various resources can be used to make hydrogen through a variety of methods. Figure ES.1 shows an overview of hydrogen production, delivery, storage, conversion and application technologies. Each technology has its own resilience, cost-effectiveness, and environmental characteristics. Hydrogen produced through these methods may then be stored and used to produce electricity or used as a fuel to power various operations, potentially decreasing the Air Force's reliance on external energy providers and, depending on the method chosen, lessen dependence on fossil fuels.

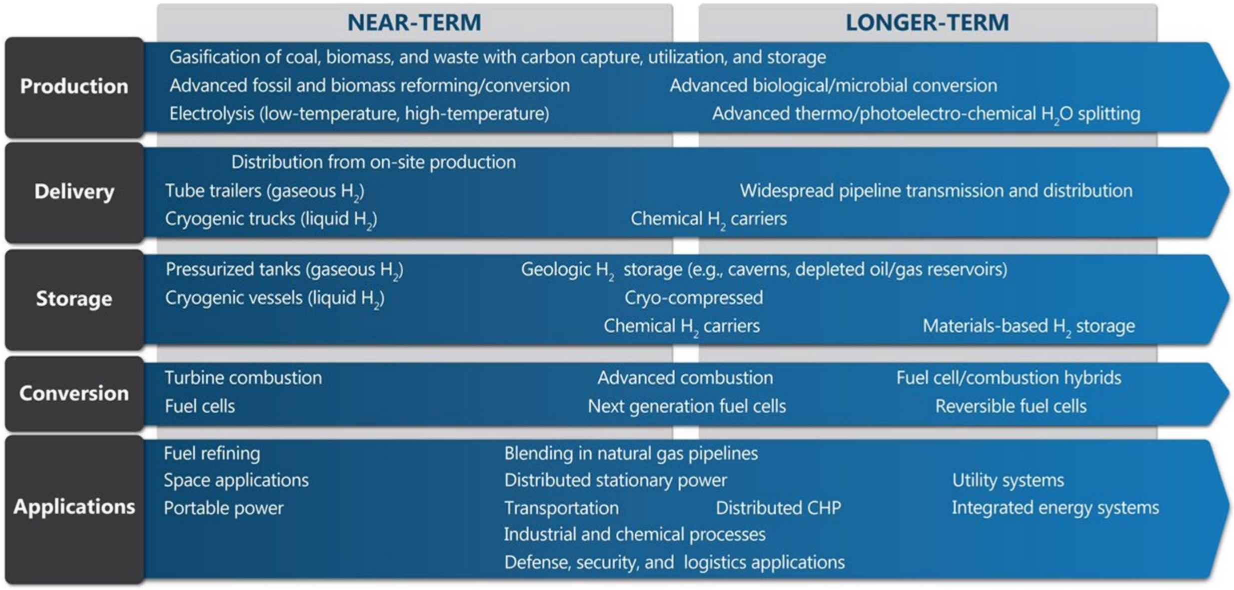

Figure ES.1. Key Hydrogen Technology Options Overview (DOE 2020a)

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[1] Air Force Installation Energy Strategic Plan, https://www.af.mil/Portals/1/documents/2021SAF/01_Jan/AF_Installation_Energy_Strategic_Plan_15JAN2021.pdf

[2] Air Force Climate Plan, https://www.safie.hq.af.mil/Programs/Climate/

The most common hydrogen production methods include steam methane reforming (SMR), electrolysis, and gasification. In SMR, steam is used to separate hydrogen from methane with carbon dioxide left over. In electrolysis, electricity is used to create a reaction that splits water molecules and produces hydrogen and oxygen. Table ES.1 provides some pros and cons associated with most common hydrogen production methods. In gasification, feedstocks like biomass or coal are exposed to steam and oxygen at high pressures to separate the hydrogen from the feedstock.

Table ES.1. Pros and Cons of Most Common Hydrogen Production Methods[(a)] (DOE 2023a; DOE HFTO 2016; DOE HFTO 2023a, Khedkar et al. 2023)

	Hydrogen (H_2) Yield	Pros	Cons
Solid oxide electrolysis	0.026 kg H_2 / kWh[(b)] 0.09-0.1 kg H_2 / L water[(c)]	• High efficiency • Multiple feedstock options • Usable waste heat • Inexpensive catalysts	• High pressures and temperatures required • Long start-up times • Corrosion issues • Limited number of shutdowns
Alkaline electrolysis	0.019 kg H_2 / kWh[(b)] 0.09-0.1 kg H_2 / L water[(c)]	• Mature technology • Lower cost components • Durable system components • Fast start up • Operates at low temperatures • High efficiency	• Complicated maintenance • Cannot produce high-pressure H_2 • Alkaline corrosion • Large and heavy system • Sensitive to CO_2 in fuel and air • Electrolyte management (aqueous) • Electrolyte conductivity (polymer)
Proton exchange membrane (PEM) electrolysis	0.019 kg H_2 / kWh[(b)] 0.09-0.1 kg H_2 / L water[(c)]	• System simplicity • Small footprint and weight • Produces H_2 at higher pressures than alkaline • Fastest start-up times • Reduced corrosion & electrolyte management problems • Operates at low temperatures	• High capital costs • Lower commercial availability • Sensitive to fuel impurities
Steam methane reforming	40-130 g H_2 / kg methane[(d)]	• Mature process • High efficiency • Lowest capital cost • Multiple feedstock options	• High pressures and high temperatures required • Process produces carbon dioxide as a byproduct – must be paired with carbon capture to be carbon-free • Can experience corrosion from carbon dioxide deposition
Gasification	40-190 g H_2 / kg biomass[(d)]	• Mature process • Does not involve combustion • Multiple feedstock options including renewables (i.e., biomass, waste) • System simplicity • High efficiency	• High pressures and high temperatures required • Process produces carbon dioxide as a byproduct – must be paired with carbon capture to be carbon-free • High capital costs

(a) Content adapted from DOE HFTO (2016), unless otherwise noted. Electrolyzers are typically described in modular units known as "stacks." Multiple stacks might be placed within one system.
(b) Bloom Energy 2022
(c) Nnabuife 2023
(d) Lepage et. al 2021

The most suitable hydrogen storage method depends on requirements for storage duration and quantity. Standard techniques for hydrogen storage include above-ground pressurized tanks, cryogenic storage vessels, pipelines, and subsurface geologic storage. Hydrogen is stored as a gas in pressurized tanks, usually for small-scale operations. Gaseous hydrogen can also be internally stored in a pipeline or in subsurface geologic formations for large-scale operations if ideal system requirements and geologic conditions exist. Supporting infrastructure such as distribution and dispensing equipment vary depending on the storage technique selected. Table ES.2 describes the differences between the storage methods mentioned above.

A hydrogen-based energy facility can have many configurations, depending on the selected production method, and storage technique. System size, components, and configuration will affect operations and maintenance, staffing requirements, cyber security considerations, and emergency planning. Many complementary technologies, including fuel cells, ammonia production, water microgrids, renewable power sources, and grid connection(s), could potentially bolster the versatility, use cases, and benefits of a hydrogen production and storage system at an Air Force installation.

Table ES.2. Description and Considerations for Common and Emerging Hydrogen Storage Technologies.

Method	State	Approx. TRL[(a)]	Pressure & Temp	Max Deliverability	Energy Cost for Method	Considerations
Pressurized tanks	Gas	9	250–1,000 bar 10–30°C	several tons per day	13–20%	• Large footprint to store large volumes • High energy costs to pressurize
Cryogenic tanks	Liquid	9	1 bar −253°C	100s of tons per day	40%	• Less volume required than pressurized tanks but still relatively large aboveground footprint • Extremely high energy costs to cool • Evaporation losses
Metal Hydrides	Solid	4-6	Near ambient pressure and temperature possible -50–200°C	**<< 1 ton per day**	12 - 24%	• High material costs lead to difficulties scaling up • Can lead to very heavy systems • Low H_2 release rate • Relatively high H_2 release temperature requirements
Pipeline	Gas	7-8	10-200 bar -45°C–175°C	100s of tons per hour	7%	• Hydrogen pipelines are not common • Hydrogen may be blended in small ratios into natural gas pipelines
Subsurface geologic	Gas	7-9	25–200 bar 10–80°C	100s of tons per hour	Application dependent	• Highest storage capacity • Requires suitable geology • Potentially the least expensive option

(a) Technology readiness level (TRL) approximation based on Defense Acquisition Guidebook (2010).

Technical considerations discussed in this report include limiting factors related to component availability, supply chains, and the environment. The main limiting factors to hydrogen production and storage are land requirements, cost, and suitable demand for hydrogen. Component availability may be affected by the use of critical and rare materials in electrolyzers and steam methane reformers. Supply chain issues may occur when scaling up systems. Environmental considerations for hydrogen systems include challenging cryogenic temperatures required for liquid storage and transportation or technical hurdles created by the large volume requirements for gaseous storage.

Multiple successful hydrogen production facilities exist across the U.S. and the world using various production and storage techniques. In the U.S., hydrogen production has tripled since 2021. Demand is expected to continue to increase with multiple plans for clean hydrogen production facilities in the near future.

Many sections of this report focus on an optimal use case and scenarios centered on a system with carbon-free electricity generation powering hydrogen production through proton exchange membrane (PEM) electrolysis using appropriate storage for the production volume. This configuration is potentially optimal for Air Force installations because of its potential for distributed generation of hydrogen and decreased dependence on external energy systems, resilience to energy disruptions with right-sized storage for critical mission needs, cost effectiveness, and carbon-free operation potential as discussed in the report.

Both federal and state regulations may influence the configuration and operation of hydrogen production and storage systems. Requirements might include reporting on facets of production (such as greenhouse gas emissions) and participation in risk prevention programs to mitigate chemical-related accidents and incidents. Approval and oversight by different state and local jurisdictional bodies (like fire authorities) for production and storage methods may also be required.

Social, environmental and safety risks are involved in hydrogen production and storage. Educating and informing the public can go a long way toward preventing and alleviating skepticism and misperceptions about hydrogen production. The planning and construction of a facility may benefit a community if local skilled workers are employed to build the facility. Extra consideration should be taken to not further exacerbate climate impacts on communities already disproportionately affected by climate change. Benefits to communities through stability of the grid can be an additional benefit if grid connection is explored. Environmental risks mainly involve contributing to greenhouse gas, furthering the effects of climate change. Safety concerns associated with storing a flammable liquid or gaseous fuel include risks of ignition and explosion if proper safety mechanisms and processes are not employed. Cold-related harm can also pose a risk to personnel operating cryogenically stored liquid hydrogen if that technology is deployed in the selected system.

System and lifecycle costs may vary considerably depending on the system configuration. Generally, alkaline electrolyzers are less expensive than PEM electrolyzers, and SMR systems are less expensive than all types of electrolyzers. System life estimates for electrolyzers and SMRs are 30 and 40 years, respectively, with periodic replacement of some system materials required at around 15 years for electrolyzers. Incentives and funding mechanisms including the Bipartisan Infrastructure Law and the Inflation Reduction Act are in place to fund infrastructure investment to produce hydrogen with emphasis on achieving climate targets and reducing carbon emissions. Revenue opportunities can also be considered to increase economic attractiveness, such as producing electricity and selling it to the grid with grid connection, using hydrogen to reduce utility costs, and supplementing or displacing fossil fuels as a cost reduction measure.

Implementation and siting considerations including space requirements, resource availability, and infrastructure requirements must be examined to determine feasibility of a hydrogen production and storage facility. The scale of production will greatly influence the space required for the facility. A 100-MW electrolyzer system requires an estimated 3,500 to 6,300 m^2 (about 1 to 2 acres) of space. Resource availability can impact hydrogen production, potentially making it difficult based on the availability of the required resources like stable natural gas supplies, renewable power generation, fresh water, or appropriate geology.

There are many prospective locations across the U.S. where the Air Force might successfully build a hydrogen production and storage facility. Hydrogen has significant potential to bolster Air Force resilience by storing energy for use during outages or periods of high demand and could open the door to integrate other technologies like fuel cells or ammonia production. Using hydrogen to replace fossil fuels could contribute to Air Force, national, and global efforts to reduce emissions and combat climate change.

Acronyms and Abbreviations

AC	alternating current
AWARE	available water remaining
BIL	Bipartisan Infrastructure Law
CGA	Compressed Gas Association
CIS CSC 18	Center for Internet Security Critical Security Controls
DC	direct current
DOD	U.S. Department of Defense
DOE	U.S. Department of Energy
FEMP	Federal Energy Management Program
HDSAM	Hydrogen Delivery Scenario Analysis Model
HESET	Hydrogen Energy Storage Evaluation Tool
HyRAM+	Hydrogen Plus Other Alternative Fuels Risk Assessment Models
IEA	International Energy Agency
IRA	Inflation Reduction Act
LHV	lower heating value
NERC CIP	North American Electric Reliability Corporation Critical Infrastructure Projection
NFPA	National Fire Protection Association
O&M	operations and maintenance
PEM	proton exchange membrane
PEMFC	polymer electrolyte membrane fuel cell
PNNL	Pacific Northwest National Laboratory
PV	photovoltaics
RFC	reversible fuel cell
SMR	steam methane reforming
SOFC	solid oxide fuel cell
TRL	technology readiness level
UGS	underground gas storage

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1.0 Introduction

As Air Force planners work to enhance the energy and water security of their bases, it is vital to identify proven methods and processes to generate, store, and distribute energy to meet critical missions. Energy resilience readiness exercises conducted by the Assistant Secretary of the Air Force for Energy, Installations, and Environment have helped to highlight the importance of resilient and reliable energy to every critical mission. Hydrogen energy technologies provide a versatile and complementary solution that can serve as a redundant energy supply during times of disruption, thereby improving installation readiness and resilience while supporting broader sustainment and environmental objectives. The use of alternative energy sources supports the requirements outlined in U.S. Department of Defense (DOD) Instruction 4170.11 (DOD 2009), which states that DOD components shall “take necessary steps to ensure the security of energy and water resources.” The U.S. Air Force Installation Energy Strategic Plan 2021 (Air Force 2021) outlines a path to greater mission assurance through the realization of more resilient energy and water systems. The new plan emphasizes a focus on resilience and mission-centric efforts. The Air Force Civil Engineer Center has tasked Pacific Northwest National Laboratory (PNNL) with investigating emerging technologies to inform the Air Force’s understanding of hydrogen production and storage systems and guide key decisions for implementing technologies that are resilient and alternative sources to the traditional methods of energy supply used in the Air Force today.

This report describes hydrogen production and storage system options based on the current technology landscape and previous research conducted by PNNL. The primary focus is on technology solutions to produce and store carbon-free hydrogen using renewable or nuclear energy, and the secondary focus is on hydrogen produced using fossil fuels with carbon capture technologies. The primary production pathway highlighted here aligns with the Air Force’s interest in carbon-free energy planning and the federal government’s shift to a cleaner energy future. To contextualize the hydrogen production and storage technologies presented in this report, brief discussions of hydrogen transportation methods and end-uses are included. But, since hydrogen production and storage technologies can be integrated as standalone pieces to complement energy systems on installations composed of many technologies, most of this report focuses on those two parts of hydrogen energy systems. Hydrogen end-use technologies, such as fuel cells, are not discussed at length, but are described in the complementary technologies section as an option to use hydrogen to produce electricity.

Section 2.0 describes the components and operational considerations of hydrogen production and storage technologies. Section 3.0 provides technical considerations for hydrogen production and storage. Section 4.0 provides an overview of the regulatory environment. Section 5.0 describes social and environmental risks inherent with this technology. Section 6.0 provides considerations for funding hydrogen production and storage. Sections 7.0 and 8.0 provide siting recommendations and a path forward for potential hydrogen production and storage in the Air Force.

2.0 Technology Description

Hydrogen has been explored as an alternative energy technology because of its versatility of uses, efficiency as a fuel, and potential production using carbon-free methods (Naber and Siebers 1998). Hydrogen is the most abundant element on Earth; however, it does not commonly exist in its pure state. Hydrogen intended for use as fuel must be obtained by processing raw materials or feedstock that contain hydrogen in other forms, such as water, biomass, fossil fuels, or waste materials (DOE 2020a). Once produced, pure hydrogen as an energy carrier most commonly is used in either the gaseous or liquid state. In its gaseous state, hydrogen has no smell, color, or taste, and is nontoxic. To be transported and stored as a liquid, hydrogen must be kept at very low temperatures to avoid vaporization, requiring special tanks and materials.

A hydrogen energy production and storage system is composed of the suite of technologies that convert various forms of input resources and feedstocks into hydrogen as the primary energy carrier and store that hydrogen so it can be delivered to various end-use applications. Figure 1 provides an overview of both near-term and long-term technology options and processes that are employed in various portions of hydrogen infrastructure systems. The primary objective of these systems is to provide a versatile energy carrier that is relatively easy to produce, store, transport, and dispense with enough resilience and decarbonization benefits to justify the costs.

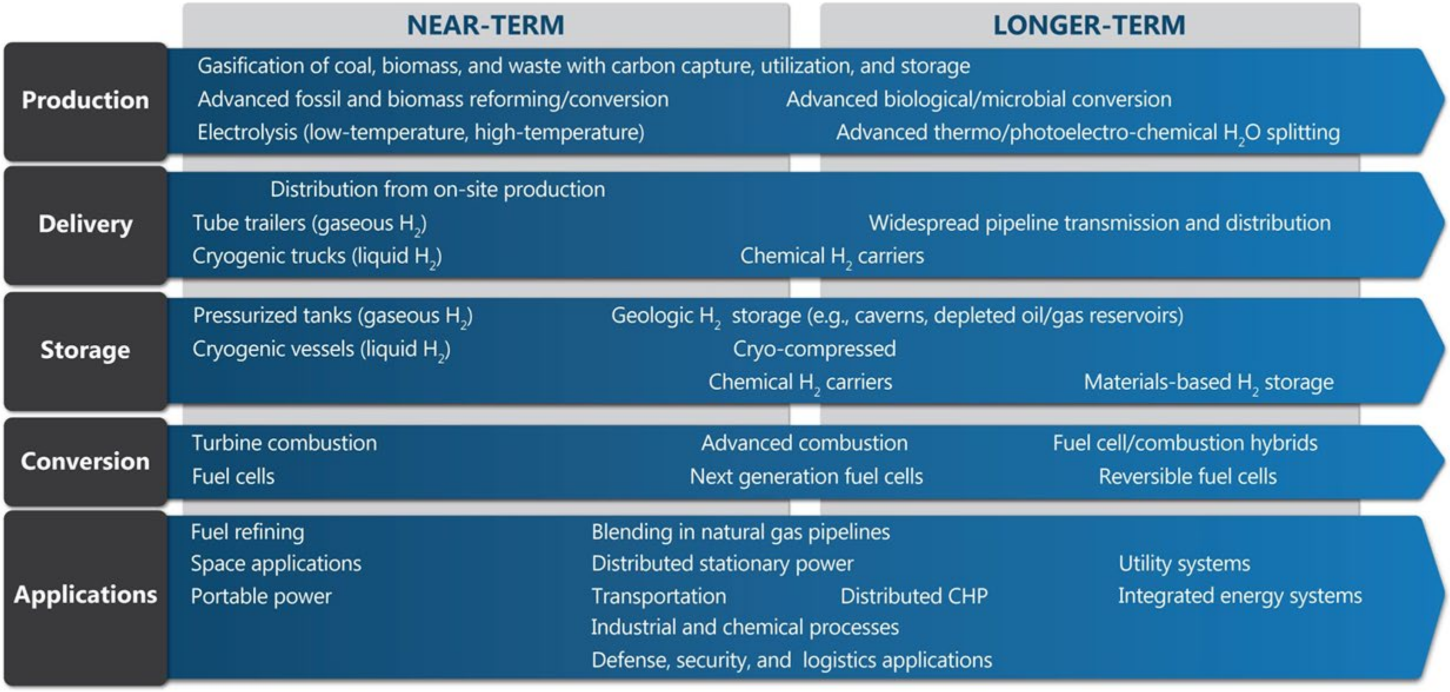


Figure 1. Hydrogen-Based Energy System Overview (Stetson 2022)

2.1 Characteristics

Hydrogen energy systems at Air Force installations could provide end-use versatility, be modular, and complement existing systems. They could also enable improvements in a site's carbon footprint and provide multiple options for transportation and storage of fuel.

End-use versatility: Hydrogen can be used as a fuel or feedstock for many end-uses. The U.S. Department of Energy (DOE) notes six key use cases for hydrogen in the U.S. economy: (1) chemical and fertilizer production; (2) heavy-duty trucking; (3) iron-, steel-, and cement-making; (4) biofuel and synthetic fuel production; (5) enabling a clean energy system through production and storage of hydrogen and power generation; and (6) blending with natural gas (DOE Hydrogen Program 2023). Through these key use case areas, the Air Force might use hydrogen for multiple key mission requirements like aviation fuel production, ground vehicle propulsion, and electric power generation, or as a feedstock to industrial processes that support the Air Force mission.

Modular and complementary: Hydrogen technologies can be self-contained as a coupled production and storage technology, or individual components that use, store, or produce hydrogen can be added to an existing system alongside other technologies, depending on the context. For instance, electrolyzers and fuel cells might be coupled with existing solar or wind power generation technologies at or near a site to produce hydrogen during times of excess electricity production from wind and solar and convert that hydrogen back into electricity using a fuel cell or other generator type to support the mission of the site when wind or solar is not available. A self-contained integrated project for a site might be used to construct all facets of the system (including the complementary solar and wind in this example) based on hydrogen as the central energy carrier for the system, rather than electrons.

Enable carbon reduction: Hydrogen can be produced through various methods using resources that are carbon-based, low-carbon, or carbon-free. If carbon-free energy sources are used to produce the hydrogen used and stored on site, the site's environmental footprint can be reduced through the displacement of hydrocarbon fuels.

Multiple transportation and storage options: Hydrogen can be transported and stored either as a gas or liquid using various technologies. Transportation options include mature technologies like rail, ocean ship, over-the-road truck and trailer, and pipeline. Storage of hydrogen can also be achieved through proven technologies in the energy system. Options available for hydrogen storage include high-pressure gaseous systems, above-ground tanks; cryogenic liquid above-ground storage tanks; internal storage in transportation systems like pipelines, railcars, and mobile tank trucks; or, potentially, in underground geologic formations.

2.2 Components

As shown in Figure 1, the main segments of a holistic hydrogen energy system are production, delivery, storage, and conversion (or end-use). This report focuses primarily on the production and storage segments of the system with some discussion of the delivery components needed to enable transfer of feedstocks between production and storage and to enable end-use for a site. The following subsections focus on specific system components and technologies that produce hydrogen from various forms of energy and chemicals, compress or liquify the produced hydrogen for storage, and transport hydrogen out of storage vessels to dispense it in either liquid or gaseous form.

2.2.1 Production

Hydrogen can be produced using a wide variety of fuels and feedstocks like natural gas, oil, and coal or low-carbon energy sources such as biomass and electricity from nuclear, solar, and wind (Figure 2). On rare occasions, hydrogen can occur naturally from microbial interaction and fermentation underground in spaces like depleted oil wells, and in extremely rare occasions hydrogen can occur as pure deposits beneath the surface without human intervention. Table 1 identifies the “colors” of hydrogen production as a naming construct to identify different production types, the major processes employed, inputs and outputs, and additional system requirements.

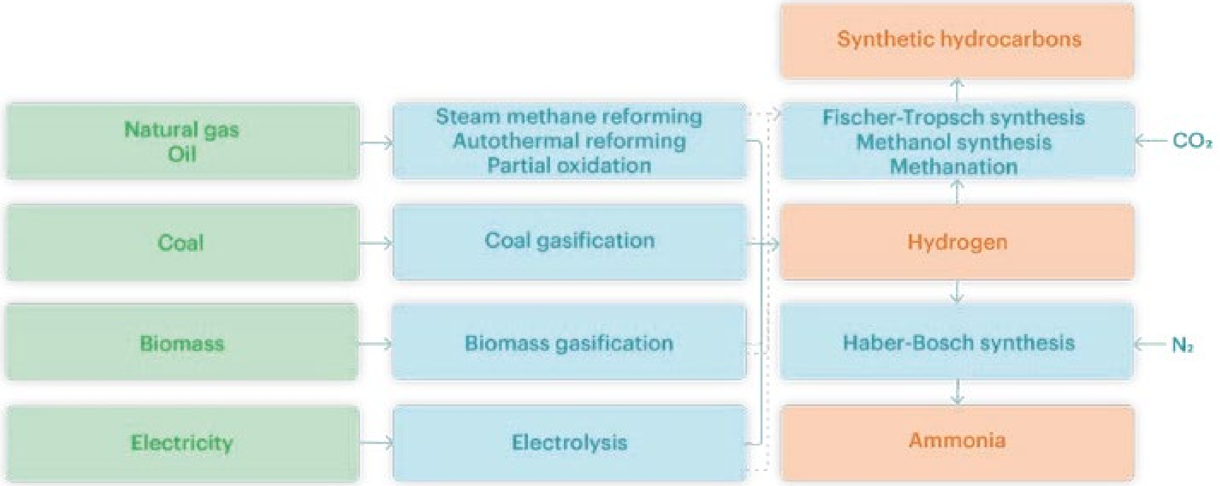


Figure 2. Hydrogen Production Pathways (IEA 2019). Solid lines show the primary hydrogen production pathways and dotted lines show hydrogen-containing syngas production.

Table 1. Colors of Hydrogen, Major Processes, Inputs, Outputs, and Complementary Technology Needs

Color (energy source)	H2 Production Process	Major Process Inputs	Process Outputs	Complementary Systems Needed
Red (nuclear)	Thermochemical water splitting	heat water	H_2, O_2	Nuclear reactor and spent fuel containment
Purple (nuclear)	Thermochemical water splitting + Electrolysis	heat electricity water	H_2, O_2	Nuclear reactor and spent fuel containment Water purification
Pink (nuclear)	Electrolysis	electricity water	H_2, O_2	Nuclear reactor and spent fuel containment Water purification
Blue (natural gas)	Fossil reforming with carbon capture	natural gas water heat electricity (CCS)	H_2	Carbon capture technologies
Turquoise (natural gas)	Fossil reforming (pyrolysis)	natural gas oxidant electricity (CCS)	H_2, solid carbon, flue gases (if no CCS)	Potentially, carbon capture technologies
Grey (natural gas)	Fossil reforming (steam)	natural gas water heat	H_2, CO_2	-
Black (coal)	Gasification	coal (Anthracite, Bituminous, or Sub-bituminous) water oxidant electricity	H_2, CO_2	carbon capture technologies
Brown (coal, biomass, or solid waste)	Gasification	coal (Lignite), some biomass types, or solid waste water oxidant electricity	H_2, CO_2	carbon capture technologies
Gold (biological)	Microbial interaction (within depleted oil wells)	electricity (for pumping, purification and transport)	H_2 and other gas constituents	**Suitable subsurface conditions** Recovered gas filtration and separation equipment
White (natural)	Geological	electricity (for pumping, purification and transport)	H_2	**Suitable subsurface conditions** Recovered gas filtration and separation equipment
Green (renewable)	Electrolysis	electricity water	H_2	Non-solar renewable power generation Water purification
Yellow (solar)	Electrolysis	electricity water	H_2	Solar power generation Water purification

The International Energy Agency (IEA) (2018) projects that natural gas, coal, biomass, and electricity will all contribute substantially to the supply of hydrogen produced in the U.S. in the next three decades (Figure 3). The remainder of this report focuses on these techniques through technology implementation as the most likely pathways to implementing hydrogen production on Air Force installations. While geologic hydrogen may exist underneath some Air Force installations and light prospecting activities may be justified, gold and white hydrogen are extremely scarce, and widespread applicability and availability of those types are not expected for most Air Force locations. Therefore, gold and white hydrogen are excluded from the remainder of this report. Moreover, since there are currently no nuclear reactors on Air Force installations, thermochemical water splitting (purple and red) is not a focal point of this section, and instead nuclear power is discussed as a complementary technology in Section 3.4.6. The sections below describe the different production pathways shown in Figure 2.

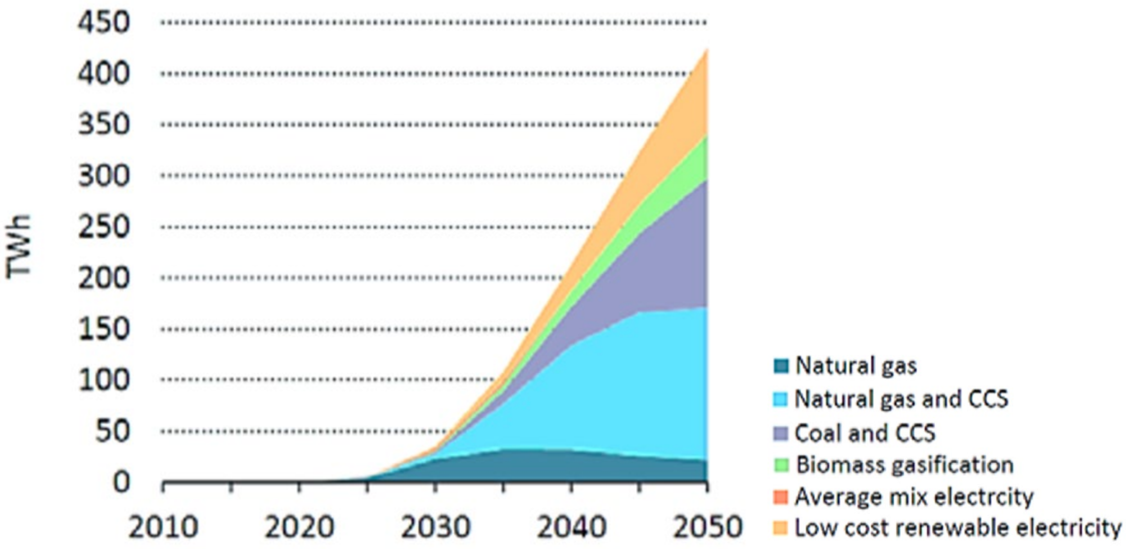


Figure 3. IEA Projections of Hydrogen Production in the U.S. by Input Energy Source (IEA 2018). CCS = carbon capture and sequestration.

2.2.1.1 Steam Methane Reforming (blue or gray hydrogen production)

Today, hydrogen is most commonly produced from fossil fuels through a process called steam reforming (Figure 4). In steam methane reforming (SMR), the most common application of the steam reforming method used today, steam (H_2O) is used to heat methane (CH_4), the primary component in natural gas, and split it into carbon monoxide (CO) and hydrogen (H_2). The produced hydrogen is separated from the carbon monoxide for off-take while the carbon monoxide is either captured and sequestered, used, or released into the atmosphere.

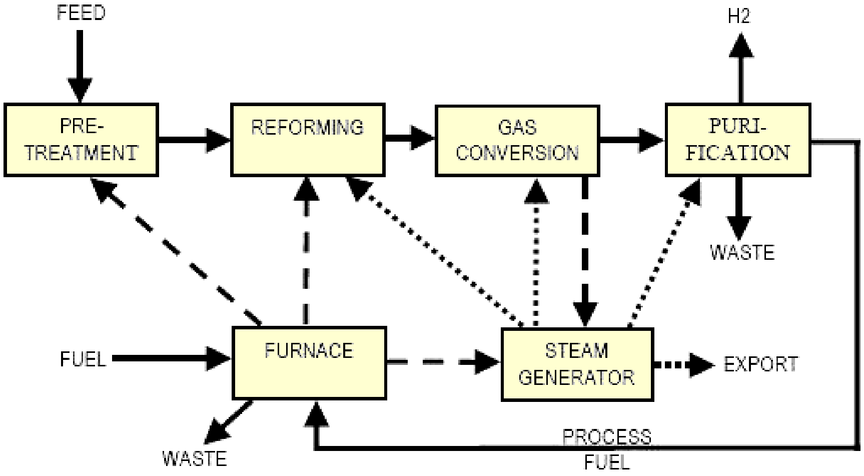


Figure 4. General Steam Reforming Process for Hydrogen Production (Molburg and Doctor 2003)

2.2.1.2 Coal Gasification (black or brown hydrogen production)

Gasification, a less common process for creating hydrogen, is a mature method where different materials are exposed in a gasifier to steam and controlled amounts of oxygen at high pressures and temperatures without combustion. Coal gasification is the most popular type of gasification globally because of coal's stable price and abundant supply across the world (NETL 2023a). Coal gasification takes place at temperatures between 800°C and 1,900°C (1,472°F – 3,452°F) and pressures up to 100 bar (1,450 psi). The application of heat and pressure force a chemical reaction where coal, oxygen, and water produce hydrogen (H_2), carbon monoxide (CO), and carbon dioxide (CO_2) mixed in a gaseous output stream. This resulting "syngas" may then be mixed with or used in place of natural gas in various applications or separated into its constituent molecules to recover pure hydrogen for other uses. Use of coal gasification to produce hydrogen and syngas is considered cleaner than a combustion electricity production plant that burns coal for power because it produces less methane and toxic waste. However, it still has the potential to significantly contribute to greenhouse gas emissions if not paired with adequate carbon capture methods (World Nuclear Association 2021a).

2.2.1.3 Biomass Gasification (brown or green hydrogen production)

Biomass gasification, a special case of gasification that can be classified as "brown" or "green" depending on the process, is a hydrogen production method that converts organic feedstocks such as agricultural waste, industrial waste, or dedicated crops like willow trees or switchgrass into hydrogen (H_2), carbon monoxide (CO), and carbon dioxide (CO_2). As with coal gasification, this process is completed without combustion and instead through exposing the biomass to steam and a small amount of oxygen at high pressures (4-7 bar or 58-101 psi) and high temperatures (greater than 700°C/1,292°F) (DOE 2023a). In general, because biomass feedstocks used for this process often remove carbon from the atmosphere during their growing cycles, biomass gasification is considered to have low net carbon emissions when it is implemented as a circular process (DOE, 2023a). If combined with carbon capture technologies, the process could become a net zero or negative carbon method. As with coal gasification, biomass gasification typically produces syngas that may then be mixed with or used in place of natural gas. Many gasifiers can gasify biomass or a mixture of coal and biomass (NETL 2023b).

Pure hydrogen can be separated from syngas product streams after biomass gasification occurs to use pure hydrogen for various processes.

2.2.1.4 Electrolysis (pink, green, or yellow hydrogen production)

Electrolysis is the second-most common hydrogen production method worldwide after SMR (Guo et al. 2019). In electrolysis, an electrochemical reaction occurs within a device called an electrolyzer, where electricity is passed through water molecules (H_2O) to split them into their component elements, hydrogen (H_2) and oxygen (O_2). Electrolysis is a versatile process that can be performed using many different input energy sources (e.g., electric and photonic) and with variations of the process (DOE 2020a) depending on the application context and system requirements. Solid oxide, alkaline, and proton exchange membrane (PEM) electrolysis are the most common electrolysis methods used today (Mittelsteadt et al. 2015). Table 2 compares these three technology applications for the electrolysis process.

Table 2. Pros and Cons of Most Common Hydrogen Production Methods[a] (DOE 2023a; DOE HFTO 2016; DOE HFTO 2023a, Khedkar et al. 2023)

	Hydrogen (H_2) Yield	Pros	Cons
Solid oxide electrolysis	0.026 kg H_2 / kWh[b] 0.09-0.1 kg H_2 / L water[c]	• High efficiency • Multiple feedstock options • Usable waste heat • Inexpensive catalysts	• High pressures and temperatures required • Long start-up times • Corrosion issues • Limited number of shutdowns
Alkaline electrolysis	0.019 kg H_2 / kWh[b] 0.09-0.1 kg H_2 / L water[c]	• Mature technology • Lower cost components • Durable system components • Fast start up • Operates at low temperatures • High efficiency	• Complicated maintenance • Cannot produce high-pressure H_2 • Alkaline corrosion • Large and heavy system • Sensitive to CO_2 in fuel and air • Electrolyte management (aqueous) • Electrolyte conductivity (polymer)
Proton exchange membrane (PEM) electrolysis	0.019 kg H_2 / kWh[b] 0.09-0.1 kg H_2 / L water[c]	• System simplicity • Small footprint and weight • Produces H_2 at higher pressures than alkaline • Fastest start-up times • Reduced corrosion & electrolyte management problems • Operates at low temperatures	• High capital costs • Lower commercial availability • Sensitive to fuel impurities
Steam methane reforming	40-130 g H_2 / kg methane[d]	• Mature process • High efficiency • Lowest capital cost • Multiple feedstock options	• High pressures and high temperatures required • Process produces carbon dioxide as a byproduct – must be paired with carbon capture to be carbon-free • Can experience corrosion from carbon dioxide deposition
Gasification	40-190 g H_2 / kg biomass[d]	• Mature process • Does not involve combustion • Multiple feedstock options including renewables (i.e., biomass, waste) • System simplicity • High efficiency	• High pressures and high temperatures required • Process produces carbon dioxide as a byproduct – must be paired with carbon capture to be carbon-free • High capital costs

(a) Content adapted from DOE HFTO (2016), unless otherwise noted. Electrolyzers are typically described in modular units known as “stacks.” Multiple stacks might be placed within one system.
(b) Bloom Energy 2022
(c) Nnabuife 2023
(d) Lepage et. al 2021

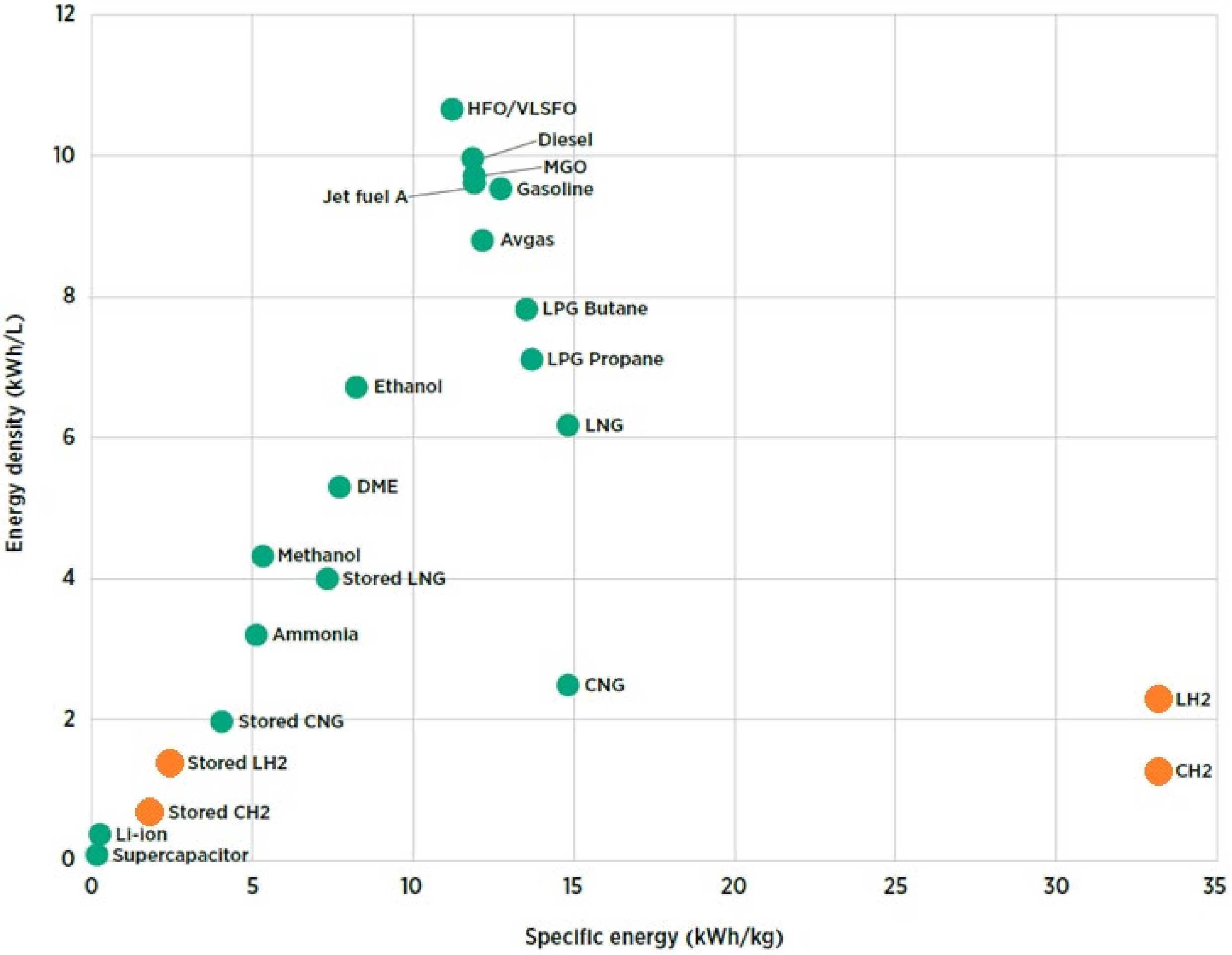
2.2.2 Compression or Liquefaction

After production, gaseous hydrogen is typically compressed to make it easier to transport and store in large quantities while reducing system footprint. This process can occur as an integrated step in the production process or afterward with separate machinery. For instance, gaseous hydrogen typically leaves an alkaline or PEM electrolyzer at 30 bar (435 psi). Depending on the desired storage or transportation methods, additional compression can be done within the electrolyzer during production, post-electrolysis using a separate compressor, or, for PEM electrolysis, using a second electrochemical device (IRENA 2020). Using an electrolyzer’s native compression functionality creates a less complex system configuration than a system where a separate compressor is needed; however, electrolyzers with added compression features tend to be more expensive and can experience increased gas permeation losses because of the higher pressure in the system (IRENA 2020).

Depending on the desired storage and off-take mechanism for the produced hydrogen, liquefaction might be a desirable alternative physical state. Hydrogen condenses into a liquid from a gas at very low temperatures (-253°C or -423°F). Equipment to remove impurities from the hydrogen gas stream and supercool it would be needed to produce hydrogen in its liquid form. The liquefaction process requires vast amounts of energy relative to the amount of energy the hydrogen itself contains. This should be carefully considered based on the application of the hydrogen project.

2.2.3 Storage

Hydrogen can be stored as a gas, liquid, or chemical compound (DOE 2020a) such as ammonia (see Section 3.4.1) or metal hydride. The intended use and scale of hydrogen demand for missions at a site will dictate the amount of hydrogen storage needed and the most suitable storage approach. Hydrogen holds 2.6 times more energy per unit of mass than gasoline, but its volumetric energy density is much lower than gasoline, with hydrogen requiring 4 times more space to store the same amount of energy as gasoline. Figure 5 shows a comparison of the energy density and specific energy of various fuels and energy storage types.



Notes: Avgas = aviation gasoline; CH2 = hydrogen compressed at 70 MPa; CNG = natural gas compressed at 25 MPa; DME = dimethyl ether; HFO/VLSFO = heavy fuel oil/very low sulphur fuel oil; LH2 = liquefied hydrogen; Li-ion = lithium-ion battery; LNG = liquefied natural gas; LPG = liquefied petroleum gas; Stored CNG = Type IV tank at 250 bar; Stored CH2 = best available CH2 tanks at 70 MPa; Stored LH2 = current small-scale LH2 on-board tanks; Stored LNG = small-scale storage at cryogenic conditions; MGO = maritime gasoil. Numbers are expressed on a lower heating value (LHV) basis. Weight of the storage equipment is included.

Figure 5. Energy Density and Specific Energy of Various Fuels and Energy Storage Systems, including Liquid Hydrogen (LH2) and Compressed Hydrogen (CH2) in Orange (IRENA 2022a). Specific energy estimates include the weight of the storage equipment and the fuel in the denominator.

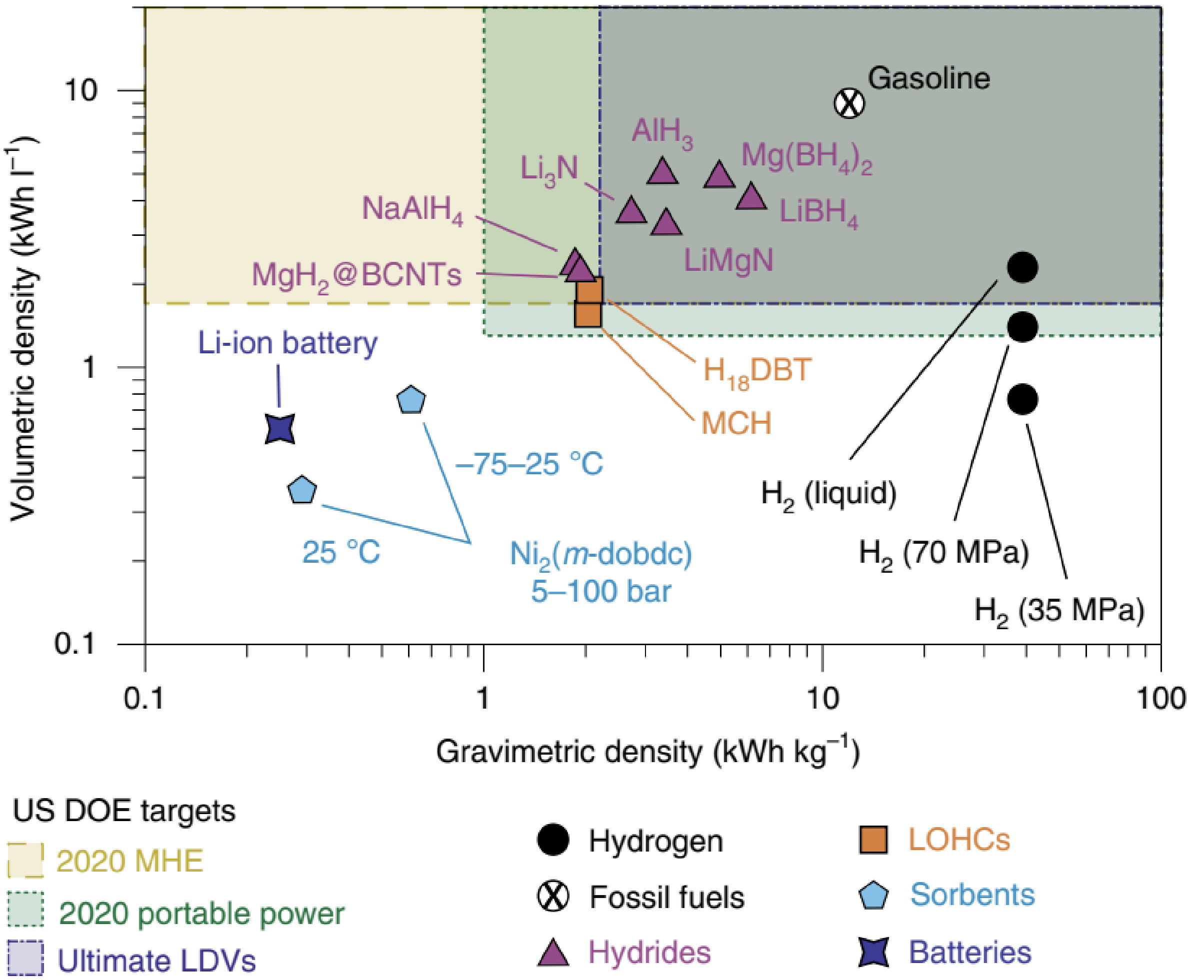


Figure 6. Comparison of Energy Density (volumetric density) and Specific Energy (gravimetric density) of Various Hydrogen Storage Options (Allendorf et al. 2022).

Even across the various types of hydrogen storage, specific energy (gravimetric density) and energy density (volumetric density) can each vary by a factor of ~6 when comparing liquid organic hydrogen carriers and metal hydrides against storage of pure hydrogen as a liquid or gas (Figure 6). Table 3 presents various storage methods for hydrogen, the most suitable scale ranges for those storage methods, an estimate of the fraction of energy required upfront to compress or liquefy the hydrogen for storage (as a function of the total energy content of hydrogen within storage), and additional considerations for the storage technology adapted from the DOE Hydrogen Program Plan (2020) and Singh et al. (2015).

Table 3. Description and Considerations for Common and Emerging Hydrogen Storage Technologies.

Method	State	Approx. TRL	Operating Pressure & Temp	Max Deliverability[(a)]	Energy Cost for Method	Considerations
Pressurized tanks	Gas	>9	250–1,000 bar 10–30°C	several tons per day	13–20%	• Large footprint to store large volumes • High energy costs to pressurize
Cryogenic tanks	Liquid	>9	1 bar −253°C	100s of tons per day	40%	• Less volume required than pressurized tanks but still relatively large aboveground footprint • Extremely high energy costs to cool • Evaporation losses
Metal Hydrides	Solid	4-6	Near ambient pressure and temperature possible -50–200°C	**<< 1 ton per day**		• High material costs lead to difficulties scaling up • Can lead to very heavy systems • Low H_2 release rate • Relatively high H_2 release temperature requirements
Pipeline	Gas	7-8	10-200 bar -45–175°C	100s of tons per hour	7%	• Hydrogen pipelines are not common • Hydrogen may be blended in small ratios into natural gas pipelines
Subsurface geologic	Gas	7-9	25–200 bar 10–80°C	100s of tons per hour	Application dependent	• Highest storage capacity • Requires suitable geology • Potentially the least expensive option

(a) For comparison, 60% efficient fuel cell systems with capacities of 1 MW, 5 MW and 10MW would require approximately 0.05, 0.25, and 0.5 tons per hour of hydrogen fuel, or a total of 0.4, 2 and 4 tons if operating continuously for 8 hours.

2.2.4 Distribution and Dispensing

Once hydrogen has been produced, compressed or liquified and, optionally, stored for later use, it must be transported to a dispensing or end-use location. The most common transportation methods for hydrogen are compressed gas tube trailers, liquid tankers, pipelines, and ships. Table 4 describes the characteristics of those technologies.

Table 4. Description of Common Transportation and Distribution Methods for Hydrogen

Method	Relative Scale	Quantity of Fuel Delivered	Input Energy Needed for Method	Energy Required Every 100 km
Tube Trailer	Small	400–800 kg/truck	Fuel for over-the-road truck transport	6% total energy content
Liquid Tanker	Medium	4,000 kg/truck	Fuel for over-the-road truck or rail transport	1% of total energy content
Pipeline	Large	100,000 kg/h	Fuel for pipeline compressors and operations	0.8% of total energy content
Ship	Large	Up to 10 million kg/ shipment	Fuel for ship transport	Fuel use unknown

Additional equipment may be needed for dispensing the fuel at its off-take or end-use location. The equipment needed for dispensing depends on the system configuration and context. For example, hydrogen automobile fueling stations typically require compressors to aid in storage and gas flow during dispensing; storage tanks to contain the hydrogen until dispensing; a cooling system including heat exchangers to remove excess heat and a chiller system to cool the hydrogen for efficient fueling; vent stacks to safely capture and release any escaped hydrogen; and dispensers that resemble traditional fueling systems with a nozzle to direct the flow of gas and a smart valve to control the flow rate (DOE 2020a). Medium- and heavy-duty refueling protocols are not fully developed; however, light-duty (e.g., passenger electric cars) hydrogen fuel is typically dispensed at 350 bar (~5,000 psi) or 700 bar (~10,000 psi) depending on the desired fuel application, and dispensing techniques may vary (DOE 2020a). These equipment considerations should be integrated with and complement existing operations and fueling plans for missions on the installation and might be configured in various ways to achieve that goal. For instance, hydrogen might be produced and stored in a large central tank or multiple satellite bulk storage tanks and distributed across the installation, or production, storage, and dispensing might be completely decentralized depending on the base’s resilience posture and stakeholder requirements.

2.3 Configuration Options

There are many ways to produce, store, and distribute hydrogen for use at Air Force installations. The system configuration options can vary significantly based on mission requirements, demand for hydrogen, storage duration needs, and other criteria (environmental impact, surface footprint constraints, etc.).

As shown in Figure 7, electric power generators on site might directly serve load in a modular manner depending on demand, or, through control switches, produce hydrogen using electrolyzers. This system might also incorporate hydrogen power generation technologies like fuel cells to convert stored hydrogen back into electricity to serve electrical demand when generators like wind and solar photovoltaics (PV) are not available. Efficiency might be gained by pairing fuel cell technologies or other hydrogen-burning technologies with heat recovery systems to heat water for uses on site.

Alternative configurations might resemble Figure 7 but incorporate other fuel feedstocks and take advantage of integrated energy systems on site. For example, an SMR might use natural gas to produce hydrogen for storage and use in a fuel cell with heat recovery, much like an electrolyzer setup. That natural gas might also, or alternatively, be used in a backup generator or prime power generator to produce the electricity on site for electrolysis. Other examples using coal, oil, or biomass as feedstocks or fuels are possible.

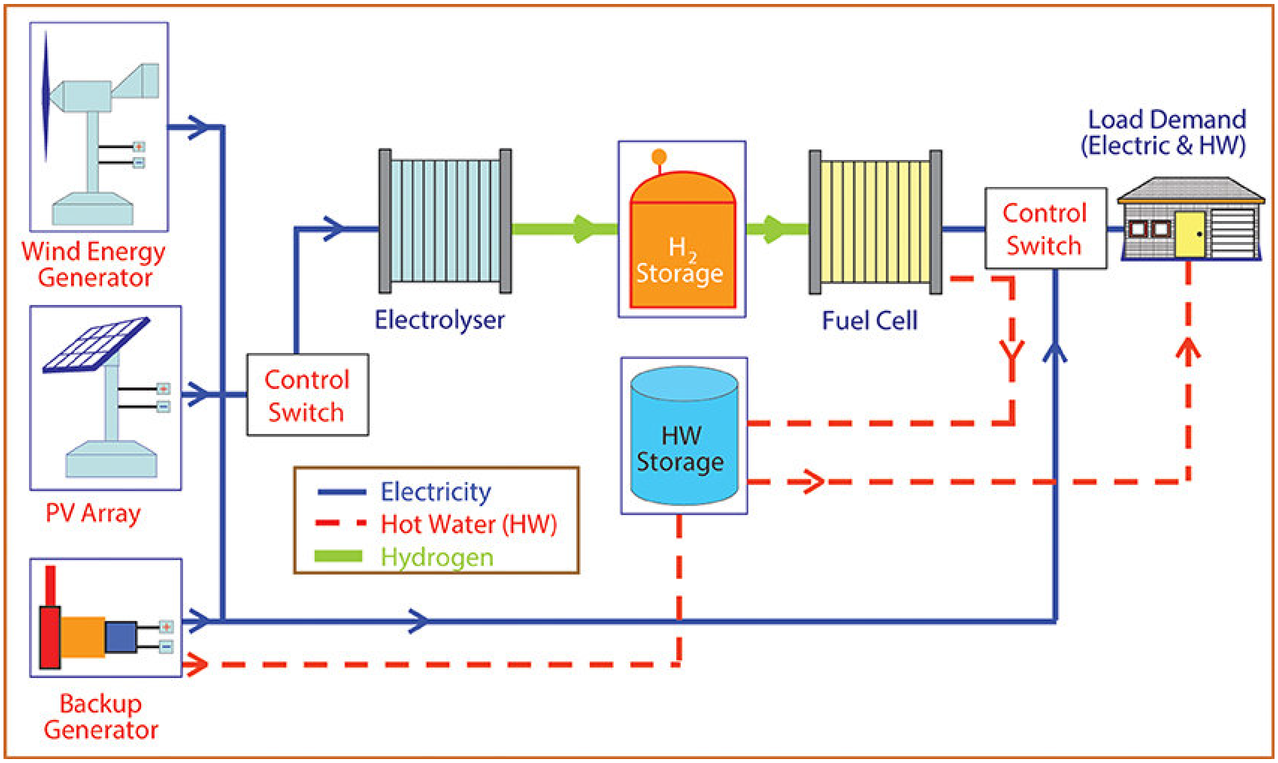


Figure 7. Example of Hydrogen Production through Electrolysis and Storage Integrated in an Energy System (Badwal et al. 2014)

2.4 Operational Considerations

This section discusses operational considerations for hydrogen production and storage systems including operations and maintenance (O&M) requirements, staffing, cybersecurity, and statutory requirements.

2.4.1 Operations and Maintenance Requirements

Hydrogen production and storage systems require regular O&M that includes, but may not be limited to, manual and computerized system monitoring, repairs and replacements, routine inspections, safety supervision, data analysis, and recordkeeping. Onsite personnel (staff or contractors) will be required to maintain and inspect equipment that is likely from multiple manufacturers/vendors. Depending on system configuration, these personnel might need elevated training and certification for the maintenance of systems that contain pressurized gaseous fuels or cryogenic liquids. Generally, as with most energy systems, the components of hydrogen production systems are manufactured to last with regular upkeep, and manufacturers are likely to provide warranties for the equipment. Production components (like electrolyzers or steam reformers), storage tanks, piping, valves, purification systems, automated controls, meters, and sensors are a few of the major system components that are likely to require regular O&M. For systems that use hydrogen in a liquid form, particular attention should be paid to recognizing the signs of material embrittlement on system components that contact cryogenic liquid hydrogen.

2.4.2 Staffing Requirements

As hydrogen production and storage system deployments are relatively limited across the U.S. and world. There is limited information about staffing requirements for continuous operation of these systems, but one reference indicates that a facility designed for a capacity of 56,000 kg/day with a PEM electrolyzer needs approximately 10 full-time equivalent operators (James et al. 2013). Fewer operators are likely to be required by a hydrogen system on an Air Force base. An electrolyzer with this level of output is likely up to ten times larger than required by an Air Force installation. These operators need the appropriate training and support of emergency response personnel on the installation and possibly beyond. Operators might require certifications from local safety authorities to operate and perform required regular testing to keep the system operating as intended. For other production technologies, the staffing may vary.

Automation of process control instrumentation can impact future buildouts of hydrogen production systems. The desire for automation is driven by interest in lower operation costs, reduced errors, and reduced dependence on uncertain labor markets. The measurement of hydrogen flows and transfer of hydrogen into storage mediums are examples of current staff needs that could be supported by automated alternatives. Thus, requirements for full-time equivalent operators could be reduced with the appropriate instrumentation included with a hydrogen production and/or storage system.

2.4.3 Cybersecurity Considerations

Depending on the sophistication of the automated control and network connectivity within the hydrogen production and storage system, digital assets, remote communications, and controllers will be needed, which are sometimes susceptible to cyber breaches. System hardening, network segmentation, and antivirus management are all important elements of a cyber defense strategy for automated hydrogen production and storage systems that may be integrated into a large energy system control strategy for a site. The risk of cyber-attacks can increase for devices with exposure to vectors like constant connections to internets of things, malicious actors, faulty equipment, compromised communications, and physical system vulnerabilities.

Not all cyber-attacks can be prevented. At a minimum, any automated and network-connected hydrogen production and storage system should be capable of detecting that an attack has taken place. Trained staff will be needed to verify secure operations through operational monitoring, log reviews, and independent system health checks. Systems to help detect and prevent cyber-attacks should be investigated. Cyber security protection plans should also be crafted around frameworks such as the North American Electric Reliability Corporation Critical Infrastructure Projection (NERC CIP), the Center for Internet Security Critical Security Controls (CIS CSC 18), or other such protocols. If integrated to a more complicated system, the hydrogen production and storage systems will need to adhere to additional security protocols of the overall system.

2.4.4 Emergency Planning

Any hydrogen production or storage system integrated into the energy infrastructure at an installation or site should be accounted for in relevant energy curtailment and emergency plans. Depending on the context of the site and complementary technologies installed there, the hydrogen production and storage system might need to be incorporated in electricity, thermal, and/or water curtailment and emergency plans. The relevant sections integrated into those plans should contain specific actor assignments and procedures for the intervention actions required such as curtailing water use for electrolysis during times of water disruption, engaging hydrogen storage reserves for power generation, or other actions. These plans should also specify the applications of hydrogen technologies that are to be suspended and clearly designate installation personnel's roles and responsibilities for executing the plan. A comprehensive emergency plan also includes testing and training programs. Emergency drills should be conducted regularly to ensure that personnel are well trained to respond to an event.

3.0 Technical Considerations

The production and storage of hydrogen requires careful technical considerations to ensure viability and resilient operations. This section discusses market and demand, component availability, and environmental considerations as key factors to consider. Siting and implementation considerations, including resource availability and supporting infrastructure requirements, are discussed in Section 7.0.

3.1 Limiting Factors and Constraints (other than siting characteristics)

Hydrogen production and storage system costs and demand conditions are generally strong limiting factors to consider when assessing a project's potential. The most significant factors that drive the cost for hydrogen production through electrolysis are capital costs, the cost of electricity, and electrolyzer efficiency (NREL 2009). Similarly, capital costs, feedstock or fuel costs and efficiency drive feasibility of SMR and gasification technologies. O&M costs can also be limiting factors for production technologies and may make a project unaffordable for a potential hydrogen producer. While O&M costs are typically small compared to capital costs and electricity costs (NREL 2009) they accumulate over the lifetime of the system.

The viability of hydrogen production also depends on suitable local demand. The global demand for hydrogen has risen threefold since 1975, with ammonia production and petroleum refining making up 80% of consumers (WHA International 2020). In a scenario analysis by DOE, expectations for clean hydrogen demand in the U.S. are dominated by medium-and heavy-duty vehicles, followed by biofuels and power-to-liquid fuels (Figure 8). Depending on the outcome of an assessment of the relevant end-uses for produced hydrogen, identifying suitable demands at Air Force installations or sites might become a limiting factor to the viability of a project.

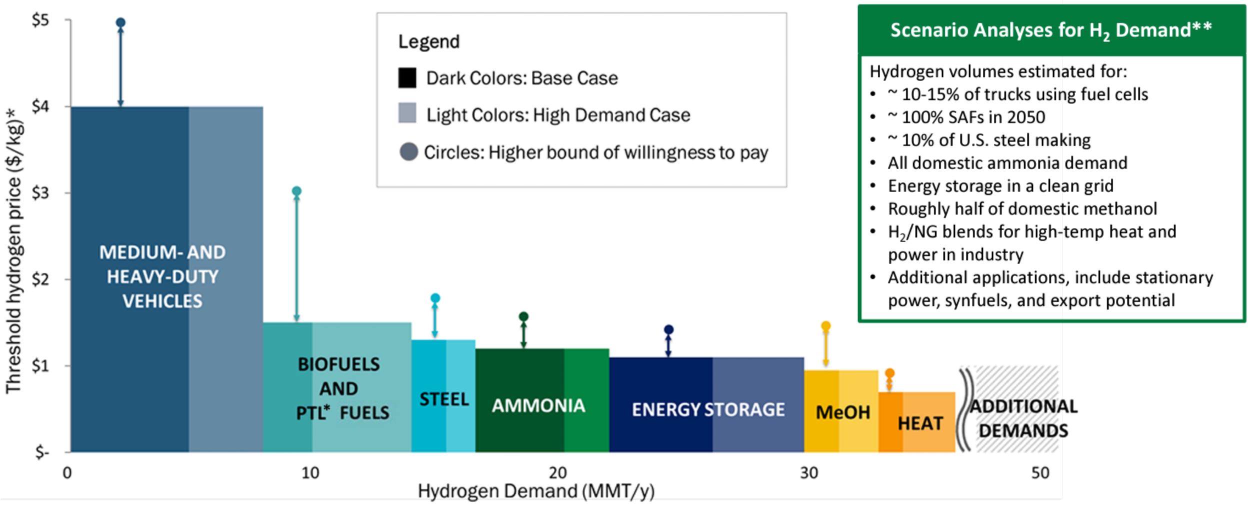


Figure 8. Clean Hydrogen Demand in Million Metric Tons per Year (MMT/y) and Costs Needed for Market Penetration. Costs include production, delivery, and dispensing to the point of use (e.g., high-pressure fueling for vehicle applications).

Depending on the intended end-use, other challenges may arise. For instance, using hydrogen as fuel can lead to high infrastructure expenses as numerous technologies designed for hydrogen fuel are still in their early stages, which could increase costs. Specifically, there is a lack of protocols for dispensing across various applications, and a lack of established supply chains to streamline storage, transportation, and dispensing (DOE 2020a).

3.1.1 Production Component Availability/Supply Chain Issues

Various rare and critical materials are used in hydrogen production technology and can impact system cost, lifetime, and associated emissions. Further, due to the rarity of these materials and high energy costs of attaining them, they can cause supply chain bottlenecks. For electrolyzers, critical materials are more of a limitation for PEM compared to alkaline. Critical materials often needed for PEM electrolyzers are iridium, titanium, platinum, and tantalum. Alkaline systems have commercialized designs that typically use nickel and sometimes platinum and cobalt. Alkaline anion exchange membrane electrolyzers do not use any critical materials; they mostly use nickel and steel. The high cost of the critical materials themselves and electrolyzer component manufacturing is largely the reason that PEM is more costly than alkaline (IRENA 2020). Globally, South Africa supplies 70% and 85% of platinum and iridium, respectively. There are only limited and short-term alternatives to these critical materials for electrolyzers, creating dependance on a single country for the majority of PEM and some alkaline electrolyzers.

For SMR, nickel is the most commonly used catalyst metal. However, other rarer metals, including noble metals like ruthenium, rhodium, palladium, iridium, and platinum, are sometimes used as a catalyst for the reaction (van Beurden 2004). Non-rare materials including iron and nickel alloys are typically used in biomass or coal gasifiers (Western Research Institute 2005). As demand for clean energy technologies has increased, coal and biomass by-products from gasification are being explored as potential sources of rare earth elements that may reduce reliance on other countries for rare elements if successful extraction processes are developed (Hower et al. 2016).

3.1.2 Constraints Related to Storage

Environmental considerations play a role in the siting of hydrogen storage. While Section 5.2 discusses the environmental considerations of hydrogen production technologies in terms of emissions impact and risk, this section identifies additional considerations in determining where to place hydrogen storage. Hydrogen's low ambient temperature density leads to low energy per unit volume, leading to a need for advanced storage methods to obtain high energy densities. This complicates the use of hydrogen as the primary energy carrier in a system when it is intended to be stored for later use or transported. Hydrogen storage and transportation can also be expensive in terms of monetary and energy costs for the amount of hydrogen that is contained or transported.

Most commonly, hydrogen is stored as gas in pressurized tanks at ambient temperature (DOE 2020a). This approach requires large above-ground tanks and as much as 20% of the energy content of the hydrogen stored is typically needed to compress the hydrogen gas to fill the tanks (Singh et al. 2015). To avoid the need for large tanks, hydrogen temperatures may be reduced to cryogenic levels, specifically -253°C (-423°F), to liquify hydrogen, increasing the density and making the storage more volumetrically efficient (Niaz et al. 2015). However, liquifying hydrogen will increase the energy requirement to as much as 40% of the energy content of the stored hydrogen (Singh et al. 2015). Liquid hydrogen storage also requires insulated cryogenic tanks, and evaporation or boil-off when contained as a liquid can cause significant loss of fuel (Niaz et al. 2015). Depending on the size of the tank, boil-off from a liquid state is estimated to be between 0.13% and 3% per day (Karp 2021). Cryogenic storage and transportation are generally only used on industrial scales (DOE 2020a).

Geological storage inside suitable subsurface formations (e.g., salt caverns, depleted oil or gas reservoirs, aquifers) may be an effective bulk storage method and generally is the least expensive method for storing multiple tons of hydrogen at one facility, often with the purpose of serving multiple customers or end uses or even balancing town-scale or region-scale hydrogen demand. Suitable geology must be present for this storage method to be successful (DOE 2020a). However, geological storage of hydrogen is not economically feasible for smaller-scale operations.

Hydrogen can also be stored in material compounds such as metal hydrides, adsorbents, and chemical hydrogen carriers including ammonia and methanol. However, none of these material-based methods are commercially mature (DOE 2020a).

Overall, the common limitations of hydrogen storage techniques are large energy and space requirements to contain, compress, or liquify the hydrogen. Geologic storage most effectively addresses these problems by providing large spaces to store hydrogen at relatively low pressures. However, because geologic storage is only economically feasible on large scales, this method is not widely adopted. If large-scale production of hydrogen is desired, the site geology should be assessed to determine its suitability for storage.

3.2 Technology Maturation

Hydrogen is used for multiple purposes. Of the approximately 70 million tons of hydrogen produced worldwide each year, roughly two-thirds is used to produce ammonia as a feedstock to the production of fertilizers and roughly one-third is used in the oil-refining industry (Karp 2021). A small fraction is used to support other industrial processes such as metal refining (Singh et al. 2015) and electric power generation.

Hydrogen production is a mature chemical process with various technologies available that can be used to produce pure hydrogen. The mature technologies primarily employ SMR, gasification, or electrolysis. As the deployment of hydrogen production facilities advances and research and development continues, newer processes with newer associated technology have also been explored. These emerging processes include photobiological and photoelectrochemical water splitting, and biomass options such as photo- and dark fermentation. These newer technologies have emerged to address some of the shortcomings of the mature technology but, as a tradeoff, are more expensive and less accessible than the mature technology.

3.2.1 Successful Pilots or Demonstrations

The suite of mature technologies have been deployed in multiple successful pilots and demonstrations throughout the US (See Figure 9) and world. This section describes a couple of the successful MW-scale applications of hydrogen production and storage.

HyDeploy is an energy trial in the UK conducted through a partnership between gas network companies, an energy storage company, low carbon technology professionals, health and safety professionals, and Keele University. HyDeploy had a £7 million pilot trial at Keele University from November 2019 to March 2021 and a follow-on pilot for the small town of

Winlaton from August 2021 to June 2022. HyDeploy produced green hydrogen from renewable energy sources with a 0.5-MW electrolyzer and mixed this hydrogen into the local natural gas system at a volumetric ratio of 20% hydrogen to 80% natural gas, showing little negative effects on the system with existing transportation infrastructure and end-use appliances able to demonstrate use of hydrogen-natural gas blends. (HyDeploy).[1]

Aramco in Saudi Arabia has a blue hydrogen production facility, where “blue” refers to the use of the process of combining fossil fuel based SMR with carbon capture techniques to produce hydrogen. To overcome technical barriers to hydrogen storage and transportation, Aramco converts some of its hydrogen to ammonia, which is more easily stored and requires less space and less extreme temperatures (-33°C compared to -253°C for liquid hydrogen). When the ammonia arrives at its use location, it can either be used or converted back to hydrogen, depending on the application. Aramco partnered with Saudi Basic Industries Corporation and the Institute of Energy Economics Japan in 2020 to ship the “blue ammonia” by boat to Japan. In Japan, the ammonia was used for multiple applications. It was blended with natural gas at a 20% ratio and used to fuel power generation in turbines for micro- and macro-grid connections. It was also co-fired with coal in a boiler at a 20% ratio to power turbines creating electricity. Hydrogen produced at this facility is also distributed at a hydrogen fueling station for transportation vehicles in Saudi Arabia (Aramco 2023).

3.2.2 Market Penetration

In the global hydrogen production market, 48% of hydrogen is produced from natural gas, 30% from oil, 18% from coal, and 4% from electrolysis (IRENA 2018). Hydrogen production in the U.S. has tripled since 2021, with over 12 million metric tons produced annually. Figure 9 shows planned and installed hydrogen production capacity in the U.S. (DOE Hydrogen Program 2023).

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[1] https://hydeploy.co.uk/

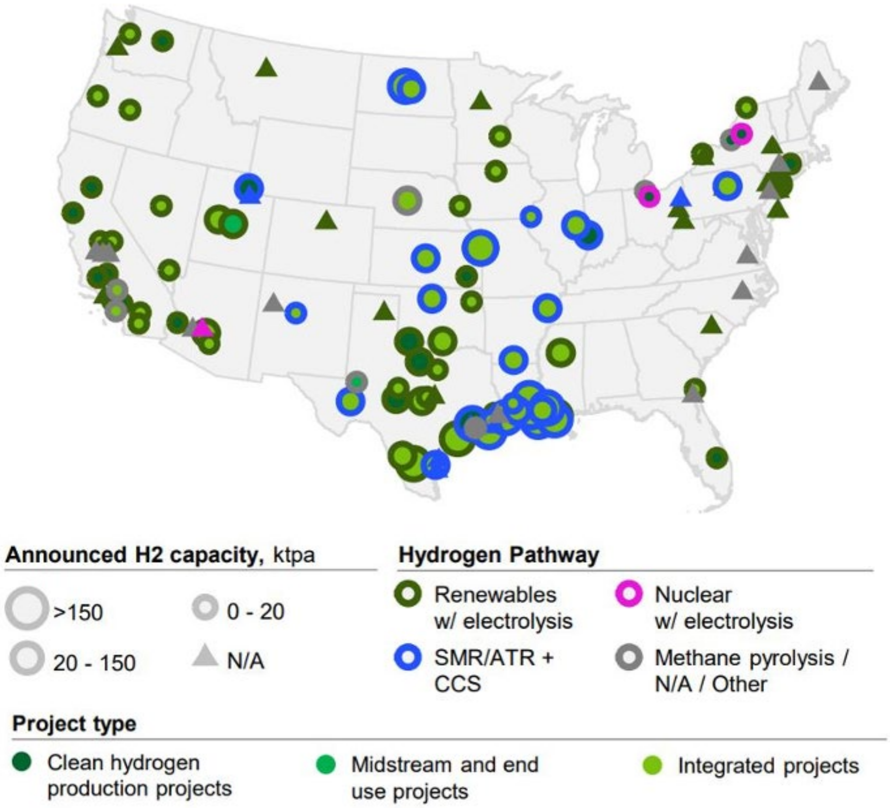

Figure 9. Officially announced hydrogen production projects as of December 2022 (DOE Hydrogen Program 2023).

3.3 Optimal Configuration and Trade-Offs

The optimal configuration to enable resilient hydrogen production and storage on Air Force bases includes on-site energy resources (potentially carbon-free options like wind or solar) that are harnessed to power an electrolyzer system to create pure hydrogen and storage of sufficient scale to provide critical mission support for on-site uses such as power generation and vehicle fueling. The sizing of a larger, integrated system to produce, store, transport and use hydrogen based on electrolysis depends on factors like the source of electricity that powers the electrolyzer, the electrolyzer operation mode, and the full demand of end-uses paired with the system. Hydrogen can be a feedstock for aviation fuel production or used in fuel cells for power generation, forklifts, vehicles, other material handling devices, and unoccupied aerial vehicles. The Air Force should evaluate needs for hydrogen within their portfolio. If, initially, the system were based roughly on power generation demand for installations with fleet refueling demand uncertain, the size of an electrolyzer system to support Air Force energy demand could be somewhere between 1 and 10 MW, producing roughly 300 to 4,500 kg/day of hydrogen.

A configuration based on electrolysis and on-site renewable power generation, specifically, is attractive for Air Force installations because of its potential for distributed generation of hydrogen, decreased dependence on external energy providers, resilience to energy disruptions with right-sized storage for mission needs, cost effectiveness, and carbon-free operation potential. The resilience characteristics of power generation and feedstock options for the optimal use case should be examined for each site. Keeping in mind the intermittent nature of on-site, renewable resources like solar and wind, alternative electrolysis systems that rely on grid power or SMR systems might be considered. These alternatives would create a trade-off between increased dependence on external energy suppliers (electricity or natural gas providers), changes in the carbon emissions profile of the system and reduced land requirement and system cost. Fuel-powered on-site gensets might instead be used to power electrolyzers. In addition to increasing reliance on external energy providers, using gensets to power electrolyzers might increase carbon emissions and may result in an efficiency penalty as compared to simply using the on-site gensets to produce electricity on-demand rather than converting electricity to hydrogen that may just be converted back to electricity in a generator or fuel cell.

Both cost and environmental attributes may favor a renewable energy powered electrolysis system of the scale required for Air Force installations. Upfront capital costs for new renewable power projects are less expensive than similarly sized fossil fuel projects in some cases. The International Renewable Energy Agency recently found that nearly two-thirds of the renewable power projects constructed in 2021 were lower in cost than fossil fuel options (IRENA 2022b). Renewable power generation also either prevents greenhouse gas emissions that would otherwise be produced using fossil fuels or helps avoid additional capital and operational costs that would need to be incurred to install carbon capture and other emissions control measures.

If selecting an electrolyzer as the hydrogen production technology and considering the commercially available options, Air Force planners may decide to either site decentralized PEM electrolyzers or a larger, central solid oxide electrolyzer. PEM electrolyzers have an advantage of faster startup times and low maintenance requirements, are resistant to corrosion, can operate at lower temperatures than other electrolyzers, and have a high water-to-hydrogen conversion efficiency rate compared to other electrolyzers (see Table 2). PEM electrolyzers as a system component have a small environmental footprint, do not produce greenhouse gases, and use less water than other electrolyzer technologies. While PEM electrolyzers are typically more expensive than alkaline electrolyzers, cost ranges for both technologies do overlap and PEM electrolyzers present clear advantages in terms of resilience and environmental footprint. However, most commercially available PEM electrolyzers are currently limited in size to systems reaching capacities on the order of 100s of kW, only recently have PEM electrolyzers begun coming to the market on the MW-scale. To avoid installing a system with many modular PEM electrolyzer stacks, a larger, multi-MW-scale, centralized Solid Oxide Electrolyzer facility might be selected because of the technology's efficiency advantage, ability to run on a variety of feedstocks and the Air Force's potential desire for useable waste heat from the system.

The storage component of the optimal use case depends on required hydrogen demand and duration with economies of scale favoring methods like geologic storage. However, it is unlikely that early adoption of hydrogen at Air Force installations, likely driven by back-up power generation or light-duty vehicle demand, will require the amount of hydrogen that could be economically stored in a geological formation. Instead, the optimal storage component of the system is probably gaseous hydrogen storage in above-ground, pressurized tanks or liquid hydrogen storage in cryogenic tanks. The choice between these two storage options will depend on the trajectory for hydrogen demand and uptake by organizations across the site. It might be desirable to begin with a gaseous tank storage system and transition to liquid storage as demand grows. The amount of hydrogen production by the system will also drive which storage configuration is optimal, with pressurized tanks typically being used with production ranging from less than 1 ton to several tons per day, and cryogenic tanks being used with production between several tons per day to several hundred tons per day (see Table 3 for more detail). The most relevant trade-offs between these technologies relate to storage volumes and energy requirements for compression/liquefaction, with pressurized tanks requiring much larger volumes compared to cryogenic tanks and cryogenic tanks requiring more energy to compress/liquefy.

3.4 Complementary Technologies

3.4.1 Ammonia Production

Hydrogen production is highly complementary with production of other chemicals and compounds that are effective hydrogen carriers. For example, ammonia (NH_3) is a much more effective hydrogen carrier than pure hydrogen. Compared to hydrogen, ammonia has 50% greater volumetric energy content, meaning it only requires about half the storage volume that liquid hydrogen would for the same amount of energy (Dolan et al. 2021). Requiring substantially less space means that storage costs can be more than three times less for ammonia than hydrogen (Ezzat and Dincer 2018). It also requires much less energy to liquify and store ammonia. Ammonia stored at ambient pressure only requires cooling to -33°C (-27°F) to remain liquefied whereas hydrogen requires temperatures of -253°C (-423°F) (Morgan et al. 2014). Ammonia can also be directly combusted in an increasing number of engine- and turbine-based generators on the MW scale from established vendors.

Ammonia production involves technology in addition to an SMR or electrolyzer used to produce hydrogen (see Figure 10). A nitrogen separation or purification system is required which pulls in air from the atmosphere and separates out the nitrogen for use. Additionally, an ammonia synthesis system is required, which combines hydrogen and nitrogen to create ammonia. The most common technique for ammonia synthesis is the Haber-Bosch technique as shown in a simplified manner in Figure 11.

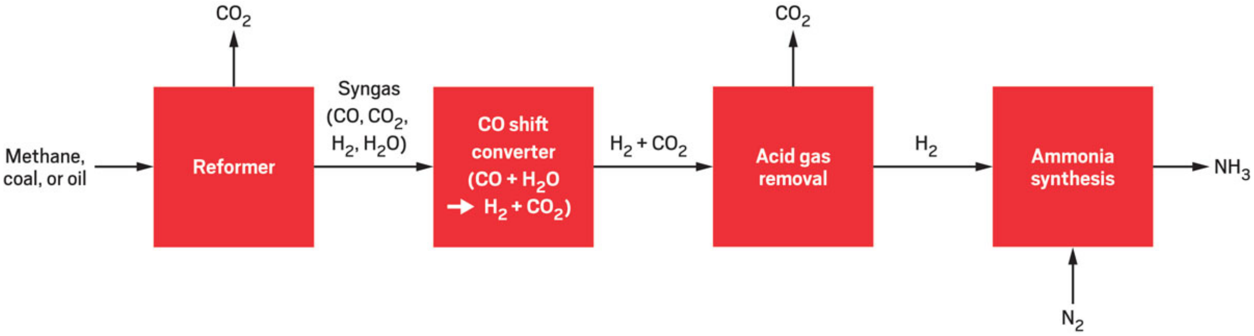

Figure 10. Industrial Ammonia Synthesis Process Using Methane, Coal, or Oil (Boerner 2019)

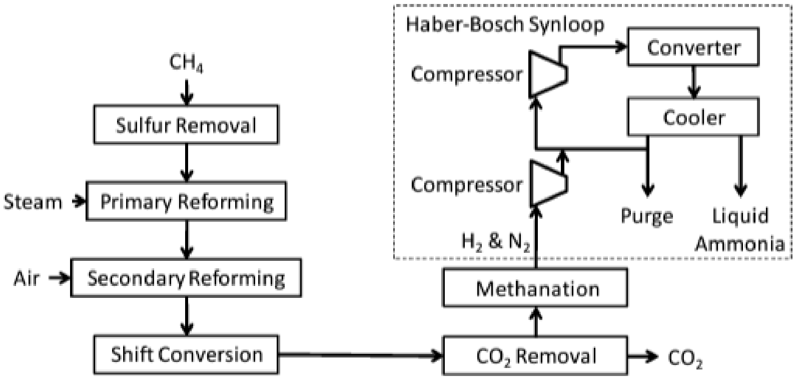

Figure 5: Haber-Bosch ammonia synthesis with natural gas

Figure 11. Haber-Bosch Ammonia Synthesis with Natural Gas (Bartels 2008)

3.4.2 Fuel Cells

Fuel cells use the reverse process of an electrolyzer, where instead of splitting water molecules into hydrogen and oxygen, the fuel cell combines hydrogen and oxygen to produce electricity with only heat and water as by-products. Fuel cells can be applied across a broad range of power applications on small (less than a kilowatt) or large scales (multi-megawatt) (DOE 2020a) Fuel cells are emerging as effective means to power various applications including passenger cars, ships and boats, heavy duty machinery, and aviation.

Fuel cells have several advantages over other electricity-producing technologies, including greater efficiency than combustion engines because they directly generate electricity instead of generating mechanical energy that is then converted to electricity (DOE 2020a). Fuel cells are also scalable, have low maintenance requirements, are quiet, do not have moving parts, do not require oil changes, and can use a wide variety of fuels including hydrogen and ammonia (DOE 2020a). Common fuel cell types include polymer electrolyte membrane fuel cells (PEMFCs), solid oxide fuel cells (SOFCs), molten carbonate fuel cells, phosphoric acid fuel cells, and alkaline fuel cells. Of these, PEMFCs and SOFCs are the most competitive in terms of cost and performance (DOE 2020a). PEMFCs have fast startup times, operate at relatively low temperatures (80°C/176°F), and can handle quick variations in load (DOE 2020a). SOFCs are generally used on larger scales and function at much higher temperatures (800°C – 1,000°C/1,500°F – 1,800°F), making their startup times much longer (DOE 2020a).

Reversible fuel cell (RFC) technology is also being developed that can function in either an “electrolysis” mode or “fuel cell” mode. This type of fuel cell may be a good fit with renewables because it can operate in electrolysis mode during periods of low electricity demand, producing hydrogen that may be stored, and then be switched to fuel cell mode to produce electricity during periods of greater electricity demand (DOE 2020a).

If using a fuel cell in complement with hydrogen production, hot water storage may also be a practice to consider. Fuel cells generate hot water, which can be collected, stored, and used.

3.4.3 Water Microgrid

Hydrogen production by electrolysis requires a secure supply of purified water. A water microgrid can boost the resilience of a hydrogen production system. A water microgrid is a local water system that supplies, treats, and distributes water, with the primary objective to meet critical water demand during a disruption of the primary supply. Water microgrids are composed of a network of components, including water supply, storage, treatment, distribution, power, and controls. A water microgrid can operate independently of an existing primary water system and includes a layer of sensing capability that provides the necessary monitoring and controls to operate the water microgrid. A water microgrid can advance an Air Force installation’s water infrastructure and water resilience by being ready to meet critical missions during a primary supply outage. The electricity used to produce hydrogen can also power a water microgrid. In addition, the water supply can be shared with an electrolyzer for clean hydrogen production. See further discussion of water microgrids in the report *Emerging Technologies Review: Water Microgrid* (Cejudo 2023).

3.4.4 Solar

Solar power, both direct solar and PV, are viable hydrogen production pathways. Direct solar energy can produce hydrogen using a water splitting process with a combination of direct sunlight and specialized semiconductors. This method has the potential for high conversion efficiency at low temperatures (DOE HFTO 2023b). Solar PV converts sunlight to electricity for electrolysis.

Conversely, hydrogen complements solar as a long-duration energy storage technology. Solar is an intermittent source of energy. Energy storage supplements intermittent energy sources like solar by storing excess energy during off-peak hours, then discharging at times of peak demand.

3.4.5 Wind

Hydrogen production and storage can complement wind generation in a similar way to how it complements solar. Generally, wind power production peaks at night, but wind can produce power at any time of day. The flexibility and long-duration storage aspects of hydrogen complement wind power that may be produced during times of low electricity demand in the middle of the night. Offshore wind, the generation of electricity by wind farms in water, can integrate system components that perform electrolysis offshore, sending the hydrogen to shore through a pipeline. Sending hydrogen gas, rather than electrons, to shore can help alleviate congested power grids (Muller and Dittmeyer 2023).

3.4.6 Nuclear

Traditional nuclear energy technologies operate at very high capacity factors and can produce zero-carbon hydrogen. Nuclear energy's role in hydrogen production spans more than two decades in cold electrolysis of water, low- and high-temperature steam electrolysis using heat and electricity from nuclear reactors, and high-temperature thermochemical production using nuclear heat (Figure 12). Nuclear heat can also be used in steam reforming of natural gas (World Nuclear Association 2021b). In coupling a nuclear reactor to hydrogen production, the process temperatures play a critical role. The operating conditions, coolant choice, conversion efficiency, and reactor type will affect the economic and technical feasibility of the nuclear-hydrogen system (Chen 2010).

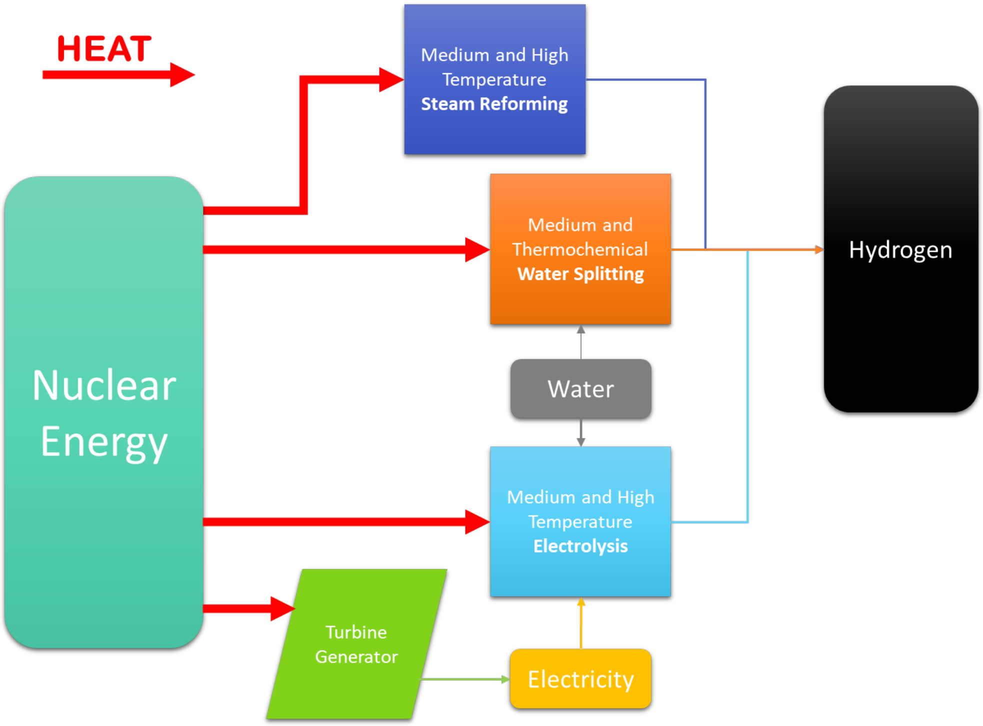

Figure 12. Hydrogen Production Methods by Nuclear Energy (adapted from Chen 2010)

3.4.7 Grid Connection

Hydrogen systems can potentially connect to the electric grid through component additions that could enable the system to operate as an RFC. In an RFC process, hydrogen production via electrolysis acts as a flexible load when connected to the electric grid. In electrolyzer mode, hydrogen can benefit electric grids by maximizing renewable energy penetration (by avoiding curtailment) and providing system support services (e.g., mitigating frequency and voltage disturbances or acting as reserves). This is because electrolyzers can rapidly and flexibly change their power operating points to support the changing needs of the grid at different time scales. Providing grid services at market value to a local utility could generate monetary benefit with the proper agreement in place. Section 6.4 further discusses potential revenue streams for grid connection.

If the system is properly configured and maintained, hydrogen can also be stored for long durations and recovered for use in peak demand or seasonal supply and demand balancing. To support this use case, stored hydrogen could be converted to electricity via a fuel cell, injected into the gas grid, or directly combusted. Through these three pathways, hydrogen could be used to improve resilience at Air Force locations or to support the local power or gas utility if the proper arrangements are in place.

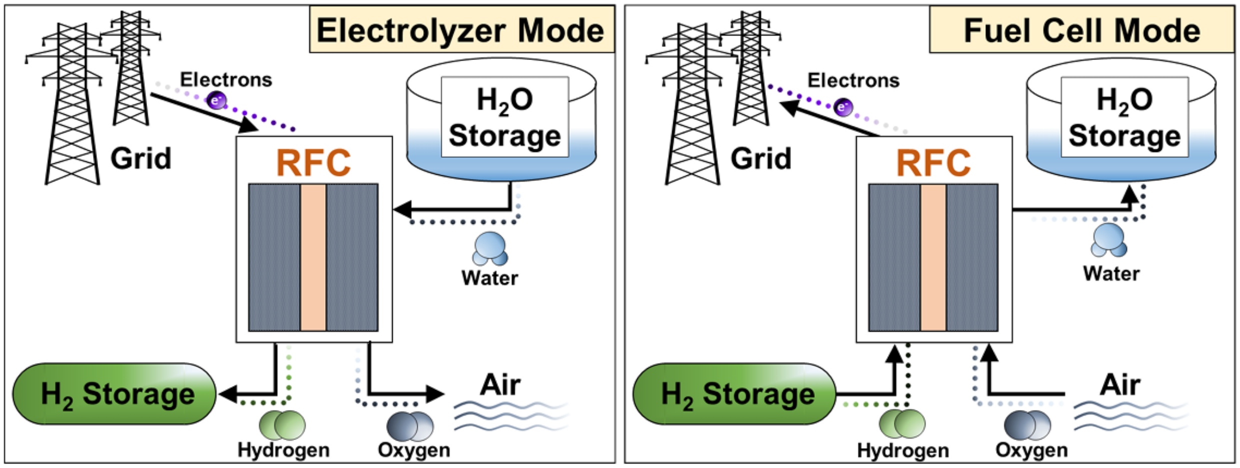

Figure 13. Long-Term Grid Energy Storage via Reversible Fuel Cells (RFC) Would Store Grid Electricity as Hydrogen for Later Conversion Back to Electricity (Papageorgopoulos 2019)

Balance of system equipment is required to connect a new source of power to the grid. This equipment typically includes power conditioning equipment, meters and instrumentation, and safety equipment. Most renewable energy technologies produce direct current (DC) electricity whereas most electrical equipment and appliances need alternating current (AC) electricity to run. Power conditioning involves converting that DC electricity to AC, so it is usable. Power conditioning equipment additionally works to protect equipment by preventing voltage surges, which can damage and degrade equipment; dampens noise; and corrects voltage fluctuations. Local power providers should be contacted to ensure the power inverter is able to match voltage, phase sequence, phase angle, and frequency profile of the grid.

4.0 Regulatory Overview

Existing regulations, guidelines, codes, and standards for hydrogen are in place due to years of hydrogen use in industrial and aerospace applications. Hydrogen production in the U.S. is regulated by 40 CFR Part 98, Subpart P – Hydrogen Production. Additionally, there are federal agencies that regulate stages of hydrogen production and require reporting of aspects of hydrogen operations like the U.S. Environmental Protection Agency Mandatory Greenhouse Gas Reporting Program and Chemical Accident Prevention Program.

Outside of federal oversight, there are several codes and standards related to hydrogen production and storage systems adopted and enforced by state or local authorities (Baird et al. 2021). Examples include (Rivkin 2017; Safe Hydrogen Project 2023):

- National Fire Protection Association (NFPA) 2, Hydrogen Technologies Code
- NFPA 70, National Electrical Code
- Compressed Gas Association (CGA) H-5, Standard for Bulk Hydrogen Supply Systems
- CGA H-10 – H-15, standards related to steam reformers, syngas systems, mechanical integrity, and other facets of hydrogen production
- CGA H-3, Standard for Cryogenic Hydrogen Storage
- CGA G-5, Hydrogen
- CGA S-1.1-1.3, Guides Cylinder Pressure Relief Device Selection and Sizing

State and local jurisdictions may adopt these codes and standards or may have other, more stringent requirements. There also may be adoption of different yearly editions of these codes and standards depending on the locality.

5.0 Risks

While hydrogen holds immense potential as a clean and versatile energy carrier for the Air Force, it is essential to consider the social and environmental implications associated with hydrogen project implementation. Public acceptance, safety management, inclusive infrastructure planning, job creation, and equity measures are vital for the widespread adoption of hydrogen production and storage technologies. Environmental considerations vary depending on the production source and associated emissions.

5.1 Human and Public Perception Risk Factors

5.1.1 Human Health and Safety

Concerns for hydrogen systems' effects on human health and safety are centered on leakage and emissions. Hydrogen leaks can occur due to several factors, including mechanical damage, material degradation, or faulty equipment. For example, hydrogen storage and transportation through pipelines can cause the metal matrix of the pipeline material to embrittle and become prone to cracking or failure. This can occur in high strength steels, titanium alloys, or other metals.

Hydrogen has a broad explosive range, has an incredibly high flame propagation speed compared to natural gas, and is corrosive (Karp 2021). Because hydrogen is flammable and has no color or odor, leaks can be dangerous without proper detection equipment. For this reason, hydrogen is subject to strict codes and standards, especially when used in an enclosed space where a leak might create an immediate health hazard.

Depending on the selected hydrogen production method, a hydrogen facility could impact the water and food supply or contribute to climate change and the associated health risks. Large-scale (MW-scale or above) hydrogen production through electrolysis or other water splitting techniques could lead to significant diversion of local freshwater supply, exacerbating local water and food supply issues. These effects and how they translate to human health impacts may vary by region. Hydrogen production methods that rely on the use of fossil fuels can exacerbate local climate-related effects that trigger health conditions in nearby populations (CDC 2022).

5.1.2 Public Perception and Community Acceptance

Depending on the selected hydrogen system configuration, nearby communities may be directly impacted by its construction and operations or may raise objections to building a project near their community. Many individuals are unfamiliar with the technical characteristics, applications, safety profiles, and risk management strategies for hydrogen systems. For instance, some of the ongoing public discourse related to hydrogen adoption includes hydrogen as a replacement for gas in heating and cooking, hydrogen for electrification compared to more direct methods like solar and wind, and hydrogen in the transportation sector compared to batteries. Within these conversations, public objections have been raised to hydrogen production from non-renewable sources because many believe this production pathway may prolong the life of fossil fuel infrastructure. SMR facilities without emission capture technologies omit unwanted byproducts that can harm human health and, even with carbon capture, there can be pushback to investments in hydrogen technologies as it may not be seen as the fastest way to achieve clean energy goals.

Taken together, these perception factors and others might contribute to a lack of public community acceptance of a hydrogen project. A lack of public acceptance could pose a risk to successful deployment of the project. Inclusive planning and construction processes and stakeholder engagement can help address these risks, minimize community and environmental impacts, and optimize infrastructure deployment to support social needs. Local skilled workers could be employed to support the construction of a hydrogen system deployed for energy resilience, but investments in training programs may be required. These programs could be facilitated through Air Force support, strengthening engagement with local communities.

5.2 Environmental Considerations

Depending on the system configuration, hydrogen production can have multiple environmental impacts. Most impacts are related to the feedstocks required to create hydrogen from other materials. The following subsections outline hydrogen production's environmental footprint and associated environmental risks and hazards that the process might create.

5.2.1 Environmental Footprint

When pure hydrogen is combusted in an engine or used in a fuel cell to generate electricity, its only byproduct is water vapor, making it a clean alternative to hydrocarbon fuels at the time of use. Therefore, hydrogen's environmental footprint depends on its production process. Hydrogen can be produced with vastly different levels of associated emissions. Hydrogen production can be a highly polluting process, and it currently contributes nearly 2% of global emissions annually (Rocky Mountain Institute 2022). This is because, currently, 95% of hydrogen is produced using fossil fuels as a feed material or power source (DOE 2023b).

Figure 14 displays a condensed version of the "colors of hydrogen" relating to the levels of emissions associated with different production processes. Hydrogen produced with fossil fuels as the feed material and/or as the energy source powering the production is categorized as "grey hydrogen" if there are no efforts to capture and store emissions. Hydrogen produced with fossil fuels as the feed material and/or energy source for production, but also with carbon capture and storage integrated into the process, is called "blue hydrogen." Hydrogen produced using water as the feed material and renewable energy sources (e.g., wind, solar, hydro) to power the production is called "green hydrogen."

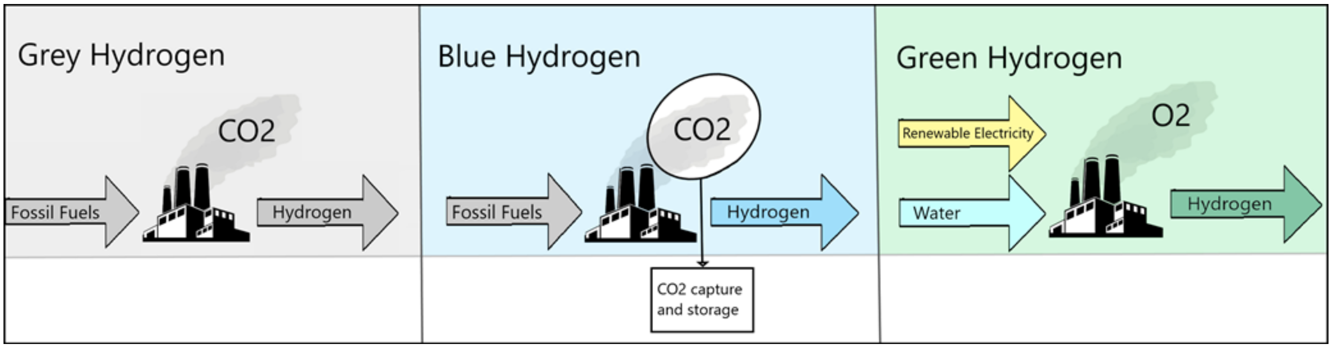

Figure 14. Hydrogen produced from different sources is often associated with colors for distinction. Grey hydrogen is that from fossil fuels, blue hydrogen is the same as grey but with carbon capture, and green hydrogen is produced from renewable sources.

Hydrogen production also requires large volumes of purified freshwater. In ideal conditions, SMR requires 4.5 kg of water to produce 1 kg of hydrogen and electrolysis requires 10 to 11 kg of water to produce 1 kg of hydrogen (WaterSMART Solutions Ltd. 2020).

5.2.2 Environmental Risks and Hazards

Greenhouse gas emissions from the production of grey or blue hydrogen can factor into the direct role of air pollutants in climate change. Production of hydrogen can also lead to the diversion of freshwater supplies for power-generation (mainly grey and blue hydrogen production methods), steam-generation (grey and blue methods) or electrolysis-based systems (grey, blue or green methods).

6.0 Economic and Funding Considerations

Cost is the biggest driver in determining market feasibility of hydrogen, especially for hydrogen produced from renewable sources. There are many research and development efforts across national laboratories and federal agencies to reduce the cost to produce and store hydrogen, meet performance requirements, and improve durability as guided by application-specific targets. Electrical energy and capital costs are the most prominent for hydrogen production by electrolysis, and for above-ground tank storage, carbon fiber precursors and processing make up the largest costs (Satyapal 2022). Figure 15 shows the breakdown of specific cost drivers within production (through high-temperature electrolysis) and storage.

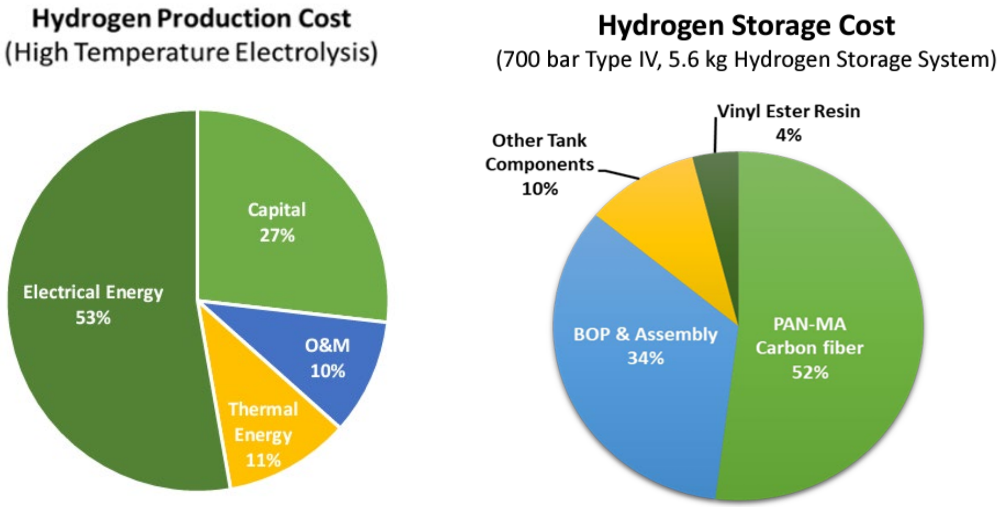

Figure 15. Examples of Cost Drivers for a Hydrogen Production Technology and Hydrogen Storage System (Satyapal 2022)

The remainder of this section covers the capital costs, lifecycle costs, potential funding mechanisms, and sources of revenue. Installed system costs depend on the production pathway and amount of hydrogen produced. Each stage of the system lifecycle has costs to consider due to internal and external factors. Funding mechanisms to support the buildout of a hydrogen system can include grants, subsidies, tax incentives, loan guarantees, and public-private partnerships. The sale of hydrogen and use of hydrogen for grid support and backup power can generate revenue.

6.1 Installed Systems Costs

Capital costs of electrolyzer systems vary widely, with alkaline systems typically costing less than PEM with some overlap in price ranges. An alkaline electrolyzer typically costs $500 to $1,000/kW and a PEM system typically ranges from $700 to $1,400/kW (Ramadan et al. 2022). Therefore, a 1-MW alkaline electrolyzer could be expected to cost $500,000 to $1 million and a 10-MW system from $5 million to $10 million. A 1-MW PEM electrolyzer could be expected to have capital costs in the range of $700,000 to $1.2 million and a 10-MW system from $7 million to $12 million. These costs include the cost of infrastructure such as electrolyzers or SMRs for hydrogen production. Balance of plant costs, like those for the compression, liquefaction, and monitoring equipment, are considered. Storage costs vary widely depending on the selected method and scale of operations and are discussed within the lifecycle cost section by storage type and duration. The cost of land, permits, and other regulatory requirements should also be considered based on jurisdiction and location. Both storage and regulatory costs are not included in the system costs described above.

Labor costs should also be considered. One data point highlights that a 20-MW PEM hydrogen production facility was built in Quebec, Canada, in under 2 years with 60,000 labor-hours (40,000 labor-hours on the build site and 20,000 labor-hours for engineering, safety inspections, supervision, and project management) of work over that timeframe (Air Liquide 2021).

6.2 Lifecycle Costs

The lifecycle cost of hydrogen production and storage is a key factor to consider when evaluating the feasibility of a hydrogen system. Lifecycle cost analysis considers the initial investment, O&M expenses, and any decommissioning or disposal costs. O&M costs include the cost of the energy and feedstocks/materials required for hydrogen production, the costs of equipment maintenance and repair, and any costs associated with transportation or distribution. The efficiency of the production process, the availability and cost of feedstocks, and the scale of operations all impact operational costs.

The cost of periodic maintenance, equipment upgrades or replacements, and any necessary repairs depends on the lifespan of the facilities, which can vary depending on factors such as technology advancements, regulatory changes, and market demand. The lifetime of an alkaline electrolyzer is up to 30 years, but the electrodes and the diaphragms must be replaced after 7 to 15 years (Kanz et al. 2021). The membrane material of PEM electrolyzers limits their lifetimes to 15 to 20 years. SMR with carbon capture has an assumed technical life of 40 years (BEIS 2021).

End-of-life costs include decommissioning and disposal of equipment. Proper decommissioning and disposal procedures are essential to minimize environmental hazards and ensure regulatory compliance. There are end-of-life technologies and strategies to recover or recycle valuable materials from the stacks of electrolyzers and fuel cells, including noble metals and other materials. The economic feasibility of metallurgical recovery methods depends on the recovery efficiency and initial concentration of the precious metals. These processes typically have high investment and operating costs. Newer methods to recover platinum group metals from PEM stacks can allow additional recovery of other materials such as the ionomer and carbon support. Alkaline electrolyzers use nickel, and thus have restricted disposal in landfills, but there are many recovery treatments available due to nickel's relatively widespread use. Recovered ceramics used in solid oxide and alkaline electrolyzers may be of interest for the construction industry to use in brick manufacturing or in clays for concrete and cement production (Valente et al. 2019).

Various external factors also influence the lifecycle cost of hydrogen production and storage. These include the availability and cost of feedstocks, the price of electricity or other energy sources used in the production process, market demand for hydrogen, and government incentives or subsidies.

Overall, SMR has a lower levelized (lifecycle) cost of hydrogen production and less cost variability compared to the cost of electrolysis to produce hydrogen. Hydrogen from electrolysis using electricity sourced from the grid or, potentially, onsite renewable power generation likely costs approximately $2.93 to $7.22/kg to produce (DOE 2020b). This estimate factors in electricity prices in the range of $0.015/kWh - $0.12/kWh. Costs associated with on-site power generation are therefore not explicitly accounted for in the cost range but may be reflected by the estimates from DOE an economic analysis of the onsite generator produces a levelized cost of electricity in the range of $0.015/kWh - $0.12/kWh.

Whereas SMR using natural gas costs $0.7 to $1.6/kg to produce or SMR combined with carbon capture methods costs $1.2 to $2.1/kg to produce (IEA 2020). These values are based on averages across the U.S. Cost multipliers may be needed depending on location. Capital costs for storage of hydrogen vary widely depending on the selected method. Figure 16 presents a current snapshot of the storage costs of various methods and their typical storage durations. These are presented as levelized costs for comparison to production costs.

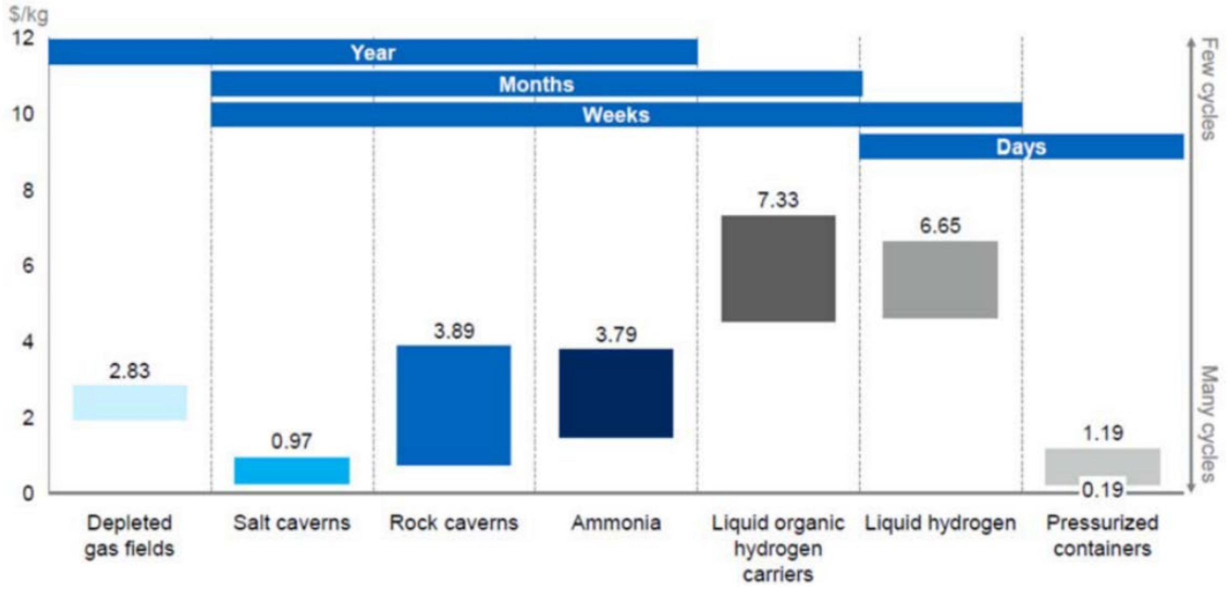

Figure 16. Levelized Costs of Hydrogen Storage Methods and Typical Storage Durations (Doomernik et al. 2020)

6.3 Potential Funding Mechanisms

As stated previously, most hydrogen production to date has relied on carbon-intensive methods. Investments under the Bipartisan Infrastructure Law (BIL) and Inflation Reduction Act (IRA) offer a hefty amount of funding for clean hydrogen to advance national efforts toward climate targets. The incentives provided by BIL and IRA are targeted to facilitate the adoption of low- or zero-emission hydrogen.

6.3.1 Incentives

As part of the BIL enacted in November 2021, also known as the Infrastructure Investment and Jobs Act, the DOE launched major clean hydrogen initiatives to accelerate domestic production, deployment, and use of clean hydrogen. There are three BIL programs investing in clean hydrogen initiatives that total over $9.5 billion. Federal agencies are eligible to participate in BIL projects as a subrecipient but are not eligible to apply as a prime recipient. Air Force would, therefore, need to develop their project with a partner to take advantage of these incentives.

The $8 billion Regional Clean Hydrogen Hubs Program will create jobs to expand use of clean hydrogen in the industrial sector and beyond (DOE 2022). BIL requires at least four regional clean hydrogen hubs that “demonstrate the production, processing, delivery, storage, and end-use of clean hydrogen” and can be “developed into a national clean hydrogen network.”[1] The funding opportunity for this program closed April 7, 2023, but there may be future opportunities to join the awarded hubs and expand the clean hydrogen network of producers and consumers.

The Clean Hydrogen Electrolysis Program, supported by $1 billion, is aimed at reducing the cost of hydrogen produced using electrolyzers to less than $2/kg of hydrogen by 2026. This will occur through “research, development, demonstration, commercialization, and deployment” to “improve the efficiency, increase the durability, and reduce the cost of producing clean hydrogen using electrolyzers.”[2] The funding mechanism for this program is a cooperative agreement, and applications are accepted until the total funding amount is expended.

The remaining $500 million is for Clean Hydrogen Manufacturing and Recycling Initiatives to support equipment manufacturing and strong domestic supply chains. Like the electrolysis program, this effort uses “research, development and demonstration projects to advance new clean H_2 delivery, storage and use equipment manufacturing technologies and techniques.”[3] The period of funding availability is open until the total funding amount is expended, with varying funding mechanisms (e.g., grants, contracts, cooperative agreements).

The IRA, enacted in 2022, includes a federal incentive program that provides credits for clean energy production. The IRA has three hydrogen-related incentives that the Air Force may be able to take advantage of through third party developers. The Clean Hydrogen Production Tax Credit will provide tax credits up to $3/kg of hydrogen produced based on associated emission levels. Production facilities also need to be built before 2033 to qualify for the production tax credit. The Advanced Energy Project Credit is a capital expenditure tax credit for hydrogen production infrastructure that credits up to 30% for infrastructure investments intended to produce clean hydrogen. Direct pay is available under the IRA for tax-exempt entities. The Energy Storage Credit makes hydrogen storage eligible for a 30% tax credit. Table 5 compares the credits in both incentives, depending on the lifecycle emissions of the hydrogen system.

Table 5. Investment Reduction Act Hydrogen-Related Tax Credits Comparison

	Clean Hydrogen Production Tax Credit	Advanced Energy Project Credit
Life Cycle Emissions (kg CO2/kg H2)	Production Tax Credit ($/kg H_2)	Investment Tax Credit Percentage
2.5-4	0.60	6%
1.5-2.5	0.75	7.5%
0.45-1.5	1.00	10%
0-0.45	3.00	30%

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[1] 42 USC § 16161a

[2] 42 USC § 16161d

[3] 42 USC § 16161c

When clean hydrogen is used in the production of clean ammonia and is not the end product, these incentives still apply. If green fuels are produced from a clean feedstock, and with power from renewable sources as expected, emissions should be minimal to none, and the highest credit incentives would apply.

6.4 Potential Revenue Considerations

There are various hydrogen system configurations that offer revenue opportunities that will support the Air Force's cost-effectiveness goals. Stored hydrogen can be converted to electricity through turbines, engines, or fuel cells. Electricity supplied to the grid can create financial benefits through the grid services it supports. Energy arbitrage, as an example of a revenue source, is when utilities purchase electricity during off-peak hours at a low price and store the electricity for use during peak hours when the price is high. Using fuel cells to "re-electrify" hydrogen from storage and sell electricity for arbitrage can support grid reliability needs and produce revenue for the Air Force. Another grid service that can create revenue opportunities is frequency regulation, which is the act of balancing supply and demand so that electricity grid frequency is maintained as close to 60 Hz as possible. The addition of a hydrogen load (electrolyzers) to the grid amplifies the regulating range of the grid operating frequency. This is because the hydrogen load can respond quickly to regulation needs.

If the hydrogen produced by the Air Force is re-electrified or consumed by the base, demand charges from the utility can be managed. Moreover, coupling onsite consumption with participation in demand response programs to shift or reduce electricity or thermal (if feasible) needs may further reduce utility prices or monetary incentives. Overall, onsite consumption of hydrogen for electricity can be a reliable source of power during disaster events, which will improve resilience and have long-term financial impacts.

The selling of produced hydrogen can also generate financial benefits; there are various industries that require hydrogen and, as discussed in Section 3.2.2, the global demand for hydrogen is increasing steadily.

7.0 Implementation and Siting Considerations

The optimal use case for a hydrogen production and storage facility may vary significantly based on installation needs, hydrogen demand, storage duration, and other factors. To achieve an optimal use scenario, the proper resources must be available to effectively run a hydrogen production and storage facility. These resources include an appropriate area of land to dedicate to a production facility and its components. Additionally, feedstock resources (water, natural gas, coal, biomass, waste, etc.) and electric power (from wind, solar, hydro, the grid, etc.) for hydrogen production are needed.

Land and space requirements, feedstock availability, and infrastructure requirements are three important considerations when planning for hydrogen production and storage siting. This section provides an overview of those considerations. Siting efforts should also consider needs and composition of the communities near the project, such as proximity to residential areas, transportation networks, community energy resilience requirements, and livelihood.

7.1 Land/Space Requirements

Depending on the system configuration, hydrogen production and storage will require varying amounts of land and might have specific land type requirements to ensure safety of operations. Spatial and facility needs should consider ventilation, accessibility, proximity to high traffic or occupied areas, distance from hazards and ignition sources, and ground stability. Required space will vary depending on the production source and the intended scale of production. Small-scale hydrogen production is becoming more popular; however, there is often a tradeoff of efficiency, reliability, durability, and cost effectiveness that cannot be attained at such small scales (Zanfir 2014).

Hydrogen production facilities do not yet exist at very large scales (greater than 20 MW). Thus, land use requirements are mostly engineering estimates from ongoing projects at those sizes. Three separate studies, one funded by the German government, a study by ITM, and one by McPhy, estimated that the land area requirements for a 100-MW electrolyzer would be 6,300 m^2 (1.6 acres), 3,500 m^2 (0.9 acres), and 4,500 m^2 (1.1 acres), respectively. Additionally, Siemens estimated that a 300-MW electrolyzer would require 15,000 m^2 (3.7 acres) (IRENA 2020). Typically, an alkaline electrolyzer will require marginally more space than a PEM system. The Institute for Sustainable Process Technology in the Netherlands estimates a 1-GW alkaline electrolyzer would require 0.17 km^2 (42 acres), whereas a 1-GW PEM electrolyzer would require 0.13 km^2 (32 acres) (IRENA 2020). Compact designs and various layout options are available to optimize land use and standardized layouts are being developed by industry participants. It's likely, based on the estimated land requirements for these much larger facilities, that a 1 – 10MW electrolyzer could occupy less than one acre of land. Depending on the intended end use of the hydrogen, additional area for fueling, storage or access to the areas by fuel transport vehicles may be required. If the electrolyzer is powered by on-site generation technologies, the footprint of the overall system could be dramatically increased. Renewable resources like solar and wind require significant spacing and offsets that planners should consider when siting hydrogen systems.

Space requirements for hydrogen storage depend on storage duration, intended application, and the energy density or deliverability required. The space requirements for compressed gas storage depend on the desired storage capacity and the pressure at which the hydrogen is stored. Generally, compressed gas storage requires larger volumes of space compared to other storage methods. Cryogenic storage tanks for liquid hydrogen storage are determined by the desired capacity and the insulation needed to prevent heat transfer. Liquid hydrogen storage generally requires less space compared to compressed gas storage. Subsurface geologic storage of gaseous hydrogen requires a small surface footprint compared to other storage types but relies on the presence of suitable rock formations beneath a potential site.

7.2 Resource Availability

Hydrogen production potential varies spatially and depends on availability of feedstock resources. For instance, SMR uses natural gas as the feedstock, so a location with a reliable natural gas connection is important. Figure 17 shows the hydrogen production potential from renewable resources, including biomass, wind, solar, waterpower, and geothermal.

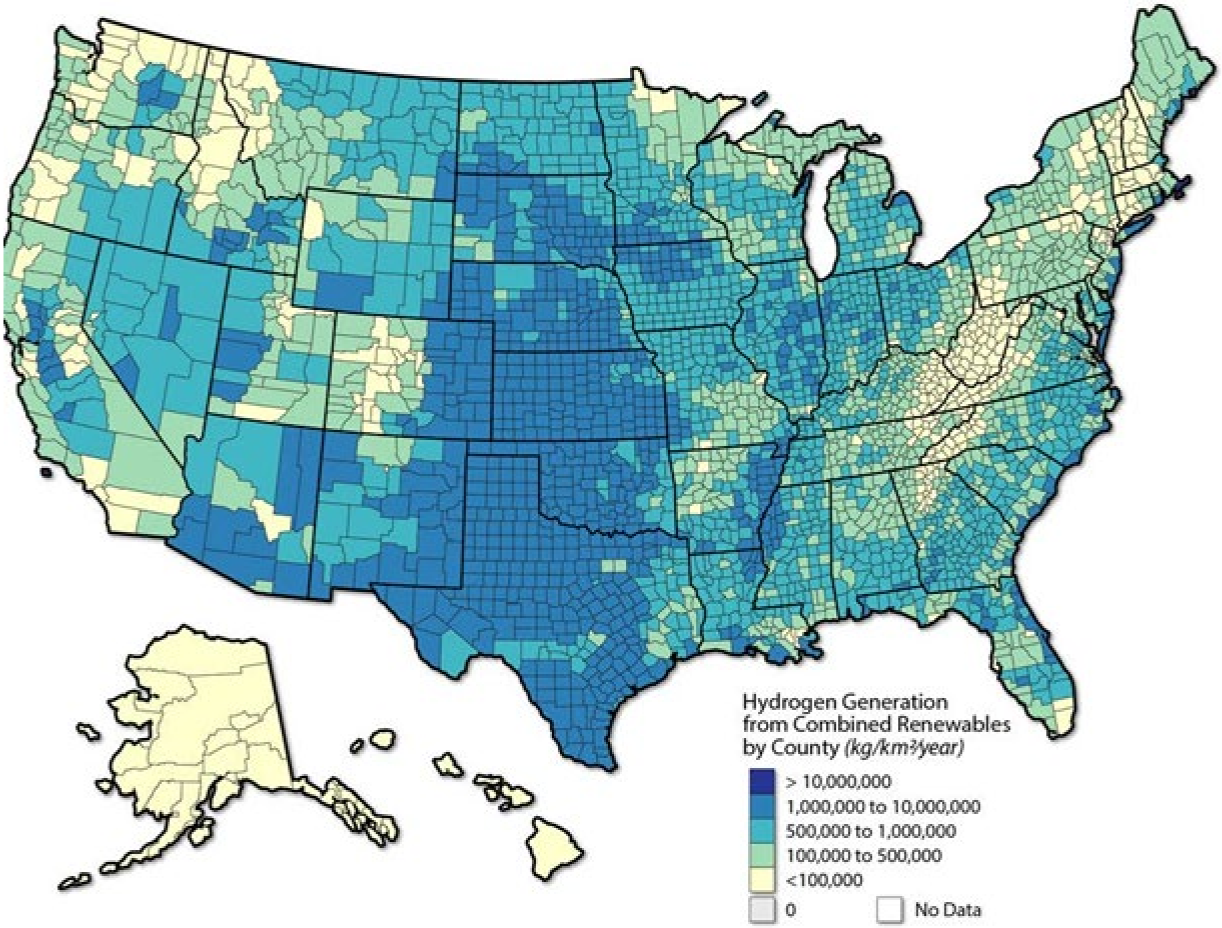

Figure 17. Hydrogen Production Potential from Renewable Resources, by County Land Area (Connelly et al. 2020)

If electrolysis is the chosen production method, then regional water availability is also important. An efficient electrolyzer requires 50 kWh to produce 1 kg of hydrogen, and 1 kg of hydrogen contains 33.33 kWh of energy. Of note, both alkaline and PEM systems require highly pure, distilled water that can be attained with a water purification system that has low maintenance requirements (Morgan et al. 2014). The available water remaining (AWARE) characterization factor reflects regional water scarcity footprint and is a useful for evaluating regional water availability. Figure 18 shows AWARE factors by county in the U.S. For hydrogen production potential by resource and more on water scarcity impacts on hydrogen production, see the NREL Resource Assessment for Hydrogen Production (Connelly et al. 2020).

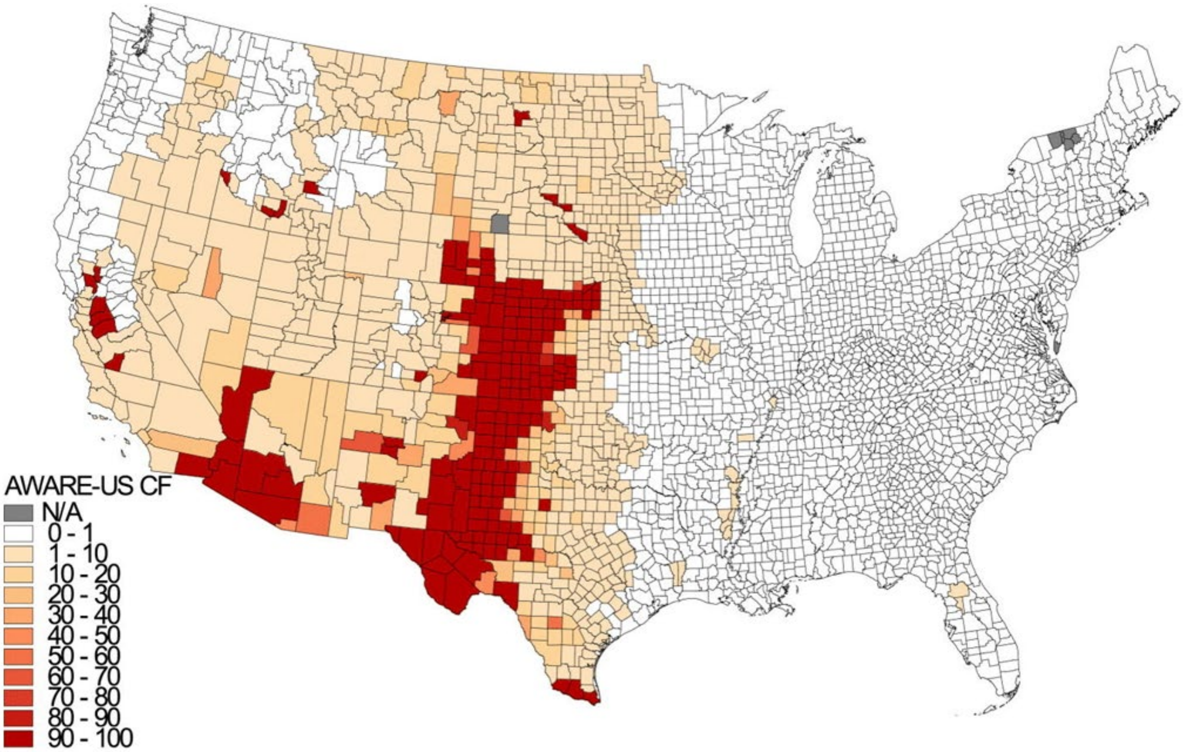

Figure 18. County-level AWARE Characterization Factors. Counties in white have a water stress level lower than the U.S. average and counties in red experience water scarcity (Connelly et al. 2020).

Subsurface storage facilities are an alternative for large-scale hydrogen storage. Suitable geological formations, such as depleted natural gas reservoirs or salt caverns, can be repurposed for hydrogen storage. A recent study (Lackey et al. 2023) showed there is an estimated 9.8 million metric tons of existing underground gas storage (UGS) capacity in the U.S. That amount of storage capacity could represent 327 TWh of energy storage of pure hydrogen nationally. But, on an energy basis, converting the facilities from natural gas to pure hydrogen storage would reduce the total energy stored by ~75%. However, if just a 20% volumetric blend of hydrogen to natural gas were stored in the facilities, current seasonal energy storage operations that balance seasonal natural gas demands could still be maintained at 73.2% of existing UGS facilities. This might present an opportunity for the Air Force to take advantage of contractual arrangements with existing natural gas storage field operators to provide storage services at offsite locations as a less expensive alternative to building storage facilities on-post.

7.3 Infrastructure Requirements

The essential infrastructure requirements for hydrogen production and storage relate to the facilities needed to house production system components and storage mediums and supporting services to operate those facilities. Stable power supply infrastructure is essential for hydrogen production. Electrolysis facilities must house electrolyzers, power supply systems, and water treatment systems. Electrolysis infrastructure should also be designed to facilitate the integration of solar, wind, or other renewable energy technologies into the hydrogen production process. Depending on the needs of the Air Force or system operator, construction of renewable energy generation facilities, energy storage systems, and grid connections may be desirable. SMR and other reforming process facilities require reformers, heat exchangers, and purification systems to ensure high-quality hydrogen production. If the hydrogen produced is not used or stored nearby, off-take contracts should be in place with adequate infrastructure to collect the hydrogen.

The configuration of the system and operational requirements also affect the amount of hydrogen produced and the amount of input resources needed for the process. Table 6 presents an example of how hydrogen production system size drives requirements for feed water and electricity for an efficient electrolyzer system.

Table 6. Example Hydrogen Electrolyzer System Outputs and Resource Requirements

	System Running 91 Days/Year				System Running 300 Days/Year			
	Output		Water Required	Electricity Required	Output		Water Required	Electricity Required
System Size	kg/yr	MMBtu/yr	(gal/yr)	(kWh/yr)	kg/yr	MMBtu/yr	(gal/yr)	(kWh/yr)
1 MW system (400 kg/day)	36,400	4,100	87,000	1,820,000	120,000	13,600	288,000	6,000,000
5 MW system (2,250 kg/day)	204,800	23,100	490,000	10,240,000	675,000	76,000	1,613,700	33,750,000
10 MW system (4,500 kg/day)	409,500	46,400	980,000	20,475,000	1,350,000	153,900	3,227,300	67,500,000

Storage infrastructure requirements will vary based on the storage type and should include appropriate safety measures to reduce the risk of leakage and ignition. Infrastructure for compressed gas storage requires specialized tanks that can withstand high pressures. Safety measures, such as pressure relief systems and leak detection systems, should be incorporated into the infrastructure. Infrastructure for liquid hydrogen storage includes cryogenic tanks designed to maintain extremely low temperatures. Safety measures, such as insulation systems and venting systems, are necessary to prevent excessive pressure buildup. Underground storage will depend on geological resources, as discussed Section 7.2. Infrastructure for underground storage includes injection and withdrawal wells, monitoring systems, purification and cleaning systems, compressors, and safety devices.

8.0 Recommendations and Path Forward

Hydrogen production and storage align with the Air Force's focus areas of resilience and climate and can be used as a technology application to support continuous mission operations. Hydrogen production via electrolysis can provide grid services to help balance supply and demand. By storing excess energy in the form of hydrogen, it can be used when needed, such as during outages. Hydrogen can enable decarbonization of hard-to-abate sectors, such as heavy-duty transportation and industrial processes. By replacing fossil fuels with hydrogen, these end uses can reduce their carbon emissions.

The Air Force should develop a strategic approach to deploying hydrogen production and storage capabilities. The following sections identify technical resources to aid in planning and plot out potential next steps.

8.1 Technical Resources Available

There are multiple tools available to support planning for hydrogen production and storage system projects.

The Hydrogen Delivery Scenario Analysis Model (HDSAM)[1] is an open-source tool developed by Argonne National Laboratory and PNNL. HDSAM is an Excel model designed to estimate hydrogen delivery pathway costs for hydrogen-powered vehicle applications. The model allows the user to input variables including market demand parameters, cost and performance data for delivery and refueling components as a function of throughput and hydrogen production volume, and economic and financial parameters. It then calculates the levelized cost in $/kg of hydrogen delivery via specified delivery method, the contribution of system processes and components to the levelized cost of hydrogen, capital, O&M costs of delivered hydrogen, annual and cumulative cash flows by system components and total, as well as land area, energy usage, efficiency, leakage, boil-off, and emissions estimates (Argonne National Laboratory n.d.).

The American Institute of Chemical Engineers maintains a Center for Hydrogen Safety. The Center has a Fundamental Hydrogen Safety Credential, which could serve as a starting point for onsite emergency personnel training, along with more advanced courses on hydrogen safety.[2] There are additional training materials on H2Tools, which is a PNNL-developed suite of public hydrogen resources.[3]

Hydrogen Plus Other Alternative Fuels Risk Assessment Models (HyRAM+) is a software toolkit that integrates publicly available data and models relevant to assessing the safety in the use, delivery, and storage infrastructure of hydrogen.[4] The risk assessments provide probabilities of failure for different components of the storage systems and the effects of those failures on people.

There are also publicly available tools to evaluate revenue opportunities for various hydrogen configurations such as PNNL's Energy Storage Cost and Performance Database and Hydrogen Energy Storage Evaluation Tool (HESET). The Energy Storage Cost and Performance

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[1] https://hdsam.es.anl.gov/index.php?content=hdsam

[2] https://www.aiche.org/chs/education/chs-fundamental-hydrogen-safety-credential

[3] https://h2tools.org/training-materials

[4] https://energy.sandia.gov/programs/sustainable-transportation/hydrogen/hydrogen-safety-codes-and-standards/hyram/

Database provides cost and performance analysis for a bi-directional PEM electrolyzer.[1] The database provides the total installed cost ($/kW and $/kWh) including fixed O&M costs ($-/kW-year). HESET[2] values hydrogen energy storage for multiple delivery pathways and grid applications through techno-economic analysis. The tool models the hydrogen production (electrolysis only), storage (underground only), and distribution pathway. The outputs are net present value, benefit-cost ratio, internal rate of return, payback period, and kilograms of hydrogen produced.

The U.S. National Clean Hydrogen Strategy and Roadmap outlines an all-of-government approach to clean hydrogen aligned with BIL 42 USC § 16161b (DOE Hydrogen Program 2023). The report is a snapshot of hydrogen production, transport, storage, and use in the U.S. today, with an assessment of the opportunity for hydrogen to contribute to national decarbonization goals across sectors over the next 30 years. The Air Force can use this roadmap to align their strategic planning with other federal agencies.

8.2 Recommended Next Steps

In addition to using the previously mentioned tools, below are logical next steps that may help the Air Force with decisions about hydrogen production and storage implementation.

- **Conduct a portfolio-level site assessment**. The Air Force could create a plan for implementation by either using Table 6 as a starting point or by more systematically assessing each site's suitability for hydrogen applications at a high level to identify strong cases for early adoption of hydrogen. Resource mapping helps identify regions with substantial clean energy resources and hydrogen demand. Conducting this assessment across the portfolio of Air Force installations could allow for prioritization of sites that are ideal candidates for hydrogen production and storage based on multiple criteria.
- **Consider Air Force applications for produced hydrogen.** Hydrogen can be a feedstock for aviation fuel production or used in fuel cells for power generation, forklifts, vehicles, other material handling devices, and unoccupied aerial vehicles. The Air Force should evaluate needs for hydrogen within their portfolio.
- **Review site-specific considerations.** Conduct a more detailed assessment considering site-level data collected on energy profiles, water needs, reliability needs, staffing capabilities, interest, state and local regulations, and system ownership options.
- **Conduct a feasibility study for each installation with suitable site characteristics.** Using the review of site-specific considerations as a screening activity, a site-specific feasibility study could entail a technoeconomic analysis comparing varying production pathways and storage options modeled at each screened site. Resources like HDSAM and HESET can help guide this analysis.
- **Evaluate economic and social viability.** Next steps should examine the Air Force's energy service procurement mechanisms and obtainability of incentives under BIL and IRA. Social and environmental considerations discussed in Section 5.0 should also be considered in planning.
- **Select a site for a pilot.** A demonstration project could test the long-term feasibility of a hydrogen system before committing to a larger scale investment. Moreover, demonstration projects can help bridge technical gaps needed to lower the cost of hydrogen and build confidence in emerging technologies.

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[1] https://www.pnnl.gov/hydrogen-bi-directional
[2] https://eset.pnnl.gov/#/ourproducts/HESET

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