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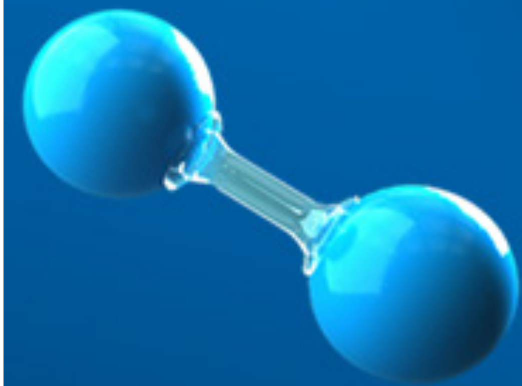
The Viability of Implementing Hydrogen in Massachusetts



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Executive Summary

The Viability of Implementing Hydrogen in Massachusetts

Hydrogen (H2) is the highest energy content fuel by weight and is a building block for a wide variety of other materials (e.g., conventional and synthetic fuels, polymers, plastics, petroleum refining, fertilizer, etc.) used in manufacturing and industrial processing. The recent interest in hydrogen utilization has been motivated by several factors including: (a) the desire to reduce carbon dioxide (CO2) emissions due to the consumption of oil, propane, and natural gas (i.e., methane) for combustion; (b) the need for new climate-neutral sources of energy generation to meet ever growing human demands; (c) the significant reduction in the levelized cost of energy (LCOE) of renewable energy sources (i.e., wind and solar) that help facilitate the economic viability of green hydrogen production on a wide-scale; and (d) future opportunities to produce hydrogen at low-cost when an over-supply of renewable electricity leads to curtailments and negative power pricing. These factors provide an opportunity for low-cost hydrogen generation for energy storage, transportable renewable energy, transportation, the thermal sector, and material production derived from hydrogen.

This study is motivated by both the opportunities and challenges of developing a hydrogen-based economy within Massachusetts and the Northeast. Other parts of the world (e.g., Japan, Iceland, and parts of Europe) and other U.S. states, are further advanced in hydrogen generation and utilization. Apart from the economic benefits, hydrogen shows promise in helping Massachusetts reach its greenhouse gas (GHG) emission reduction goals. A multidisciplinary team from the University of Massachusetts Lowell (UMass Lowell) has conducted a study to investigate the viability of implementing hydrogen within Massachusetts. This investigation has identified the opportunities and existing barriers to integrating hydrogen throughout the Commonwealth's economy.

Opportunities and Challenges of Hydrogen for Massachusetts

A hydrogen-integrated economy relies on a diverse range of applications that utilize hydrogen. These applications include energy storage, thermal heating, industrial processes (e.g., manufacture of polymers, methanol), transportation, electricity production, synthesis of synthetic fuels, upgrading oil, and ammonia/fertilizer production. If successfully implemented, each application is likely to provide measurable benefits in meeting the carbon emission targets, including net-zero emissions by 2050, for Massachusetts [Lenton, 2021]. However, successful implementation will need to overcome widespread adoption challenges, including safety concerns, to ensure the Commonwealth has a robust energy and economic infrastructure (see Figure 1).

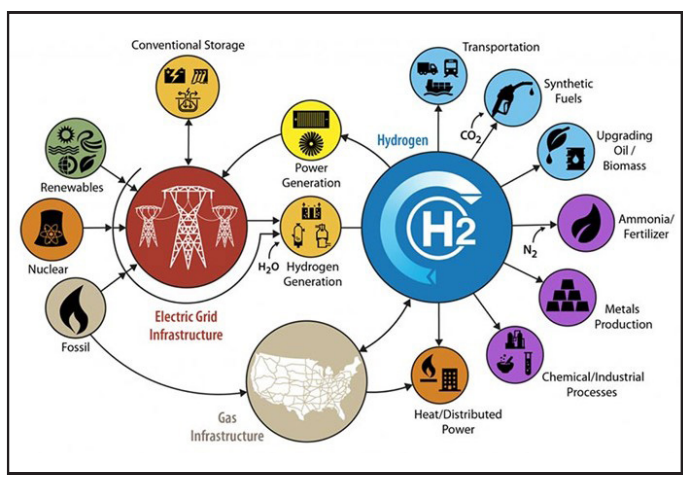


FIGURE 1 Schematic Illustration of H2@Scale Concept [Pivovar, Rustagi, and Satyapal, 2018]

Energy Storage

With the planned installments and reliance on gigawatts of new renewable power capacity (e.g., offshore wind and solar), there will be opportunities to store excess energy instead of curtailing power generation systems and a need for energy storage to respond to peak demands associated with renewable energy intermittency. **For large-scale reliance on renewable energy, energy storage must be integrated to balance and create a resilient electrical grid when either a lack or overabundance of renewable energy exists.**

Presently, lithium-ion batteries have been introduced in some utility-scale storage systems. Although they are appropriate in providing a cost-effective short-duration energy storage solution (typically a few hours), when considered for long-duration energy storage, lithium-ion batteries are generally not cost-effective due to their relatively short lifespan. When these batteries are used for stationary energy storage and need to last several decades, their state of health will decrease nonlinearly (including capacity fade and increase in internal resistance) [Kendall, Ambrose, 2020; Bazant, et al., 2021]. Another drawback to solely relying on lithium-ion batteries is the limited global resource of lithium. Lithium is a critical material and is expected to be subject to supply shortages in the future, even considering extensive recycling operations. It is estimated that the earth has approximately 26 million tons of lithium reserves. Even with an optimistic higher assessment that assumes potential extractable mineral deposits, there is an estimated 51 million tons of lithium reserves. The current demand for lithium is 0.16 million tons per year and by 2030, the annual demand for new lithium is expected to be 2 million tons per year [BloomberNEF; Greim, et al., 2020]. According to the International Energy Agency, in order to achieve the Paris climate goals, by 2040 lithium will need to be consumed at a rate 42 times higher than current levels [Bader, 2021]. **To electrify vehicles, electronics, and leverage energy storage in the electrical grid with the best policy scenario and recycling efforts, the balance of lithium demand and supply could extend only to about 2050, and the market will then begin to experience a large deficit that lasts for the remaining half of the century [Greim, et al., 2020]. Therefore, solely relying on lithium-ion batteries for energy storage is generally seen as not a viable long-term option.**

The use of hydrogen can be an effective method for storing large amounts of energy for long periods of time (e.g., days or weeks) either as a gas, liquid, or in the form of ammonia. When coupled with fuel cells or gas turbine engines, hydrogen energy storage systems can be used to provide a reliable backup energy source to address intermittency and ensure the energy grid is resilient to disruption. Based on a preliminary techno-economic analysis conducted at UMass Lowell, which compared energy storage using lithium-ion batteries to a hydrogen storage/fuel cell system, the results indicate that for long-duration energy storage, hydrogen is more viable in terms of weight (1/193 times), volume (1/2 times), lifetime (3 times), and capital cost (1/7 times) than lithium-ion batteries (see Figure 2). However, some hydrogen production challenges need to be overcome due to the high costs of electrolyzers. Electrolyzer and fuel cell stack costs are still high due to limited production capability, small market share, and strict policy codes related to hydrogen generation and power-delivery devices. Furthermore, hydrogen storage and delivery capability with the existing infrastructure have not been demonstrated on a larger scale. If solutions to these challenges have been met, then hydrogen for energy storage will be able to meet cost targets and be cost competitive in the market. The overall near-term targets that have been set out by DOE are \$2/kg for hydrogen production and \$2/kg for delivery and dispensing for transportation applications [Satyapal, 2021]. Additional research needs to be performed in the following areas to decrease the cost and expand the hydrogen energy storage market: (1) technologies to reduce cost as well as to improve performance and reliability of fuel cell stacks and of storage and delivery methods; (2) harmonize codes and standards to address safety concerns; and (3) establish and safeguard a global supply chain and market, as well as workforce development.

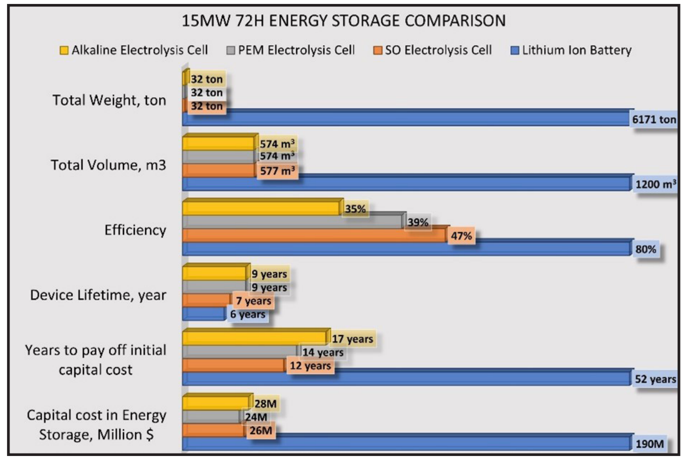


FIGURE 2 Techno-Economic Analysis performed at UMass Lowell comparing lithium-ion battery energy storage to a proposed hydrogen storage approach for a 15 MW turbine and a 3 day energy storage solution.

Thermal Heating

The thermal heating sector includes all home and commercial business, excluding agricultural and industrial activities. Implementing hydrogen into the thermal heating sector can provide opportunities to complement electrification by meeting energy demands during peak periods and periods of intermittent renewable energy production, thereby increasing resiliency. Currently, 52.3% of Massachusetts homeowners use a natural gas system for heating [EIA, 2021] and to meet the Commonwealth's zero-emission goals, most if not all of these natural gas homeowners would need to switch to either an all-electric system (e.g., heat pumps and resistive heating), decarbonized gas, a network geothermal system, or apply some other possible new technology such as carbon capture at a customer site. This switch will be costly and cause pushback by consumers especially for the sector of the population who are economically disadvantaged. Gas companies would also need to either repurpose or abandon the existing pipeline infrastructure. However, if increasing percentages of natural gas can be displaced by hydrogen, end-users could potentially keep their existing appliances (with some modifications or retrofits depending on the blend fraction) while also enabling the state to meet its zero-emission goal.

There are challenges with hydrogen implementation for the thermal heating sector that do need to be overcome in order to be commercially mature. A wholesale shift to change to a 100% pure hydrogen system, would require a significant investment in infrastructure and technology. A useful analogy is to think about gasoline and Diesel fuel. A vehicle operator cannot just simply put gasoline in a Diesel engine, or put Diesel in a gasoline vehicle. While they are both "fuels", their properties are different and so the hardware/technology must be designed appropriately to take advantage of the unique properties. The same can be said for hydrogen versus natural gas. While they are both fuels, they are not the same, and thus cannot be treated the same. However, much of the existing research on residential and industrial appliances has shown that low blend levels of hydrogen (i.e., less than 20%) can be tolerated without a significant change in performance. **Because hydrogen has a lower volumetric energy density than methane, volumetric blending of hydrogen with methane does not provide a linear reduction of carbon emissions per unit energy. For example, if methane is blended with hydrogen at 5%, 20%, or 75% by volume, the carbon emission reductions per unit energy of the blended gas will be approximately 1.5%, 6%, and 50%, respectively [Goldmeer, 2019] (see Figure 3).**

Another potential challenge with using hydrogen in the thermal heating sector is hydrogen embrittlement of cast iron pipes and a lack of information and research done on how high blends and pure hydrogen in a natural gas system will affect the end-user's appliances. Massachusetts has approximately 21,000 miles of main pipelines used for the transportation of natural gas from meter stations throughout the distribution system [Mass.gov, 2021]. The materials for main pipelines in Massachusetts vary depending on location and the distribution company and are made of either cast iron, steel, or a polyethylene plastic. There are approximately 7,928 miles of steel pipelines, 11,016 miles of plastic pipelines, and 2,809 miles of cast iron pipelines.

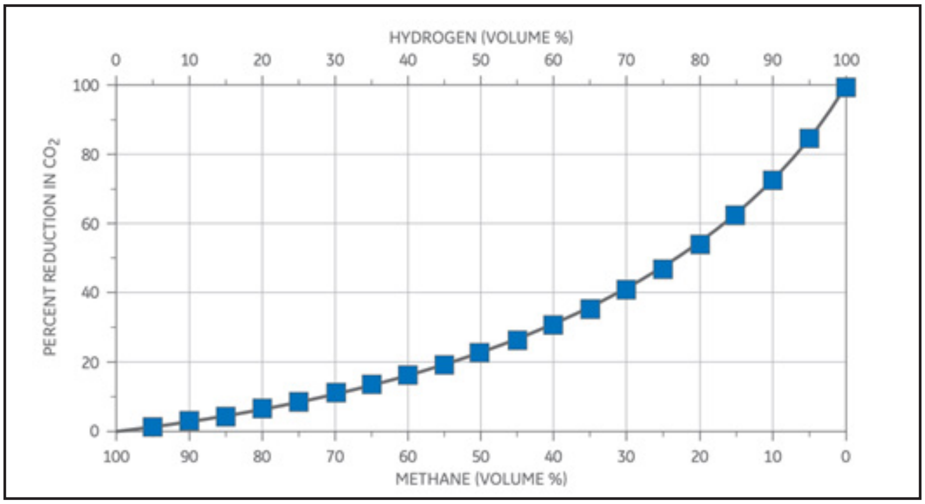


FIGURE 3 CO2 Reduction with Respect to Hydrogen and Methane Blend Percentage [Goldmeer, 2019]

Depending on the pipeline's material, using hydrogen in either a pure form or a blend may cause embrittlement in pipelines. Polyethylene and lower-strength thicker wall steel pipelines are most compatible with hydrogen and have shown to be successful in large-scale pilot projects as well as with low blend ratios. Other forms of steel pipelines are still being studied in national laboratories and individual companies. Cast iron (commonly found in distribution systems in Massachusetts and the Northeast) has been shown to be unsuitable for hydrogen [Blanton, et al. 2021].

Once the blended hydrogen is delivered to the end-user appliances, functionality will vary depending on the blend ratio. Research done by HyDeploy has shown that a 20% blend by volume of hydrogen in a natural gas system has worked in city-wide pilot projects and residential appliances can function effectively up to a 28% blend of hydrogen without issue [HyDeploy, 2021a]. However, this project is the largest hydrogen blending project to date and little to no research has been done on larger ratio blends of hydrogen. To ensure the safety of the end-user and their appliances, more testing must be done to understand the effects of blending higher percentages of hydrogen in the natural gas network as well as the impact on residential appliances (i.e., stoves, furnaces, and hot water heaters) (see Figure 4).

For the hydrogen thermal heating sector to be successful, replacement of old and insufficient pipelines for hydrogen blending needs to be performed, more research needs to be done on higher blend ratios of hydrogen, and appliances may need to be redesigned or retrofitted to operate on hydrogen-natural gas blends or pure hydrogen. When a pipeline becomes old or damaged and needs to be replaced, it will be more cost-effective to replace the old pipeline with a hydrogen compatible pipeline made of low strength carbon steel or polyethylene.

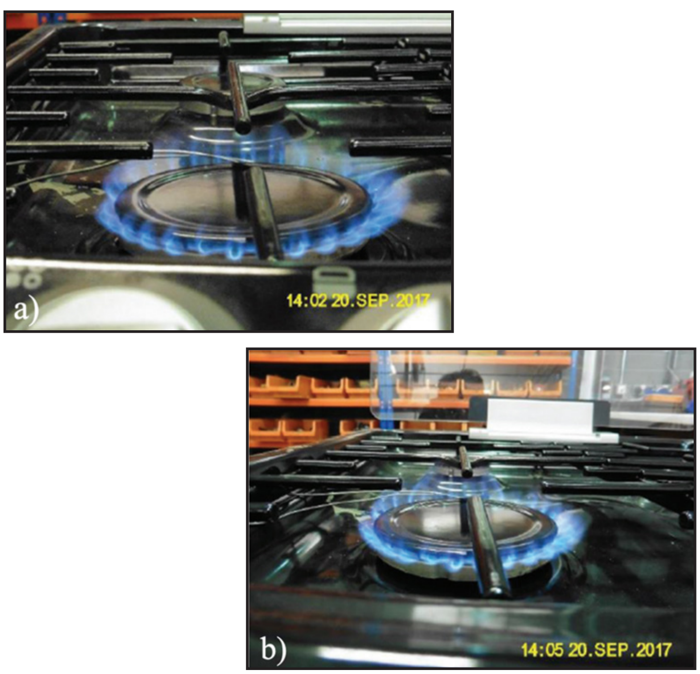


FIGURE 4 a) 100% Methane Flame; b) 28.4% Hydrogen Blend Flame [Issaac, 2019]

Industrial Processes

FIGURE 5 Hydrogen Based Steel Manufacturing [Collins, 2020]

Hydrogen for industrial processes provides opportunities for decarbonizing industries when a large amount of heat is needed. One example is steel manufacturing that would otherwise be hard to completely electrify (see Figure 5). Due to the processes used today to extract steel from iron ore, electricity cannot be used, instead, hydrogen is more viable as a replacement for coke (a derivative of coal) in the gasification processes used in industrial manufacturing. Using hydrogen in steel production only produces 0.056 tons of carbon dioxide for every ton of iron produced and represents 2.8% of the carbon emissions when compared to using coke [Vogl, et al., 2018].

The primary challenges for industrial processing (requiring heat generation) to replace fossil fuels (coal, oil, natural gas) are the capital cost required to convert existing equipment as well as the cost of the fuel used in the manufacturing process. **Currently, green hydrogen is more expensive for a given amount of energy compared to fossil fuels and there are no significant policies or incentives motivating companies to transition away from using fossil fuels.** For example, carbon credits can be implemented to incentivize low or no carbon-emitting industrial processes and help make hydrogen fuel for industrial methods cost competitive [Vogl, et al., 2018]. At the federal level there is a bill that has been introduced (not passed), the Clean H2 Production Act, that would create production tax credits and investment tax credits for hydrogen [Congress.gov, 2021]

Transportation

The transportation sector generates the largest share of greenhouse gas emissions within Massachusetts and represents a sizable opportunity for hydrogen utilization through fuel cell electric powertrains and traditional internal combustion engines. The transportation sector is composed of different applications including passenger vehicles, trucks, ships, and airplanes. Opportunities that hydrogen can bring to the transportation sector include fast refueling compared to battery electric vehicles (BEVs), zero nitrogen oxides (NOx) emissions (if used in fuel cell vehicles), a long-range driving alternative to BEVs, longer storage duration, and avoidance of CO2 emissions. Due to hydrogen's high energy density, it allows for more energy to be stored per kilogram than other energy storage methods, including electric batteries.

The challenges in the transportation sector that hinder the adoption of hydrogen are the lack of infrastructure for refueling stations in Massachusetts and regulations that restrict the operation of hydrogen vehicles on some roadways (particularly tunnels). There are currently zero operating public hydrogen refueling stations and only two private hydrogen refueling stations in Massachusetts. When compared to electric charging stations, there is a drastic difference as significant expansion has been made in the last decade and there are 4,090 public and 299 private electric charging stations in Massachusetts [AFDC, 2021] (see Figure 6). Currently, hydrogen fuel purchases for new automobiles are subsidized by the auto manufacturers (e.g., Toyota Motor Corp.) by providing free hydrogen fill-ups, up to $15,000 for new automobile purchases. The limited network of hydrogen fueling stations in Massachusetts hinders the driving range for hydrogen-powered vehicles, preventing market penetration and causing relatively-high prices due to a lack of economy of scale.

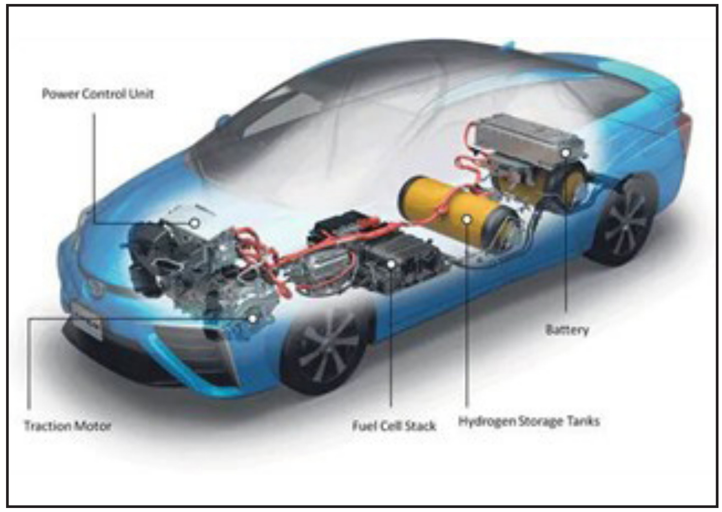


FIGURE 7 Internal Working of a Typical Fuel Cell Vehicle [Spiegel, 2019]

A convincing body of evidence in both California and internationally has revealed that hydrogen-based vehicles can be operated safely with cost competitiveness compared to gasoline or other fuels. Of the 11,674 hydrogen-powered automobiles operating in California, there have been no significant issues with fires for vehicles involved in accidents [CFCP, 2021].

FIGURE 6 Commercially Available Hydrogen Powered Automobil [Gardner, 2021]

In cold weather environments, as in Massachusetts' winters, the driving range for battery electric vehicles is reduced. Several studies have reported that the average driving range for battery electric vehicles decreases by 41% depending on the temperature and driving conditions [Olsen, 2019; AAA, 2019; Delos Reyes, et al., 2016]. A Norwegian study tested common battery electric vehicles and their driving range in cold climates and found that there was an average decrease of 18.5% in driving range and vehicles took between 27 and 60 minutes to achieve an 80% charge under rapid charging conditions [Veihjelp, 2020]. In contrast, a hydrogen automobile can be refueled in approximately 3 minutes and its driving range is not greatly affected by cold temperature operation (see Figure 7).

For a mid-sized city with 100,000 parking spaces and an average cost of $1,200 per electric charger, the cost to electrify would be approximately $120 million dollars, not including the wiring infrastructure cost required for electrical transmission. **It is not likely feasible for the vehicle transportation sector to be carbon neutral by relying solely on electric vehicles that utilize chemical batteries because of (1) the technical limitations of lithium-ion batteries operating in cold environments, (2) the inability for all drivers to have vehicles connected to charging stations at their homes throughout the night, and (3) a lack of suitability of using batteries for the trucking, shipping, and aviation sectors.** The path forward for increasing hydrogen in the transportation sector would be to increase the number of hydrogen fueling stations available to the public and address policies that hinder hydrogen transportation from further developing, such as restrictions for compressed hydrogen-powered vehicles traveling in tunnels in Massachusetts.

Safety

Hydrogen as a fuel source and form of energy storage has brought up concerns with the public whether hydrogen is safe to use. This misconception has been perpetuated ever since the Hindenburg disaster in 1937. **Today the U.S. has 1,600 miles of existing hydrogen pipeline used in the Gulf Coast that has a track record of safety commensurate if not better than natural gas. Every year hydrogen is safely transported through these hydrogen pipelines to be used in petroleum refineries and chemical plants.**

Like many gasses, hydrogen is a colorless and odorless gas making it difficult to detect if a leak has occurred. Direct coloring agents may not be possible to add to hydrogen to hydrogen, but odorants can be added to provide a smell for hydrogen [HyDeploy, 2021b]. Sensors can also be installed to allow for fast and efficient detection of leaks without having to worry about seeing or smelling hydrogen. Other safety concerns regarding hydrogen include the wide ignition range of air concentrations from 4-74% [Carcassi, Fineschi, 2005] and the low energy ignition required (0.019 mJ) [Kumamoto, et al., 2011] making hydrogen more likely to ignite in a wider range of scenarios than other combustible gases (e.g., natural gas). When stored in tanks or equipment, hydrogen is a safe fuel source and cannot be combusted unless there is a failure in the storage system. Safety codes and standards are put into place to minimize safety concerns and ensure the proper handling of hydrogen. Testing methods are also used to ensure the rigidity and verify the lifespan of these storage methods.

Testing has also been done on hydrogen igniting in enclosed spaces such as tunnels and it was found that no additional risk existed when compared to fuels like gasoline [LaFleur, et al., 2017]. For example, for a typical automobile, the energy available for combustion (~13 gallons of gasoline) is approximately 3 times higher than for a hydrogen vehicle (~4k kg of hydrogen). If a hydrogen fuel leak were to occur resulting from a crash, the hydrogen would disperse upward rapidly as opposed to gasoline that wets the vehicle or pavement and does not disperse quickly in an accident.

Emissions of NOx is a safety concern with the combustion of hydrogen because it is a byproduct of the combustion process in air. Combustion of hydrogen blended with natural gas increases NOx emissions by 92.81% for a 25% blend and upwards of 360% for a 75% blend [Cellek, Pinarbasi, 2018]. However, it is important to note that NOx emissions can be controlled and mitigated using certain techniques and modifications (e.g., by using a lean or lower fuel-to-air ratio). NOx is generated through combustion and the quantity of NOx is dependent on the flame temperature; by reducing the flame temperature, NOx emissions can be reduced [Menzies, 2019]. The flame temperature can be decreased by slowing down the rate of the fuel and air mixture. This leads to a lower flame temperature, therefore a reduction of NOx, and keeping the heat from the combustion process radiant, so the end-user does not experience any change when using the appliance [Menzies, 2019]. Water injection can also be used to reduce the hydrogen flame temperature and thereby reduce NOx for combustion in air. Other additions such as catalytic converters can be added to some appliances or furnaces to aid in the removal of NOx. European manufacturers have already started working on using these techniques and modifications and have found success in producing zero to low NOx emissions residential appliances [Sadler, et al., 2017].

Greenhouse Gas Emissions

Gases that are responsible for trapping heat in the atmosphere are referred to as greenhouse gases (GHG). There are two primary concerns regarding the use of hydrogen and its effect on climate neutrality. The ***first*** is that NOx is generated during combustion of hydrogen and has a Global Warming Potential (GWP) 265–298 times that of CO2 for a 100-year timescale and represents about 7% of the total greenhouse gas emissions. For reference the GWP of methane is 28–36 over 100 years [EPA, 2021]. However, a majority of NOx emission in the U.S. comes from agriculture (75%) and only about 5% comes from stationary combustion [Menzies, 2019] and can be mitigated by the emission control strategies previously mentioned. It's important to note that with a hydrogen-based system, carbon monoxide (CO) emission will also be avoided. This is very important as historically trade-offs are typically made in designing combustion systems for hydrocarbons, whereas trying to mitigate CO usually results in more NOx. But, if CO is not a concern, then there are multiple solutions that can be utilized to reduce NOx.

Another very important point is that NOx is a "catch-all" term that usually encompasses NO, NO2, and N2O when talking about combustion. The majority of emissions during hydrogen combustion are NO and NO2, not N2O, which is the worst NOx in terms of GWP. The combustion of hydrogen will raise NOx emissions by 20-40% compared to methane. However, if one compares the NOx emissions during the stationary combustion of methane, one can see that the effect of N2O is insignificant. Greenhouse gas emissions are reported in units of carbon dioxide equivalent (CO2e) by multiplying by their GWP by their emission factors [EPA, 2018]. During the combustion of natural gas, the CO2e for CO2 is 53.06 kg CO2/mmBTU while the CO2e for N2O is 0.0298 kg N2O/mmBTU. This reveals that the resulting carbon dioxide emission has approximately 1780 times stronger effect on climate than the N2O gas emission for stationary combustion of natural gas. According to the reference [Thompson Academy, 2021], "Nitrous oxide (N2O) gas should not be confused with nitric oxide (NO) or nitrogen dioxide (NO2). Neither nitric oxide nor nitrogen dioxide are greenhouse gases, although they are important in the process of creation of tropospheric ozone (O3) which is a greenhouse gas." The nitrogen oxides (NO + NO2) do not directly affect Earth's radiative balance, but they accelerate the generation of a direct GHG – tropospheric ozone. However, the impact on climate is difficult to directly quantify [Dentener, et al., 2001]. Lastly, it is important to mention **NOx is only generated in combustion processes when fuels (like hydrogen and natural gas) are burned in the presence of air. However, for applications that use a direct hydrogen fuel cell (e.g., in automobiles and electricity generation), the only byproducts are water, heat, and electrical energy with zero NOx emissions.**

The ***second*** concern is that hydrogen itself (GWP of 5.8 over a 100-year timescale) is an indirect greenhouse gas that reacts in the atmosphere with tropospheric hydroxyl (OH) radicals and disrupts the distribution of methane in the ozone and thereby cause an increase in global warming. The release of hydrogen prolongs methane's atmospheric residence time, increasing its accumulation and greenhouse gas impact [Derwent, et al., 2006]. According to one study by Derwent et al., if a global hydrogen economy replaced the current fossil fuel-based energy system and exhibited a leakage rate of 1% or 10%, then it would decrease the climate impact to 0.6% or 6% of the current fossil fuel based system, respectively. Another more recent literature review on the atmospheric impacts of hydrogen from heating found that the most likely outcome is that hydrogen has a greenhouse gas effect that is small but not zero, and the global atmospheric impacts are likely to be small [Derwent, 2018]. Within the existing body of literature presented, there is significant uncertainty and additional research on this topic should be conducted. These findings emphasize the importance to ensure that leaks in hydrogen production, transportation, and utilization are minimized.

Pipeline Transportation

Pipelines are the most cost-effective way to transport hydrogen compared to truck or rail. Although technical challenges remain on blending hydrogen with methane, solutions are being studied to identify how to increase the blending ratio while using the existing pipeline infrastructure [Melaina, et al. 2013]. Hydrogen has approximately one-third the heat value per unit volume compared to methane and so for the same pressure level, higher volumes of hydrogen need to be transported to deliver an equivalent amount of useable energy. This would require higher compression horsepower and will result in some additional energy losses compared to methane. The metering equipment used in gas distribution pipelines would also likely need modification based on the blend ratios [Blanton, et al. 2021].

Gas emissions via leaks in pipelines and other distribution equipment are also important when assessing the GHG emissions of the carrier fuel, whether it is methane or hydrogen [Abel, 2021]. Leaks are emitted via permeation through the pipe wall or through joints, fittings, and threads. For steel and ductile iron pipes, leakage mainly occurs through threads or mechanical joints and the volume leakage rate for hydrogen is about a factor of three higher than that for natural gas. For plastic pipes, permeation accounts for the majority of gas losses and are estimated to be about 4 to 5 times faster than for methane [Melaina, et al. 2013]. However, the leak rate depends on the blend percentage, pressure, and other factors. For example, in one study of a Dutch pipeline system, the experimentally estimated gas leakage rate was 0.0005% with a 17% hydrogen blend and considered to be insignificant [Haines, at al., 2003]. Because hydrogen is a smaller molecule than methane, hydrogen was thought to permeate through plastic pipelines more readily than methane, however, recent research has shown those leak rates are similar. Additionally, an application of a copper-based epoxy to thinly coat the steel pipe has been shown to successfully contain all hydrogen gas blends, and threaded pipe fittings to prevent hydrogen leaks [Mejia, et al., 2020]. Another study calculated that the yearly loss of hydrogen by leakage through polyethylene pipelines amount to approximately 0.0005–0.001 percent of the total transported volume [Klopffer, et al., 2015; Wassenaar, Micic, 2020].

One of the recommendations of a study performed by the Columbia University – Center on Global Energy Policy was to change the regulations on methane leak detection and repair the existing pipeline to be as low emission as possible, as well as accelerate the pace of cast-iron pipeline replacement [Blanton, et al. 2021]. These recommendations and others within their study are applicable to the Commonwealth of Massachusetts.

FIGURE 8 Example of a Synthetic Fuel [Morris, 2021]

Synthetic Fuels

Synthetic fuels are hydrocarbon fuels that are produced by chemically combining hydrogen with carbon sources such as CO2 or biomass. Synthetic fuels can be created to emulate common fuels such as gasoline, diesel, methane, and kerosene (see Figure 8). The opportunities of using synthetic fuels over regular fuels is the use of CO2 (e.g., from atmospheric sequestration) in the manufacturing process and its compatibility with existing distribution systems, fueling stations, and conversion technologies without significant modifications to existing infrastructure or equipment. By using CO2 to produce synthetic fuels, it prevents additional CO2 emissions in the atmosphere and helps in meeting net-zero emissions goals. For example, renewable or synthetic natural gas can be created by combining waste CO2 from anaerobic digesters or power plants in MA with green hydrogen in a process referred to as methanation [Tsiotsias, et al., 2020]. Synthetic fuels can also be used in already existing refueling stations and combustion engines, which allow for a cost-effective transition to this carbon-neutral fuel.

Massachusetts currently lacks existing infrastructure dedicated to producing synthetic fuels and the green hydrogen necessary to make these fuels carbon neutral. The processing facilities to produce synthetic fuels are currently expensive and there are only a few test plants in operation. Massachusetts currently has no test plants for synthetic fuels or a large-scale infrastructure of green hydrogen to produce synthetic fuels. Massachusetts is currently not a leader in the production of conventional fossil fuels. However, in the future, with an established large offshore wind resource, the low cost generated electricity could potentially position the Commonwealth to be an early mover or leader in production of economically viable synthetic fuels.

The path forward for Massachusetts to produce synthetic fuels would need to include more research to be done on the production of synthetic fuels as well as the development of a synthetic fuel infrastructure and market. **Once more testing facilities have shown the benefits and challenges of synthetic fuels, then Massachusetts will be able to better assess if a synthetic fuel infrastructure would be beneficial for the Massachusetts economy.** Before an economically viable carbon-neutral synthetic fuel infrastructure is developed, a large-scale green hydrogen facility would first need to be created.

Biomass: Including Bio-oil and Bio-gas

Biomass, including bio-oil and bio-gas can be used in steam reforming and water-gas shift processes to produce hydrogen. The opportunity with using biomass as a feedstock for hydrogen production is that biomass waste products are an available resource and can be used to sequester carbon dioxide from the atmosphere. It is estimated that up to 1 billion dry tons of sustainable biomass is available for energy generation use annually, which amounts to approximately 13-14 quadrillion Btu/year (in 2030) [DOE, 2021]. Biomass can also lead to an offset in carbon dioxide emissions because of the consumption of carbon dioxide in the production process of biomass (see Figure 9).

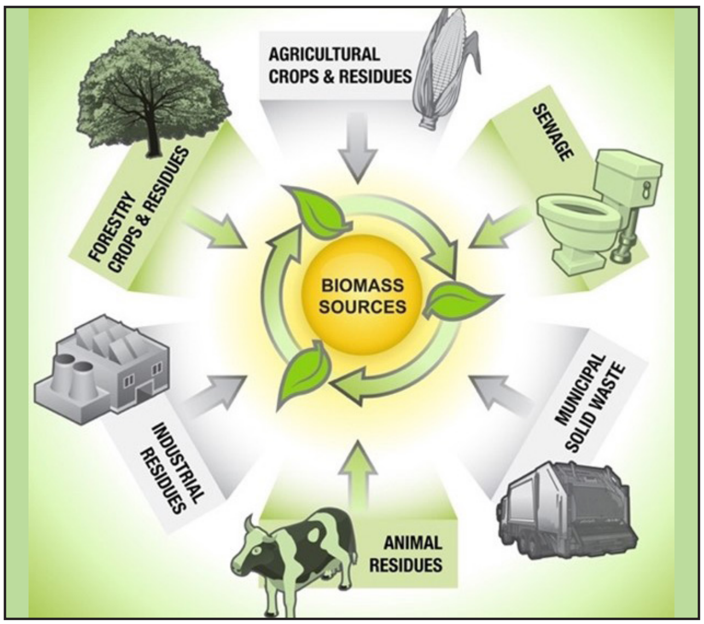


FIGURE 9 Sources of Biomass [Zafar, 2020]

Currently, there are no biomass production sites in Massachusetts that are used for hydrogen generation and therefore is not currently part of the Massachusetts economy. More research needs to be performed on the carbon offset and economic benefits for the Commonwealth. The challenges with reforming biomass include the cost of biomass-derived liquid, capital cost, and carbon emissions. Biomass-derived liquids are composed of larger molecules with more carbon atoms than natural gas and this makes them more difficult to separate and reform in the steam reforming process. Steam reforming processes for biomass have a high capital equipment cost as well as operation and maintenance cost. There are processes other than steam reforming that can produce hydrogen through biomass such as pyrolysis, but they are more costly and should be further researched and investigated before implementation.

Ammonia/Fertilizer

Hydrogen can be produced and stored in the form of ammonia (NH3). The opportunity with ammonia for hydrogen storage is that it does constitutes a practical, low-cost storage alternative, not requiring high pressure or cryogenic temperatures. Ammonia can be liquified at a pressure of 10 bars and contained at a temperature of -33°C. When compared to liquid hydrogen, liquefaction requires pressures of about 100 bars and containment at temperatures of -253°C or lower. This significant decrease in pressure and temperature allows for a less energy-intensive method to store and transport hydrogen (see Figure 10). Ammonia is an inhibitor for hydrogen embrittlement, meaning that ammonia can be safely transported through existing iron and steel natural gas pipelines.

The challenge with ammonia is the carbon-intensive processes currently used for its production. Today the common production of ammonia requires both the generation of hydrogen through steam methane reforming and nitrogen through air separation. Hydrogen and nitrogen are used as inputs to form ammonia in a catalyzed process at high temperature and pressure (i.e., the Haber-Bosch process). The use of green hydrogen in ammonia production is not currently economical. There still needs to be development in enhanced ammonia production before ammonia can be used at a large scale for green hydrogen storage or as an energy carrier. Currently, there are no ammonia or fertilizer production sites in Massachusetts and therefore it is not part of the state's economy. More research needs to be performed on the economic benefits of manufacturing ammonia or fertilizer and their carbon impact on the Commonwealth.

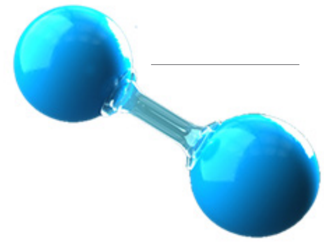
FIGURE 10 Example of Liquid Ammonia Storage [Simon, Taylor, 2021]w

The Vision and Next Steps for Hydrogen Integration

Further integration of green hydrogen into the Massachusetts economy enables a diversification of energy sources, supports market competition, affords greater energy resiliency, enables sector coupling, and minimizes changes of existing infrastructure to meet zero-emission goals. By diversifying Massachusetts' fuel sources, hydrogen integration allows for the promotion of consumer choice, market competitiveness, and enhanced grid reliability. Consumers will be able to choose a low carbon energy source that best fits their needs and what may be more suitable in their area or for their socioeconomic status. Sector coupling with hydrogen energy allows for an increased integration of energy end-use and multiple supply sectors [Travers, 2021; He, et al., 2021]. This allows for an increased efficiency and flexibility of a hydrogen economy, as well as working with electrification to reduce the cost of decarbonization [Nuffel, 2018]. For maximum carbon reduction, green hydrogen should be considered as a future potential fuel source as opposed to other forms (grey and blue hydrogen) that require the utilization of fossil fuels in their production or because carbon sequestration technologies are not presently effective for net-zero large-scale production. In the future, new technologies may make the production/sequestration of blue or pink hydrogen have a lower carbon footprint and more economically viable. Blending methane with green hydrogen may be considered as a transitional fuel until sufficient electrification infrastructure exists, appropriate pipeline replacements are completed, the cost of green hydrogen is reduced, and the distribution infrastructure can accommodate 100% green hydrogen or carbon neutral synthetic fuels. The Massachusetts electrification efforts for commercial and residential heating and cooling (i.e., heat pumps) should initially be implemented in locations that currently rely solely on the dirtier fossil fuels (e.g., coal or oil) and do not have access to the natural gas infrastructure.**Direct use of renewable electricity for heat and power should be a first consideration, when possible and economical, rather than using renewable energy to generate fuel or for storage because of round trip efficiency losses.** Complete electrification may be difficult or impossible due to several factors such as intermittency, physical constraints, retrofitting limitations, transmission line augmentation, infrastructure replacement, permitting, public acceptance, and cost. Massachusetts' climate 2030 goals include electrifying 100,000 homes per year, but in 2020 only 461 homes made the switch revealing an extreme shortfall in electrification progress for a variety of reasons [Shankman, 2021]. In the end, to achieve widespread electrification and hydrogen production and distribution, the technology that will be embraced by consumers will be driven by cost per unit energy, performance, ease of implementation, capital expenditures required for retrofit and new energy infrastructure, and policy.

Challenges that a hydrogen economy will face includes producing green hydrogen at a cost competitive rate, incorporating the necessary infrastructure for safe utilization, addressing public acceptance, as well as adopting policies and creating incentives that enable hydrogen integration and consumption. Other countries and states (e.g., U.K. and NY) have already begun to explore the potential role of green hydrogen as part of a comprehensive decarbonization strategy [[NY.gov, 2021]. **In order to achieve carbon neutrality in Massachusetts, research and advancements need to be made in green hydrogen technology and further integration should be embraced. New policies and programs need to support the de-risking of large-scale commercial projects and pilot studies for technology and safety validation as well as public acceptance.** These may include state or federal tax credits and other subsidies, loan guarantee programs, and research funding. New carbon neutral energy standards and infrastructure (e.g., fueling stations) will generate demand, help reduce costs, and increase energy resiliency, enabling widespread use of hydrogen for the commercial, residential and transportation industries relevant to Massachusetts.

The Commonwealth of Massachusetts, the U.S., and the world are reaching an inflection point to address climate change and immediate action is necessary to transition to a world that does not rely on fossil fuels as its main energy source. Accomplishing this goal, in the short time necessary to make a difference, will require the planning and deployment of differing options, some of which are in initial or intermediate levels of development, but are anticipated to be realized in the near future or still face challenges with public perception and acceptance. For example, the vast renewable energy resource from offshore wind is expected to be available, but currently does not exist. Diversity, flexibility, and forward thinking will be necessary to make sure the Commonwealth's energy supply is resilient to disruption. Some of these technologies may be useful in more than one sector, others may not be. For practical reasons, there is no one size fits all approach that will transition all sectors quickly and efficiently. All options need to be evaluated and considered, and it is particularly important to continue research into those technologies that are still in their nascent stage. The use of hydrogen, in some applications that currently use fossil fuels, will reduce overall greenhouse gas emissions, and help contribute to meeting the Commonwealth's 2050 net-zero carbon goals, and if widely adopted, help reduce CO2 emissions globally. Challenges related to the use of hydrogen (e.g., cost, safety, public perception) can be overcome with proper and appropriate technological advancements, public awareness, and regulations.



Recommendations

To make the use of hydrogen a reality, the Commonwealth should consider the following:

1. The development of an overall hydrogen policy that integrates the use of hydrogen to reduce the intensity of or eliminate the carbon of the fuels used in the thermal sector in Massachusetts.

2. A continuation of study of the advantages of green hydrogen within the transportation system (passenger, medium and heavy-duty vehicles, marine, rail, and aviation sectors) that would enable a cost-effective market and reduction in carbon footprint.

3. A re-evaluation of the policies in place that hinder hydrogen transportation from further development, such as traveling restrictions for compressed hydrogen-powered vehicles.

4. Continued research into the use of long-duration energy storage using hydrogen in partnership with the offshore wind industry and other renewable energy sources available to Massachusetts.

5. The establishment of an optional Pilot program implemented in participating gas local distribution companies' (LDCs) distribution systems for a blended mix of hydrogen with natural gas to reduce the amount of carbon for thermal delivery.

6. The alignment of the existing Gas System Enhancement Program (GSEP) with the net-zero reduction goals of the Commonwealth to make sure the pipeline system is as low emission as possible and ready for use when the expected green hydrogen resource becomes available to address the thermal needs. The GSEP should also incorporate hydrogen compatible design standards.

7. The creation of a renewable procurement standard for natural gas utilities and suppliers similar to the electric renewable portfolio standard (RPS) programs, allowing hydrogen to qualify for "thermal renewable energy credits" (TRECs) that will encourage its use to further reduce the carbon footprint in the Commonwealth of Massachusetts.

8. The electrification efforts should initially be implemented in locations that currently rely solely on the dirtier fossil fuels (e.g., coal or oil) and do not have access to the natural gas infrastructure. Direct use of renewable electricity for heat and power should be a first consideration, when possible and economical, rather than using renewable energy to generate fuel or for storage because of round trip efficiency losses.

Appendix 1. Stakeholder Interviews

The University of Massachusetts Lowell (UMass Lowell) conducted over 20 individual interviews with stakeholders to have a better understanding of the opportunities and challenges of developing a hydrogen-based economy within Massachusetts and the Northeast. The stakeholders interviewed came from a wide variety of professional backgrounds, industries and organizations including: automotive, gas distribution, researchers, safety, and advocacy organization. A list of the stakeholders interviewed is shown in Table 1.1. Within each interview, stakeholders presented information from their perspective regarding hydrogen adoption, production, consumption, safety, public perception, economics, etc. The findings from each interview were used to help identify existing barriers, benefits and impacts of integrating hydrogen within the Commonwealth's economy.

Table 1.1 Stakeholder Interviews

Name	*Company*	*Date of Meeting*
Stakeholder 1	Ameresco	6/11/21
Stakeholder 2	National Grid	6/25/21
Stakeholder 3	National Grid	6/25/21
Stakeholder 4	Enbridge Inc.	7/9/21
Stakeholder 5	Enbridge Inc.	7/9/21
Stakeholder 6	Enbridge Inc.	7/9/21
Stakeholder 7	Enbridge Inc.	7/9/21
Stakeholder 8	Siemens Gamesa	7/16/21
Stakeholder 9	Siemens Gamesa	7/16/21
Stakeholder 10	Siemens Gamesa	7/16/21
Stakeholder 11	Clean Energy Group	7/23/21
Stakeholder 12	California Fuel Cell Partnership	7/29/21
Stakeholder 13	MassH2	7/30/21
Stakeholder 14	Washington State University	8/6/21
Stakeholder 15	AIChE - American Institute of Chemical Engineers	8/13/21
Stakeholder 16	H2Tools	8/13/21
Stakeholder 17	Avangrid, Inc.	8/20/21
Stakeholder 18	Avangrid, Inc.	8/20/21
Stakeholder 19	Avangrid, Inc.	8/20/21
Stakeholder 20	Avangrid, Inc.	8/20/21
Stakeholder 21	Energy Energy Center In Maine	8/27/21
Stakeholder 22	National Grid	8/27/21
Stakeholder 23	Stony Brook University	9/10/21
Stakeholder 24	Plug Power	9/17/21
Stakeholder 25	Acadia Center	10/1/21
Stakeholder 26	Toyota North America	10/1/21
Stakeholder 27	National Grid	10/11/21
Stakeholder 28	Mitsubishi Power	10/15/21
Stakeholder 29	Gas Leaks Allies	10/15/21
Stakeholder 30	Gas Leaks Allies	10/15/21
Stakeholder 31	International Association of Plumbing (IAPMO)	10/22/21
Stakeholder 32	New Energy Development Company LLC	10/29/21
Stakeholder 33	Salem Alliance for the Environment (SAFE)	10/29/21
Stakeholder 34	heet	11/2/21
Stakeholder 35	heet	11/2/21
Stakeholder 36	heet	11/2/21

The research in this study was conducted under sponsorship from the Associated Industries of Massachusetts (AIM) Foundation. Any opinions, findings, conclusions or recommendations expressed in this report are those of the authors and do not reflect the views of the AIM Foundation or the stakeholders interviewed.

Appendix 2. Introduction

Many countries, such as the United States, have passed bills that discourage the production of carbon emission fuels and encourage a “greener” form of energy because as seen in Figure 2.1 the global energy consumption heavily relies on fuels that produce greenhouse gases. However, challenges have occurred with national transition to a carbon free economy. These challenges include the need to diversify fuel sources, minimize stranded assets, and enable long-term storage and long-distance transportation of fuel sources. Converting to a fully electric system would decrease carbon emissions drastically but would lack diversification and impose risks to the end user if there were outages in the electrical system. With an already functioning natural gas system in place, if it can be utilized with a green form of energy, it can help create a green economy faster and minimize the amount of stranded assets. Long-term storage and long-distance transportation of fuel sources are difficult sectors to decarbonized due to the cost competitiveness of natural gas (i.e., the largest sources of energy for electricity generation) and electricity’s inability to be stored for long periods of time.

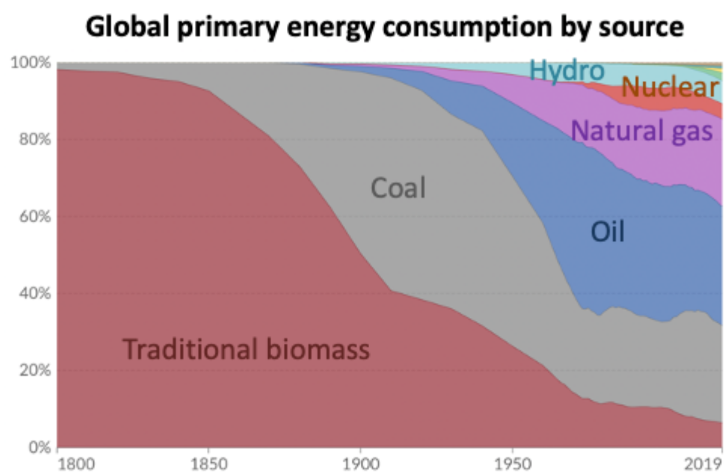


Figure 2.1 Global Primary Energy Consumption by Source [Smil, 2017; BP Statistical Review of World Energy]

Massachusetts is leading the way in renewable energy, being the second most energy efficient sate according to American Council for an Energy-Efficient Economy (ACEEE) and installing the first major offshore wind farm [Kuffner, 2021]. To achieve the renewable energy goals in Massachusetts renewable energy goals, the Commonwealth has developed a roadmap to achieve zero carbon emissions by the year 2050. This roadmap addressed complex issues related to decarbonization and possible approaches to achieve zero carbon emissions while also maintaining a healthy, equitable, and thriving economy [Ismay, et al. 2020]. One approach was to retire all thermal generation infrastructure if a zero-carbon combustion thermal generation is not available. This brings into question what other combustion fuels are available other than natural gas and are they able to achieve net-zero carbon emissions.

Fuels have been transitioning from solids, to liquids, to gases over the last century (see Figure 2.2), because of this there has been increased interest in hydrogen as an energy source. Hydrogen (H2) is the highest energy content fuel by weight and is a building block for a wide variety of other materials (e.g., conventional and synthetic fuels, polymers, plastics, petroleum refining, fertilizer, etc.) used in manufacturing and industrial processing. The recent interest in hydrogen utilization has been motivated by several factors including: (a) the desire to reduce carbon dioxide (CO2) emissions due to the consumption of oil, propane, and natural gas (i.e., methane) for combustion; (b) the need for new climate-neutral sources of energy generation to meet ever growing human demands; (c) the significant reduction in the levelized cost of energy (LCOE) of renewable energy sources (i.e., wind and solar) that help facilitate the economic viability of green hydrogen production on a wide-scale; and (d) future opportunities to produce hydrogen at low-cost when an over-supply of renewable electricity leads to curtailments and negative power pricing. These factors provide an opportunity for low-cost hydrogen generation for energy storage, transportable renewable energy, transportation, the thermal sector, and material production derived from hydrogen.

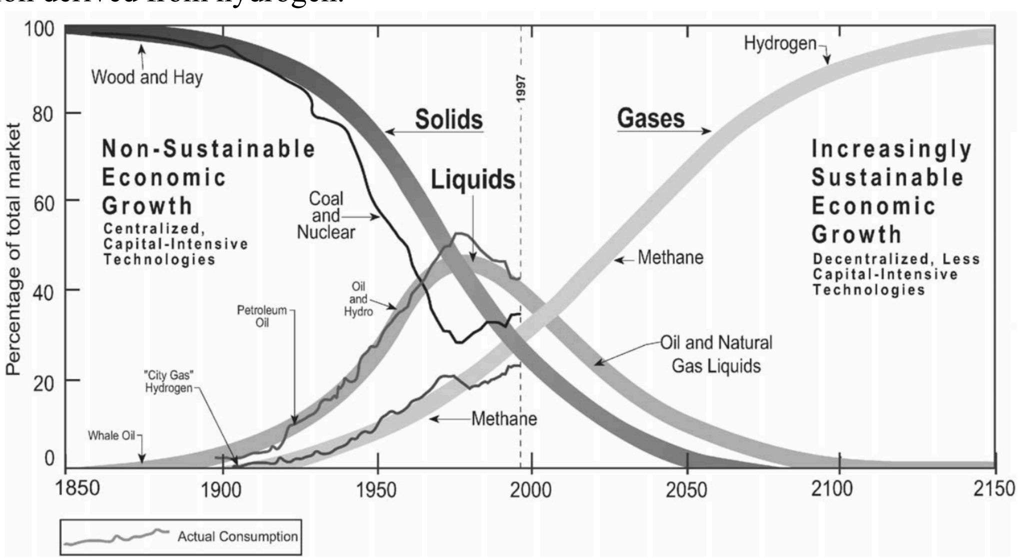


Figure 2.2 Economic Fuel Transition [Dunn, 2002]

This study is motivated by both the opportunities and challenges of developing a hydrogen-based economy within Massachusetts and the Northeast. Other parts of the world (see Figure 2.3) and other U.S. states are further advanced in hydrogen generation and utilization. Apart from the economic benefits, hydrogen shows promise in helping Massachusetts reach its greenhouse gas (GHG) emission reduction goals. A multidisciplinary team from the University of Massachusetts Lowell (UMass Lowell) has conducted a study to investigate the viability of implementing hydrogen within Massachusetts. This investigation has identified the opportunities and existing barriers to integrating hydrogen throughout the Commonwealth's economy.

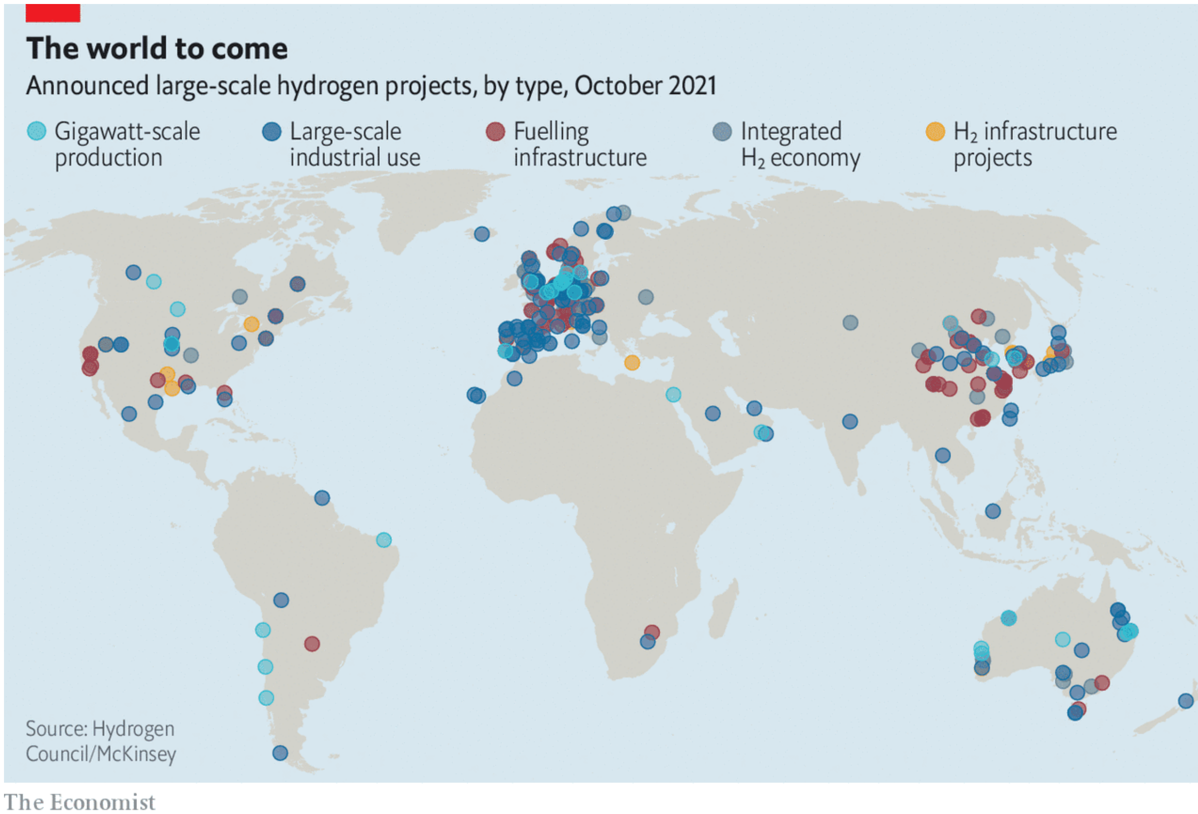


Figure 2.3 Large-scale Hydrogen Projects Around the World [The Economist, 2021]

2.1. What is Hydrogen Energy (H_2)

In 1874, science fiction writer Jules Verne wrote of a world where "water will be one day employed as a fuel, that hydrogen and oxygen will constitute it, used singly or together, will furnish an inexhaustible source of heat and light, of an intensity of which coal is not capable" [Verne, 1875]. What Jules Verne is describing is a society fueled by hydrogen. At that time this literary work by Jules Verne's seemed nothing more than just a science fiction dream. However, with the advancements in green hydrogen energy, that science fiction dream may soon be the reality of renewable energy production.

With the demands to reduce carbon emissions and stop global warming from rising above 1.5ºC by the year 2030, new methods of green energy production have been advancing at a rapid pace. Zero-carbon energy, hydrogen energy, is being promoted to addresses climate issues, as indicated by the New York Times and many other journals. Hydrogen has the possibility to become a competitive fuel source in hard to decarbonize sectors such as long-distant transportation and aviation, with the ability to blend with natural gas and be distributed in existing pipelines. However, concerns have been brought up with hydrogen being used as a fuel source and whether it is truly viable in today's economy.

Hydrogen element (H) is a the most fundamental one on Earth containing only one proton and one electron. It is one of the most abundant elements in the universe. However, since hydrogen is highly reactive, H is only found in a compound form with other elements [Jolly, William Lee, 2020]. Thus, hydrogen (H_2) must be extracted from other compounds such as water or methane. Once hydrogen is extracted it can be stored and used as a form of zero-carbon energy later.

Zero-carbon energy from hydrogen is produced in a fuel cell when hydrogen reacts with other species to form another compound. This is commonly done with oxygen to form water and generate electricity and heat through an exothermic reaction shown in equation 1.1.

$$2H_2(g) + O_2 \rightarrow 2H_2O(l) \tag{2.1}$$

This equation is a basic equation to generate electricity with hydrogen in a fuel and can vary depending on the type of fuel cell used.

Hydrogen can also be used as a replacement for natural gas for residential and commercial appliances. There are however some application differences between hydrogen and natural gas. Hydrogen has a flammability range, being able to ignite between 4% and 75% in air, where the range is much wider than natural gas and requires much lower energy to initiate combustion. In addition, hydrogen has a lower heating value (LHV) of hydrogen is 10.8 MJ/Nm^3 as compared to the natural gas (i.e. methane) of 35.8 MJ/Nm^3 [Goldmeer 2019]. This indicates that to generate the same amount of heat, the volume flow rate of hydrogen needs to be three times more than that of methane.

Hydrogen energy has the potential to reduce greenhouse emissions, help the diversification of fuel sources, and achieve net-zero carbon goals. However, not all hydrogen is inherently green. Some methods of hydrogen production can produce vast amounts of carbon emissions, such as steam methane reforming (SMR) and autothermal reform (ATR). Therefore, to reduce carbon emissions, the production methods of hydrogen need to be carefully considered.

2.2. Colors of Hydrogen Based on Hydrogen Production Methods

There are several different methods of producing hydrogen. Some methods of hydrogen production are energy intensive and produce large amounts of carbon emissions (i.e. grey hydrogen), while other methods of hydrogen production are more costly and dependent on renewable energy sources (i.e. green hydrogen). A color is assigned to the different methods of hydrogen production to distinguish them from one another. Figure 2.4. shows the some of the different colors (i.e., green, blue, grey, pink, yellow) of hydrogen and their corresponding production methods.

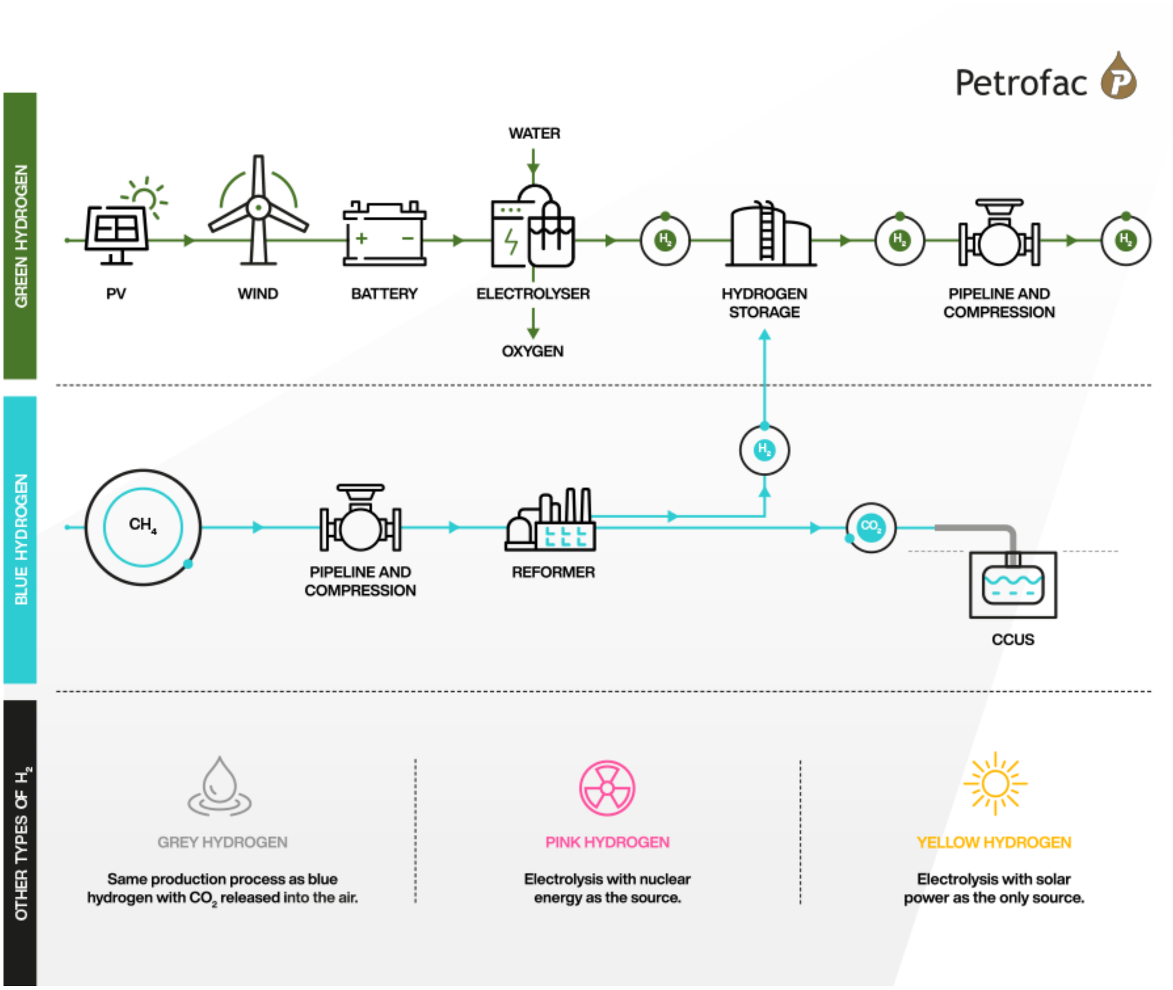


Figure 2.4 Different Colors of hydrogen based on their production methods [Petrofac, 2021]

2.2.1. Green Hydrogen

Green hydrogen is hydrogen generated through electrolysis of water powered by renewable energy sources (i.g. solar, wind, or hydro power). In this method, renewable-energy activated electrolyzer will electro-catalyze water and split it into oxygen and hydrogen. The oxygen will be either collected or released into the atmosphere and the hydrogen will be stored in a form as liquid or gaseous. Stored hydrogen would then be transported via tanker trucks or pipeline systems upon usage.

Renewable energy is defined as the energy production from a natural source that cannot be depleted [Shinn, Lora, 2018]. The benefit of green hydrogen using renewable energy is that the overall process releases essentially zero carbon emissions into the atmosphere since the only byproduct of water electrolysis is oxygen. However, the current challenge of green hydrogen is economically costly as the price to produce green hydrogen being approximately US $6.00 per kilogram [Watson et al., 2021]. To widely utilize green hydrogen in the market, as identified in the report of "Path to Hydrogen Competitiveness", the potential tipping price for green hydrogen needs to be approximately US $2.00 per kilogram [Hydrogen Council, 2020].

To produce enough hydrogen for any large-scale applications, green hydrogen will need to be cost-competitive and currently there is no wide-scale renewable energy resources that would enable this. The anticipated offshore wind installations on the East coast, as well as additional solar photovoltaic installations, are expected to change that. The Department of Energy is working toward making the cost of clean hydrogen to $1 per kilogram with their Energy Earthshots Initiative by the year 2030.

2.2.2. Grey Hydrogen

Grey hydrogen is the most widely used form of hydrogen to date, making up over 95% of the world's hydrogen produced [Rapier, 2020] and costs approximately US $1.00 per kilogram [Watson et al., 2021]. This form of hydrogen is produced from natural gas (i.e., methane, CH_4) via nickel-catalyzed steam methane reforming (SMR) process, in which methane and steam react over nickel catalysts at a high temperature (i.e., 1000 K) to produce carbon monoxide and hydrogen. The carbon monoxide then reacts with steam to produce additional hydrogen and carbon dioxide via water gas shift reaction. During the grey hydrogen production process, the generated carbon dioxide has little economic value and therefore is released into the atmosphere, contributing to the climate change. The total amount of carbon dioxide that is being released to the atmosphere is approximately 9 to 12 tones for every ton of hydrogen produced [Watson et al., 2021].

2.2.3. Blue Hydrogen

Similar to grey hydrogen, blue hydrogen is also generated with natural gas resources through SMR with a byproduct of carbon dioxide. The difference between grey and blue hydrogen is that instead of releasing carbon dioxide into the atmosphere, carbon dioxide for blue hydrogen is captured and stored. This process is called Carbon Capture Utilization and Storage (CCUS). Once carbon dioxide is captured, it will then be compressed into a fluid and transported to a storage site or used in other processes such as enhanced oil recovery (EOR) [Gonzales et al., 2020]. However, the addition of a carbon capture storage system to an existing natural gas power plant would raise the price of blue hydrogen to approximately $1.50 per kilogram [Watson et al., 2021].

Studies published by Cornell and Sandford universities have mentioned that even though blue hydrogen may seem like a "greener" alternative to grey hydrogen, there are still carbon emissions associated with its carbon capture and storage systems. Carbon emissions of blue hydrogen are only reduced by 9-12% as compared to grey hydrogen because carbon capture systems are not 100% efficient in capturing carbon dioxide. To power the carbon capture system during the blue hydrogen production process, natural gas would need to be used and would inherently increase the emissions of fugitive methane. Methane emissions are >100-times more powerful to cause global warming than carbon dioxide. It is also important to note that in this study, 2.25kWh/m^3 of hydrogen was used as the energy needed to drive the SMR process [Howarth, Jacobson, 2021]. This value is at the high end of the SMR process, while in an ideal scenario, 0.7 kWh/m^3 of hydrogen would be an appropriate value. Therefore, the calculated values and percentages may be different from ones found in real world scenarios, but it does not weaken the points that this study has made. At this time the use of blue hydrogen does not provide the necessary carbon reduction needed to meeting climate goals or is cost effective to provide economic benefits. Therefore, blue hydrogen should not be used for carbon reduction unless new technologies make the production/sequestration of blue hydrogen have a lower carbon footprint and be more economically viable.

2.2.4. Other Colors

There are other methods for hydrogen production other than green, grey, and blue, however, these methods are less common. These colors of hydrogen include pink, yellow, turquois, and brown. Pink hydrogen is generated using electrolysis through an electrical current that is powered by nuclear power plants. Yellow hydrogen is another type of hydrogen generated by electrolysis, but it uses only solar energy to power the electrolyzer. The distinction between green hydrogen and other methods of hydrogen production those use electrolysis, is that green hydrogen refers to using one and/or multiple forms of renewable energy as the energy source for the electrolyzer. Pink hydrogen and yellow hydrogen refer to only one specific form of renewable energy being used. Turquois hydrogen refers to hydrogen being produced through methane pyrolysis, which may be valuable as a low-emission form of hydrogen. Lastly, brown hydrogen refers to the production of hydrogen with the process of gasification. The process of gasification consists of coal being heated with water and releasing syngas containing a mixture of carbon dioxide, carbon monoxide, methane, hydrogen, and a small quantity of other gases [Farmer, 2020].

Appendix 3. Hydrogen Production

The purpose of this appendix is to provide an overview on the common sources to produce hydrogen via various production methods. Hydrogen is not found in nature by itself and needs to be produced through processes such as electrolysis, steam methane reformation, autothermal reforming, and pyrolysis. Examples of various hydrogen production methods are shown below in Figure 3.1.

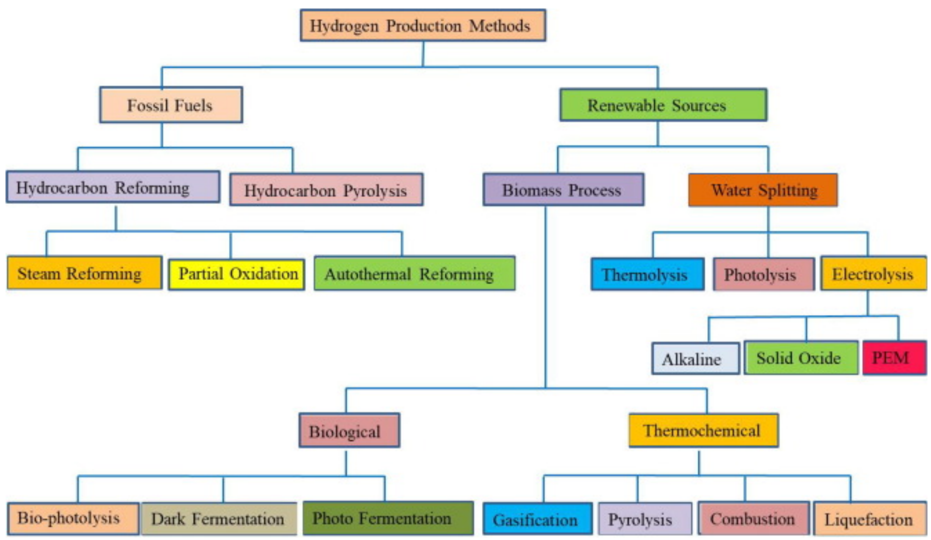


Figure 3.1 Methods of Hydrogen Production [Shiva Kumar, Himabindu 2019]

Hydrogen production from fossil fuels (Figure 3.1) is considered as grey hydrogen due to the lack of a carbon capture system and carbon dioxide emissions. With the implementation of a carbon capture system, the generated hydrogen would be considered as blue hydrogen. Hydrogen production using the renewable sources is considered as green hydrogen because no carbon dioxide is released. Due to the broad range of available renewable energy sources for hydrogen production, other colors of hydrogen fall under the renewable sources section. For example, yellow hydrogen is the hydrogen produced by the separation of molecules via light-activated photolysis of water splitting.

3.1. Hydrogen from Water

One approach to generate hydrogen is water electrolysis. In electrolysis, electricity is used to break down a compound into its molecular components. This is done by connecting a power source to two electrodes, an anode and a cathode. Figure 3.2 shows that the anode and cathode, colored blue, submerged into the electrolyte (liquid), colored grey. The anode has a positive charged catalytic surface, in which the oxidation occurs, and the generated electrons are giving to the cathode to complete the circuit. The cathode has a negative charged catalytic surface, in which the electrons are being used during the reduction process. From this process, the split molecular products can be captured or released depending on their usage.

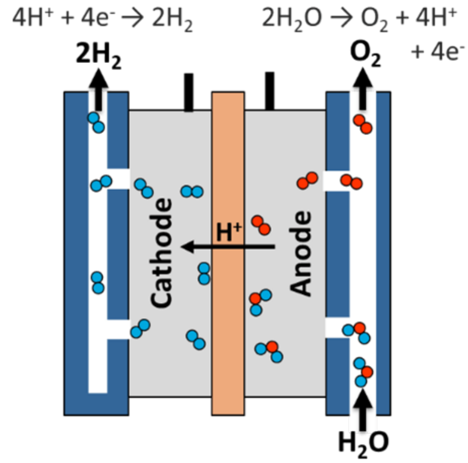


Figure 3.2 Diagram of Water Electrolysis [DOE, 2021a]

During water electrolysis, water is used and broken down into dihydrogen (H_2) and dioxygen (O_2). The industrial hardware used to break down water at larger scales is called an electrolyzer. An electrolyzer contains two electrodes (the anode and cathode), a power source, and a conductive electrolyte such as sulfuric acid or a material that conducts electricity from the power source to flow through the compound. Once the power source is turned on and the anode and cathode are formed, the electrolysis reaction can begin. Hydrogen proton has a +1 charge and will be attracted to the cathode and gain electrons through reduction reaction, as shown in Eq. 3.1:

$$2H^+(l) + 2e^- \rightarrow H_2(g) \quad (3.1)$$

Oxygen ion has a -2 charge and will be attracted to the anode and lose electrons through oxidation reaction, as shown in Eq. 3.2:

$$2H_2O(l) \rightarrow O_2(g) + 4H^+ (g) + 4e^- \quad (3.2)$$

The overall reaction is described by Eq. 3.3:

$$2H_2O(l) \rightarrow O_2(g) + 2H_2 (g) \quad (3.3)$$

The chemical equations above are the stoichiometric equations for water electrolysis in an acidic environment and can vary depending on the different methods of electrolysis used. These methods of electrolysis include solid oxide electrolysis (SOE), polymer electrolyte membrane electrolysis (PEM), and alkaline water electrolysis (AWE). The difference between each method of electrolysis varies but a key difference is the type of their electrolyte.

Hydrogen production from water electrolysis using renewable sources is a promising strategy due to its absence of carbon emissions. Currently, such hydrogen production approach is economically costly and thus, only 4% of the global industrial hydrogen is generated through electrolysis of water [Shiva Kumar, Himabindu 2019]. However, this percentage is expected to increase by the year 2030 due to an increase demand for renewable energy and a decrease in price of necessary components of hydrogen production such as electrolyzers.

3.1.1. Solid Oxide Cells

Another hardware of water electrolysis to generate hydrogen is solid oxide electrolyzer cells, which consist of two porous electrodes and a dense ceramic electrolyte that can transport negatively charged oxygen ions. By separating only oxygen ions from the compound, the left-over ions can be captured and used for different applications. In solid oxide electrolyzer cells, electrons, water and carbon dioxide can react to produce hydrogen, carbon monoxide and oxygen ions, at the fuel electrode side. Then the oxygen ions will diffuse through the electrolyte to the oxygen electrode side to form oxygen and electrons to finish the circuit. The electrochemical reactions that occur during electrolysis of water and carbon dioxide through the cell are shown in Figure 3.3.

The dense ceramic electrolyte needed for a solid oxide cell is most commonly made from yttria-stabilized zirconia (YSZ) or nickel doped yttria-stabilized zirconia (Ni-YSZ). YSZ is a solid solution made up of a few mol % of yttria in zirconia. The electrode material is dependent on the applications of the cells, lanthanum strontium manganite (LSM) is used for low demanding applications whereas a mixed conductor such as lanthanum-strontium ferrite-cobaltite (LSCF) or lanthanum-strontium-cobaltite (LSC) is more suitable for higher demanding applications. A thin layer (0.1 to 5 µm) of gadolinia-doped ceria (CGO) is also applied in between the electrodes to prevent reactions between the oxygen electrode materials [Hauch, et al. 2020].

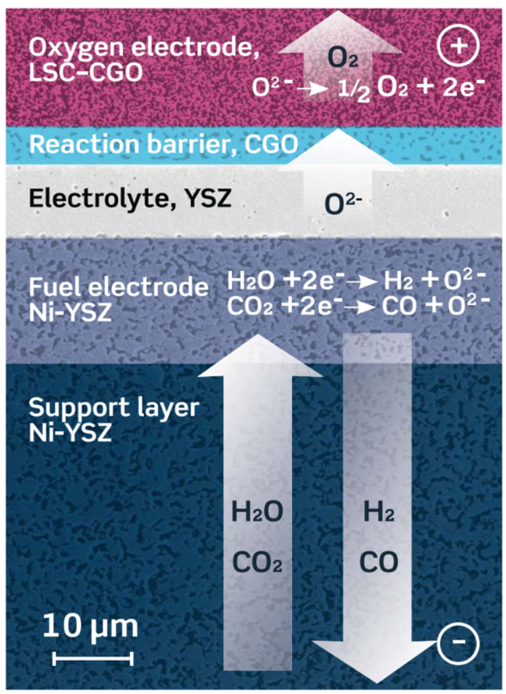


Figure 3.3 Electrolysis through a Solid Oxide Cell [Hauch, et al. 2020]

Figure 3.4 shows the production of hydrogen and carbon monoxide from a nanoscale to a macroscale. A single 100 cm^2 solid oxide cell operating at a current density of 0.8 A/cm^2 will produce 33 liters of hydrogen gas per hour. To increase output capacity and meet industrial demands, cells are connected in series and assembled into stacks, which are then combined to create a solid oxide electrolysis plant. A stack can contain anywhere from 30 to 100 cells. To secure the cells together, metallic interconnections are used. To allow the transportation of compounds and ions, flow channels are applied, and glass sealings are used to contain all the components of a stack.

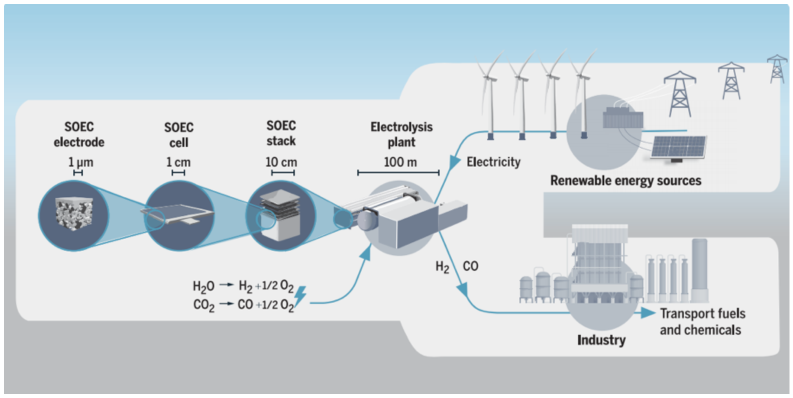


Figure 3.4 Solid Oxide Electrolyzer Cells [Hauch, et al., 2020]

Over time a solid oxide cell and stack will undergo changes that will affect the systems lifespan. The interconnects will corrode and creep, glass sealings will crystallize, and the electrodes in the cell will begin to degrade. There have been improvements to slow down changes and imperfections within solid oxide cells and stacks to improve their lifespans. The average lifespan of a solid oxide stack in 2020 is 2.5 years which is a 400% increase compared to its lifespan in 2011 which was less than 6 months. The degradation rate of a solid oxide cell in 2015 is 0.4% per 1000 hour of use which is a 99% decrease compared to 2005 which had a degradation rate of 40% per hour of use [Hauch, et al. 2020].

To have different layers of the solid oxide cell to function properly, a high temperature range of 600°C to 850°C must be achieved. Such high temperature may be difficult to achieve and maintain, but it results in high efficiencies that would otherwise be hard to obtain from other types of cells. The Department of Energy set out goals to have solid oxide cells reach a water electrolysis efficiency greater than 78% and are on track to doing so while also meeting hydrogen production costs of $2.3/kg. To reach an efficiency greater than 78% the solid oxide cell would need to reach an ultra-high current density of at least 3 A/cm^2 with a voltage upper limit of 1.6 V [Tang, et al. 2018].

3.1.2. Polymer Electrolyte Membrane

A polymer electrolyte membrane (PEM) cell is another type of water electrolyzer. PEM uses a polysulfonated membrane such as Nafion or Fumapem as an electrolyte, allowing electricity to flow through water, separating hydrogen and oxygen. The polysulfonated membrane is placed between two electrodes, these electrodes contain a catalyst layer that accelerates the reactions occurring at cathode and anode side. The catalyst layer is composed of noble metals such as Pt or Pd on the cathode side and IrO_2/RuO_2 on the anode side. The overall chemical reaction in the PEM electrolyzer is shown in Figure 3.5.

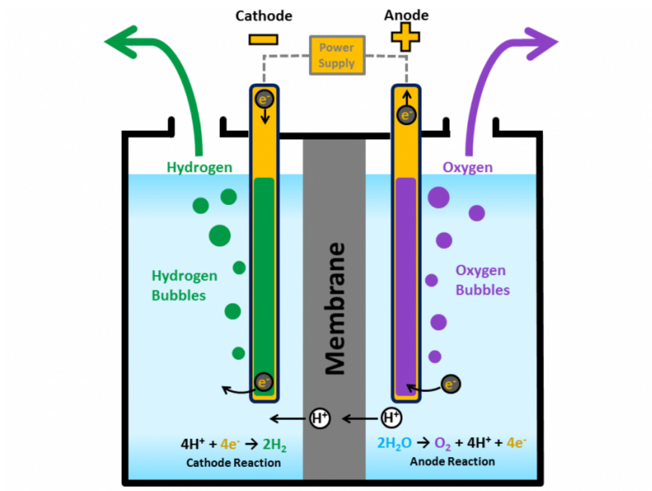


Figure 3.5 PEM Electrolyzer [Homann, 2020]

PEM cells come with many advantages compared to other cells due to their compact size (20-300 µm), high-pressure operations, and temperature range of operation (20-80°C) [Shiva Kumar, Himabindu, 2019]. The efficiency of a PEM electrolyzer in working applications is about 80%. Higher efficiencies have been simulated in the range of 88% to 92% with a maximum of 98% reached but only for a certain period [Fărcaş, et al. 2012]. Lifespan for a PEM cell is approximately 15,000 hours or 1.7 years till the cell begins to degrade in performance. However, due to the high cost of the noble metal catalyst layer, the main challenge for PEM cells is their high production cost.

3.1.3. Anion Exchange Membrane

As compared to PEM, anion exchange membrane (AEM) is a cheaper method of water electrolysis by substitution the noble metals in the catalytic layer with non-precious metals. However, anion exchange membranes use a solid alkaline membrane instead of a polymer membrane. This difference in membrane changes the charge carrier in the electrolysis process. Instead of hydrogen production from water splitting and oxygen ion moving towards the cathode in PEM, hydroxide is split from water and moves towards the anode, as shown in Figure 3.6. AEM cells are cheaper than PEM cells but they suffer from low stability and low conductivity. This causes a decrease in the efficiency of the AEM cell and cannot match the 80% efficiency produced from PEM cells.

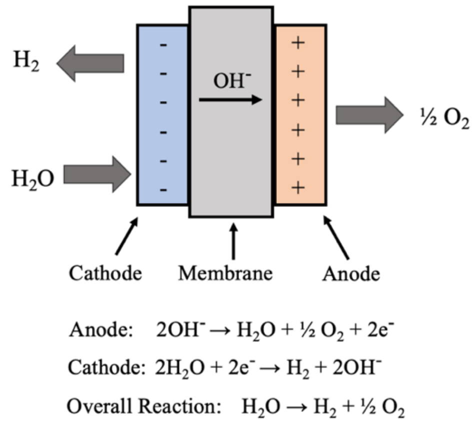


Figure 3.6 Anion Exchange Membrane Electrolyzer

According to The Department of Energy, it costs \$4 to \$6 to produce a kilogram of green hydrogen in a PEM electrolyzer. This cost is dependent on the cost of electricity to power the electrolyzer, the capacity factor of the system, and the systems capital cost. Table 3.1 shows the different PEM components The Department of Energy used to calculate the costs of hydrogen per kilogram.

Table 3.1 PEM Electrolysis Cost for Producing Hydrogen [Vickers, Randolph 2020]

	Electricity Cost (¢/kWh)	Capacity Factor	System CapEx ($/kW)	H_2 Cost ($/kg)
Grid Low	5.0	90.0%	1,500	**$5.13**
			1,000	**$4.37**
Grid High	7.0	90.0%	1,500	**$6.27**
			1,000	**$5.50**
	NREL ATB 2020 [1]			
Solar PV Utility Los Angeles, CA	3.2	31.8%	1,000	**$6.09**
Solar PV Utility Daggett, CA	2.9	35.1%	1,000	**$5.54**
Wind Onshore Utility, Class 6	3.8	38.0%	1,000	**$5.76**
Wind Onshore Utility, Class 1	2.8	52.1%	1,000	**$4.22**

The Department of Energy's target cost for hydrogen is \$2/kg-H_2. Existing projects have gotten close to reaching this \$2/kg-H_2 benchmark, the closets being Bloomberg New Energy Finance (BNEF) with~\$2.50/kg-H_2. International Renewable Energy Agency (IRENA) and Energy Environmental Economics (E3) have also gotten close with a lower limit cost of ~\$2.75/kg-H_2. It should be noted that the production costs of hydrogen for all four studies from Figure 3.7 were calculated through a mix of renewable and grid feedstocks. Therefore, some of the calculated costs of hydrogen may not be feasible in certain areas that struggle to produce renewable energy. All studies that were examined do show a decrease in the cost of hydrogen from PEM electrolysis.

This is attributed to an increase in availability of cheap renewable electricity, a price decrease in expensive system components, improved efficiency and lifetime of PEM cells, and advancements in manufacturing electrolyzer [Vickers, Randolph 2020]. The Hydrogen and Fuel Cell Technologies Office (HFTO) is currently focusing on decreasing the cost of hydrogen production by funding studies and other relevant projects to meet The Department of Energy's target price.

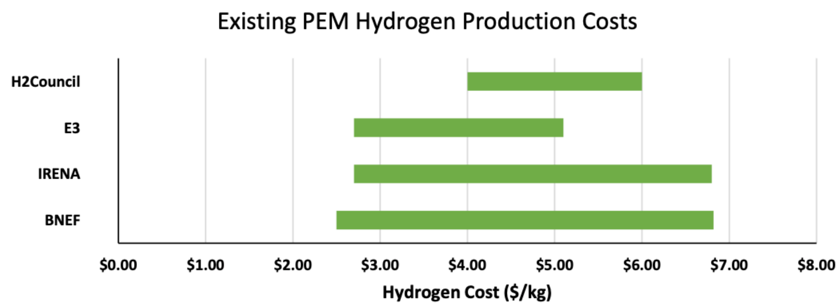


Figure 3.7 PEM Hydrogen Production Costs from Different Sources [Vickers, Randolph, 2020]

3.1.4. Molten Carbonate Electrolysis Cells

Molten carbonate electrolysis cells (MCEC) are able to produce either hydrogen or syngas (H_2+CO) (see Figure 3.8). These cells use an electrolyte made of molten carbonate, which is composed of either lithium and potassium carbonate, $(Li/K)_2CO_3$, or lithium and sodium carbonate, $(Li/Na)_2CO_3$. When the electrolysis cell reaches operating temperatures of 600-700ºC, the electrolyte becomes a liquid and develops a high conductivity rate, allowing for carbonate ions (CO_3^{2-}) to move from the cathode to the anode. Due to the high operational temperatures, MCEC can use non-precious metal-based catalysts, such as nickel (Ni) at the anode and NiO at the cathode.

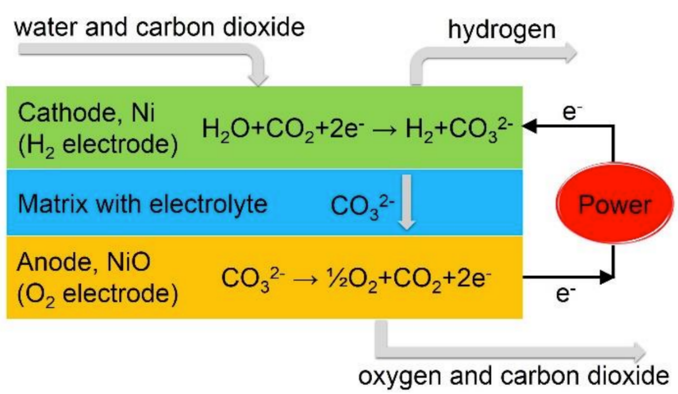


Figure 3.8 Molten Carbonate Electrolyzer [Hu, 2016]

To produce hydrogen or syngas from a MCEC, water and carbon dioxide are the reactants input from the electrolyzer inlet. At the cathode, electrolysis of water takes place where water combines with carbon dioxide and two electrons to form hydrogen and carbonate:

$$H_2O + CO_2 + 2e^- \rightarrow H_2 + CO_3^{2-} \quad (3.4)$$

The excess carbonate then moves towards the anode and passes through the molten carbonate electrolyte to produce oxygen, carbon dioxide, and two electrons:

$$CO_3^{2-} \rightarrow \frac{1}{2}O_2 + CO_2 + 2e^- \quad (3.5)$$

The overall reaction for a molten carbonate electrolyzer is described by Eq. 3.6:

$$H_2O + CO_2 \rightarrow H_2 + \frac{1}{2}O_2 + CO_2 \tag{3.6}$$

Molten carbonate cells are known as reversible cells. They can switch from an electrolyzer that uses electricity to produce fuel gases to a fuel cell that uses fuels to produces electricity. Reversible cells can economically benefit power plants because they reduce expenses of buying both an electrolyzer and a fuel cell. A molten carbonate cell being used as a fuel cell will have an electric efficiency of 55% and a total efficiency of upwards of 90% if combined heating and power or combined cooling and power is integrated [Hu 2016].

There are two main issues when using a molten carbonate cell: the degradation of the electrolyte and solubility of the cathode. When molten carbonate cells are operating for long periods of time, the electrolyte suffers from corrosion and vaporization [Bodén 2007]. This is caused from the nickel oxide at the cathode reacting with carbon dioxide to form nickel ions:

$$NiO + CO_2 \rightarrow Ni^{2+} + CO_3^{2-} \tag{3.7}$$

The nickel ions then travel through the electrolyte matrix and precipitate in the electrolyte causing corrosion and vaporization, which leads to the short-circuiting of the cell. The nickel oxide and carbon dioxide reaction also cause dissolution of the porous cathode. This dissolution caused by nickel is the main factor that limits the lifetime of the cell. To reduce the dissolution and increase the life span of a molten carbonate cell, three areas are being studied: developing a new material for the cathode, changing the structure of the current nickel oxide electrode, and changing the carbonate melt composites that cause corrosion and vaporization [Hu 2016].

The price of producing hydrogen from a molten carbonate electrolyzer cell is approximately \$6.50/kg-H_2, assuming an electricity price of \$0.103/kWh and a production of 125 kg- H_2/day. This price can easily be reduced by \$1.00 if there is a reduction in the capital expenditure or an increase in lifespan for the electrolyzer stack [Ahmed, et al. 2016]. The price can also be reduced by utilizing fuel cell applications of molten carbonate cells and selling the excess electricity produced. The excess electricity can be sold to Electric Vehicle (EV) charging stations and for every \$0.10/kWh premium that is applied, the price of hydrogen is further reduced to ~\$0.8/kg-H_2 [Ahmed, et al. 2016].

3.1.5. Applications of Water Electrolysis from Renewables

Countries have started developing pilot projects to test the feasibility of producing hydrogen from electrolysis of water, with electricity provided from renewable energy. The United States has just started construction of green hydrogen facilities but European countries surrounding the North Sea lead the charge in green hydrogen production. The North Sea has become a central component for these projects (e.g. Dolphyn and PosHydon) because of an already existing pipeline infrastructure that can be used to transport hydrogen, an optimal wind speed, and sufficient water depths to support wind energy.

The Dolphyn project, led by ERM and funded by Business Energy Industry Strategy (BEIS), proposes to construct a 4 GW offshore wind farm consisting of 10 MW turbines on the coast of Aberdeen, Scotland by the early 2030s. Figure 3.9 shows the schematic of the project and how the wind turbines will be connected to the onshore location. The wind turbines will be set up in a 20 by 20 array, which connects to a pipeline to transport the hydrogen. The hydrogen will then be stored on the coast and distributed on-demand to surrounding applications such as motor vehicles, residences, fueling stations, and port/industrial infrastructure. Test projects will be done to show the proof of concept by the year 2024 with a 2MW turbine 15km off the coast of Aberdeen [Excell, 2021]. The Dolphyn wind turbine design can be seen within Figure 3.10. This design uses a PEM electrolyzer for the local hydrogen production and an integrated water treatment unit that can use the seawater for electrolysis. The wind turbine is also on a semi-submersible platform so it can rest on top of the seawater. The reason of choosing a semi-submersible foundation for ERM was due to its cost effectiveness.

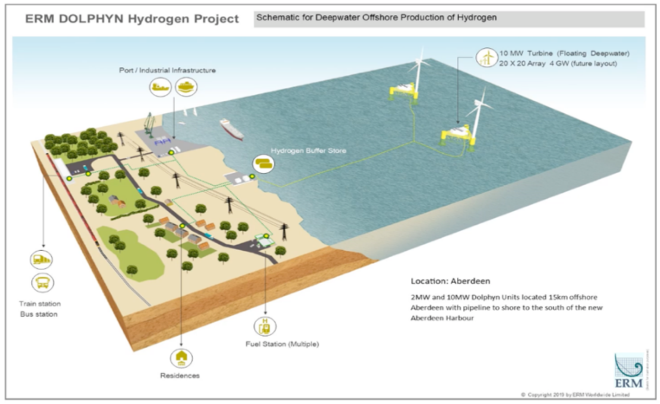


Figure 3.9 Dolphyn Hydrogen Production Schematic [Excell, 2021]

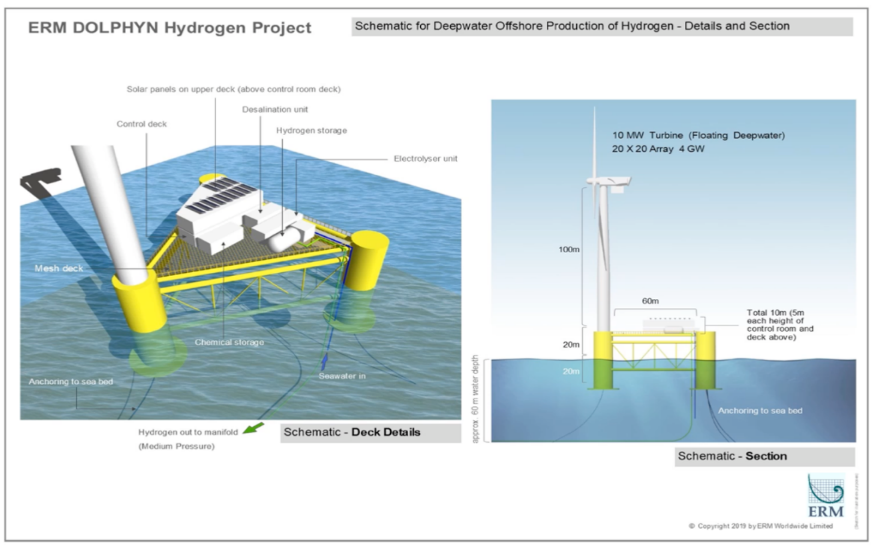


Figure 3.10 Dolphyn Offshore Wind Turbine [Excell, 2021]

The PosHydon Hydrogen project led by Neptune Energy also focused on taking advantage of the abundant resources from the North Sea. The project aims to integrate three energy systems in the North Sea, including offshore wind, offshore gas, and offshore hydrogen. Here, green hydrogen production will be powered by offshore wind energy. This will be done by updating the existing gas and oil infrastructure in the North Sea so that it can allow the use of the pipeline system to transport hydrogen to onshore. A test pilot is underway on Neptune Energy's existing offshore oil and gas platform, called Q13a. where a large scale electrolyzer is installed and powered by an offshore wind farm. A demineralizer is also attached to purify water before it undergoes electrolysis.

Plug Power is one of the leading companies in the United States, establishing green hydrogen generation power plants. Plug Power's projects include a 120 MW PEM electrolyzer located in New York that will produce 45 tonnes of green liquid hydrogen per day. To power the

PEM electrolyzer locally generated hydropower will be used. In Pennsylvania Plug Power is working alongside Brookfield Reenable Partners (BEP) to construct a plant that will service the broader transportation and logistics industries of the Northeast and mid-Atlantic by producing 15 tonnes of liquid hydrogen daily. The last notable Plug Power Project is set to begin construction in Georgia where an electrolyzer plant will be produce 15 tonnes of liquid hydrogen daily to serve the southeastern US. Each of Plug Power's projects are set to finish construction by the year 2024 or sooner [Shumkov, et al., 2021].

In the Northeastern part of the U.S., states are trying to utilize the excess amount of wind energy generated for hydrogen production (Figure 3.11 shows projected offshore wind farms) it is still difficult to estimate the proportion of wind energy capacity that will be used for hydrogen production. There is no doubt that there will be opportunities for allocating a portion of the offshore wind generated power for hydrogen production when supply exceeds demand. A good animation of one proposed concept is shown in National Grid's Hydrogen Hub Vision for New York (https://www.nationalgrid.com/us/cop26/hydrogen-vision). The percentage of power that will be used for hydrogen generation depends on the supply, demand, power pricing, hydrogen commodity pricing, and power purchase agreements. These variables are presently difficult to estimate many years in advance.

States in the Northeast that have already started development for hydrogen projects include New Jersey and New York. New Jersey Resources Corp (NJR) announced the construction of a green hydrogen project that will use electricity from adjacent solar facility to power electrolyzers to produce hydrogen. The produced hydrogen will then be blended into New Jersey's gas system. NJR also has plans to develop a green hydrogen offshore wind project with Atlantic Shores Offshore Wind LLC. This offshore wind project is contracted to develop 1,510 MW of offshore wind energy, and excess electricity that does not go to grid generation will be devoted to product hydrogen [DiChristopher, et al., 2021]. New York Governor Cuomo has announced that it will explore potential role of green hydrogen as method of decarbonization with plans of hydrogen a pilot project in place [NY.gov, 2021]. In Long Island, New York National Grid has started their first green hydrogen blending projects title HyGrid. This project is expected to heat 800 homes with a methane and green hydrogen fuel blend [National Grid, 2021].

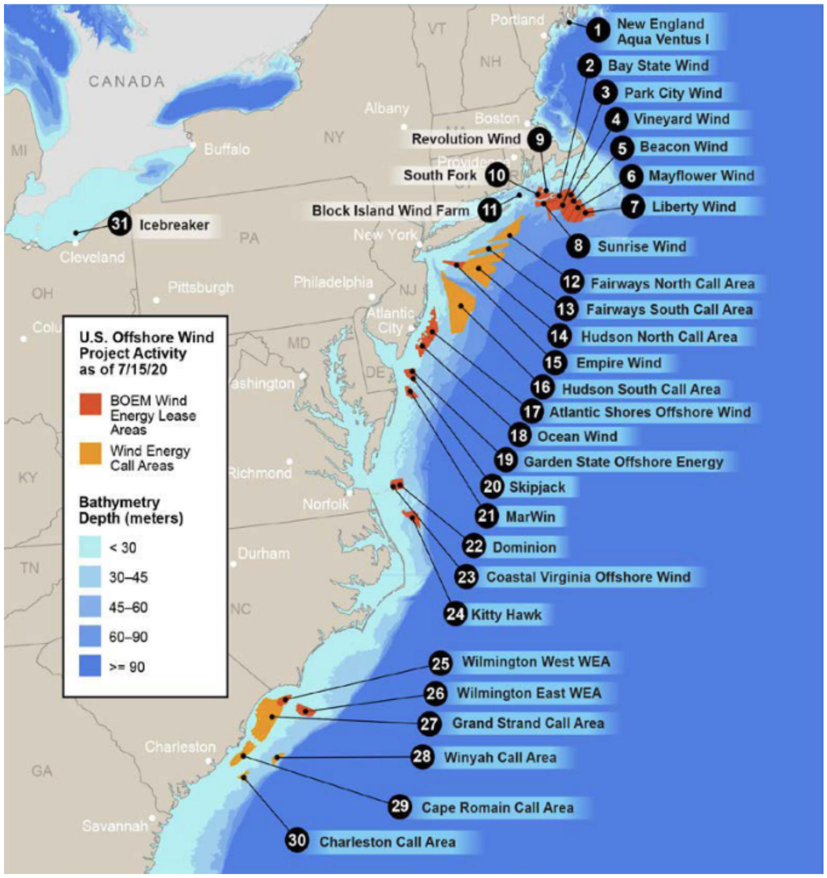


Figure 3.11 Projected Northeast Offshore Wind Farms [Carnevale, 2021]

3.2. Hydrogen from Hydrocarbons

Today, up to 95% of the world's hydrogen is produced through hydrocarbons [Rapier 2020]. Hydrocarbons are compounds composed only of the elements hydrogen (H) and carbon (C) and are commonly found in petroleum and natural gas. Examples of hydrocarbons for hydrogen production include methane (CH_4) and ethane (C_2H_6). Two common methods for using hydrocarbons to produce hydrogen is reforming and pyrolysis. During the reforming process, hydrocarbons react with steam or carbon dioxide to produce syngas. Hydrogen is then filtered from the syngas and captured. Reforming methods also measure the effectiveness for every H_2 generated to every CO generated, known as the H_2:CO ratio. In pyrolysis, hydrocarbons are split into two components: hydrogen and carbon. Hydrogen will be captured, and the carbon will be left over as a solid. These methods can be able to produce blue and green hydrogen if the correct steps are implemented in their process, such as adding in a carbon capture system, using a PEM electrolyzer, or using only electricity from renewable sources.

3.2.1. Steam Methane Reforming

Steam methane reforming (SMR), also known as steam reforming, is the most common method of hydrogen production in industry. During SMR, methane reacts with steam over a nickel-based catalyst to produce hydrogen and carbon monoxide:

$$CH_4 + H_2O \rightarrow CO + 3H_2 \tag{3.8}$$

This is considered as the "reforming" stage, as shown in Figure 3.12. The reforming phase is endothermic, meaning heat must be added to the process for the chemical reaction to occur. Heat is typically added by combustion of additional methane and/or available energy through the exhaust stream. Once heat is added to the reforming phase, the nickel-based catalyst will reach a temperature of 700-100ºC. The pressure of reactants is around 73-363 psi [Simpson, Lutz 2007], which will initiate the chemical reaction to produce syngas (hydrogen and carbon monoxide). The generated H_2:CO ratio from this process is a 3:1 ratio.

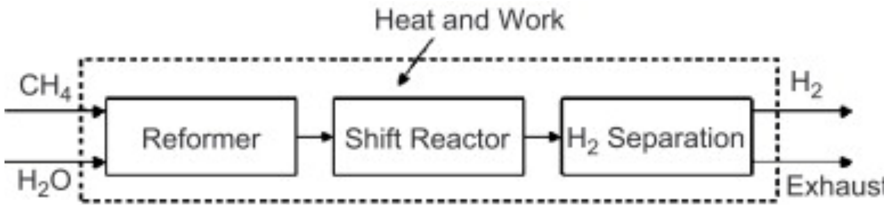


Figure 3.12 Steam Methane Reforming System [Simpson, Lutz, 2007]

A second stage known as "water gas shift" reaction can be added to the SMR process to decrease the harmful carbon monoxide content while also producing more hydrogen. The water gas shift reaction uses the carbon monoxide produced from the reforming process and has it react with steam to produce hydrogen and carbon dioxide:

$$CO + H_2O \rightarrow CO_2 + H_2 \quad (3.9)$$

The water gas shift reaction has two phases, the high-temperature water gas shift (HTS) and the low-temperature water gas shift (LTS). This is done because a high temperature is favored due to kinetics but is limited to thermodynamic chemical equilibrium. By adding in a low temperature phase, the volume of carbon monoxide can be reduced to 1% or less. The HTS will usually operate at a temperature range of 310-450ºC using a Fe_3O_4/Cr_2O_3 catalyst and the LTS will usually operate at a temperature range of 180-250ºC using a $Cu/ZnO/Al_2O_3$ catalyst [Kalamaras, Efstathiou 2013].

By integrating the water gas shift reaction with the original reforming process, the overall chemical formular is shown in Eq. 3.10:

$$CH_4 + 2H_2O \rightarrow CO_2 + 4H_2 \quad (3.10)$$

The final process in SMR is the separation of hydrogen from the syngas, which is mostly H_2, H_2O, and CO_2. There are three common methods for separating hydrogen, including pressure-swing adsorption (PSA) to separate H_2 and CO_2, condensation to remove the remaining water, and the use of a membrane to separate the hydrogen from the syngas. All separation methods are capable of producing a hydrogen at a purity rate of 99.99% [Simpson, Lutz 2007]. Some of these separation methods can also be utilized as carbon capture systems to lower the carbon footprint of a power plant.

The advantages of using SMR are high efficiency rates and low operational and production costs. SMR at an industrial scale has an efficiency of around 70-85% [Kalamaras, Efstathiou 2013]. The price to produce grey hydrogen via SMR is under \$1/kg-H_2. Such low price is due to the cheap catalysts used in SMR and the high ratio of hydrogen to carbon dioxide that is produced. If blue hydrogen were to be generated, a carbon capture system would need to be implemented, which would increase the price to \$1.40/kg-H_2 [Robinson 2020]. To produce green hydrogen, an electrolyzer like PEM electrolyzer would need to be installed, and the price would increase to about \$4.42/kg-H_2.

3.2.2. Autothermal Reforming

Autothermal reforming (ATR) is similar to steam methane reforming, however, oxygen is used and implemented in a process known as partial oxidation. Feedstocks, such as methane, will react with air and carbon dioxide in a reformer to produce syngas and water. The reformer is lined with a catalyst and operates at a temperature of 950-1050ºC and a pressure of 30-50 bar [Lamb, et al. 2020]. ATR can function with either carbon dioxide or steam. If CO_2 is used in ATR the reaction is as shown in Eq. 3.11:

$$2CH_4 + O_2 + CO_2 \rightarrow 3H_2 + 3CO + H_2O \tag{3.11}$$

If steam is used in ATR the reaction is Eq. 3.12:

$$4CH_4 + O_2 + 2H_2O \rightarrow 10H_2 + 4CO \tag{3.12}$$

When ATR uses carbon dioxide, the H_2:CO ratio is 1:1. While when steam is used, the H_2:CO ratio is 2.5:1. This shows that steam has a better H_2:CO ratio than that of carbon dioxide. Thus, ATR with steam is the preferred method for hydrogen production. To produce more hydrogen, a water-gas shift reaction can be implemented, reacting carbon monoxide and steam to further produce hydrogen.

The byproduct of each reaction is carbon monoxide. Thus, the hydrogen will be separated from the syngas mixture in order to be used. Similar to SMR, the separation stage can either be a pressure-swing absorption (PSA) or a membrane layer. When syngas is present at an elevated pressure, PSA operates on adsorbent beds. The beds absorb certain components of the syngas mixture, and allow the unabsorbed components to pass through the bed layer as purified product gas. Membrane layers are made up of palladium or palladium and are heated to high temperatures. Hydrogen molecules are absorbed into the membrane layers, broken down to hydrogen atoms, and then reformed into hydrogen molecules at the back surface of the membrane [Myers, et al. 2002].

Advantages of using ATR include low energy requirements, low operational temperature, and ease of operation with a smaller system. Comparing the capital costs of SMR to ATR shown in Figure 3.13, ATR has a lower overall capital cost than SMR. After changing the hydrogen separation stage from a PSA to a membrane layer, both methods will have a capital cost increase of approximately \$20,000 but ATR still has a lower capital cost than SMR. The disadvantage of using ATR is the low efficiency compared to SMR. The thermal efficiency for ATR is only 60-75%, which is around 20% smaller as compared to SMR. Due to the low efficiency, there would be an increase in production costs for hydrogen for ATR. Thus, to produce grey hydrogen via ATR, it would still cost approximately \$1/kg-H_2. To produce blue hydrogen, a carbon capture system will need to be installed, raising the cost of hydrogen to \$1.48 kg-H_2 [Kayfeci, et al. 2019].

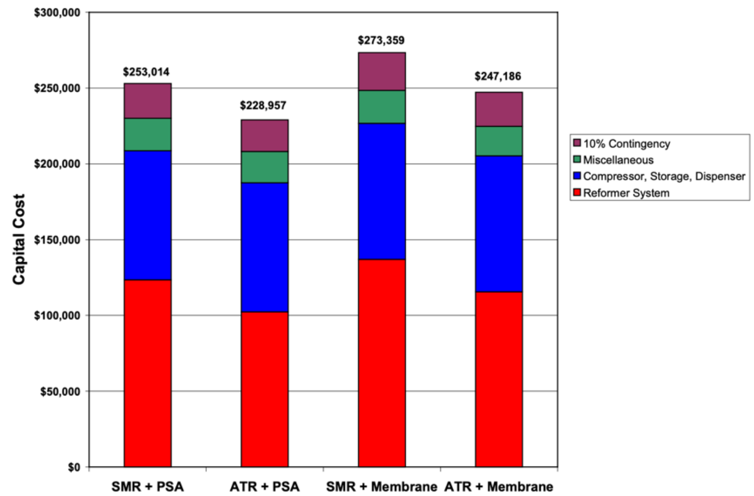


Figure 3.13 Comparison of Capital Cost of SMR to ATR [Myers, et al., 2002]

3.2.3. Methane Pyrolysis

Companies such as Monolith are utilizing a low carbon method of hydrogen production known as methane pyrolysis. Pyrolysis is the decomposition of materials at an elevated temperature in absence of oxygen. For methane pyrolysis, methane is used as a feed stock to produce hydrogen.

$$CH_4 \rightarrow C + 2H_2 \tag{3.13}$$

Methane flows into a non-catalytic reactor, operating at over 1,000ºC with an electrical source. If a catalyst is incorporated, then the operating temperature can be reduced. At the center of the reactor, methane is split into gaseous hydrogen and solid carbon, as shown in equation 3.13. Then the hydrogen floats to the top of the reactor where it can be removed and stored, while carbon will be left at the bottom to be disposed or sold as carbon black or synthetic graphite.

When compared to steam methane reforming, methane pyrolysis produces significantly less CO_2. The only associated CO_2 emissions from methane pyrolysis is from the supplied electricity for the process and can be reduced if the electricity is from a renewable energy source. Disadvantages of using methane pyrolysis for hydrogen production is the low technology readiness level. More research needs to be down to increase efficiency and decrease costs. Additional cycles for power generation can be added to the process, such as a steam cycle to increase power output and quantity of hydrogen produced, for lowering the hydrogen production cost per kilogram. However, the additional cycles can increase CO_2 emissions. Methods of reducing CO_2 emissions such as carbon capture can be added but would then increase the price per kilogram of hydrogen.

3.3. Hydrogen from Alternative Sources

Hydrogen can be produced from other feedstocks including biomass. Biomass is an organic material that stores chemical energy from sun and is produced from plants and animals. Examples of biomass include wood, agricultural crops, biogenic materials in municipal solid waste, animal manure, and human sewage. There are two processes used to produce hydrogen with biomass as a feedstock, pyrolysis and gasification.

As previously discussed, pyrolysis is the process of decomposition of materials at an elevated temperature in the absence of oxygen. When using biomass in pyrolysis, it replaces methane in the process (see Figure 3.14). There are three byproducts of biomass pyrolysis, bio-oil, char, and pyrolytic gas. Bio-oil is a dark brown organic liquid with a high thermal instability and low heating value, making it insufficient as an engine fuel. Char is a solid carbonaceous residue that has many applications including catalytic utilization, energy storage, and as a sorbent for the removal of pollutants in water. Pyrolytic gas is a gaseous mixture composed of carbon dioxide, carbon monoxide, hydrogen, methane, ethane, ethylene, propane, sulfur oxides, nitrogen oxides, and ammonia [Hu, Gholizadeh, 2019]. The yield for each byproduct various depending on the type of biomass used.

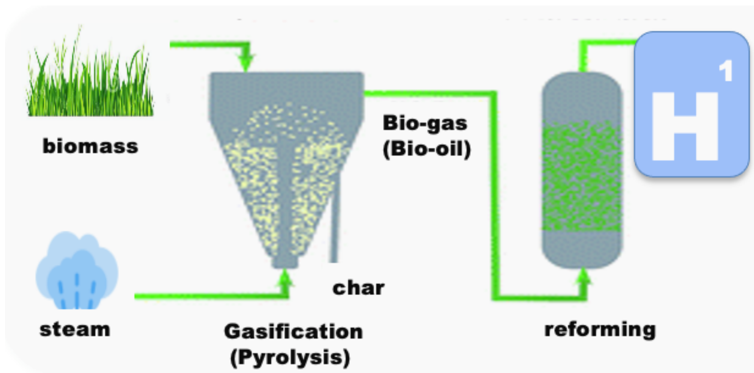


Figure 3.14 Biomass Pyrolysis Cycle

Additional stages are implemented in the pyrolysis process to filter the pyrolytic gas to obtain hydrogen. These stages include steam reforming and water gas shift reactions, which is also common in the steam methane reforming process. Stream reforming reaction in Eq. 3.8 states that methane and water from the pyrolytic gas produce carbon monoxide and hydrogen. To reduce the output of carbon monoxide and increase hydrogen production, water is then reacted with carbon monoxide to produce carbon dioxide and hydrogen, this is known as the water gas shift reaction, also shown in EQ. 3.9.

With the use of gasification, biomass can be converted into a hydrogen-containing gas mixture. Biomass gasification technology is well developed for the large-scale production of hydrogen; however, it is accompanied by high amounts of CO_2 emissions as well as energy intensive post-treatments for hydrogen purification. For these reasons, biomass gasification is only used to produce syngas that will then be used as a feedstock.

Appendix 4. Conversion of Hydrogen to Energy

The purpose of this appendix is to provide an overview of the different types of conversion methods used to convert hydrogen into a useable energy source. These types of conversions include fuel cells, combustion engines, and gas turbines. Hydrogen itself can also be used for residential or commercial use as a replacement for natural gas.

4.1. Fuel Cells

Fuel cells are electrochemical devices that convert the chemical energy of a fuel such as hydrogen or methane and an oxidizing agent such as oxygen into electricity. A fuel cell, shown in Figure 4.1, consists of two electrodes (anode and cathode), an electrolyte that located between the two electrodes, and a catalyst that is attached to the anode and cathode. When a hydrogen fuel cell is in operation, the fuel – hydrogen, is fed into the anode side of the cell and the oxidizing agent – oxygen is fed into the cathode side. At the anode side, hydrogen reacts with the catalyst and forms negatively charged electrons with positively charged protons:

$$H_2 \rightarrow 2H^+ + 2e^- \tag{4.1}$$

The electrons then move through an external circuit, creating an electrical current. The protons move through the electrolyte towards the cathode, where they will then react with the oxidizing agent [Foorginezhad, et al. 2021]. The purpose of the oxidizing agent is to react with excess electrons and the positively charged hydrogen protons to form water. When this reaction is completed for a hydrogen fuel cell, water should be the only products:

$$\frac{1}{2}O_2 + 2H^+ + 2e^- \rightarrow H_2O \tag{4.2}$$

The overall chemical process of a fuel cell is described in Eq. 4.3

$$2H_2 + O_2 \rightarrow H_2O \tag{4.3}$$

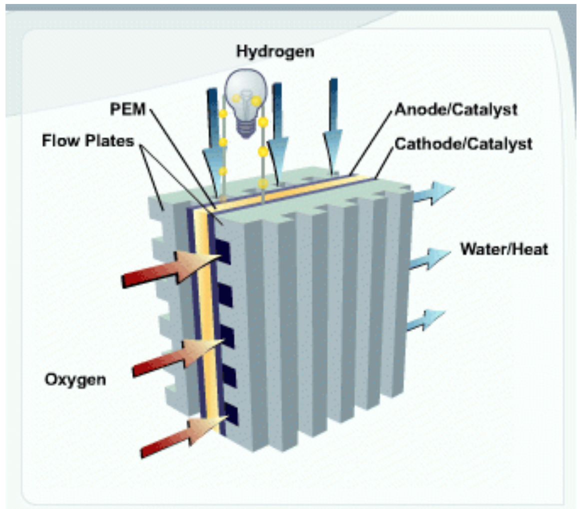


Figure 4.1 Hydrogen Fuel Cell [DOE, 2021b]

Similar to electrolyzers, there are many different fuel cells, including solid oxide fuel cells, polymer electrolyte membrane fuel cells, molten carbonate fuel cells, and so on. The distinct feature that differentiates the different kinds of fuel cells is the method of extracting hydrogen electrons to be used as an energy source. The mostly commonly method is to change the electrolyte used in the fuel cell. The chemical reactions can vary depending on the type of fuel cell, but all follow the same overall reaction stated in Eq. 4.3.

The amount of power that a fuel cell can output is dependent on several factors, including fuel cell type, efficiency, temperature, and pressure operations. A single fuel cell on average produces less than 1.16 volts of electricity. This amount of electricity can barely power the smallest appliances. To increase the voltage output. fuel cells are combined in series to form a fuel cell "stack", as shown in Figure 4.2.

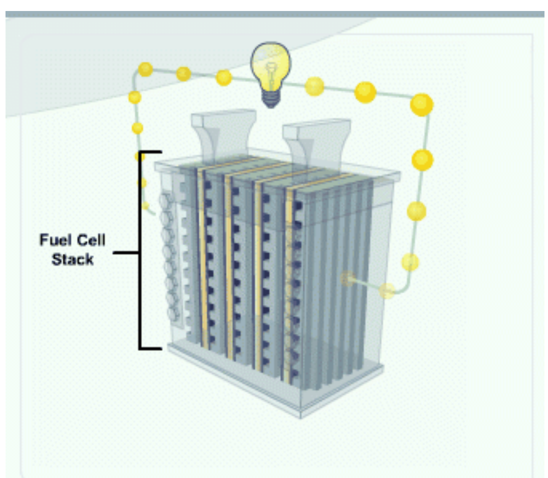


Figure 4.2 Fuel Cell Stack Cell [DOE, 2021b]

Fuel cell stacks typically consist of hundreds of fuel cells and can be modified to output specific voltages for different applications.

A big incentive for using fuel cells compared to combustion engines is its zero to low carbon dioxide emissions. This means there is no production of air pollutants that will create smog or cause health problems during operation for hydrogen fuel cells. The only products produced through hydrogen fuel cells are water, electricity, and heat. These products address critical challenges and goals of achieving a zero-carbon energy source, meaning the hydrogen fuel cell is an inherently green source of energy.

Areas that hydrogen fuel cells need to be improved are cost, performance, and durability. The total system costs vary drastically depending on the type of fuel cell used and the amount of output energy. Comparing Table 4.1 and Table 4.2, the total system cost of PEM systems on average is 57.33% more than that of SOFC systems:

Table 4.1 Polymer Electrolyte Membrane (PEM) System [BMI, 2016]

Description	100 kW 1,000 Units/year	100 kW 10,000 Units/Year	250 kW 1,000 Units/year	250 kW 10,000 Units/Year
Total Stack Manufacturing, Testing & Conditioning Costs	$34,480	$23,303	$71,151	$53,494
Fuel, Water, and Air Supply Components	$22,857	$20,894	$28,186	$25,744
Fuel Processor Components	$48,005	$43,629	$58,304	$53,895
Heat Recovery Components	$33,994	$30,868	$51,218	$46,680
Power Electronic, Control, and Instrumentation Components	$43,221	$35,258	$94,238	$74,725
Assembly Components and Additional Work Estimate	$26,790	$24,080	$36,955	$33,300
Total system cost, pre-markup	$209,348	$178,032	$340,052	$287,838
System cost per KWnet, pre-markup	$2,093	$1,780	$1,360.21	$1,151.35
Sales markup	$1	$1	50.00%	50.00%
Total system cost, with markup	$314,021	$267,048	$510,077	$431,758
System cost per KWnet, with markup	$3,140	$2,670	$2,040	$1,727

Table 4.2 Sold Oxide Fuel Cell (SOFC) System [BMI, 2016]

Description	100 kW 1,000 Units/year	100 kW 10,000 Units/Year	250 kW 1,000 Units/Year	250 kW 10,000 Units/Year
Total Stack Manufacturing, Testing & Conditioning Costs	$32,005	$28,537	$73,566	$70,452
Fuel and Air Supply Components	$6,995	$6,293	$12,439	$11,391
Fuel Processor Components	$5,675	$5,114	$9,255	$8,377
Heat Recovery Components	$19,698	$18,430	$31,718	$29,718
Power Electronic, Control, and Instrumentation Components	$43,627	$35,622	$95,050	$75,453
Assembly Components and Additional Work Estimate	$9,975	$8,950	$16,935	$15,240
Total system cost, pre-markup	$117,976	$102,946	$238,963	$210,630
System cost per KW_{net}, pre-markup	$1,179.76	$1,029.46	$955.85	$842.52
Sales markup	50.00%	50.00%	50.00%	50.00%
Total system cost, with markup	$176,964	$154,418	$358,445	$315,945
System cost per KW_{net}, with markup	$1,770	$1,544	$1,434	$1,264

The reason of higher cost of PEM as compared to SOFC is that the catalyst of PEM is high-cost platinum. However, a PEM system does result in higher efficiencies than a SOFC system. By either substituting a non-precious metal for platinum in PEM while also maintaining high efficiency or increasing the efficiencies of SOFC, will lead to a decrease in the total cost of the systems.

Fuel cells also suffer from a durability problem. Under realistic operating conditions, fuel cells will meet the challenges, including starting and stopping stabilities, poisoning from impurities in reactants, load cycles fatigue, as well as stress on the chemical and mechanical stability of the components. The Department of Energy's goal is to have fuel cells operating 8,000 hours for light-duty vehicles, 30,000 hours for heavy duty trucks, and 80,000 hours for distributed power systems [DOE, 2021c].

4.2. Hydrogen Internal Combustion Engines

Internal Combustion engines are used in about 250 million highway vehicles in the United States alone [DOE, 2021d]. Combustion engines convert chemical energy from an air fuel mixture into mechanical energy. This is done by combusting a fuel source with an oxidizer, creating a force that is applied to a piston. The piston then moves up and down causing the crank shaft to rotate shown in Figure 4.3. Through the movement of other components in the engine, the chemical energy used to start this process is converted into mechanical energy, also known as work. This work is used to operate things such as the motion of a vehicle's wheels.

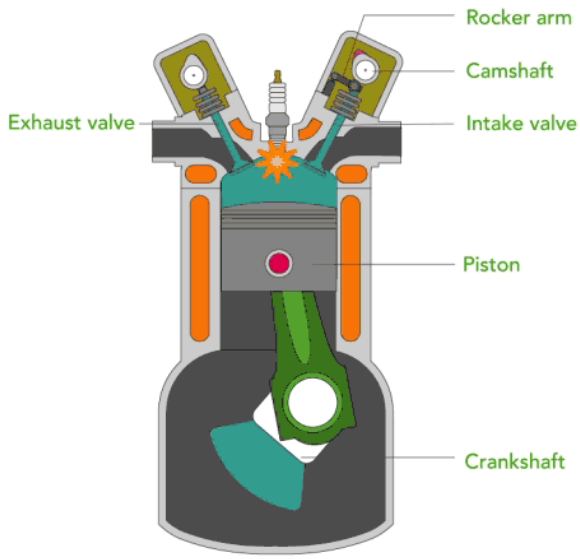


Figure 4.3 Internal Combustion Engine Diagram [Anglin, 2018]

Liquids derived from fossil fuels such as gasoline or diesel are used as the fuel source for a combustion engine, however these fuels emit air pollutants such as carbon dioxide and particulates. Hydrogen can be blended with these fossil fuels or completely replace them to lower carbon emissions. It is important to note that due to the combustion reaction, nitrogen oxides, otherwise known as NOx is created. The NOx levels that are created are much lower than that of gasoline and diesel fuel due to the air-to-fuel ratio. Hydrogen combustion engines need more air and less fuel than regular combustion engines which leads to less NOx produced [Crosse, 2021]. More information on the production and removal of NOx can be found in section 7.1 Hydrogen Combustion.

4.3. Gas Turbine

A gas turbine is similar to an internal combustion engine but produces energy at a much larger scale. In a gas turbine air enters the compressor through an air intake valve and is then heated and compressed. A fuel source is then injected in the combustor where it ignites with the hot air causing a gas mixture to form, generating chemical energy. This gas mixture is then used to rotate turbine blades at speeds of 3000RPM, converting chemical energy into mechanical energy. As the turbine blades rotate the drive shaft, which is attached to the generator, also begins rotating. At the end of the generator a magnet is attached with coil surrounding it. When the magnet rotates at certain speeds a powerful magnetic field is created that causes electrons around the coils to move and electrical current is generated.

The most common fuel source for gas turbines is natural gas, however most gas turbines are inherently fuel-flexible, meaning they can operate on hydrogen or similar fuels as natural gas. Depending on the fuel source or blending rates, modifications may need to be made to the fuel accessories, bottoming cycle components, and safety systems within the plant to ensure the turbine is operating as desired. Shown in Figure 4.4 are the different models of General Electric gas turbines and operation capabilities for using blended hydrogen. All of General Electric's gas turbines can run at least a 50% blend of hydrogen and the end goal is to have every model run at 100% hydrogen.

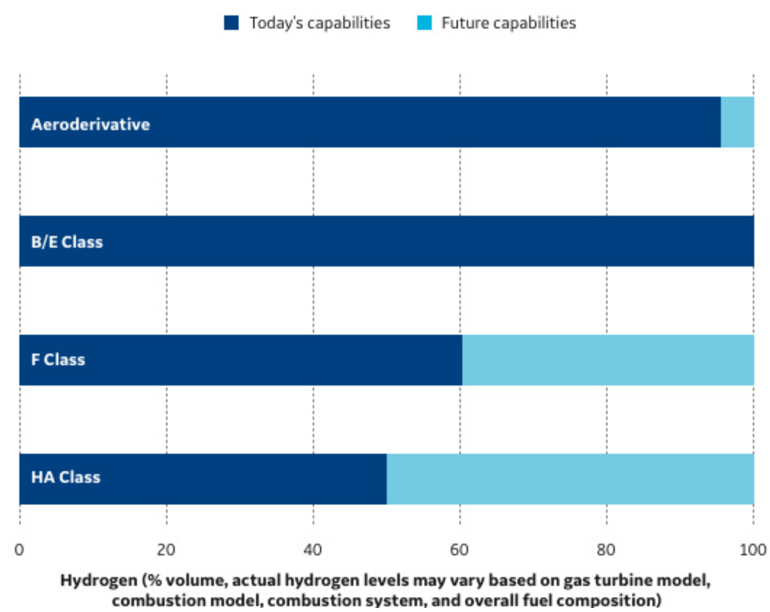


Figure 4.4 Hydrogen Blending in Gas Turbines [Goldmeer, 2021]

Other companies such as Mitsubishi Power used an operating blend of at least 30% hydrogen and are working towards 100% hydrogen certified gas turbines by the year 2025. Mitsubishi is also working towards retrofitting outdated coal-fired power plants to run on 30% hydrogen and increasing the blend percentage to 100% by the year 2045.

Using 100% hydrogen for gas turbines will lead to the elimination of essentially all CO_2 emissions caused from natural gas turbine. CO_2 emissions attributed to a hydrogen fuel will be zero, however, there is a small amount of CO_2 emitted during the combustion phase because there is approximately 0.04% (by volume) CO_2 in the air. This is still a more than 99% reduction in CO_2

emissions relative to the CO_2 emissions from a 100% methane. Figure 4.5 shows the rate of CO_2 reduction with respect to blending of hydrogen and methane. The blending rate and CO_2 reduction does not have a linear relationship, this is because of hydrogen having a lower volumetric energy density than methane (see Figure 4.6). For example, a 5% blend of hydrogen with a 95% blend of methane would only reduce CO_2 emissions by 1.5% because the volumetric energy density ratio ends up being 0.65% hydrogen and 99.35% methane on a heat input basis. To obtain a 50% reduction in CO_2 emissions then a 75% blend by volume of hydron would be required [Goldmeer, 2019].

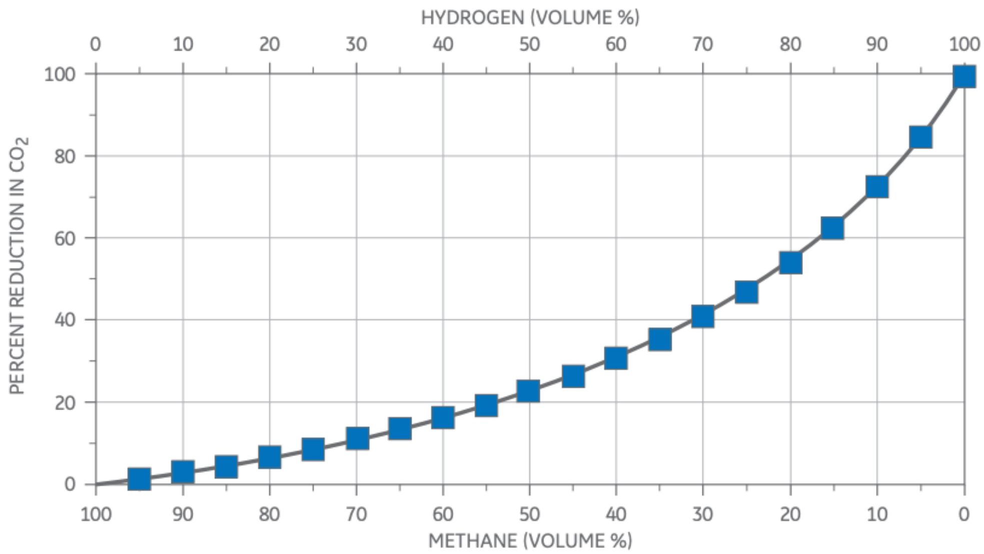


Figure 4.5 CO2 Reduction with Respect to Hydrogen and Methane Blend [Goldmeer, 2019]

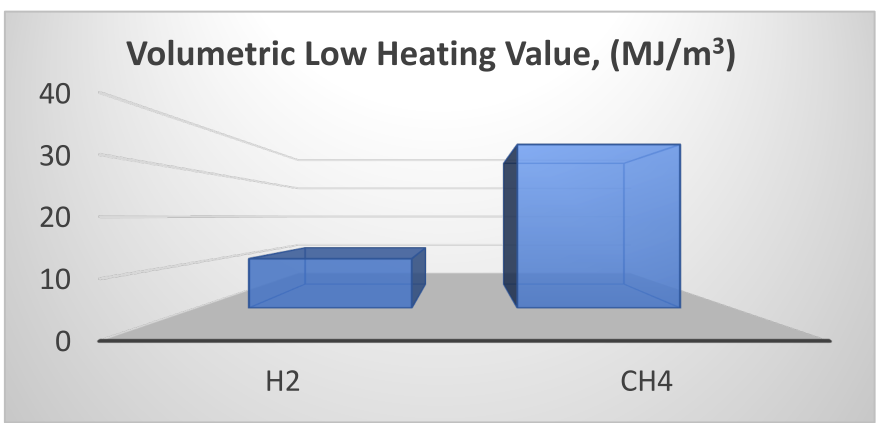


Figure 4.6 Comparison of Hydrogen's Volumetric Energy Density

4.4. Comparison of Efficiency

The different efficiency for each conversion method of hydrogen to energy is shown on Table 4.3. Fuel cells will have an efficiency of around 50%-60% [DOE, 2015]. This fuel cell efficiency is not the total efficiency but the efficiency of each individual cell. The total efficiency of this process will be around 30%, depending on the production method of the hydrogen supplied and the method of storage. Combustion engines that run off hydrogen will have an efficiency range from 20% to 25% [Hosseini, Butler, 2019]. This efficiency for a combustion engine is standard and shows that hydrogen had little to no effect on efficiency for a combustion engine. Gas turbines with a 30% hydrogen blend have an efficiency of approximately 64% [Mitsubishi, 2021]. This efficiency for a gas turbine is standard for a gas turbine running on natural gas.

Table 4.3 Comparison of Efficiency for Each Energy Method

Conversion Methods	**Efficiency**
Solid Oxide Fuel Cell	60%
Polymer Electrolyte Membrane Fuel Cell	60%
Molten Carbonite Fuel Cell	50%
Combustion Engine	20-25%
Gas Turbine	64%

Appendix 5. Hydrogen Delivery and Storage

Hydrogen storage and delivery play a key role in the development of a hydrogen economy. The purpose of this appendix is to give an introduction on how hydrogen is stored and then transported to end users as shown in Figure 5.1.

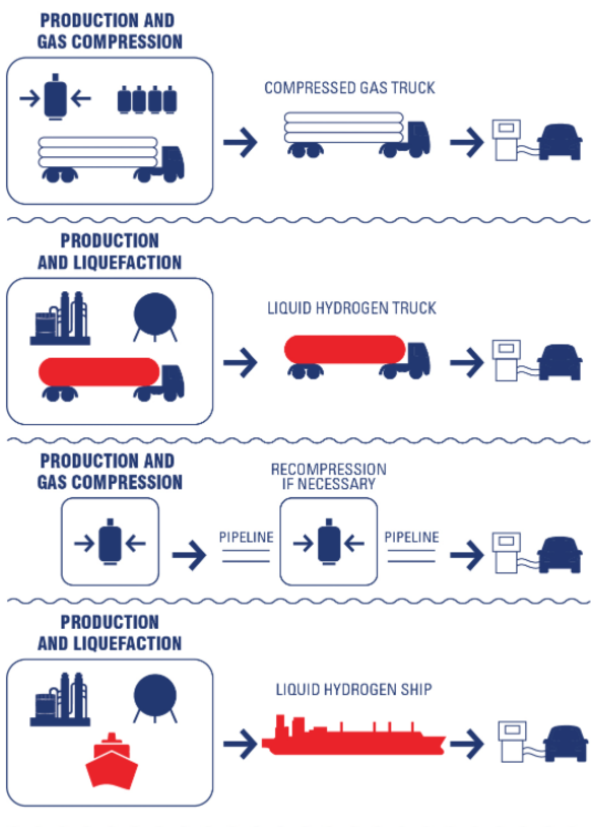


Figure 5.1 Methods of Hydrogen Transportation [Hydroville, 2021]

5.1. Physical Storage

Hydrogen can be an effective solution to decreasing carbon emissions, however due its characteristics and properties challenges arise when hydrogen is stored. The two most common methods for storing hydrogen are compressed gas hydrogen storage (CGH_2) and liquid hydrogen storage (LH_2). Compressed gas and liquid hydrogen storage are considered physical storage. Physical storage focuses on changing storage conditions such as pressure or temperature. There are other methods of storying hydrogen shown in Figure 5.2, most notable material-based (chemical) storage. Material based storage focuses on having hydrogen be absorbed into porous medium to allow for easier storage conditions [Hassan, et al., 2021]. Material storage is still in its infancy and more research needs to be done before it can be used in the everyday market.

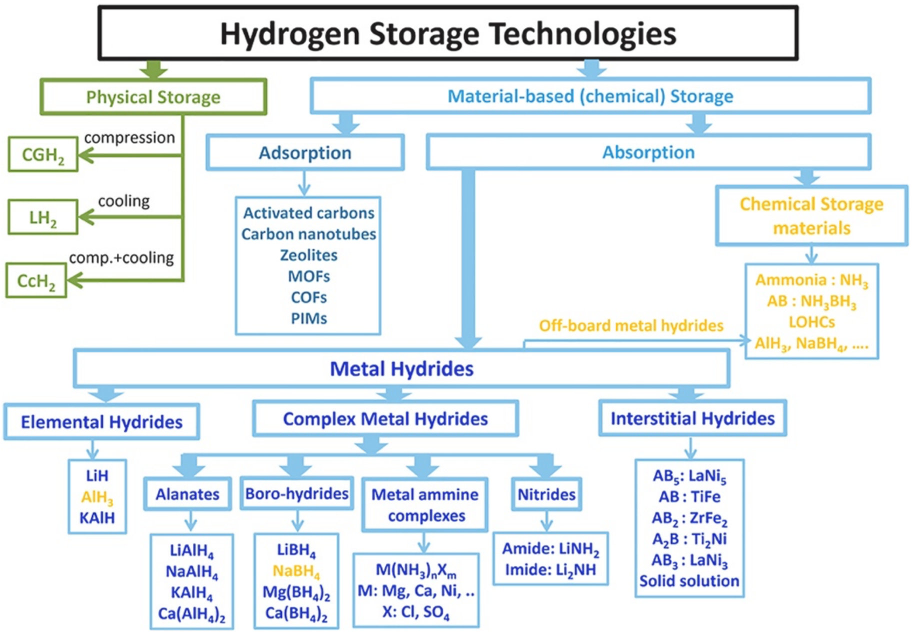


Figure 5.2 Different Hydrogen Storage Technologies [Hassan, et al., 2021]

There are two methods for storing hydrogen in today's market, compressed storage tanks and cryogenic storage tanks. However, each method of hydrogen storage comes with its own benefits and challenges. Compressed storage tanks store hydrogen as a gas and requires extremely high pressures around 350-700 bars (5,000-10,000 psi). Cryogenic storage tanks store hydrogen as a liquid and requires temperatures below -252.8°C due to hydrogens boiling point [DOE, 2021e]. When compared to natural gas, compressed storage must be kept at about 250 bars (3600 psi) [Burchell and Rogers, 2000] and liquid natural gas must be kept at a temperature of about -162°C [Ct.gov, 2021].

5.1.1. Compressed Gas Hydrogen Storage

For compressed gas hydrogen storage there are four different types of storage tanks that can be seen in Table 5.1. The most common tank to store hydrogen in is a Type IV tank. Figure 5.3 is an example of a Type IV tank that is being implemented in fuel cell electric vehicles (FCEVs). The tank shown has a carbon-fiber composite overwrap to provide strength to the tank as well as a polymer liner.

Table 5.1 Different Types of High-Pressure Storage Tanks [DOE, 2021e]

Type I	All-metal cylinder
Type II	Load-bearing metal liner hoop wrapped with resin-impregnated continuous filament
Type III	Non-load-bearing metal liner axial and hoop wrapped with resin-impregnated continuous filament
Type IV	Non-load-bearing, non-metal liner axial and hoop wrapped with resin-impregnated continuous filament

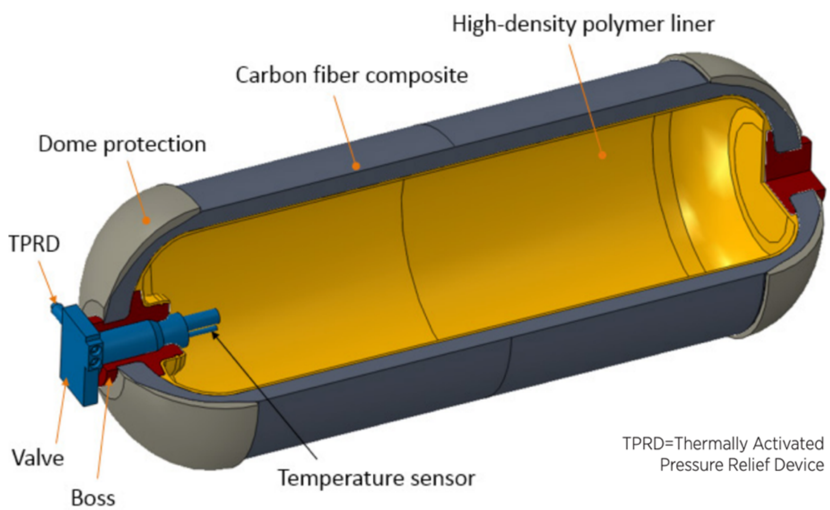


Figure 5.3 Schematic of Type IV Pressure Tank for FCEV [DOE, 2017]

Figure 5.4 shows another example of a gas hydrogen storage tank. It is lined with an ultra-high molecular weight polymer that is wrapped with multiple layers of carbon fiber to reinforce the tank from corrosion and fatigue. A reinforced external protective shell is applied to protect the tank from an impacts or abrasions it may experience.

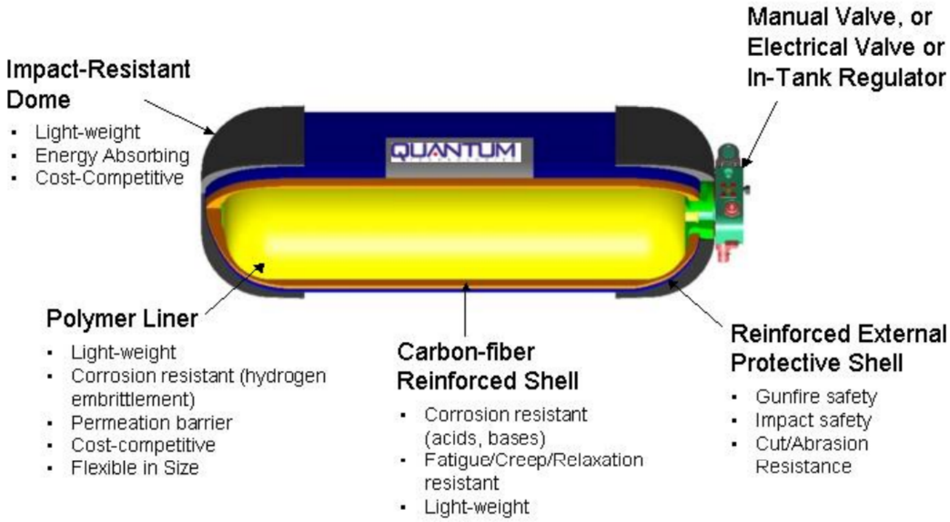


Figure 5.4 Schematic for Type IV TriShield Tank [Sirosh, 2002]

Type IV tanks may be the best tanks for storing hydrogen but due to their need of carbon fiber these tanks can be expensive. There are goals and initiatives to decrease the price of carbon fiber and make things such as hydrogen tanks cheaper and more readily available to consumers. Table 5.2 shows the Department of Energy's projected cost performance for a 700 bar Type IV hydrogen tank. The Department of Energy's goal is to have a Type IV hydrogen tanks cost approximately \$8/kWh in 2007 dollars, while also having a volumetric capacity of 2.3 kWh/L and gravimetric or weight capacity of 2.5 kWh/kg.

Table 5.2 Department of Energy (DOE) Projected Cost (\$ USD) and Performance for 700 bar Type IV [Ordaz, et al., 2015]

	Units	2020 Target [1]	Ultimate Target [1]	2013 Status [2]	2015 Status
Gravimetric Capacity	kWh/kg system	1.8	2.5	1.5	1.40±0.04[a]
Volumetric Capacity	kWh/L system	1.3	2.3	0.8	0.81±0.01[a]
Cost at 500,000 units/year	2007\$/kWh	10	8	16.8	14.8 [-0.8, +1.7][b]

The breakdown of the cost of a 700 bar Type IV tank and the Department of Energy's projected cost is shown in Figure 5.5. The majority of the cost for a Type IV tank is from the carbon fiber manufacturing and utilization, making up 72% of the cost. The Balance of Plant (BoP) which refers to the systems used to manufacture and assemble the storage tanks are the next leading percentages for the costs of Type IV tanks with 25%. Reducing any of these factors will lead to major cost reductions.

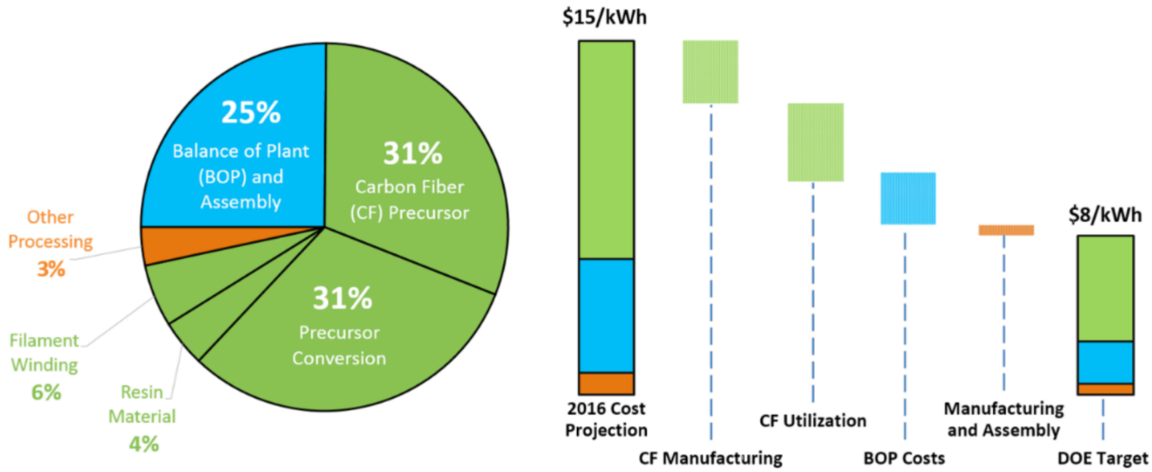


Figure 5.5 Breakdown of 700 Bar Type IV Tank and Projected Cost [DOE, 2017]

Some companies that specialize in compressed hydrogen storage tanks are NPROXX, Worthington Industries, and MAHYTEC. NPROXX produces large scale stationary compressed type IV storage tanks that can hold up to 1,000 kg of hydrogen. NPROXX has also built refueling stations for city buses outside Cologne, Germany and refueling facilities for hydrogen powered local and regional trains. Worthington Industries produce type III hydrogen storage tanks for fuel cells and internal combustion engines, with a max capacity of 10 kg of hydrogen. Worthington has numerous locations across the U.S. with one pressure cylinder facility located in Rhode Island. MAHYTEC is a French company that produces type IV hydrogen tanks found in fuel cell vehicles or residential applications, with a maximum storage capacity of 9.5 kg of hydrogen.

5.1.2. Liquid Hydrogen Storage

For storing large quantities of hydrogen, it is best stored as a liquid in cryogenic liquid storage tanks, also known as “dewars” pictured in Figure 5.6. Cryogenic tanks are very well insulated low-pressure vessels that are able to store hydrogen at temperatures of -253°C (-423°F) and be able to have an inside pressure of no more than 5 bars (73 psi) [DOE, 2021e]. One of the challenges for storing liquid hydrogen is maintaining a low temperature. Hydrogen must be stored in temperatures below -252.8°C, compared with liquid natural gas which has to be kept around -160°C.

Hydrogen has a boiling point of -252.8°C, anything above the boiling point will cause the liquid hydrogen to be converted to gaseous hydrogen and form a gas layer at the top of the tank. If hydrogen is converted from a liquid to a gas it would need to be either released from the tank or recompressed to stop the pressure of the tank from rising.

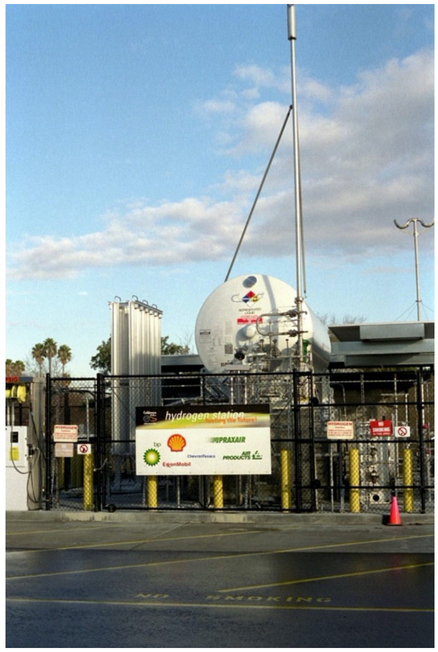


Figure 5.6 Cryogenic Liquid Hydrogen Tank [DOE, 2021e]

5.2. Transportation

Today, hydrogen is being transported from point of production to the point of end user via pipelines and on the road in trailers or tanker trucks. There are currently 1,600 miles of pipelines dedicated to delivering hydrogen in regions of the U.S. with substantial demand for hydrogen [DOE, 2021f]. Regions that have a smaller demand for hydrogen will have company's transport hydrogen with either liquid tankers or tub trailers. This current hydrogen transportation infrastructure will not be able to meet the demand of hydrogen in the near future if there is not an increase in either pipelines dedicated to hydrogen and/or hydrogen delivery companies. The challenges that are limiting the growth of the hydrogen transportation infrastructure include cost, hydrogen purity, efficiency, leakage, and regulations, and public acceptance.

5.2.1. Pipelines

Pipelines are the most promising infrastructure for creating a hydrogen network due to the already existing natural gas pipelines. By using the natural gas pipeline system, the existing infrastructure may allow for a low-cost option to transport large volumes of hydrogen. There is approximately 3 million miles of natural gas pipelines in the United States that connect production and storage facilities with consumers [EIA, 2020a]. Compared to the 1,600 miles of pipelines that are dedicated to specifically delivering gaseous hydrogen. Instead of creating new pipelines that will have a high initial capital cost the current natural gas pipelines can be updated to handle hydrogen at a much cheaper cost. According to European studies, it is estimated that to repurpose the natural gas pipelines to support hydrogen would be 10-35% of the required cost to build a new hydrogen pipeline system [Wang, et al., 2020].

The main concern when using hydrogen in natural gas pipeline is the embrittlement of the steel and welds of the pipeline. Hydrogen embrittlement occurs when a metal is exposed to hydrogen and the hydrogen molecules are absorbed by the metal. The metal then becomes brittle, forming cracks and fractures shown in Figure 5.7. These cracks and fractures can then lead to leakage or possible failure of the system. High strength steels are the most susceptible to hydrogen embrittlement and it is recommended that a lower carbon grade or a stainless-steel welded pipe is used. Plastic pipes made of polyethylene (PE) have shown to be compatible with hydrogen and have not experienced hydrogen embrittlement [Blanton, et al., 2021].

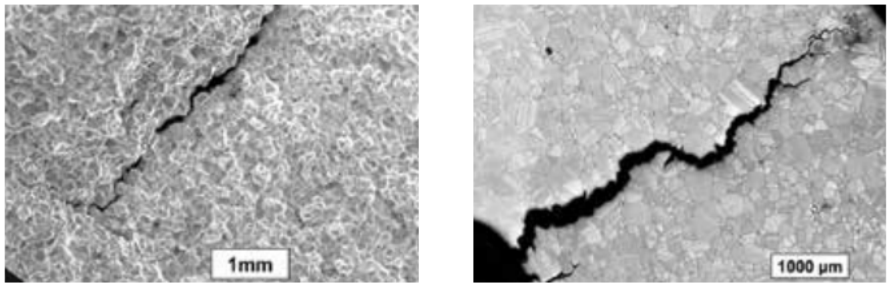


Figure 5.7 Effects of Hydrogen Embrittlement

To help decrease the impact of hydrogen embrittlement and to help with the transition to a hydrogen-based infrastructure many companies are blending hydrogen with natural gas in natural gas pipelines. Hydrogen blending entails injecting hydrogen into the existing natural gas infrastructure creating a blending of both hydrogen and natural gas and is primarily done with a small percentage of hydrogen. Figure 5.8 shows the blending rates, also known as blend walls, that countries are using for hydrogen. The highest percentage of hydrogen blending that is being practiced is 20%. When hydrogen blending surpasses a 20% blend the combustion properties begin to change, the color of the flame becomes more translucent, and the energy density begins to decrease.

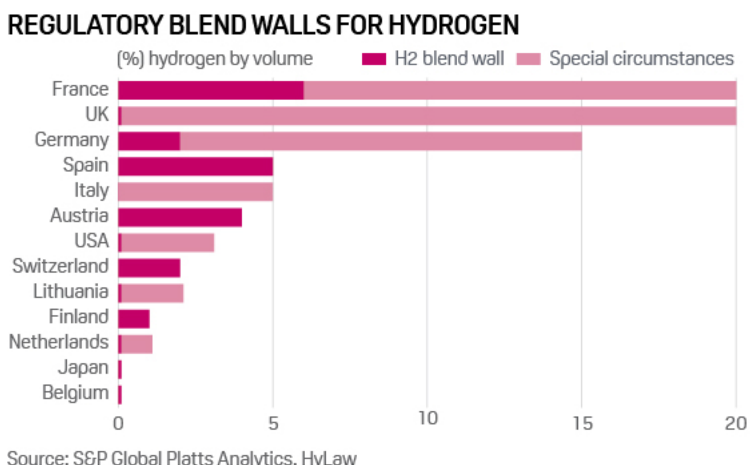


Figure 5.8 Hydrogen Blending by Country [McDonald, 2021]

Gas emissions via leaks in pipelines and other distribution equipment are also important when assessing the GHG emissions of the carrier fuel, whether it is methane or hydrogen [Abel, 2021]. Leaks are emitted via permeation through the pipe wall or through joints, fittings, and threads (see Figure 5.9). For steel and ductile iron pipes, leakage mainly occurs through threads or mechanical joints and the volume leakage rate for hydrogen is about a factor of three higher than that for natural gas. For plastic pipes, permeation accounts for the majority of gas losses and are estimated to be about 4 to 5 times faster than for methane [Melaina, et al., 2013]. However, the leak rate depends on the blend percentage, pressure, and other factors. For example, in one study of a Dutch pipeline system, the experimentally estimated gas leakage rate was 0.0005% with a 17%

hydrogen blend and considered to be insignificant [Haines, at al., 2003]. Because hydrogen is a smaller molecule than methane, hydrogen was thought to permeate through plastic pipelines more readily than methane, however, recent research has shown those leak rates are similar.

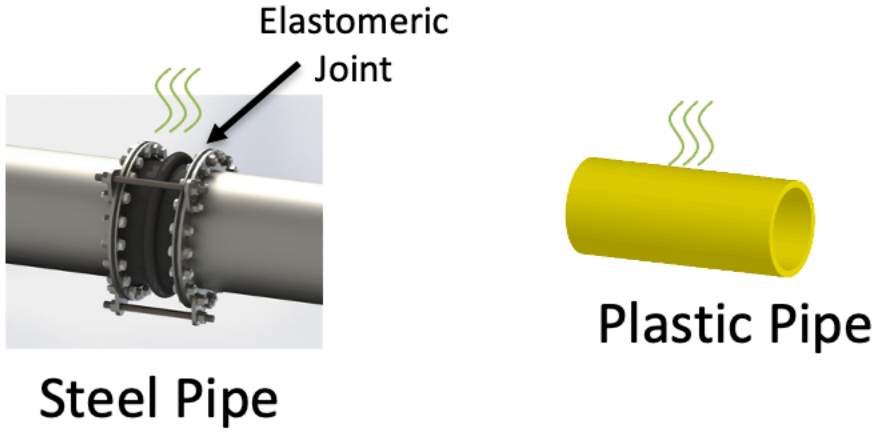


Figure 5.9 Pipeline Leakage

Additionally, an application of a copper- based epoxy to thinly coat the steel pipe has been shown to successfully contain all hydrogen gas blends, and threaded pipe fittings to prevent hydrogen leaks [Mejia, et al., 2020]. Another study calculated that the yearly loss of hydrogen by leakage through polyethylene pipelines amount to approximately 0.0005–0.001 percent of the total transported volume [Klopffer, et al., 2015; Wassenaar, Micic, 2020]. One of the recommendations of a study performed by the Columbia University – Center on Global Energy Policy was to change the regulations on methane leak detection and repair the existing pipeline to be as low emission as possible, as well as accelerate the pace of cast-iron pipeline replacement [Blanton, et al., 2021]. These recommendations and others within their study are applicable to the Commonwealth of Massachusetts.

The benefits of blending hydrogen with natural gas include a reduction in carbon emissions, diversification of energy, and provides a method of delivering pure hydrogen. In 2020 the US produced about 1.7 billion metric tons of carbon dioxide from natural gas alone, contributing to 36% of the total carbon emissions in the US [EIA, 2021a]. If a 5% blend of hydrogen was implemented then there would be a reduction of 1.5% in CO_2 emissions, which is equivalent to a reduction of 25.5 million tons of carbon dioxide [Goldmeer, 2019]. By increasing the blend of hydrogen then more significant reductions in emissions can be made, especially in areas that are otherwise hard to do so. Implementing hydrogen blending will allow for the diversification of renewables without requiring a significant change for the end user, especially when compared to switching to fully electric. If larger reductions in carbon emissions are necessary and pure hydrogen is desired it is possible to extract hydrogen from a natural gas blend, with an additional $0.3-$1.3 cost per kg of hydrogen for a 10% blend [Melaina, et al., 2013]. This method would be desired for cast iron and steel pipes that are not suitable for delivering pure hydrogen due to embrittlement.

5.2.2. Trucks and Ships

Other than pipelines, hydrogen can be transported via trucks and ships. These methods can be more costly due to the specific pressure and temperature hydrogen has to be stored at. However, to develop a hydrogen infrastructure it is important to diversify because the needs and resources of the end user will vary depending on region and market. Trucks and ships can also reach a wide range of consumers who may not otherwise be reached through pipelines.

Trucks are able to transport both compressed gas hydrogen and liquid hydrogen. Compressed hydrogen is usually transported in small quantities, approximately 1,100 kg of gaseous hydrogen, on trucks known as tube trucks. Tube trucks contain several pressurized gas cylinders that are bundled together, seen in Figure 5.10. These trucks must still must pressurize hydrogen to 200-500 bar, however there is a pressure limit of 250 bar imposed by the U.S. Department of Transportation (DOT). There have been exemptions granted by DOT to allow for higher pressures of 500 bar to be transported [DOE, 2021g]. Tube trucks are commonly used to transport hydrogen to hydrogen fueling stations.

Figure 5.10 Tube Truck [DOE, 2021g]

Transporting large amounts of hydrogen is primarily done in liquid form and by a liquid tanker truck shown in Figure 5.11. An average liquid hydrogen truck can transport about 3,500 kg of hydrogen, which is over three times the amount a gas hydrogen truck can transport. Liquid hydrogen is usually used for high demand volume with the absence of a pipeline due to the high investment cost needed to keep the hydrogen below -252.8°C. After liquid hydrogen is transported, it is then vaporized to a high-pressure gaseous product and used as a fuel source.

Figure 5.11 Liquid Tanker Truck [DOE, 2021h]

Shipping hydrogen allows for countries to diversify their energy imports and meet low carbon standards. Similar to liquid natural gas, to ship hydrogen it first is sent to a marine terminal where it is converted to liquid hydrogen. Once hydrogen is liquefied it is then loaded on to insulated tanker ships. Based off of the current liquid natural gas tanker ships capacity a hydrogen tanker ship would hold approximately 12,750,00-18,400,000 kg of hydrogen [McDonald, 2021]. The tanker ship will then finish its journey at another marine terminal where the liquid hydrogen can be loaded onto trucks for transport.

An area of concern when transporting hydrogen via shipping is insulation. During transportation hydrogen will not be able to stay perfectly insulated and will evaporate producing a gas that is referred to as boil-off gas (BOG). Liquid natural gas tanker ships also experience BOG and lose about 2% of their cargo on an average journey (approximately 11 days) and it is expected that liquid hydrogen will have the same losses [McDonald, 2021]. To help avoid BOG and a loss of profit a portion of the BOG can be utilized for propulsion, however tanker ships will need to be equipped to use hydrogen as a fuel source.

5.3 Limitations of Existing Battery Energy Storage Approaches

There are significant long-term challenges for massive adoption of lithium-ion battery as the dominating energy storage technique for both the transportation and stationary sectors.

5.3.1 Lithium deficit after 2050

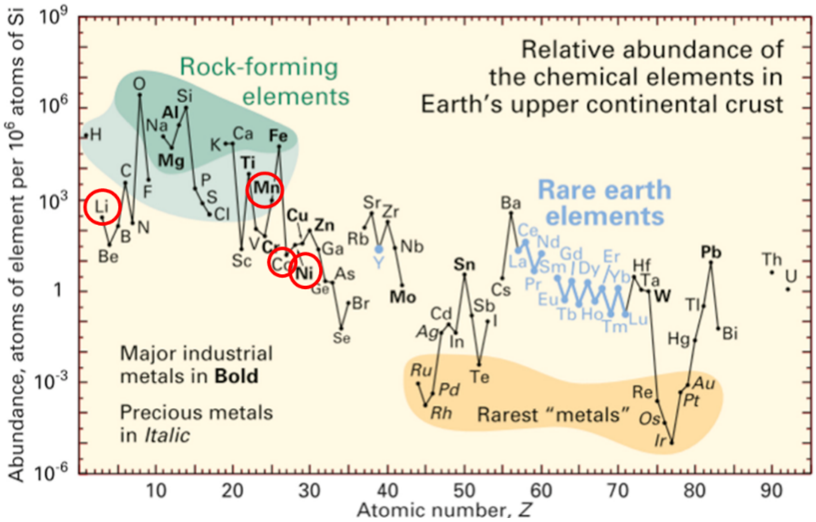


Figure 5.12 Relative abundance (verse Silicon) of the chemical elements in earth's upper continental crust (Li, Mn, Co, and Ni highlighted in the red circles are extensively used in lithium-ion batteries)

The forthcoming global energy transition to renewable power generation technologies requires a rapid expanding of lithium-ion batteries production for the transportation and stationary energy storage sectors. Considering the outstanding dimension of quantities required, questions of resource availability receive increasing attention. Amongst others for rare-earth metals (Ni, Mn, Co), one most-used element is lithium (Li), as shown in Figure 5.12. Because of its high chemical reactivity, lithium has no elemental occurrence in nature, but can be mainly found in ionic compounds like oxides or chlorides. These are enriched either in ores as minerals or in salt solutions as brines. Due to the poor maturity of extraction techniques and expensive production costs, seawater extraction is not expected in the near future.

The latest data from the United States Geological Survey indicate total resources of 80 million tons (Mt) of Li resources [USGS, 2020]. However, an in-depth literature review reveals the subjective, non-transparent and imprecisely defined character of resource estimation. Figures ranging from 30 to 95 Mt Li differ by more than a factor of three in the literature. Germany scientist Dr. Solomon and his colleagues recently published a study on Nature Communication [Greim, et al., 2020]. They used four scenarios covering one low (26 Mt), one medium (41 Mt), one high (56 Mt) and one very high (73 Mt) resource value of lithium. The lowest number covers the range of proven reserves and describes a worst-case situation. The next two higher assessments assume the potential extractable mineral deposits. The very-high reserve covers the range of some very high, but due to missing rationale, rather unrealistic estimates. With the current low lithium production capacity of 0.18Mt/year, we are still extracting the cheapest lithium. As we ramp up the production capacity, more expensive deposit must be exploited to meet the demand in the next couple of decades.

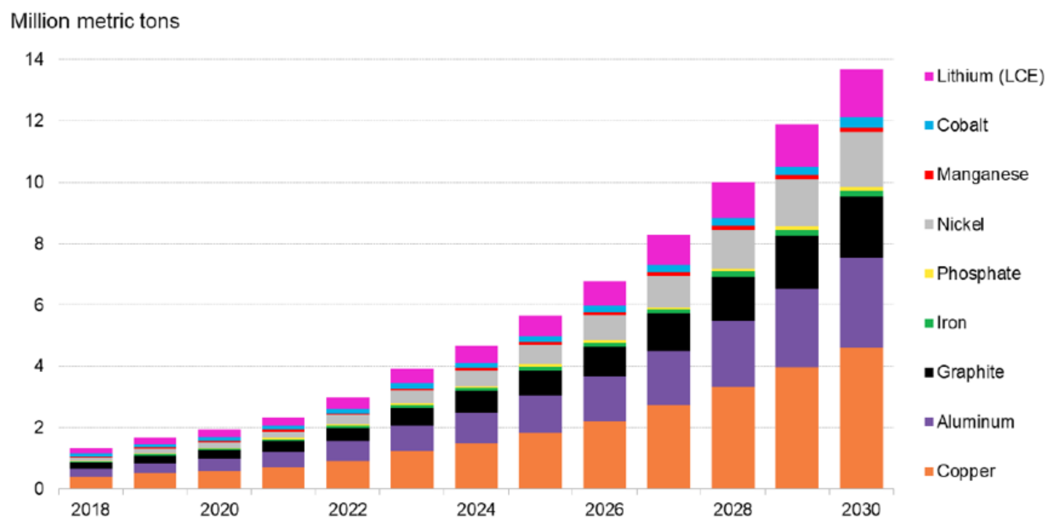


Figure 5.13 Annual Lithium-ion battery metal demand at the mine reported [Bloombeg Law, 2021]

BloombergNEF projects global demand for lithium-ion batteries will climb to 2,045GWh by 2030 as electric vehicle sales dramatically accelerate [Bloombeg Law, 2021]. This would mark a 954% increase over current demand as measured in gigawatt-hours. According to National Renewable Energy Laboratory (NREL), grid-scale U.S. storage capacity will grow fivefold by 2050 with 1040GWh of lithium-ion batteries [NREL, 2021]. With the rapid growth of lithium-ion battery demands, it will consume 1.5 million metric tons of lithium, 1.5 million metric tons of Nickel, and 0.2 million metric tons of cobalt annually, based on BloombergNEF in Figure 5.13. According to the International Energy Agency, in order to achieve the Paris climate goals, by 2040 lithium will need to be consumed at a rate 42 times higher than current levels [Bader, 2021].

Combining 8 demand related variations with 4 supply conditions, Dr. Solomon and his colleagues explored 18 scenarios in Figure 5.14. For the Best Policy Scenario with aggressive BEV adoption, which is BPS3bLDV under Figure 5.14, and is similar to the proposed Massachusetts decarbonization roadmap, the observed good balance of Li demand and supply extends to about 2050. After 2050 the market started to experience a large deficit that lasts for the remaining half of the century. The inflow of virgin material and the increase in recycling is not sufficient to supply the important transition years for most part of the second half of the century. The deficit moves from 2054 to 2077 for the current policy scenario with conservative electric vehicle demand target, shown under demand scenario CPS 2b LDV.

The result clearly shows that scenarios that can conform to the stated climate target and improved transport equity will result in serious Li supply deficits over the next century. On the contrary, low demand scenarios, such as the CPS 2b LDV or lower, achieve a balanced Li supply and demand throughout the century. However, such scenarios compromise the climate change target of reaching net zero by 2050. It also shows that Li availability will become a serious threat to the long-term sustainability of the transport sector unless a mix of measures is taken to ameliorate the challenge.

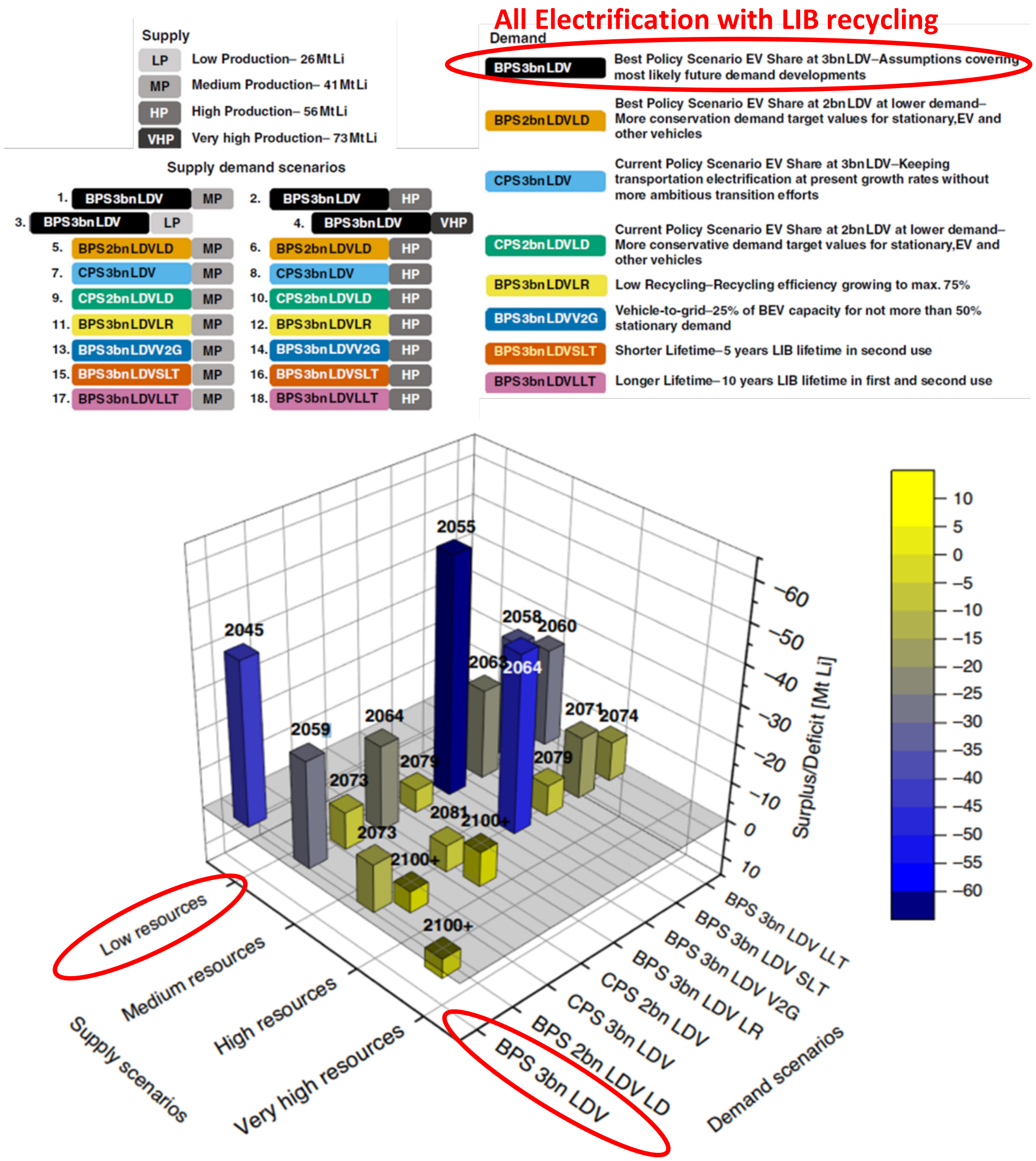


Figure 5.14 Availability of Lithium by the year 2100 [Greim, et al., 2020]

To illustrate the lithium deficit, Figure 5.15 shows the hypothetical material flow using the best policy scenario with aggressive battery electric vehicle adoption (BPS3bLDV) to understand the process for the year of 2100. The required 68.03Mt of Li is hypothetically available but only under the very-high resource scenario which was found to not be a reasonable scenario for the near future. With a base global reserve of 51.29Mt (high resources scenario), 16.74Mt of lithium (deficit) is leaving the system and is lost due to collection rate and recycling efficiency which is less than unity. At medium resources, Li deposits are already depleted in 2055. Even with the very high resources scenario, the start of the lithium deficit will be slightly delayed to the next century.

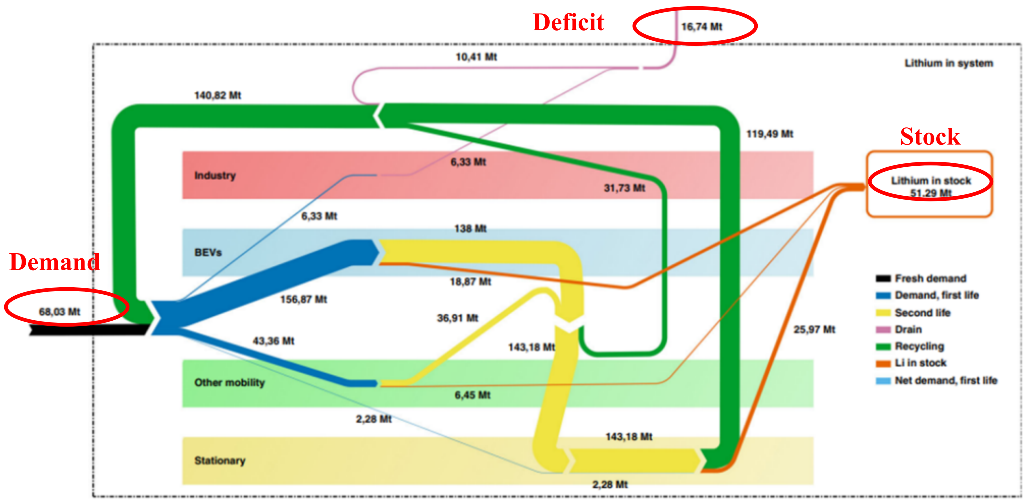


Figure 5.15 Lithium flow until the year 2100

In summary, present production trends shows that in the short term, supply and demand is well balanced but the long-term sustainability of the transport sector is at risk. At present, a concern on climate actions dominates discussions; however, it is equally important to address policy gaps in order to address the embedded long-term risk of sustainable transport sector pathways.

5.3.2. Long-term Grid-Scale Stationary Energy Storage

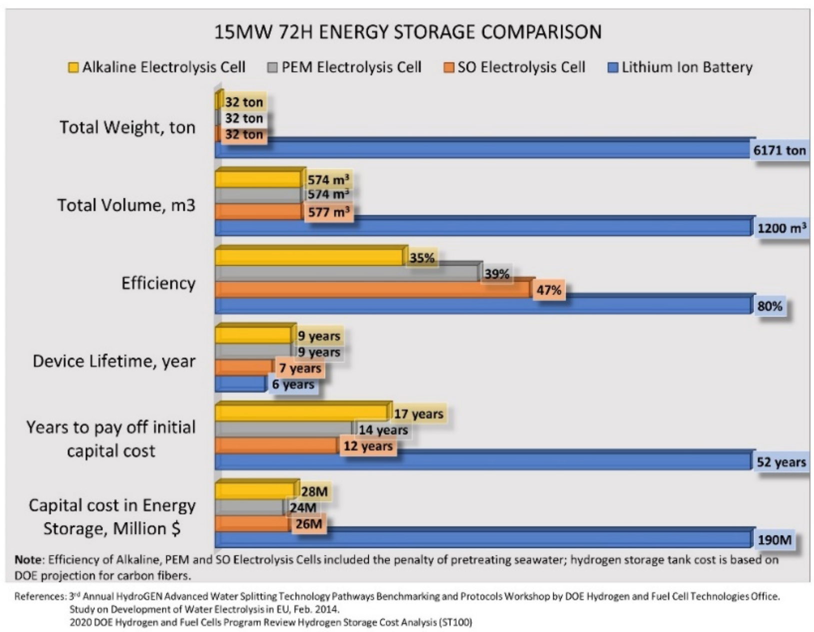


Figure 5.16 Techno-Economic Analysis comparing LIB energy storage to the hydrogen storage approach for a 15MW turbine and 3 days energy storage solution

From a techno-economic cost analysis (conducted at UMass Lowell) comparing energy storage using lithium-ion batteries (LIB) to the hydrogen solution (Figure 5.16), it indicates that for longer duration storage with a 15MW wind turbine power system for 3 days (72 hours), hydrogen solution is much more beneficial in terms of weight (1/193 times), volume (1/2 times), lifetime (3 times) and capital cost (1/7 times). Because of the current focus of electrifying the transportation sector, not much attention has been focused on the long-term storage from the policy makers.

There is a common misunderstanding about the efficiency of those two technologies. As shown in the 'Net-Zero America' study published by Princeton University [Princeton, 2020] the authors claimed a round-trio efficiency of lithium-ion batteries of 81%, which almost doubles that of hydrogen technology of 49%. However, the authors neglected that 81% is the efficiency of fresh batteries and their performance will degrade by 80% after 300-500 cycles. When these batteries are used for stationary energy storage and need to last several decades, their state of health will decrease nonlinearly (including capacity fade and increase in internal resistance) [Kendall, Ambrose, 2020; Bazant, et al., 2021]. After that, the batteries are designed to retire and will be used as second-life batteries with a much lower efficiency, faster degradation rate, and higher possibility of thermal runaway events. Because of the complexity of the composite and porous structure of the micrometer-thin electrode design of the lithium-ion batteries, it is extremely difficult to recycle. Those factors could significantly accelerate the start of the deficit of lithium-ion battery material flow cycle. On the other side, the current degradation rate of electrolyzers is 2%/year and DOE target for 2030 is 0.5%/year, which elongates the stack lifetime beyond 20-40 years. Therefore, if a threshold capital investment could be achieved, hydrogen becomes very economic competitive to serve as the energy storage pathway to achieve net-zero emission.

Until now, the energy storage demand is projected to be driven by transportation sector. However, to transition to all or high percentage of renewable power generation system, grid-scale energy storage will play an important role to maintain the reliability and resilience of the power system. According to the ISO New England (ISNE) electricity generation by energy source in 2019 shown in Figure 5.17, the wind power will fluctuate by 74% hourly, 59% daily, 33% weekly, and 25% monthly. There is a lack of understanding in the Massachusetts decarbonization roadmap [MA Office of Energy, 2020], with almost 80% of wind and solar integration into the grid till 2050, but an unknown percentage of energy is needed for grid-scale storage and reliability in addition to massive battery electric vehicle adoption. A mix of energy storage options could tackle the challenge and hydrogen will become a unique solution with its intrinsic zero emission characteristic.

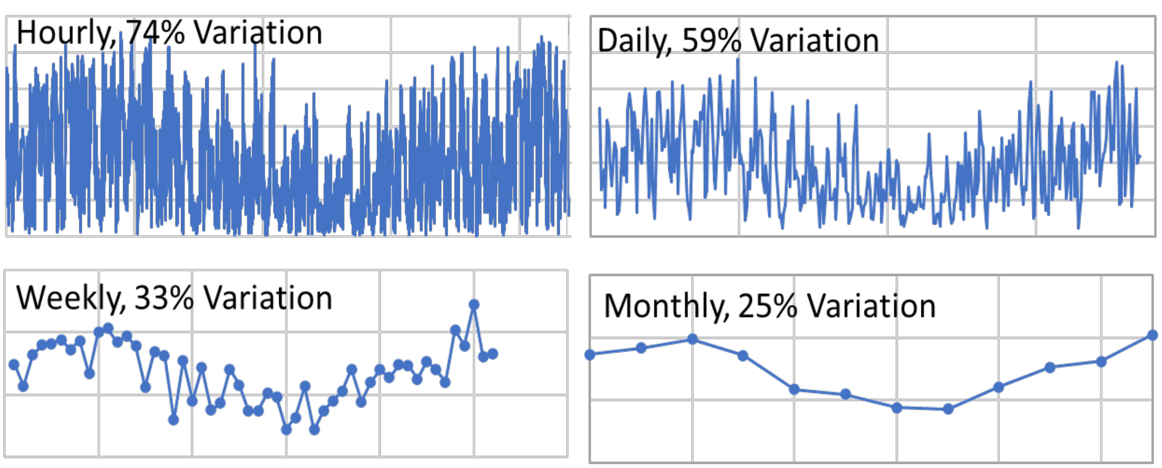


Figure 5.17 2019 Wind power generation with different duration in New England

The use of hydrogen can be an effective method for storing large amounts of energy for long periods of time (e.g., days or weeks) either as a gas, liquid, or in the form of ammonia. When coupled with fuel cells or gas turbine engines, hydrogen energy storage systems can be used to provide a reliable backup energy source to address intermittency and ensure the energy grid is resilient to disruption. Based on a preliminary techno- economic analysis conducted at UMass Lowell, which compared energy storage using lithium-ion batteries to a hydrogen storage/fuel cell system, the results indicate that for long-duration energy storage, hydrogen is more viable in terms of weight (1/193 times), volume (1/2 times), lifetime (3 times), and capital cost (1/7 times) than lithium-ion batteries (see Figure 5.16). However, some hydrogen production challenges need to be overcome due to the high costs of electrolyzers. Electrolyzer and fuel cell stack costs are still high due to limited production capability, small market share, and strict policy codes related to hydrogen generation and power-delivery devices. Furthermore, hydrogen storage and delivery capability with the existing infrastructure have not been demonstrated on a larger scale. If solutions to these challenges have been met, then hydrogen for energy storage will be able to meet cost targets and be cost competitive in the market. The overall near-term targets that have been set out by DOE are $2/kg for hydrogen production and $2/kg for delivery and dispensing for transportation applications [Satyapal, 2021]. Additional research needs to be performed in the following areas to decrease the cost and expand the hydrogen energy storage market: (1) technologies to reduce cost as well as to improve performance and reliability of fuel cell stacks and of storage and delivery methods; (2) harmonize codes and standards to address safety concerns; and (3) establish and safeguard a global supply chain and market, as well as workforce development.

Appendix 6. Applications

A hydrogen-integrated economy relies on a diverse range of applications that utilize hydrogen. These applications include energy storage, thermal heating, industrial processes (e.g., manufacture of polymers, methanol), transportation, electricity production, synthesis of synthetic fuels, upgrading oil, and ammonia/fertilizer production. If successfully implemented, each application is likely to provide measurable benefits in meeting the carbon emission targets, including net-zero emissions by 2050, for Massachusetts [Lenton, 2021]. As well as achieving sector coupling with hydrogen energy allows for an increased integration of energy end-use and multiple supply sectors and increased efficiency and flexibility of a hydrogen economy [Travers, 2021; He, et al., 2021; Nuffel, 2018]. However, successful implementation will need to overcome widespread adoption challenges, including safety concerns, to ensure the Commonwealth has a robust energy and economic infrastructure (see Figure 6.1).

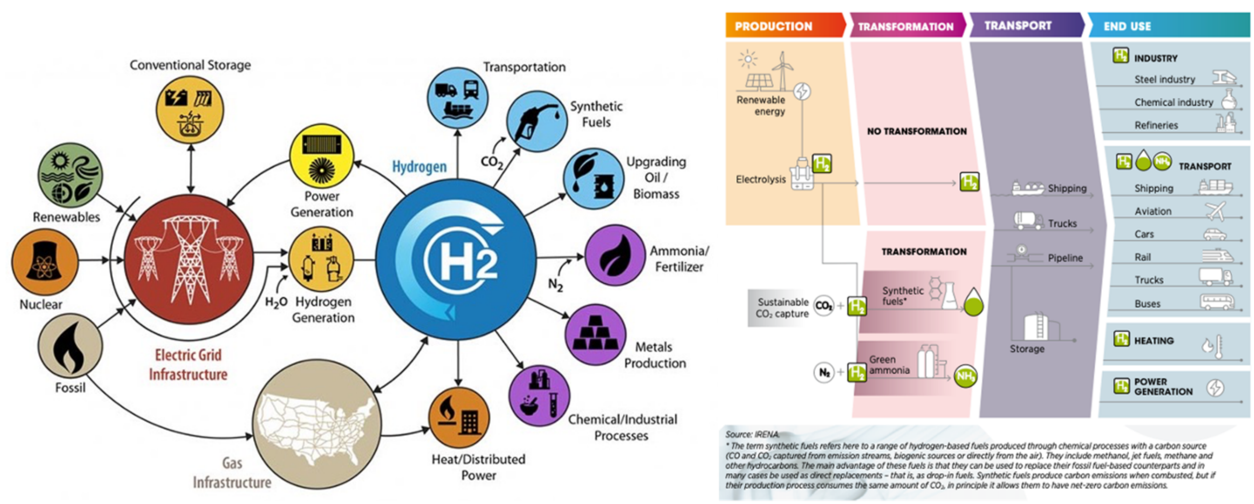


Figure 6.1 Applications of Hydrogen Energy [NREL, 2020; Chugh, Tailbi, 2021]

6.1. Thermal Heating

The thermal heating sector includes all home and commercial business, excluding agricultural and industrial activities. Implementing hydrogen into the thermal heating sector can provide opportunities to complement electrification by meeting energy demands during peak periods and periods of intermittent renewable energy production, thereby increasing resiliency. Currently, 52.3% of Massachusetts homeowners use a natural gas system for heating [EIA, 2021b] and to meet the Commonwealth's zero-emission goals, most if not all of these natural gas homeowners would need to switch to either an all-electric system (e.g., heat pumps and resistive heating), decarbonized gas, a network geothermal system, or apply some other possible new technology such as carbon capture at a customer site. This switch will be costly and cause pushback by consumers especially for the sector of the population who are economically disadvantaged. Gas companies would also need to either repurpose or abandon the existing pipeline infrastructure. However, if increasing percentages of natural gas can be displaced by hydrogen, end-users could potentially keep their existing appliances (with some modifications or retrofits depending on the blend fraction) while also enabling the state to meet its zero-emission goal.

There are challenges with hydrogen implementation for the thermal heating sector that do need to be overcome in order to be commercially mature. A wholesale shift to change to a 100% pure hydrogen system, would require a significant investment in infrastructure and technology. A useful analogy is to think about gasoline and Diesel fuel. A vehicle operator cannot just simply put gasoline in a Diesel engine, or put Diesel in a gasoline vehicle. While they are both "fuels", their properties are different and so the hardware/technology must be designed appropriately to take advantage of the unique properties. The same can be said for hydrogen versus natural gas. While they are both fuels, they are not the same, and thus cannot be treated the same. However, much of the existing research on residential and industrial appliances has shown that low blend levels of hydrogen (i.e., less than 20%) can be tolerated without a significant change in performance. Because hydrogen has a lower volumetric energy density than methane, volumetric blending of hydrogen with methane does not provide a linear reduction of carbon emissions per unit energy. For example, if methane is blended with hydrogen at 5%, 20%, or 75% by volume, the carbon emission reductions per unit energy of the blended gas will be approximately 1.5%, 6%, and 50%, respectively [Goldmeer, 2019] (see Appendix 4.3). Another potential challenge with using hydrogen in the thermal heating sector is hydrogen embrittlement of cast iron pipes and a lack of information and research done on how high blends and pure hydrogen in a natural gas system will affect the end-user's appliances. Massachusetts has approximately 21,000 miles of main pipelines used for the transportation of natural gas from meter stations throughout the distribution system [Mass.gov, 2021]. The materials for main pipelines in Massachusetts vary depending on location and the distribution company and are made of either cast iron, steel, or a polyethylene plastic. There are approximately 7,928 miles of steel pipelines, 11,016 miles of plastic pipelines, and 2,809 miles of cast iron pipelines.

Depending on the pipeline's material, using hydrogen in either a pure form or a blend may cause embrittlement in pipelines. Polyethylene and lower-strength thicker wall steel pipelines are most compatible with hydrogen and have shown to be successful in large-scale pilot projects as well as with low blend ratios. Other forms of steel pipelines are still being studied in national laboratories and individual companies. Cast iron (commonly found in distribution systems in Massachusetts and the Northeast) has been shown to be unsuitable for hydrogen [Blanton, et al. 2021].

In residential units it is common to see the use of gas-powered furnaces, water heaters, ovens, and stoves. However, with the demand to lower carbon emissions, these natural gas appliances may have to be replaced. The alternative for using gas appliances in residential units are heat pumps and electric appliances. Many homeowners have stressed that they do not want to switch to an all-electric system due to potential cost increase for replacing old appliances. Hydrogen can be a possible solution in which homeowners would not need to replace appliances while also meeting lower carbon emission goals.

Projects have been announced to test the safety and viability of hydrogen for residential use, with some projects being mature enough that they are already testing in everyday households. More than 650 households and commercial properties in England have started on a hydrogen trial to blend green hydrogen for heating [Mace, 2021]. This project is led by Northern Gas Networks, as part of HyDeploy Northeast scheme to lower carbon emissions to zero. In Ontario, Canada natural gas distributor Enbridge has started implementing a 2% blend of hydrogen into their natural gas network [Sheridan, et al., 2021]. This blend of natural gas and hydrogen is transported to the end user via steel and polymer pipes and Enbridge has found that this blend percentage does not affect appliances and there could be a possibility to increase the blend percentage.

Several other studies have discussed a key issue with blending hydrogen and the modifications needed for the end user. The maximum blend level that does not adversely influence appliance operation or safety will vary depending on the type and age of the appliance. Acceptable blending levels for end-use systems range from 5%-20% hydrogen [Melaina, et al., 2013]. NREL's program NaturalHy studied blending rates of hydrogen and found that the maximum hydrogen blend percentage that can be used without fully replacing appliances was up to 28.4% [Issaac, 2019].

A comparison of the different flames for a standard at home cooking burner was done by HyDeploy. Figure. 6.2a shows a 100% methane flame and Fig. 6.2b shows a 28.4% hydrogen blend flame, comparing the two flames there are no noticeable differences between the flame color or size. The temperature of the 28.4% hydrogen blend flame was also examined, and it remained within acceptable limits for gas appliances [HyDeploy, 2021a]. There were variations in the temperature of the flame due to the fuel composition but at no point did the temperature result in overheating of the appliance or potential degradation.

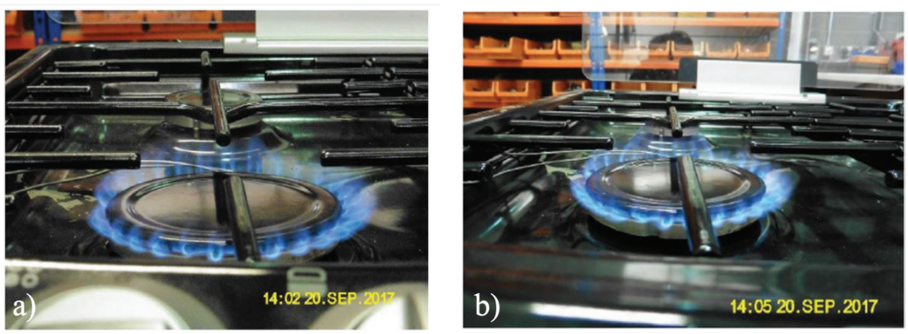


Figure 6.2 a) 100% Methane Flame b) 28.4% Hydrogen Blend Flame [Issaac, 2019]

Different blends of hydrogen, including up to a 28.4% hydrogen was also tested by HyDeploy on gas-boilers, heating plates, and heat exchangers. Gas-boilers testing focused on flue-gas analysis internal-temperature measurements and flame current. Each test performed on a gas-boiler was successful in achieving combustion and having a stable flame. Testing done on heating plates and heat exchangers showed variation in heating but not enough to cause incremental degradation or performance issues. As expected for these appliances the flame-ionization current reduced with the addition of hydrogen but the reduction did not compromise any safety function of the devices Issaac, 2019].

The long-term (more than 15 years) effects of hydrogen blending on materials and domestic appliances are still uncertain. Therefore, hydrogen blending must still be monitored regularly. For older and poorly adjusted appliances, hydrogen blending would not be acceptable due to safety risks. The life span for gas appliances is approximately 15 years when well-maintained, this means that the long-term effects may not be an issue for some appliances because they would already need to be replaced. When a gas appliance is being replaced, an appliance that is more suitable to operate with higher blends of hydrogen or even pure hydrogen can be installed. However, a challenge that the thermal sector will face in the future have companies to start modifying their appliances to handle higher blends of hydrogen.

6.2. Steel Production

Heavy industry which includes concrete and steel manufacturing is a large industry that produces about 23% of total greenhouse gas emissions [EPA, 2021a]. This industry faces challenges with decarbonization because of the processing methods used, making it difficult and almost impossible to integrate electricity. Hydrogen can be an alternative to the carbon intensive feedstocks used in manufacturing products like steel (see Figure 6.3).

Figure 6.3 Hydrogen Based Steel Manufacturing [Collins, 2020]

Today steel is manufactured by superheating coal to remove impurities, creating a material known as coke. Once coke is formed it is added into a blast furnace with iron ore and limestone, where air is blasted into the furnace at temperatures over 1000ºC. From this reaction Molten iron is generated at the bottom of the furnace while vast amounts of CO_2 emissions are released from the top. This reaction is shown in Eq. 6.1, where carbon monoxide from the coke reacts with iron ore to produce molten iron and carbon dioxide. For every ton of molten iron produced about 2 tons of CO_2 is emitted [Portha, et al., 2021].

$$Fe_2 + 3CO \rightarrow 2Fe + 3CO_2 \tag{6.1}$$

Hydrogen used in steel manufacturing replaces the need for coke, reducing drastically CO_2 emissions. This process heats up iron ore and hydrogen to about 800ºC. The byproduct of this process is water and a type of iron known as "sponge iron". The chemical equation for this reaction is shown in Eq. 6.2. Sponge iron, also known as direct reduced iron, is iron produced from the direct reduction of iron ore. The sponge iron is then used in an electric arc furnace where it will react with carbon and lime to reduce impurities and produce steel. When compared with coke reduction for steel manufacturing, hydrogen steel produced only 2.8% of CO_2 emissions that coke reduction produces, which is approximately 0.056 tons of CO_2 for every ton of iron produced [Vogl, et al., 2018].

$$Fe_2O_3 + 3H_2 \rightarrow 2Fe + 3H_2O \tag{6.2}$$

Currently, green hydrogen is more expensive for a given amount of energy compared to fossil fuels and there are no significant policies or incentives motivating companies to transition away from using fossil fuels. However, hydrogen steel manufacturing does have the potential to be cost competitive with coke reduction steel manufacturing. To be cost competitive a carbon tax would need to be in place. Estimates have shown that a steel carbon tax would range from a low end of \$40/ton of CO_2 and a high end of \$80/ton of CO_2 [Vogl, et al., 2018]. This wide range in carbon tax is due to variations with steel manufacturing plants, making it difficult to provide an exact price. Steel manufacturing is one of the highest producers of carbon emissions, producing about 8% of global emissions [IEA, 2020a]. By making hydrogen steel manufacturing cost competitive it allows for a large reduction in emissions that causes modifications to only one industry sector. At the federal level there is a bill that has been introduced (not passed), the Clean H2 Production Act, that would create production tax credits and investment tax credits for hydrogen [Congress.gov, 2021]

6.3. Automotive

The transportation sector generates the largest share of greenhouse gas emissions within Massachusetts (see Figure 6.4), consumes 32.6% of Massachusetts energy by end-use (see Figure 6.5), and represents a sizable opportunity for hydrogen utilization through fuel cell electric powertrains and traditional internal combustion engines.The transportation sector is composed of different applications including passenger vehicles, trucks, ships, and airplanes. Opportunities that hydrogen can bring to the transportation sector include fast refueling compared to battery electric vehicles (BEVs), zero nitrogen oxides (NOx) emissions (if used in fuel cell vehicles), a long-range driving alternative to BEVs, longer storage duration, and avoidance of CO2 emissions. Due to hydrogen's high energy density, it allows for more energy to be stored per kilogram than other energy storage methods, including electric batteries.

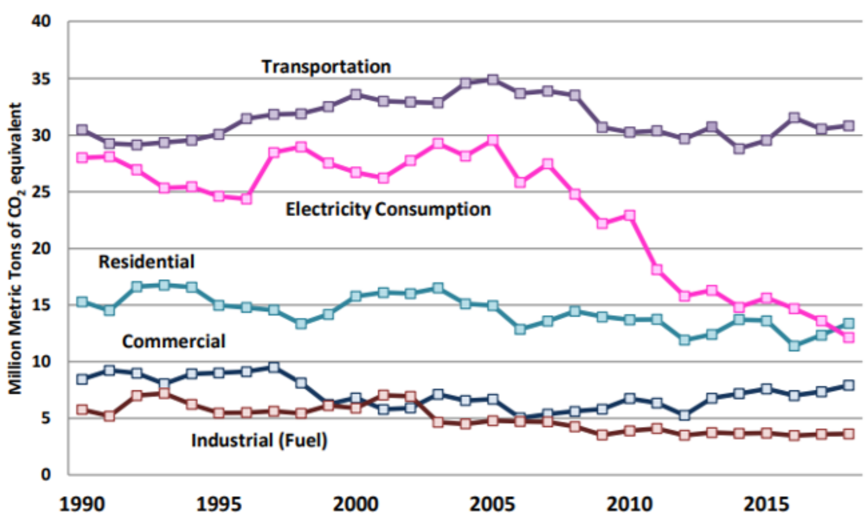


Figure 6.4 Massachusetts 1990-2018 Fuel Combustion GHG Emissions by Sector [MassDEP]

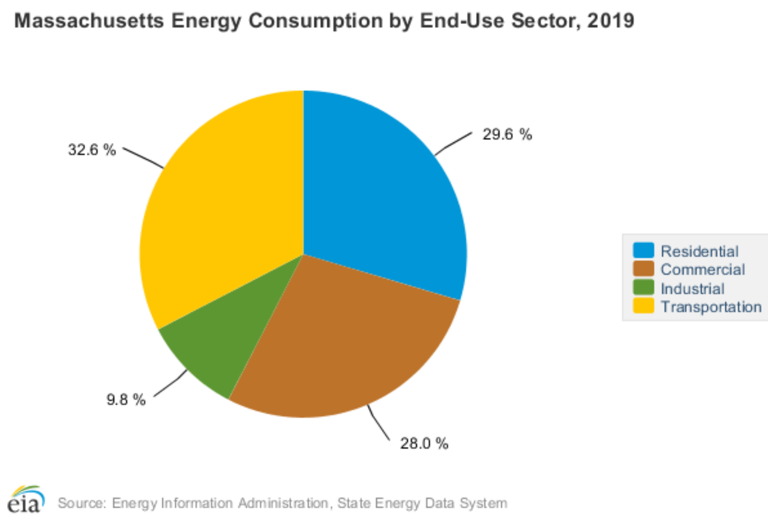


Figure 6.5 Massachusetts Energy Consumption 2019 [EIA, 2021c]

The challenges in the transportation sector that hinder the adoption of hydrogen are the lack of infrastructure for refueling stations in Massachusetts and regulations that restrict the operation of hydrogen vehicles on some roadways (particularly tunnels). There are currently zero operating public hydrogen refueling stations and only two private hydrogen refueling stations in Massachusetts. When compared to electric charging stations, there is a drastic difference as significant expansion has been made in the last decade and there are 4,090 public and 299 private electric charging stations in Massachusetts [AFDC, 2021] (see Figure 6.6). Currently, hydrogen fuel purchases for new automobiles are subsidized by the auto manufacturers (e.g., Toyota Motor Corp.) by providing free hydrogen fill-ups, up to $15,000 for new automobile purchases. The limited network of hydrogen fueling stations in Massachusetts hinders the driving range for hydrogen-powered vehicles, preventing market penetration and causing relatively-high prices due to a lack of economy of scale.

Figure 6.6 Commercially Available Hydrogen Powered Automobile [Gardner, 2021; LaFleur, et al., 2017]

Electric vehicles have gained a large popularity in the recent years, with approximately 7.2 million electric vehicles in use [IEA, 2020b]. However, there are weaknesses related to this technology that limits the growth of electric vehicles. This includes short driving range, long charging time, high investment costs, and limited infrastructure when compared to gas-powered vehicles. Most challenges with electric vehicles are centered around the battery that possesses a limited driving range. If a larger capacity is necessary then a larger battery would be used, leading to an increase weight of the vehicle and consequently a decrease in efficiency. Fuel cell vehicles are able to overcome the challenges that electric vehicles have due to hydrogen's high energy density. With respect to driving range, fuel cell vehicles are comparable to conventional gasoline vehicles, with a range between 400 to 550 km (250 to 340 miles) per tank, as well as a 3 to 5 min refueling time [Ajanovic, Haas, 2020].

In cold weather environments, as in Massachusetts' winters, battery operated vehicles face a reduction in driving range. Several studies have reported that the average driving range for battery electric vehicles decreases by 41% depending on the temperature and driving conditions [Olsen, 2019; AAA, 2019; Delos Reyes, et al., 2016]. A Norwegian study tested common battery electric vehicles and their driving range in cold climates and found that there was an average decrease of 18.5% in driving range and vehicles took between 27 and 60 minutes to achieve an 80% charge under rapid charging conditions [Veihjelp, 2020]. In contrast, a hydrogen automobile can be refueled in approximately 3 minutes and its driving range is not greatly affected by cold temperature operation (see Figure 6.7).

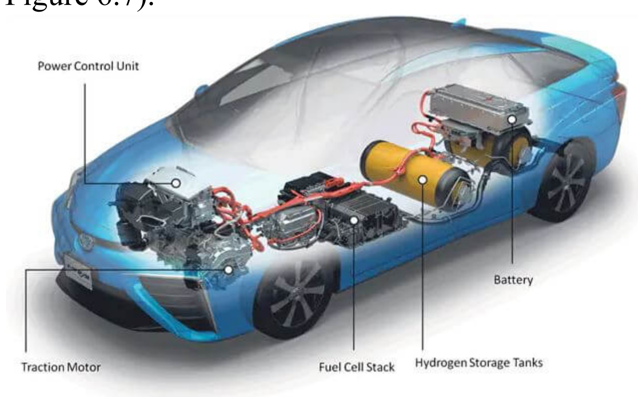


Figure 6.7 Internal Working of a Typical Fuel Cell Vehicle [Spiegel, 2019]

As of 2019 there is approximately 13,000 fuel cell vehicles in use, most of which are used in the USA, Japan, and China, and is shown in Figure 6.8 [Ajanovic, Haas, 2020]. This number is projected to rise with the addition of large-scale production of fuel cells but is still limited to the number of hydrogen refueling stations available to the public, as shown in Figure 6.9. Currently there are 48 retail stations of hydrogen available in the USA. However, all 48 stations are located in California. There are private hydrogen fueling stations across the USA that could be used as fuel stations but require pre-authorization from the station's provider.

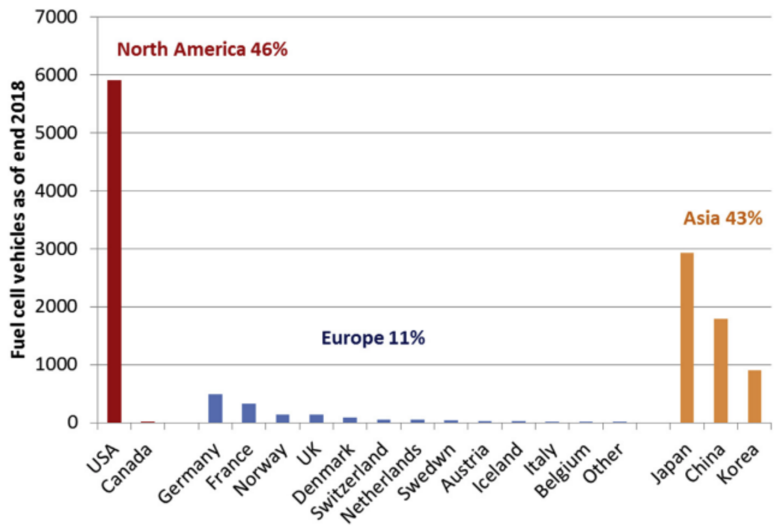


Figure 6.8 Fuel Cell Vehicles at the end of 2018 [Ajanovic, Haas, 2020]

Figure 6.9 Hydrogen Refueling stations as of 2021 [DOE, 2021i]

Car manufactures have already moved from prototypes of fuel cell vehicles to production. The most notable fuel cell vehicle on the market today is the Toyota Mirai, which is currently mass produced. There are still challenges in the capital cost of fuel cell vehicles that can be seen in Figure 6.10 when compared with gasoline or internal combustion engine vehicles. However, it is estimated that in the future the capital cost of fuel vehicles will decrease due to advances in manufacturing and the development of a hydrogen infrastructure. Internal combustion vehicles are also expected to have an increase in fuel cost caused by tax penalties associated with producing carbon emissions. These factors would make fuel cell vehicles cost competitive with internal combustion engine vehicles.

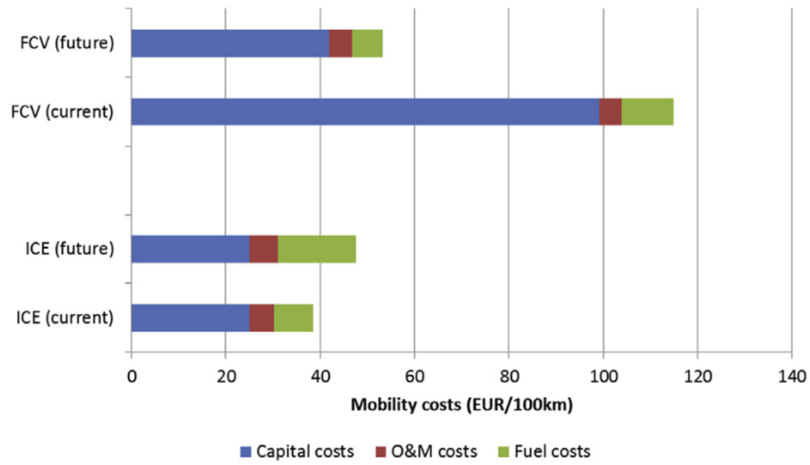


Figure 6.10 Costs of Fuel Cell Vehicles (FCV) Compared to Internal Combustion Engines (ICE) Vehicles [Ajanovic, Haas, 2020]

For a mid-sized city with 100,000 parking spaces and an average cost of $1,200 per electric charger, the cost to electrify would be approximately $120 million dollars, not including the wiring infrastructure cost required for electrical transmission. It is not likely feasible for the vehicle transportation sector to be carbon neutral by relying solely on electric vehicles that utilize chemical batteries because of (1) the technical limitations of lithium-ion batteries operating in cold environments, (2) the inability for all drivers to have vehicles connected to charging stations at their homes throughout the night, and (3) a lack of suitability of using batteries for the trucking, shipping, and aviation sectors. The path forward for increasing hydrogen in the transportation sector would be to increase the number of hydrogen fueling stations available to the public and address policies that hinder hydrogen transportation from further developing, such as restrictions for compressed hydrogen-powered vehicles traveling in tunnels in Massachusetts.

For heavy duty vehicles such as long-haul trucks and industrial vehicles, fuel cells are slowly being implemented. As previously stated, electric vehicles have a limited driving range due to its battery, making it inefficient for large scale vehicles and vehicles that are in operation for long periods of time. Worldwide there are currently 25,000 forklifts, 500 buses, 400 trucks, and 100 vans in use that are powered by hydrogen [Ajanovic, Haas, 2020]. Amazon has chosen to switch all electric forklifts to fuel cell forklifts manufactured by Plug power due to hydrogen benefits in driving range, as well as fast refueling times.

6.4 Synthetic Fuels

Synthetic fuels are hydrocarbon fuels that are produced by chemically combining hydrogen with carbon sources such as CO2 or biomass. Synthetic fuels can be created to emulate common fuels such as gasoline, diesel, methane, and kerosene (see Figure 6.11). The opportunities of using synthetic fuels over regular fuels is the use of CO2 (e.g., from atmospheric sequestration) in the manufacturing process and its compatibility with existing distribution systems, fueling stations, and conversion technologies without significant modifications to existing infrastructure or equipment (see Figure 6.12). By using CO2 to produce synthetic fuels, it prevents additional CO2 emissions in the atmosphere and helps in meeting net-zero emissions goals. For example, renewable or synthetic natural gas can be created by combining waste CO2 from anaerobic digesters or power plants in MA with green hydrogen in a process referred to as methanation

[Tsiotsias, et al., 2020]. Synthetic fuels can also be used in already existing refueling stations and combustion engines, which allow for a cost-effective transition to this carbon-neutral fuel.


Figure 6.11 Example of a Synthetic Fuel [Morris, 2021]

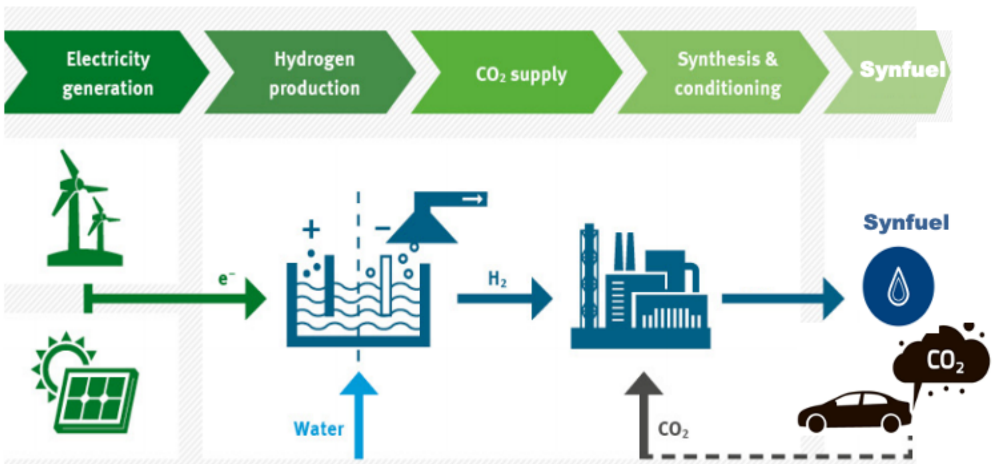


Figure 6.12 Synthetic Fuel Life Cycle

Massachusetts currently lacks existing infrastructure dedicated to producing synthetic fuels and the green hydrogen necessary to make these fuels carbon neutral. The processing facilities to produce synthetic fuels are currently expensive and there are only a few test plants in operation. Massachusetts currently has no test plants for synthetic fuels or a large-scale infrastructure of green hydrogen to produce synthetic fuels. Massachusetts is currently not a leader in the production of conventional fossil fuels. However, in the future, with an established large offshore wind resource, the low cost generated electricity could potentially position the Commonwealth to be an early mover or leader in production of economically viable synthetic fuels.

The path forward for Massachusetts to produce synthetic fuels would need to include more research to be done on the production of synthetic fuels as well as the development of a synthetic fuel infrastructure and market. Once more testing facilities have shown the benefits and challenges of synthetic fuels, then Massachusetts will be able to better assess if a synthetic fuel infrastructure would be beneficial for the Massachusetts economy. Before an economically viable carbon-neutral synthetic fuel infrastructure is developed, a large-scale green hydrogen facility would first need to be created.

6.5 Biomass

Biomass, including bio-oil and bio-gas can be used in steam reforming and water-gas shift processes to produce hydrogen. The opportunity with using biomass as a feedstock for hydrogen production is that biomass waste products are an available resource and can be used to sequester carbon dioxide from the atmosphere. It is estimated that up to 1 billion dry tons of sustainable biomass is available for energy generation use annually, which amounts to approximately 13-14 quadrillion Btu/ year (in 2030) [DOE, 2021i]. Biomass can also lead to an offset in carbon dioxide emissions because of the consumption of carbon dioxide in the production process of biomass (see Figure 6.13).

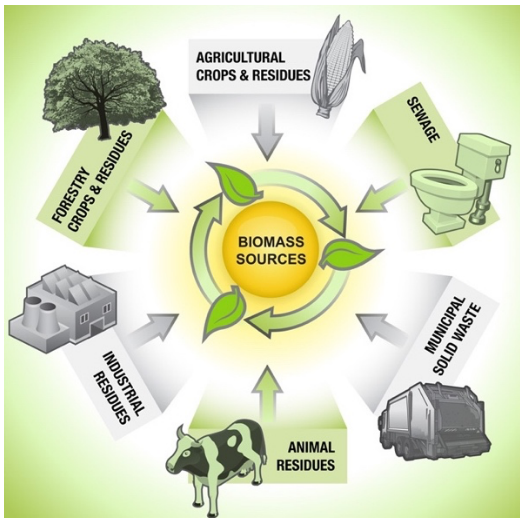


Figure 6.13 Sources of Biomass [Zafar, 2020]

Currently, there are no biomass production sites in Massachusetts that are used for hydrogen generation and therefore is not currently part of the Massachusetts economy. More research needs to be performed on the carbon offset and economic benefits for the Commonwealth. The challenges with reforming biomass include the cost of biomass-derived liquid, capital cost, and carbon emissions. Biomass-derived liquids are composed of larger molecules with more carbon atoms than natural gas and this makes them more difficult to separate and reform in the steam reforming process. Steam reforming processes for biomass have a high capital equipment cost as well as operation and maintenance cost. There are processes other than steam reforming that can produce hydrogen through biomass such as pyrolysis, but they are more costly and should be further researched and investigated before implementation.

6.6 Ammonia/Fertilizer

Hydrogen can be produced and stored in the form of ammonia (NH_3). The opportunity with ammonia for hydrogen storage is that it does constitutes a practical, low-cost storage alternative, not requiring high pressure or cryogenic temperatures. Ammonia can be liquified at a pressure of 10 bars and contained at a temperature of -33ºC. When compared to liquid hydrogen, liquefaction requires pressures of about 100 bars and containment at temperatures of -253ºC or lower. This significant decrease in pressure and temperature allows for a less energy-intensive method to store and transport hydrogen (see Figure 6.14). Ammonia is an inhibitor for hydrogen embrittlement, meaning that ammonia can be safely transported through existing iron and steel natural gas pipelines. Ammonia can also be used as a fertilizer, within the shipping industry, and as a green chemical, as shown in Figure 6.15.

Figure 6.14 Example of Liquid Ammonia Storage [Simon, Taylor, 2021]

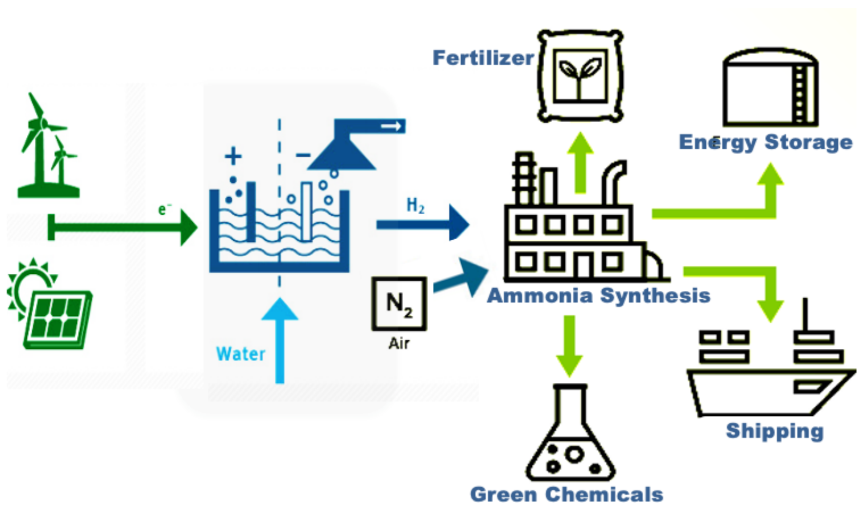


Figure 6.15 Lifecyle of Ammonia

The challenge with ammonia is the carbon-intensive processes currently used for its production. Today the common production of ammonia requires both the generation of hydrogen through steam methane reforming and nitrogen through air separation. Hydrogen and nitrogen are used as inputs to form ammonia in a catalyzed process at high temperature and pressure (i.e., the Haber-Bosch process). The use of green hydrogen in ammonia production is not currently economical. There still needs to be development in enhanced ammonia production before ammonia can be used at a large scale for green hydrogen storage or as an energy carrier. Currently, there are no ammonia or fertilizer production sites in Massachusetts and therefore it is not part of the state's economy. More research needs to be performed on the economic benefits of manufacturing ammonia or fertilizer and their carbon impact on the Commonwealth.

Appendix 7. Safety

Hydrogen energy has the potential to play an important role in lowering carbon emissions and meeting a carbon neutral economy within the next few decades, however, many people are concerned with hydrogen's safe use as a source of energy. Much of this fear and public sentiment has been driven by the famous Hindenburg airship disaster that was filled with hydrogen, caught fire, and was destroyed during its attempt to dock in 1937. However, hydrogen has been used safely in industry for past 40 years in a diversity of applications including rocket fuels, oil refineries, and fertilizer products. Standards development organizations have worked together to develop strict safety standards when handling hydrogen. Hydrogen does have safety issues that need to be considered, but when handled correctly it can be as safe if not safer than other conventional fuels such as gasoline or methane. The purpose of this appendix is to review the safety concerns that surround hydrogen, these include hydrogen combustion, storage and delivery standards, and implementing hydrogen in pipeline systems

7.1. Hydrogen Combustion

By nature, all fuel sources have some level of danger associated with them. It is important to reduce these levels of danger to prevent unwanted and dangerous situations from occurring. Combustion is the most prevalent cause of danger when producing energy but can easily be mitigated with a proper understanding of a fuel source's properties. By understanding fuel sources' properties, fuel systems can be designed appropriately, and guidelines can be put in place to allow for the safe handling of fuels such as hydrogen.

Like many gasses, hydrogen is a colorless and odorless gas making it difficult to detect if a leak has occurred and when combusted hydrogen gives off a faint blue flame (see Figure 7.1). Direct coloring agents may not be possible to add to hydrogen at this time but possible in the near future. Odorants can be added as a safety precaution to provide a smell for hydrogen in case of a gas leak [HyDeploy, 2021b]. Sensors can also be installed to allow for fast and efficient detection of leaks without having to worry about seeing or smelling hydrogen. Other safety concerns regarding hydrogen include the wide ignition range of air concentrations from 4-74% [Carcassi, Fineschi, 2005] and the low energy ignition required (0.019 mJ) [Kumamoto, et al., 2011] making hydrogen more likely to ignite in a wider range of scenarios than other combustible gases (e.g., natural gas). When stored in tanks or equipment, hydrogen is a safe fuel source and cannot be combusted unless there is a failure in the storage system. Safety codes and standards are put into place to minimize safety concerns and ensure the proper handling of hydrogen. Testing methods are also used to ensure the rigidity and verify the lifespan of these storage methods.

Figure 7.1 Hydrogen Flame [Issaac, 2019]

A common concern when combusting hydrogen is its production of nitrogen oxide. Nitrogen oxide, also known as NOx, is a chemical compound that is formed when nitrogen and oxygen are combusted at high temperatures. When inhaled NOx can cause serious health damages, including respiratory diseases. NOx also causes environmental issues such as smog and acid raid. Because of these health and environmental issues NOx is highly regulated and laws are put in place to ensure the safety of the end-users. It is important to note that NOx regulations vary depending on location. EPA regulations on NOx emissions for gas turbines are 30 ppm but in certain areas of California it can be as low as 3 ppm due to air quality concerns [Lieuwen, et al. 2021]. Combustion of hydrogen blended with natural gas increases NOx emissions by 92.81% for a 25% blend and upwards of 360% for a 75% blend [Cellek, Pinarbasi, 2018]. The referenced paper [Colorado, et al., 2016] also concludes that non-negligible levels of N_2O can be emitted at short-term or corner-case scenarios including ignition, blow-off, or ultra-lean operation for a single high-blend ratio (70% H_2 in natural gas). The paper also shows that under normal steady-state operation at lean (PHI>0.6) conditions, N_2O emissions are sub-ppm, even for this high-blend ratio mixture. This was further discussed in a subsequent paper focused on residential appliances by the same researchers who found that "*the measured N_2O and NH_3 emission levels were negligible in the context of the measurement accuracy*" [Zhao, et al., 2019]. Nitrous oxide emissions have been shown to be extremely low in devices when operated under normal conditions. Of course, the use of hydrogen blended with natural gas requires attention to device compatibility, operation envelopes, and relevant emission control strategies.

There techniques and modifications (e.g., by using a lean or lower fuel-to-air ratio) that can control and mitigate NOx emissions, a common example of a modification used to optimized combustion is shown in Figure 7.2. NOx is generated through combustion and the quantity of NOx is dependent on the flame temperature; by reducing the flame temperature, NOx emissions can be reduced [Menzies, 2019]. The flame temperature can be decreased by slowing down the rate of the fuel and air mixture. This leads to a lower flame temperature, therefore a reduction of NOx, and keeping the heat from the combustion process radiant, so the end-user does not experience any change when using the appliance [Menzies, 2019]. Water injection can also be used to reduce the hydrogen flame temperature and thereby reduce NOx for combustion in air. Other additions such as catalytic converters can be added to some appliances or furnaces to aid in the removal of NOx. European manufacturers have already started working on using these techniques and modifications and have found success in producing zero to low NOx emissions residential appliances [Sadler, et al., 2017].

Figure 7.2 Example of a Combustion Optimization [Menzies, 2019]

A common method to reducing NOx emissions is the use of a catalytic converter (see Figure 7.3) which is used in both natural gas and hydrogen applications. A catalytic converter is made up of three rare metals, platinum, palladium, and rhodium. These metals are arranged in a honeycomb structure to increase surface area and minimize the amount of materials required. There are two stages in a catalytic converter, the reduction stage and oxidation stage. In the reduction stage platinum and rhodium pull oxygen off the nitrogen atoms from nitrogen oxide (NO) or nitrogen dioxide (NO_2), producing oxygen and nitrogen molecules. In the oxidation stage platinum and palladium use oxygen molecules from the reduction stage and the exhaust and to oxidize any unburnt hydrocarbons or carbon monoxide as they pass through the honeycomb structure. Catalytic converters efficiency is dependent on the temperature it is heated too. Under ideal conditions a catalytic converter can reach 100% conversion efficiency of carbon monoxide and 90% conversion efficiency for nitrogen oxide and nitrogen dioxide emissions [Milton, 1998].

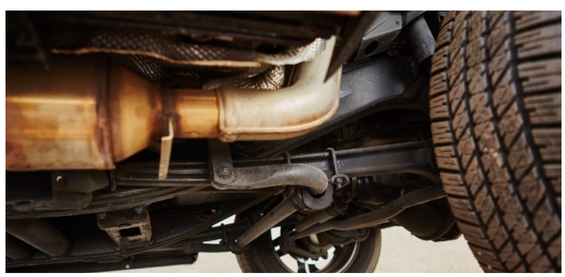


Figure 7.3 Example of a Catalytic Converter [Cellek, Pinarbasi, 2018]

Another safety concern about hydrogen is its ignition rate. Due to hydrogen's chemical structure, it has a lower ignition energy than gasoline or natural gas and wider temperature range for combustion. This means hydrogen can ignite more easily than other fuel sources, imposing certain safety risks. Even though hydrogen is easier to ignite than other fuels it gives off less radiant heat. Therefore, it typically causes less damage than a regular gasoline fire and people are able to stand closer to a hydrogen flame then compared to a gasoline flame [Tae, 2021]. However, when hydrogen is ignited, it gives off a clear flame that cannot otherwise been seen without a sensor or in dim lighting. Certain precautions including flame detectors and sensors need to be utilized to assure the safety of everyone using hydrogen in residential settings.

Hy4Heat conducted a safety assessment on risk of using hydrogen for combustion use and compared it with the risk of using natural gas. In Hy4Heat's assessment each type of explosion was categorized and a predicted number of events per year in Great Britain (GB) were calculated.

The total natural gas-based risks were predicted to be 17 individual injuries per year, for hydrogen the total risks were predicted to be 65 individual injuries per year [Hy4Heat, 2021]. The hydrogen risk assessments had no mitigation techniques implemented, therefore leading to the higher individual injuries per year. By implementing two excess flow valves (EFV) the predicted individual injuries per year for hydrogen decreased from 65 to 16. Hy4Heat recommends that two EFVs should be installed at every meter point, one upstream of the meter installation and one located within the smarter meter installation.

7.2. Storage and Delivery

All fuels containing energy can be harmful and dangerous if handled improperly. Today gasoline vehicles are the most common car on the market and yet there are still numerous accidents caused by gasoline fires at service stations (see Figure 7.4). It is necessary to acknowledge fuels have risks associated with them even if they are widely used in everyday life but important to try to mitigate these risks as best as possible. A convincing body of evidence in both California and internationally has revealed that hydrogen-based vehicles can be operated safely with cost competitiveness compared to gasoline or other fuels. Of the 11,674 hydrogen-powered automobiles operating in California, there have been no significant issues with fires for vehicles involved in accidents [CFCP, 2021]

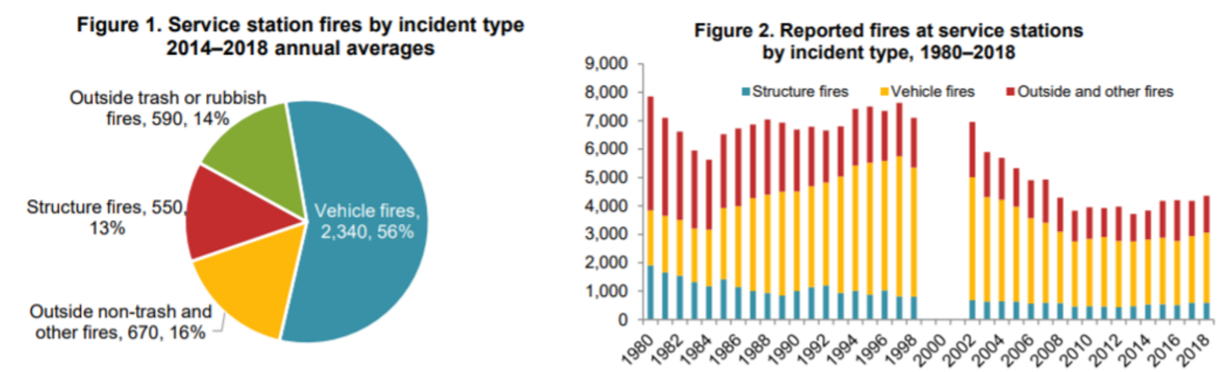


Figure 7.4 Service Station Fires [Ahrens, 2020]

Hydrogen storage tanks are used worldwide and have gone through many different stages of testing to make sure they are safe and reliable. The current standards used for high pressure tanks that are used to contain hydrogen are shown in Table 7.1. Each tank has a different set of standards and requirements that need to be met depending on their maximum storage pressure. All tanks undergo extensive testing to make sure they meet certain specifications, so they do not rupture and are safe to use. For example, high pressure tanks are subject to more than twice the maximum pressure that they are supposed to experience under regular working conditions to ensure there is no failure within their design. Hydrogen pressure stations have numerous redundant overpressure protection systems from over-pressurizing tanks in case a tank goes over its pressure limit.

Table 7.1 Current Standard Compliance for Pressure Vessels [DOE, 2021j]

STORAGE PRESSURE	STANDARDS COMPLIANCE
25 MPa (3,600 psi)	NGV2-2000 (modified) DOT FMVSS 304 (modified)
35 MPa (5,000 psi)	E.I.H.P. / Rev 12B ISO 15869 is derived from EU 97/23/EG NGV2-2000 (modified) FMVSS 304 (modified) Reijikijyun Betten 9
70 MPa (10,000 psi)	E.I.H.P. / Rev 12B ISO 15869 is derived from EU 97/23/EG FMVSS 304 (modified) Betten 9 (modified)

Other testing procedures that are used to further ensure safety include cycle testing. Cycling tests are used to ensure hydrogen can be pressurized and depressurized without effecting the safety of the take. These cycle testing procedures are done many more times than an average pressurized tanker would experience. For example, a carbon-composite tank which handles around 5,000-10,000 psi is cycled more than 500,000 times. If this tank was used on a vehicle, it would be refilled about once a week for a lifespan of 20 years, making the total number of cycles experienced about 1045. Pressurized tanks are also dropped 6 feet when empty, experience high temperatures, and exposed to acids, salts, and other hazards that they may experience [DOE, 2021j]. These testing measures are done to validate that the pressurized tanks being used today are safe even under severe or unusual conditions.

If by any chance, there is a leak in a hydrogen storage tank then due to hydrogen's low density would disperse very quickly in an open environment. Hydrogen is 14 times lighter than air and 57 times lighter than gasoline vapor [Tae, 2021]. When hydrogen is released, it will typically rise and disperse into the atmosphere, reducing risk of ignition. When common gaseous such as propane and gasoline are released, they tend to remain at ground level because they have a higher density than air. This increases the risk of fires potentially harming people and buildings.

Testing has also been done on hydrogen igniting in enclosed spaces such as tunnels and it was found that no additional risk existed when compared to fuels like gasoline [LaFleur, et al., 2017]. For example, for a typical automobile, the energy available for combustion (~13 gallons of gasoline) is approximately 3 times higher than for a hydrogen vehicle (~4k kg of hydrogen). If a hydrogen fuel leak were to occur resulting from a crash, the hydrogen would disperse upward rapidly as opposed to gasoline that wets the vehicle or pavement and does not disperse quickly in an accident.

Common industry practice is that if there is any damage or concerns of leakage in a hydrogen tank, then it is immediately removed from service. However, it is highly unlikely that these tanks will fail. When used in hydrogen fuel cell vehicles, pressurized tanks have remained intact in collisions, and, when tested after, they have passed numerous pressure tests. In the case of a vehicle fire or events in which a tank is engulfed by flames, a release system activates. This release system is known as the pressure relief device and is activated when surrounding temperatures reach typically 102ºC (216ºF). When activated, hydrogen is safely released from the tank. This safety procedure has been validated through performance tests that are in accordance with existing standards (NGV2-2000).

7.3. Pipelines

There are multiple factors involved when considering blending hydrogen in the existing U.S. natural gas pipeline system that make it difficult to provide a detailed risk assessment. These factors include gas build up and explosions in enclosures. According to a Gas Technology Institute (GTI) study on various safety hazards, implementing a 20% or less blend of hydrogen to the natural gas pipeline system, results in a minor increase in risk of ignition. GTI also found in this study that there would be a minor increase in the severity of the explosion with a 20% or less blend of hydrogen. Blending rates that go up to a 50% blend also have a minor increase in overall risk [Melaina, et al. 2013].

A study by NaturalHy examined gas buildup behavior in two scenarios, one in a smaller household room and another in a large room typically found in a commercial or industrial building. The findings of this study concluded that the gas buildup behavior for blends of hydrogen and natural gas were similar to that of pure natural gas. There was no separation observed between hydrogen and natural gas during the experiment. The only notable distinction between the blend and the pure natural gas was a slight increase in concentrations for blending rates up to 50% of hydrogen and a greater increase for blends greater than 70% [Melaina, et al. 2013].

To avoid the potential build of gas and explosions, leak detection devices can be installed in pipelines. However, leak detection devices like flame ionization detectors (FID) that are commonly installed in natural gas pipelines may need to be replaced due to a possibility of having an inaccuracy response from dilution effects of adding hydrogen. Leaks that have a 5% blend of hydrogen can still have an accurate response from FIDs but higher levels of blending will need further investigation [AGA, CGA, 2019].

As previously discussed in appenix 7.1 Hydrogen combustion, excess flow valves (EFV) can be used to drastically decrease the individual injuries per year caused by hydrogen. The purpose of EFVs is to restrict the flow of gas if a pipeline is broken to mitigate the risk of combustion.

7.4. Greenhouse Gas Emissions

Gases that are responsible for trapping heat in the atmosphere are referred to as greenhouse gases (GHG). There are two primary concerns regarding the use of hydrogen and its effect on climate neutrality. The *first* is that NOx is generated during combustion of hydrogen and has a Global Warming Potential (GWP) 265–298 times that of CO2 for a 100-year timescale and represents about 7% of the total greenhouse gas emissions. For reference the GWP of methane is 28–36 over 100 years [EPA, 2021b]. However, a majority of NOx emission in the U.S. comes from agriculture (75%) and only about 5% comes from stationary combustion [Menzies, 2019] and can be mitigated by the emission control strategies previously mentioned. It's important to note that with a hydrogen- based system, carbon monoxide (CO) emission will also be avoided. This is very important as historically trade- offs are typically made in designing combustion systems for hydrocarbons, whereas trying to mitigate CO usually results in more NOx. But, if CO is not a concern, then there are multiple solutions that can be utilized to reduce NOx.

Another very important point is that NOx is a "catch-all" term that usually encompasses NO, NO2, and N2O when talking about combustion. The majority of emissions during hydrogen combustion are NO and NO2, not N2O, which is the worst NOx in terms of GWP. The combustion of hydrogen will raise NOx emissions by 20-40% compared to methane. However, if one compares the NOx emissions during the stationary combustion of methane, one can see that the effect of N2O is insignificant. Greenhouse gas emissions are reported in units of carbon dioxide equivalent (CO2e) by multiplying by their GWP by their emission factors [EPA, 2018]. During the combustion of natural gas, the CO2e for CO2 is 53.06 kg CO2/mmBTU while the CO2e for N2O is 0.0298 kg N2O/mmBTU. This reveals that the resulting carbon dioxide emission has approximately 1780 times stronger effect on climate than the N2O gas emission for stationary combustion of natural gas. According to the reference [Thompson Academy, 2021], "Nitrous oxide (N2O) gas should not be confused with nitric oxide (NO) or nitrogen dioxide (NO2). Neither nitric oxide nor nitrogen dioxide are greenhouse gases, although they are important in the process of creation of tropospheric ozone (O3) which is a greenhouse gas." The nitrogen oxides (NO + NO2) do not directly affect Earth's radiative balance, but they accelerate the generation of a direct GHG – tropospheric ozone. However, the impact on climate is difficult to directly quantify [Dentener, et al., 2001]. Lastly, it is important to mention NOx is only generated in combustion processes when fuels (like hydrogen and natural gas) are burned in the presence of air. However, for applications that use a direct hydrogen fuel cell (e.g., in automobiles and electricity generation), the only byproducts are water, heat, and electrical energy with zero NOx emissions.

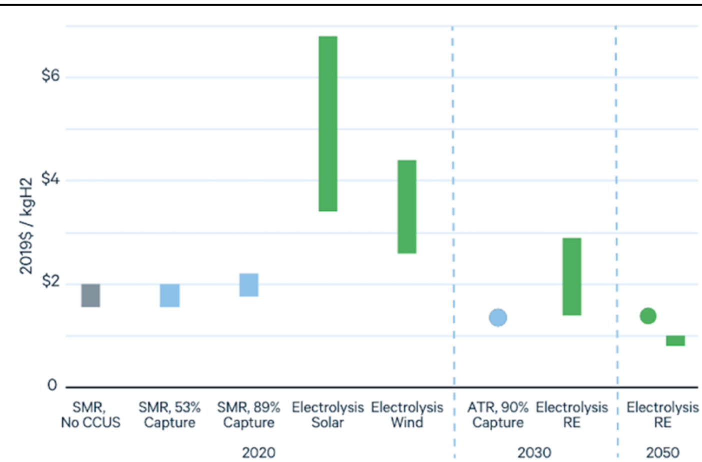
The *second* concern is that hydrogen itself (GWP of 5.8 over a 100-year timescale) is an indirect greenhouse gas that reacts in the atmosphere with tropospheric hydroxyl (OH) radicals and disrupts the distribution of methane in the ozone and thereby cause an increase in global warming. The release of hydrogen prolongs methane's atmospheric residence time, increasing its accumulation and greenhouse gas impact [Derwent, et al., 2006]. According to one study by Derwent et al., if a global hydrogen economy replaced the current fossil fuel-based energy system and exhibited a leakage rate of 1% or 10%, then it would decrease the climate impact to 0.6% or 6% of the current fossil fuel based system, respectively. Another more recent literature review on the atmospheric impacts of hydrogen from heating found that the most likely outcome is that hydrogen has a greenhouse gas effect that is small but not zero, and the global atmospheric impacts are likely to be small [Derwent, 2018]. Within the existing body of literature presented, there is significant uncertainty and additional research on this topic should be conducted. These findings emphasize the importance to ensure that leaks in hydrogen production, transportation, and utilization are minimized.

Appendix 8. The Economics of Hydrogen Production and Use

In this appendix sections 8.1 and 8.2, summarize the current and projected costs of hydrogen production, storage, transmission, and distribution. These sections focus on the extent to which scale-up must occur to make hydrogen a cost-effective fuel for heating.

8.1. Costs of Hydrogen Production

The cost of hydrogen production is the most important factor in assessing the feasibility of widespread hydrogen implementation in the US economy. Grey hydrogen, produced with natural gas using steam methane reforming (SMR) and no carbon capture, is currently the least expensive production method due to low natural gas prices. Grey hydrogen production costs on average between \$1.00-\$1.50/kg [Blanton, et al. 2021]. Blue hydrogen and green hydrogen, which have a much lower carbon footprint, represent the future of hydrogen production if costs can be reduced. Subsections 8.1.1. and 8.1.2. examine the costs of blue and green hydrogen. Figure 8.1 provides an overview of the current and projected costs of grey, blue and green hydrogen production. 8.1.3 concludes with a brief discussion of costs associated with the use of water as an input in the production of blue and green hydrogen.



Sources: Friedmann et al. 2019; IRENA 2019; Hydrogen Council 2020; Mathis and Thornhill 2019.
Notes: Bars indicate cost ranges; circles indicate point estimates. Gray and blue hydrogen assume a delivered natural gas price of \$3.50/MMBtu. 2020 and 2030 costs assume social costs of carbon of \$51/tCO_2 and \$61/tCO_2, respectively, from IWG (2016), inflated from 2007\$ to 2019\$. Includes only CO_2 emissions from combustion and chemical conversion.

Figure 8.1 Current and Projected Hydrogen Costs (where CCUS is capture, utilization, and storage and RE is renewable energy) [Bartlett and Krupnick 2020a]

8.1.1. Costs of Blue Hydrogen Production

The costs of blue hydrogen, hydrogen from fossil fuels using SMR are largely driven by carbon capture, utilization, and storage (CCUS) and include capital expenditures, operating expenses, and fuel costs. Capital expenditures mainly comprise the cost of purchasing CCUS equipment and incorporating it into SMR plants. Operating expenses are related to the transportation and storage of CO_2, and fuel costs entail the cost of energy needed for carbon capture itself. For SMR plants, capital expenditures and operating expenses are the largest cost components [Bartlett and Krupnick 2020a].

Blue hydrogen production with 60-90% carbon capture currently costs between $1.40-$3.00/kg [Blanton, et al. 2021; Hydrogen Council 2020; US DOE 2020]. These costs are expected to remain between $2-$3/kg in most US geographic locations by 2030. For optimal locations, costs are expected to fall to $1.00-$1.50/kg by 2030 due to increased electrolyzer capacities and decreased levelized costs of energy (LCOE) of renewables [Hydrogen Council 2020]. For blue hydrogen to be more viable, the cost of CCUS must fall and industry must transition from SMR to autothermal reforming (ATR) reactors. With reduced costs, blue hydrogen is positioned to replace grey hydrogen in the near term. Blue hydrogen with 90 percent capture can be the least expensive production method by 2030 [Bartlett and Krupnick 2020a].

8.1.2. Costs of Green Hydrogen Production

Green hydrogen, produced from renewable or nuclear energy using electrolysis, is at present too costly to outcompete grey and blue hydrogen. It is currently the most expensive to produce ranging from $4.50-$8.50/kg [Blanton, et al. 2021; US DOE 2020]. For green hydrogen to be competitive, significant cost reductions must be realized in capital expenditures, electricity costs and electrolyzer utilization. Capital expenditures include the purchase of electrolyzer stacks, power electronics and plant infrastructure [Bartlett and Krupnick 2020a]. Technological improvements that drive down the costs of production equipment is key to lowering capital costs. The following discussion focuses on driving down electricity and electrolyzer utilization costs.

Electricity costs vary depending on the electricity source used by the hydrogen production plant. Plants either have a dedicated power source or are grid-connected with green hydrogen. In plants with a dedicated power source, the power cost is dependent on the (LCOE) of solar and wind power available. These plants face a fixed power cost with no price uncertainty. For green hydrogen plants connected to the grid using renewable or nuclear energy, the electricity cost is the power price in the wholesale or industrial consumer market plus the market premium for zero-carbon power. Wholesale power prices vary hourly and seasonally and can drop to zero or below when renewable energy sources create excess power supply. Grid-connected plants can capitalize on higher utilization and lower power prices for a short time; however, low prices will not prevail, resulting in price uncertainty [Bartlett and Krupnick 2020a].

Regardless of the plant's energy source, reducing the cost of renewables is crucial to reducing the costs of green hydrogen production, and many reductions have already been realized [Siemens, 2021; Bartlett and Krupnick 2020a; Hydrogen Council 2020; IRENA 2020; IEA 2019]. Solar and wind power prices have fallen rapidly over the last decade, by about 75-80% for solar and 25% for wind, making electrolysis that utilizes renewables 60% less costly [Hydrogen Council 2020; IEA 2019]. Renewable electricity costs are expected to fall further in the future, albeit less rapidly. Projections for 2040 are $11/MWh for solar and $16/MWh for onshore wind power [Siemens, 2021; Bartlett and Krupnick 2020a; Hydrogen Council 2020]. These costs are close to the current record low wind and solar auction prices of $13.50/MWh for solar and $17.86/MWh for wind [BloombergNEF 2021; PV Magazine 2021; IRENA 2020]. According to the International Energy Agency (IEA), electricity prices of $10-$40/MWh are low enough for electrolysis (with efficient operating capacity) to compete with hydrogen produced by using natural gas and CCUS [IEA 2019].

Regarding the costs associated with electrolyzer utilization, plants with dedicated energy sources and grid-connected plants face different optimal strategies for cost minimization. For green hydrogen plants with a dedicated power source, in which power prices are fixed, it is optimal to operate as much as possible. For green hydrogen plants connected to the grid facing variable power costs, there are trade-offs between utilization and power prices. Production costs are minimized when power prices are low, subject to operating enough to cover fixed capital costs. At low electrolyzer utilization, production costs decrease with increasing utilization until a point where increasing utilization rates results in increased production costs. At this point higher utilization requires production during periods of higher power prices [Bartlett and Krupnick 2020a; IEA 2019]. At lower levels of utilization, minimizing capital costs requires the minimization of production costs as these are the primary expenses at low utilization. At higher utilization, the cost of electricity is the primary expense [Bartlett and Krupnick 2020a; IRENA 2020].

Green hydrogen has the potential to compete with grey hydrogen as soon as 2030, with small- and medium-scale production costs falling from produce at $4.50-$8.50/kg to $3.53/kg [Blanton, et al. 2021; US DOE 2020; Glenk and Reichelstien 2019]. Price parity with grey hydrogen is feasible by 2030 using onshore wind generation and by 2035 using offshore wind generation [Siemens Gamesa Renewable Energy 2021]. The International Energy Agency (IEA) predicts a 30% cost reduction in green hydrogen due to increased electrolyzer capacity and decreased LCOE of renewables in the next decade [IEA 2019]. At prices between $3-$4/kg, green hydrogen can reach cost parity with other decarbonized alternatives, such as heat pumps. However, it will be difficult for hydrogen used for residential heating to be competitive with heat pumps in areas where direct electrification is low-cost. These are areas that have a strong electricity grid already in place, access to clean electricity and no existing natural gas network; hence, a full hydrogen pipeline network would need to be built [Hydrogen Council 2020].

Green hydrogen could become the most economical production process as early as 2030 due to projected rapid improvements in electrolyzers and cost reductions in wind and solar power. Between 2030 and 2050, reductions in electrolyzer and power costs could bring the cost of green hydrogen down to $0.80-$1.38/kg by 2050 [BloombergNEF 2021; PV Magazine 2021; Bartlett and Krupnick 2020a; IRENA 2020]. More optimistically, Nel Hydrogen, an international hydrogen company, plans to reach a production cost for green hydrogen of $1.50/kg by 2025 through significant electrolyzer capacity expansions at their HerØya plant in Norway [Szymanski 2021]. Similarly in June 2021, the US Department of Energy (DOE) announced a target to reduce the cost of green hydrogen by 80% from $5/kg in 2020 to $1/kg by 2030 [APPA 2021].

Other areas for cost reductions include distribution and storage costs. To reduce supply costs, the development of hydrogen storage, pipelines, and infrastructure is necessary to expand off-site production and to supply to more end-users over long distances. This is particularly important as storage costs could act as a barrier to the competitiveness of green hydrogen. Green hydrogen will likely not be cost competitive with on-site blue hydrogen production without significant reductions in the cost of storage, underscoring the need for government incentives to achieve green hydrogen competitiveness [Bartlett and Krupnick 2020a].

8.1.3. Other Costs of Hydrogen Production

Hydrogen production uses water, which is an input cost to production and can be costly in areas with water shortages. Production costs are mainly due to the desalinization and purification needed for electrolyzer water usage. Water purity level requirements depend on the electrolyzer technology used. Regardless, the cost of water purification is marginal, less than \$0.01/kg H_2. The largest cost of impurities is the reduction in the lifetime of electrolyzer stacks [IRENA 2020].

There is also an opportunity cost in devoting water to hydrogen production. In areas for which water is a scare resource, hydrogen production and other uses must compete for water. 1kg of hydrogen production could require between 18kg and 24kg of water, raising concerns about water security. However, water scarcity issues vary locally and can be ameliorated with the use of desalinated seawater. Furthermore, when freshwater is used, hydrogen production through electrolysis uses much less water than thermoelectric power plants in the US. For large-scale hydrogen production, IRENA concludes that "the overall water demand would be relatively small compared to the global water consumption" [IRENA 2020, p.12].

8.2. Costs of Hydrogen Storage and Transmission & Distribution

8.2.1. Cost of Hydrogen Storage

Salt caverns, depleted oil and gas fields, aquifers and rock caverns are currently used for natural gas storage and can be used for hydrogen storage. Salt caverns are ideal as they can store pure hydrogen without any modifications. They are the most cost-effective storage method, allowing for rapid extraction of nearly all injected hydrogen with no need for contaminant removal. BloombergNEF estimates salt cavern storage costs at \$0.23/kg. Salt caverns are, however, not an option in all geographic regions including the Northeast [Bartlett and Krupnick 2020a; IEA 2019].

Depleted oil and gas fields, aquifers, and rock caverns can provide long-term and large-scale storage in locations without access to salt caverns. BloombergNEF estimates a storage cost of \$1.90/kg for depleted oil and gas fields and \$0.71/kgH2 for rock caverns. These options are less efficient and cost-effective relative to salt caverns for several reasons. First, they are more permeable, resulting in potential hydrogen reactivity with rocks, fluid, and micro-organisms. This necessitates contaminant removal. In addition, funds must be devoted to the exploration and development of these alternative storage options to assess their feasibility. Finally, the aforementioned storage options have large size and minimum pressure requirements and are not ideal for small-scale and short-term storage. For short-term and small-scale storage, storage tanks are more suitable [Bartlett and Krupnick 2020a; IEA 2019].

8.2.2. Cost of Hydrogen Transmission & Distribution

Gas pipelines are the most efficient means of transporting large quantities of hydrogen [Blanton, et al. 2021; Staffell, et al. 2019; Dodds and Hawkes 2014]. Updating existing pipeline infrastructure avoids the high costs of secure rights-of-ways, construction and public objections to new developments [Blanton, et al. 2021; IEA 2019; Staffell, et al. 2019]. Using existing natural gas pipelines to transport and deliver hydrogen is most cost-effective though not without issues (see Figure 8.2 for reference of pipeline infrastructure). Transporting hydrogen can cause embrittlement in pipes that were designed to accommodate only natural gas, due to the type of material used to transport natural gas. Before using existing infrastructure, natural gas pipes must be assessed on a case-by-case basis to determine the maximum hydrogen blend that can be supported [IEA 2019; Staffell, et al. 2019].

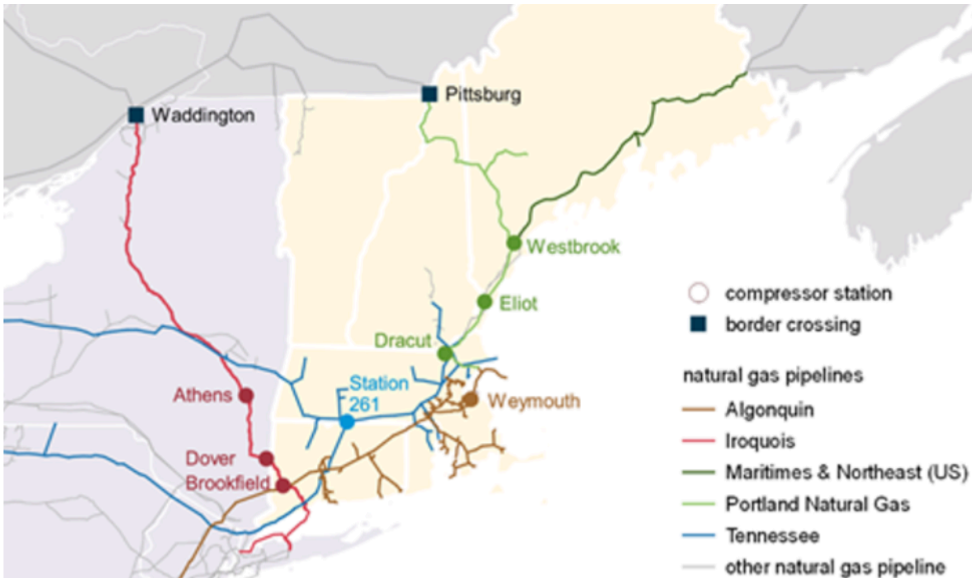
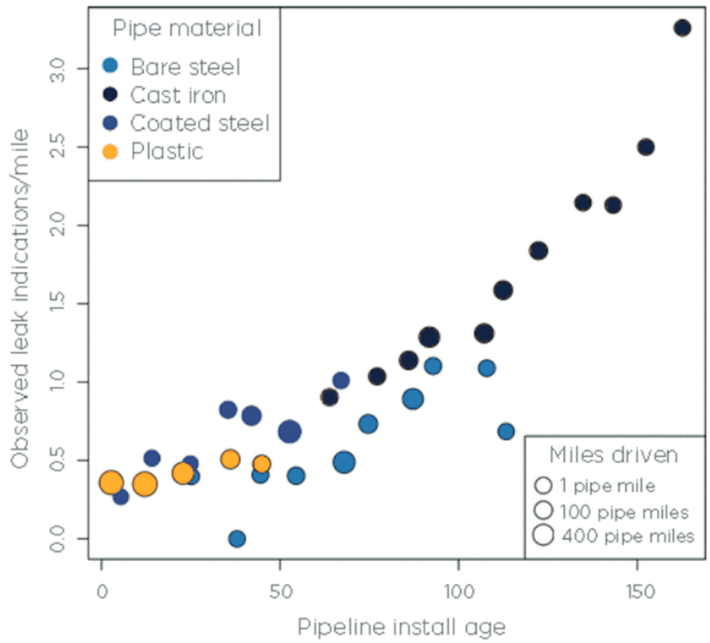


Figure 8.2 Existing Pipeline Infrastructure [EIA, 2020b]

Hydrogen compatibility is particularly an issue in metals pipes. Lower carbon grade and stainless-steel welded pipes are more susceptible to hydrogen embrittlement. Cast-iron pipes, which are mainly in the Northeastern US, are not hydrogen compatible [Blanton, et al. 2021; Dodds and Hawkes 2014]. This issue, however, is not insurmountable, and Massachusetts has been working to replace iron and steel pipes with plastic pipes in the last few decades. These replacements have been and continue to be driven by efforts to curb methane leaks from aging metal pipeline infrastructure. Cast-iron pipelines are responsible for a disproportionate number of leaks within gas distribution networks across the US as shown in Figure 8.3. Leaks can be costly to end-use consumers as utilities are legally allowed to increase base-rates to recover costs of unavoidable gas leaks. Addressing methane leaks is also an important factor in reducing greenhouse gas emissions [Blanton, et al. 2021].



Source: Z. D. Weller, S. P. Hamburg, and J. C. von Fischer, "A National Estimate of Methane Leakage from Pipeline Mains in Natural Gas Local Distribution Systems," Environmental Science & Technology 54, no. 14 (2020): 8958–67, https://pubs.acs.org/doi/10.1021/acs.est.0c00437

Figure 8.3 National Estimate of Methane Leakage from Natural Gas Pipelines

In Massachusetts, steel and iron pipe have been steadily replaced with plastic. As shown in Figure 8.4, between 1990-2019, Massachusetts replaced nearly half of iron pipeline miles and 21 percent of steel pipeline with plastic. As of 2019, 51 percent of the nearly 21,000 miles of pipelines are plastic [MassDEP 2021]. It is important to note that 11,016 miles of plastic pipeline do not need to be replaced for hydrogen use, 7,928 miles of steel pipeline will need to be retrofitted for higher blends of hydrogen, and 2,809 miles of cast iron pipeline will need to be replaced. [MassDEP, 2021]. To retrofit steel pipelines a copper epoxy coating will be necessary to prevent embrittlement of the steel pipeline at higher blends. For lower blends of hydrogen the steel pipeline can be used without retrofitting.

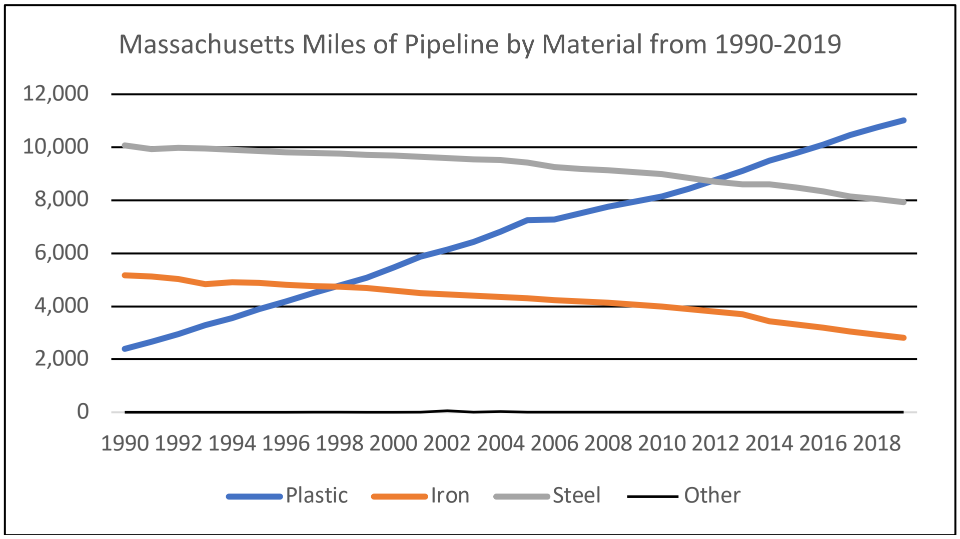


Figure 8.4 Miles of natural gas pipelines by material in Massachusetts from 1990 to 2019 [MassDEP 2021]

Note: Iron pipelines include cast, wrought and ductile iron. Steel pipelines include various combinations of protected, unprotected, coated and uncoated steels. Other pipeline materials as undefined by the MA DEP data.

In 2014, Massachusetts passed the Gas Leaks Act (Chapter 149), establishing a classification system for gas leak severities and a timeline for which each type of leak must be repaired. Leaks are categorized as Grade 1, 2, or 3. Grade 1 leaks, presenting the largest risk, must be addressed immediately. Grade 2 leaks must be addressed within 12 months and continuously monitored while Grade 3 leaks must be monitored only [IEA 2021]. Under the Gas Leaks Act, utility companies can submit Gas System Enhancement Programs (GSEPs), which are "annual plans to repair or replace aged natural gas infrastructure in the interest of public safety and to reduce lost and unaccounted for gas ("LAUF")" [MassDEP 2021]. With the GSEP active, metal pipelines will continue to be replaced with plastic independent of any interest updating infrastructure for hydrogen compatibility. However, the GSEP could be amended, mandating pipelines be replaced with hydrogen compatible pipelines, mitigating the need to retrofit pipelines for higher blend rates in the future if Massachusetts proceeds with hydrogen for thermal heating. Additionally, the GSEP timeline could be accelerated to hasten Massachusetts' displacement of natural gas with green hydrogen, reducing carbon emissions more quickly.

Blanton et al. [2021] note that using existing pipeline infrastructure for hydrogen blends should be viewed as a transition to zero-carbon energy transmission. Over time it will be necessary expand the capacity of US pipeline infrastructure for hydrogen to provide an equivalent energy to that of natural gas. However, in the near term, the US (and New England in particular) needs to update natural gas pipelines anyways to address methane leaks and repairs, which is important to the reduction of greenhouse gas emissions. Though updating pipeline infrastructure will be a costly and lengthy process, zero-carbon hydrogen can play an important role in the energy transition to achieve net-zero targets by 2050. In the next few decades with updates to the natural gas system, the gas grid could transport 100 percent carbon-free fuels with a mix of natural gas with CCUS, biomethane, and zero-carbon hydrogen. Using existing infrastructure can speed up the full decarbonization of the energy sector by 2050; although, any achievement of net-zero emissions by 2050 will very likely require support from the public sector [Blanton, et al. 2021].

Appendix 9. Thermal Hydrogen Pathway for the Commonwealth of Massachusetts

Section 9.1 discusses the costs of transitioning from natural gas to hydrogen for residential heating. Section 9.2 examines the benefits of using hydrogen blends in the residential heating sector. The appendix concludes in sections 9.3 and 9.4 with public policy recommendations to aid in the timely creation of hydrogen markets. Government support is imperative to capitalize on hydrogen's many benefits and its potential to further decarbonization goals in the short- and long-term.

9.1 The Use of Hydrogen Blends in Residential Heating

Many of Massachusetts homeowner relies heavily on natural gas for house hold heating, causing large amounts of carbon emissions (see Figure 9.1 for a breakdown of Massachusetts Household heating). Though blending is not a 100% carbon-free solution, it does provide a non-trivial carbon reduction and a solution to displacing some natural gas in the next few decades. As an illustration, assuming 3.3 million households use natural gas heat, a five percent hydrogen blend could reduce 200,000 tons of CO_2 annually [Hydrogen Council 2020]. For many countries, blending initially is a gateway to completely phasing out natural gas and replacing it with 100% hydrogen. Although the use of 100% hydrogen for heating has not yet been done, this is a target internationally. For example, in the United Kingdom, H21 North of England's goal is to supply 100% hydrogen by pipeline to buildings by 2035 [IEA 2019].

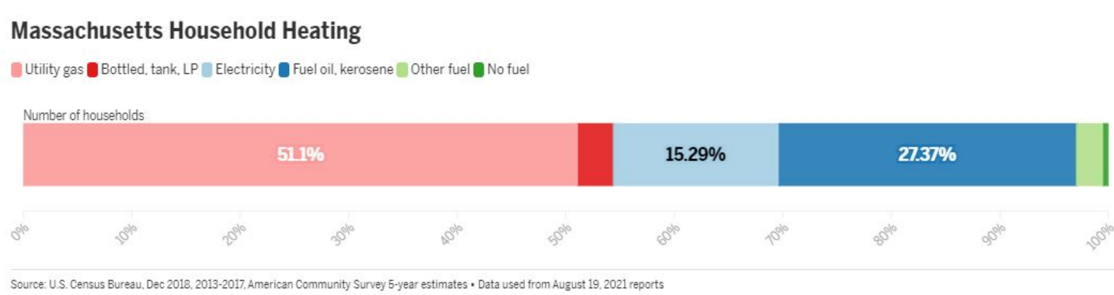


Figure 9.1 Massachusetts Household Heating [Boston Globe 2021]

Studies performed by HyDeploy, NREL, and HyGrid have shown the benefits of small-scale hydrogen blending for thermal use. Pilot programs can be established to assess hydrogen's blending viability, quantify performance, and understand safety issues. Successful blending of hydrogen with methane can provide essentially immediate carbon reduction with very little modification of existing infrastructure to much of the Commonwealth.

9.1.1 Hydrogen Compatibility with End-Use Appliances

To pipe hydrogen blends into households for heating, an important consideration is hydrogen's compatibility with end-use appliances designed for natural gas. European studies find that 20 percent hydrogen blends are compatible with gas networks and heating equipment and have no issues with leakage, flame stability, backfiring or ignition. American studies have found that blends up to five percent are compatible with end-use equipment. Appliances should be tested on a case-by-case basis for safety, especially for older appliances and particularly for blends above 10 percent [Blanton, et al. 2021; US DOE 2020; IEA 2019; Dodds and Hawkes 2014; Staffell, et al. 2019].

There are several considerations when evaluating the use of hydrogen blends with existing appliances. First, blends are more flammable and burn hotter than natural gas, increasing the risk of explosion. Second, hydrogen flames are also odorless and difficult to see, making the addition of odor and flame detectors essential for consumer safety [IEA 2019; Dodds and Hawkes 2014]. With the odor and flame detectors, consumers notice no difference in the appearance or operation of hydrogen gas boilers relative to natural gas boilers [Hydrogen Council 2020; Dodds and Hawkes 2014]. Finally, blending tolerance can vary widely across infrastructure. The maximum blend volume through the network is limited by the end-use applications that support the lowest blends as it is too costly to separate hydrogen from natural gas [Blanton, et al. 2021; Bartlett and Krupnick 2020a]. Studies in the US are currently being funded to determine the compatibility of various blends with end-use appliances.

Though end-use appliances can be safe for blends, transitioning to 100 percent hydrogen will likely require the replacement of end-use appliances [Bartlett and Krupnick 2020a; Dodds and Hawkes 2014]. A complete and large-scale replacement of end-use appliances is not unprecedented. The UK switched from town gas (produced using coal) to natural gas, successfully replacing roughly 40 million appliances over 11 years at a cost of 8 billion Euros (in 2015$) [Staffell, et al. 2019]. It is also within the realm of possibility that existing appliances can be designed to work with hydrogen gas specifications, though modern appliances designed for efficiency and environmental considerations are likely to reduce the range of compatible hydrogen blends [Dodds and Hawkes 2014]. It is important to note that lower hydrogen blends, between five to 20 percent, can be used with existing end-use appliances. Increasing hydrogen blends may require modifications of end-use appliances until 100 percent hydrogen use requires replacement. In the case of full electrification, however, homes with gas appliances will need to replace end-use appliances as well and will have to do so now.

If end-appliances must be replaced to be compatible with hydrogen blends, monetary incentives may be necessary to encourage homeowner adoption of new or retrofitted appliances. Price plays are large role in consumer decisions, and homeowners may be reluctant to replace appliances in the absence of malfunction and without a broad home renovation. In addition, aesthetics and space usage are also important considerations for consumers [Dodds and Hawkes 2014]. Consumers may also be concerned about safety and higher energy prices associated with hydrogen-compatible appliances [IEA 2019]. Lastly, some end-users may be reluctant to adapt to unfamiliar technologies [Dodds and Hawkes 2014].

There are several reasons affluent households may choose to stay on the gas system: 1) For older buildings, hydrogen heating can be more cost competitive than heat pumps [Hydrogen Council 2020; IEA 2019]. 2) Price plays a large role in consumer decisions, and any homeowner may be reluctant to replace appliances in the absence of malfunction and without a broad home renovation. In addition, aesthetics and space usage are also important considerations for consumers [Dodds and Hawkes 2014]. 3) Phasing out gas systems entirely may face opposition from customers, independent of household income. Blending provides those who prefer gas cooking and heating with a low-carbon gas option [Staffell, et al. 2019]. It would be important to look at the correlation between household income and household heat-sources decisions to help answer the question of which households are more likely to switch to heat pumps.

Regarding cost increases for rate-payers: again, this is an empirical question. At this time there is no known study that quantifies the costs of blending, how these costs compare to those of electrification, and how the costs of either would affect end-users. Any rate increases, however, can be managed with strategic policy – such as subsidies and incremental rate increases. Policies targeted at lower income households already exist in Massachusetts (for example, https://www.mass.gov/service-details/learn-about-low-income-home-energy-assistance-program-liheap). In addition, energy prices charged by utilities are subject to regulation and cannot be increased without government approval, allowing more room for policy intervention in cases of environmental injustices. The cost of electrification could also put an undue burden on marginalized communities as well. More research on the impact of electrification and hydrogen blending needs to be performed to assess the impact on environmental justice communities.

9.1.2 Blended Hydrogen versus Heat Pumps as Low-Carbon Heating Solutions

Heat pumps are the main decarbonized alternative to blended hydrogen for residential heating. In places where existing natural gas networks exist, hydrogen boilers have the potential to provide cost-effective, low-carbon heating to residential buildings. By 2030, the projected cost of hydrogen boilers is $900-$1,600 per household per year, a cost that is not largely different from natural gas boilers, biomethane, and heat pumps for new buildings. For older buildings, hydrogen heating can be more competitive than heat pumps at a cost of $5.40/kg for hydrogen. For newly built homes, the price of hydrogen must drop to $3/kg to compete with biomethane and heat pumps [Hydrogen Council 2020; IEA 2019]. It is, however, difficult for both heat pumps and hydrogen to outcompete natural gas on cost in the near-term. Hydrogen must reach $1/kg to reach cost-parity with natural gas, underscoring the need for government incentives to support low-carbon technologies now [Hydrogen Council 2020; IEA 2019].

Integrating hydrogen gas as a residential energy source has several advantages relative to relying on only heat pumps. Hydrogen pipeline networks can manage issues with variability in energy supply from renewables (i.e., intermittency) by providing energy storage within the pipeline network [Hydrogen Council 2020]. In addition, capitalizing on existing infrastructure, using natural gas pipelines to deliver a low-carbon fuel source, is not possible in the case of full electrification, which requires entirely new infrastructure [Hydrogen Council 2020]. The continued use of existing pipeline infrastructure also precludes the high costs of stranded assets being passed on to customers. For customers located in areas where it would be prohibitively costly to site electric infrastructure, continued use of gas systems will be necessary and cost-effective [MA EEA 2020].

Phasing out gas systems entirely may face opposition from customers. Blending provides those who prefer gas cooking and heating with a low-carbon gas option [Staffell, et al. 2019]. Consumers can likely use their existing appliances for up to 20% blends, and existing pipeline infrastructure can likely support such blends without costly updates. This transition provides time to slowly introduce any cost increases and necessary appliance updates over time while infrastructure updates are made over the next two decades to accommodate higher hydrogen blends or the time needed to enhance the electrical grid for wide-scale electrification. This can particularly benefit low-income individuals as heat pump installations currently have high upfront investment costs [Blanton, et al. 2021; Hydrogen Council 2020]. Realistically, the conversion of the gas grid to 100 percent hydrogen cannot feasibly or cost-effectively happen rapidly, but rather through a well-designed gradual process. Starting with small hydrogen blends that offer some early decarbonization without causing significant affordability issues for consumers and producers [Dodds and Hawkes 2014].

Any transition from one type of energy source to another takes time and money. The transition from burning coal to oil to natural gas was expensive and did not take place overnight. According to a Boston Globe article By Jon Gorey November 7, 2021, "*In a 2020 MassCEC pilot program, the median cost of installing a whole-home heat pump system was $18,400 — less for new construction and gut rehabs, more for retrofits of existing buildings.*" The capital expense of heat pump installations will impact low-income families disproportionately and prevent adoption. Likewise, for many consumers who currently use gas for cooking, replacing those appliances is a capital expense along with the electrical rewiring necessary to accommodate new or higher electricity demand. The impact any changes in infrastructure whether it is for hydrogen or electrification will demand capital expense and it is presently unclear what is the less expensive option.

Another benefit of hydrogen is its potential to complement electrification. Electrification can be used in homes where it is cost-effective and efficient, while blended hydrogen offers an opportunity to displace natural gas in locations where electrification is more costly. Massachusetts could implement both electrification of homes and displacement of natural gas with hydrogen blends simultaneously. This strategy could improve the expediency of decarbonization in Massachusetts, particularly with the existing lag in meeting state electrification goals. To achieve decarbonization by 2050, Massachusetts' plans to convert 100,000 homes per year from natural gas to electric. In 2020, however, these conversions fell significantly short with only 461 homes switching [Shankman, 2021]. The Boston Globe did a similar analysis and found the same results of a shortfall in electrification progress (see Figure 9.2). This shortfall can be attributed to the high upfront costs of heat pump installation, lack of consumer confidence in heat pumps, and contractors and state-employed energy efficiency personnel lacking knowledge of heat pump technology. Education campaigns can help to inform customers and contractors; however, it will be difficult to overcome the price increases customers will see moving from natural gas to heat pumps without large subsidies from the state now. National Grid, a utility company that supplies natural gas and electricity to over one million customers in the Massachusetts, is skeptical that complete electrification is the most cost-effective and efficient strategy for decarbonization in the state. They suggest that replacing natural gas with renewable hydrogen can serve as complementary path to net-zero emissions alongside electrification [Boston Globe 2021].

Figure 9.2 Massachusetts Heat Pump Installation 2020 [Boston Globe 2021]

Massachusetts electrification efforts for commercial and residential heating and cooling (i.e., heat pumps) should initially be implemented in locations that currently rely solely on the dirtier fossil fuels (e.g., coal or oil) and do not have access to the natural gas infrastructure. Direct use of renewable electricity for heat and power should be a first consideration, when possible and economical, rather than using renewable energy to generate fuel or for storage because of round trip efficiency losses. Complete electrification may be difficult or impossible due to several factors such as intermittency, physical constraints, retrofitting limitations, transmission line augmentation, infrastructure replacement, permitting, public acceptance, and cost. Additionally, complete electrification will take several decades to accomplish. Massachusetts' climate 2030 goals include electrifying 100,000 homes per year, but in 2020 only 461 homes made the switch revealing an extreme shortfall in electrification progress for a variety of reasons [Shankman, 2021]. For these reasons, in order to get to net-zero emissions as quickly as possible, the inclusion of hydrogen as a replacement for natural gas should be a consideration for Massachusetts.

9.2 Benefits of Replacing Natural Gas with Hydrogen in Decarbonization Plans

In the absence of public policy support, it is highly unlikely the U.S. will reach net-zero CO2 emissions by 2050. The complete phase-out of fossil fuels will be particularly difficult in the U.S. due to a strong dependence on natural gas. Natural gas has the lowest carbon content of all fossil fuels and is very cheap. Natural gas will be the last to be decarbonized and will be more difficult to transition away from than the switch from coal [Blanton, et al. 2021]. Even with growing negative sentiments toward natural gas from politicians and the public, empirical trends do not reflect these opinions. Spending on natural gas infrastructure has remained consistent in recent years and demand for natural gas from end-users has increased. Nearly half of homes in the US use natural gas, and utilities have gained half a million customers each year since 2010 (see Figure 9.3).

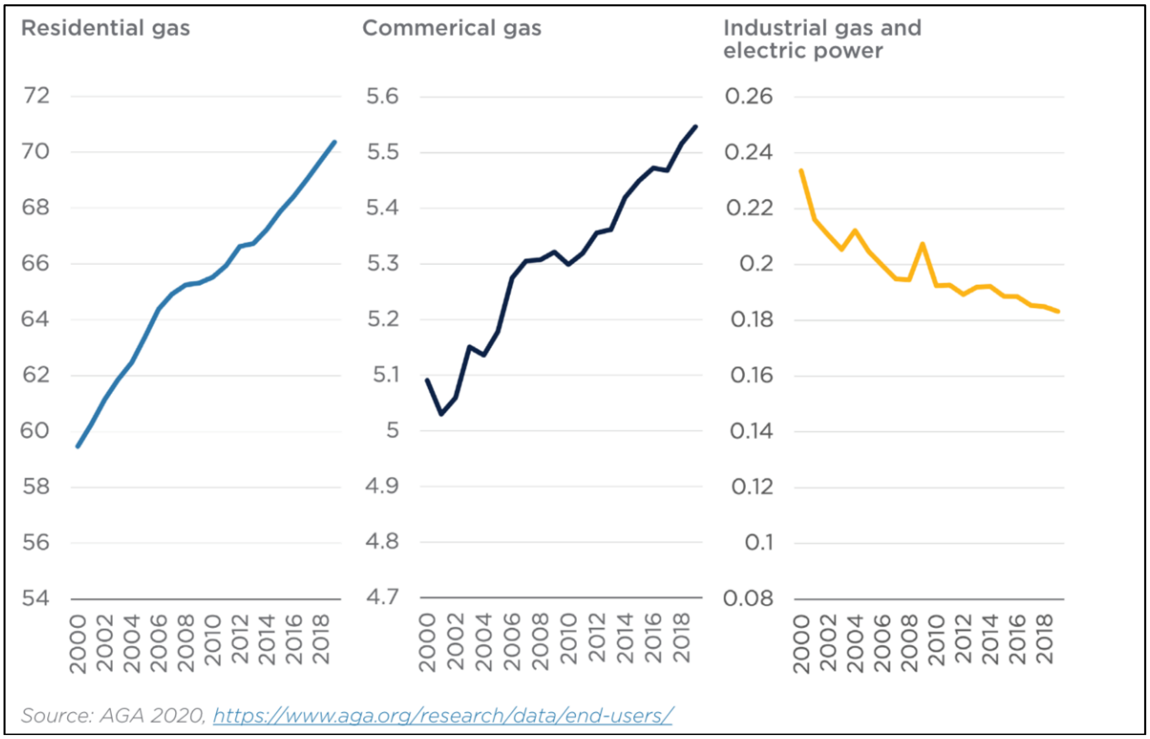


Figure 9.3 USA Natural Gas End Users (millions) [Blanton, et al. 2021]

Even recent city-wide bans of new residential natural gas hookups in California have proven ineffective at curtailing the growth of natural gas customers. Blanton et al. [2021] cite an increase in 34,000 gas customers for one California utility company, SoCalGas, in 2019 alone. On the producer-side, the US has been a net-exporter of natural gas since 2017. There will remain incentives for firms to produce natural gas in the absence of interventions [Blanton, et al. 2021].

A study by the IEA suggests natural gas consumption can significantly decline by 2040 with investment in gaseous fuel, such as low-carbon hydrogen, with existing natural gas pipeline infrastructure plays an important role. Similarly, the University of California, Berkley's 2035 report finds that in order to achieve a 90 percent clean power sector by 2035, natural gas plants must still operate until 2035. These plants play a particularly large role in the summer months when cooling energy demand is high and there is a simultaneous fall in wind production. To fully decarbonize, the report suggests reliance on CCUS, green hydrogen technologies and the continued use of pipeline systems [Blanton, et al. 2021].

Decarbonization plans that include hydrogen consistently assume the use of existing natural gas pipelines to deliver hydrogen gas. For hydrogen to replace natural gas in a cost-effective manner, a managed approach with policy incentives is required to steadily build up hydrogen technologies and demand. With such an approach, green hydrogen could completely replace natural gas over time without complete abandonment of existing pipeline assets or popular gas-based consumer appliances. A European study titled the "No-regret hydrogen: Charting early steps for Hydrogen infrastructure in Europe," emphasizes the importance of strategic investments in hydrogen infrastructure. The development of hydrogen networks early on can be focused in areas best served by gas energy to reduce the risk of oversized networks [ACER 2021].

Furthermore, in analyses of different decarbonization plans, many studies conclude that natural gas remains in the US energy mix through 2050, even in scenarios in which net-zero emissions are achieved. According to the US Energy Information Administration (EIA), even with a carbon-free electricity generation standard and a $15/ton cost of carbon, natural gas consumption still increases through 2050. The EIA estimates that natural gas demand will only fall by 2050 in the case where oil and gas supplies are limited or the carbon price is at least $25/ton [Blanton, et al. 2021]. The Massachusetts 2050 Decarbonization Roadmap, commissioned by the Executive Office of Energy and Environmental Affairs (EEA), also recognizes the significant barriers to completely divesting from gas, stating "that gas use continues in some quantity across all Net Zero pathways, including for space heating" [MA EEA 2020, p. 51]. To address the challenge in moving away from carbon-emitting natural gas, replacing natural gas with hydrogen gas blends over time provides for a more smooth and expedient transition away from natural gas and the associated carbon emissions. Many net-zero scenarios include growth in hydrogen consumption transported using existing pipeline infrastructure. In these cases, zero-carbon hydrogen offers a more affordable transition to decarbonization.

Hydrogen also offers more reliability, providing a backup of energy delivery during electrical outages, particularly due to natural disasters. The Northeast has experienced a documented increase in intensity of rainfall events over the last 50 years, more so than any region in the United States. This trend will continue resulting greater impacts of flood events and Nor'easters as well. As a result of climate disasters, Massachusetts experienced over 100 percent more power outages from 2018-2020 compared to 2013-2015 (see Figure 9.4) [Resilient MA 2021; Washington Post 2021]. A number of measures have been suggested to protect electric grids during weather events, such as battery storage, microgrids, and burying powerlines underground. These measures, however, are expensive and often opposed by state regulators to avoid passing high costs onto consumers [Washington Post 2021]. In case studies of the economic impacts of climate events on electricity systems and power outages, Sanstad et al. [2020] find that states consistently underestimate the costs of power outages due to extreme weather events, resulting in the underinvestment in the resiliency of energy systems. The impact of climate-related weather events on the reliability of energy transmission is an important consideration when designing the future of Massachusetts' energy systems.

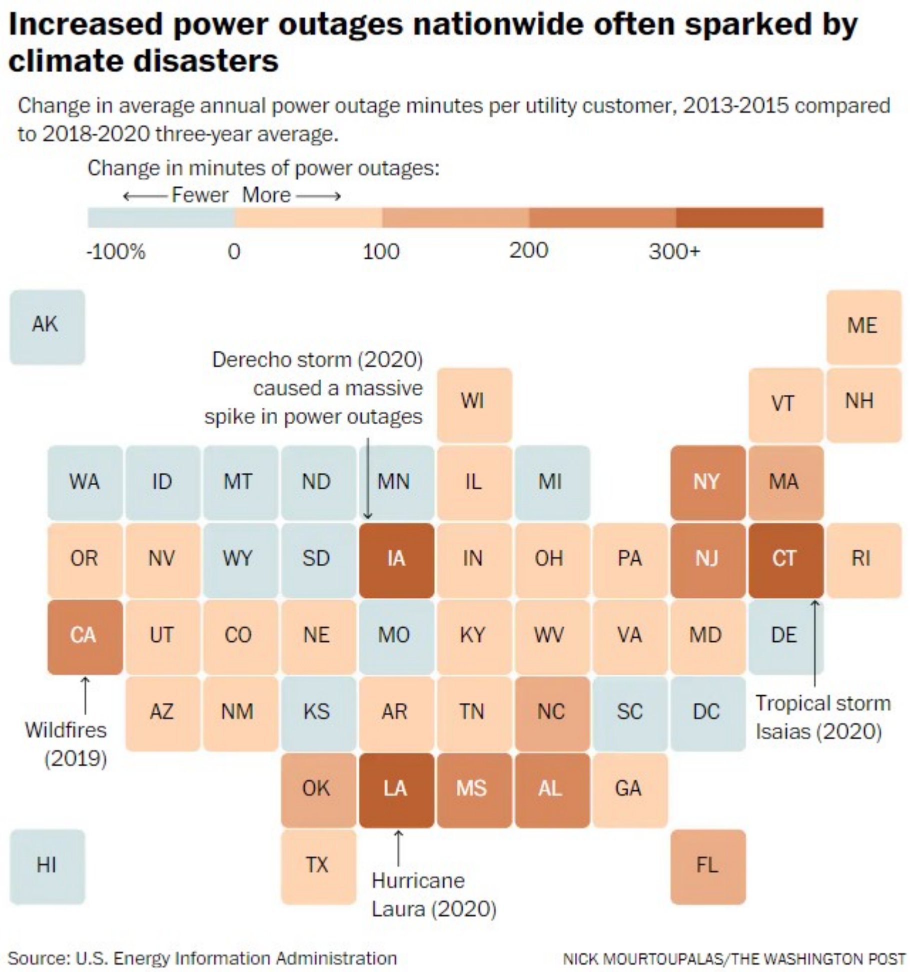


Figure 9.4 Massachusetts Power Outages Increases Due to Climate Change Weather Events [Washington Post 2021]

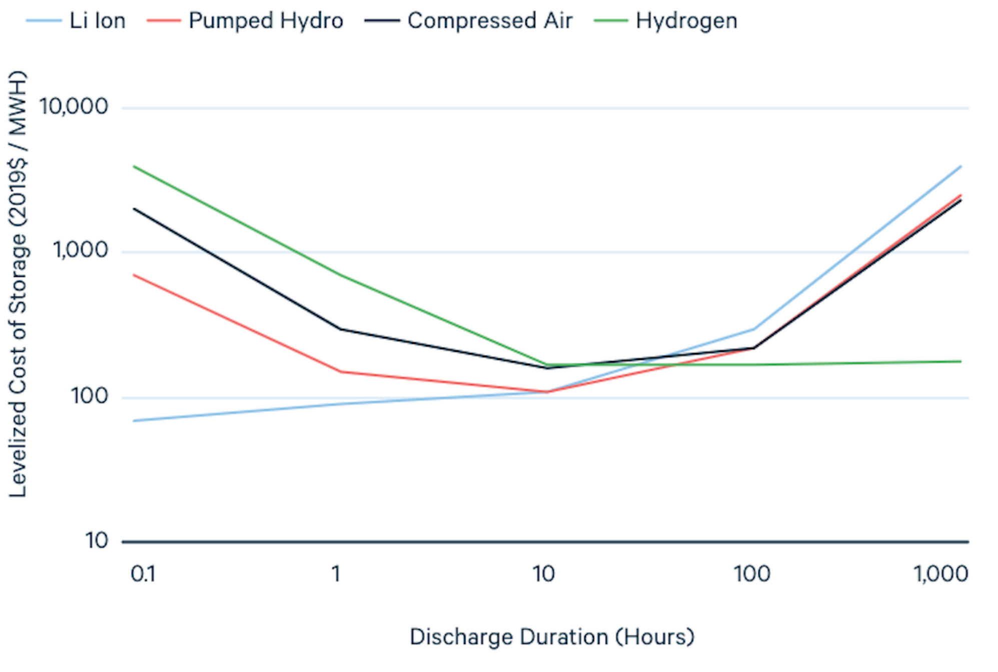
9.2.1 Specific Benefits for Massachusetts

Swift action to incentivize the addition of hydrogen to decarbonization plans has great potential to support an efficient and cost-effective transition to a zero-carbon economy. Though a shift from natural gas to hydrogen will incur costs, it is only a part of the full costs incurred by a transition to net-zero economy. There are several reasons for which the inclusion of hydrogen into Massachusetts's decarbonization plan is appealing. A major benefit of hydrogen investment is the ability to capitalize on existing pipeline assets, avoiding the cost of stranded assets [Hydrogen Council 2020]. The US already has extensive investments in distribution pipelines and has a very large demand for natural gas. Hydrogen offers a unique opportunity to capitalize on already in place delivery networks and already in place gas demand, which can accelerate and minimize the costs of decarbonization [Blanton, et al. 2021; IEA, et al. 2019; Dodds, Hawkes, 2014]. Hydrogen blends can be delivered now without the barrier of large capital costs. Using hydrogen blends and ramping up to 100 percent hydrogen over time can smooth cost increases to customers, offering customers time to adapt with small changes in price over time. In addition, starting with blending using existing infrastructure results in no commitment to investment in pure hydrogen pipeline networks before hydrogen scale-ups [Bartlett and Krupnick, 2020a; IEA 2019]. Using existing pipelines also precludes the need to go through the lengthy process of getting new permits. In order to transition to an electrified society, the existing electrical transmission system will need upgrading throughout and require a significant number of additional transmission lines that will face challenges from a public acceptance and cost perspective. There is also no need for new construction work, which will likely be opposed by local populations [IEA 2019]. The need to transition to a carbon free electrified society is clear, however, the process to do so in Massachusetts will take several decades and achieving a net-zero emissions goal can be expedited by leveraging hydrogen within the existing energy delivery assets.

Another benefit of including hydrogen in Massachusetts' decarbonization plan is the ability of hydrogen to complement electrification. Electrification is undoubtedly a vital component in decarbonization, and hydrogen integrated pipeline networks can support some of the challenges of electrification. One challenge of complete electrification is the large extent of household conversions required. The Massachusetts 2050 Decarbonization Roadmap recognizes that, "electrification and efficiency in existing buildings present a larger challenge, as this stock represents the bulk of emissions reductions needed by 2050," [MA EEA 2020, p. 52]. The MA EEA estimates one million homes in Massachusetts need updated heating systems by 2030 to achieve decarbonization by 2050 [MA EEA 2020]. As discussed in section 8.3.2, Massachusetts is struggling to make these conversions for natural gas to electricity in a timely fashion.

According to the U.S. Census Bureau's latest American Community Survey, roughly 50 percent of households in Massachusetts are currently heated by natural gas [Mass.gov 2021]. Natural gas usage and networks are so large and embedded that it will be difficult to meet peak demand with full electrification, particularly in heating sectors [Blanton, et al. 2021]. In addition, due to the widespread use and popularity of gas appliances, hydrogen boilers may be preferred over electric appliances. Though there is a noticeable difference between gas and electric appliances, consumers will experience insignificant differences between hydrogen and natural gas appliances. Continuation of gas use may also be the least costly for customers located in places with dedicated pipelines [Hydrogen Council 2020; Dodds, Hawkes 2014].

Hydrogen can help manage the intermittent nature of renewable energy. Relying solely on solar and wind energy, which have variable outputs, requires the development of costly new energy storage systems. The gas pipeline system is already designed for storage to meet peak heating demands in the winter, while full electrification in heating sector cannot handle seasonal imbalances without grid upgrades and energy storage capacity development. On a peak day, gas pipelines can deliver a much as four times the energy relative to an electric network [Blanton, et al. 2021; Bartlett, Krupnick 2020b; IEA, et al. 2019; Dodds, Hawkes 2014]. The primary storage method for renewable energy is lithium-ion batteries, which are currently not cost-effective or suited for long-term storage [Blanton, et al. 2021; Bartlett, Krupnick 2020b]. For long-term storage durations (more than two days), hydrogen has the efficiency advantage over battery, pumped hydropower, and compressed air storage (See Figure 9.5). In Figure 9.5 lithium-ion batteries, pumped hydro, and compressed air all increased in levelized cost of storage when a discharge duration of 1,000 hours was calculated and only hydrogen decreased in levelized cost of storage at 1,000 hours. When batteries have a large discharge duration it causes more stress on the components, therefore shortening the batteries life span and increasing costs. To have a long discharge duration for pumped hydro and compressed air there needs to be large storage, resulting in higher cost. Hydrogen decreases in levelized cost because most of the cost of hydrogen storage is a result of capital cost (i.e., electrolyzers and storage tanks). Hydrogen can also be stored for longer periods of time in high pressure and liquid tanks resulting in higher volumetric energy density and lower cost.



Source: IEA 2019.
Note: Levelized costs of storage reflect an input electricity price of $50/MWh as well as other assumptions from IEA (2019).

Figure 9.5 Storage Costs and Discharge Duration [Bartlett and Krupnick 2020a]

Due to climate change, Massachusetts will experience more extreme temperatures, resulting in more periods where large amounts of energy must meet heating and cooling demand [Resilient MA 2021]. The consequences of not meeting energy demands during extreme temperature are high, including residents losing access to heat, air conditioning, food, medicine, and potentially transportation if they rely on electric vehicles. Even with energy losses when reconverting hydrogen to power, the long-term storage capacity of hydrogen is significantly less costly per unit of energy relative to other storage technologies [Bartlett, Krupnick 2020b]. Diversifying energy sources though the continued use of pipeline networks is not only important for storage issues but also provides a significantly higher degree of protection from weather events that is not afforded by complete electrification [Blanton, et al. 2021]. It is important to emphasize that investments upgrading pipeline infrastructure do not represent a choice between natural gas and electrification or between fossil fuels and zero-carbon fuels. This investment can provide a cost-effective, reliable transition pathway to decarbonization. According to the Columbia University SIPA's Center on Global Energy Policy, "In the same way that the electric grid allows for increasingly low-carbon electrons to be transported, the natural gas grid should be viewed as a way to enable increasingly low-carbon molecules to be transported" [Blanton, et al. 2021, p.6].

9.2.2 International Efforts to Replace Natural Gas with Hydrogen

Replacing natural gas with hydrogen is in effect or has been proposed around the world, and is growing in population for a number of reasons presented in Figure 9.6.

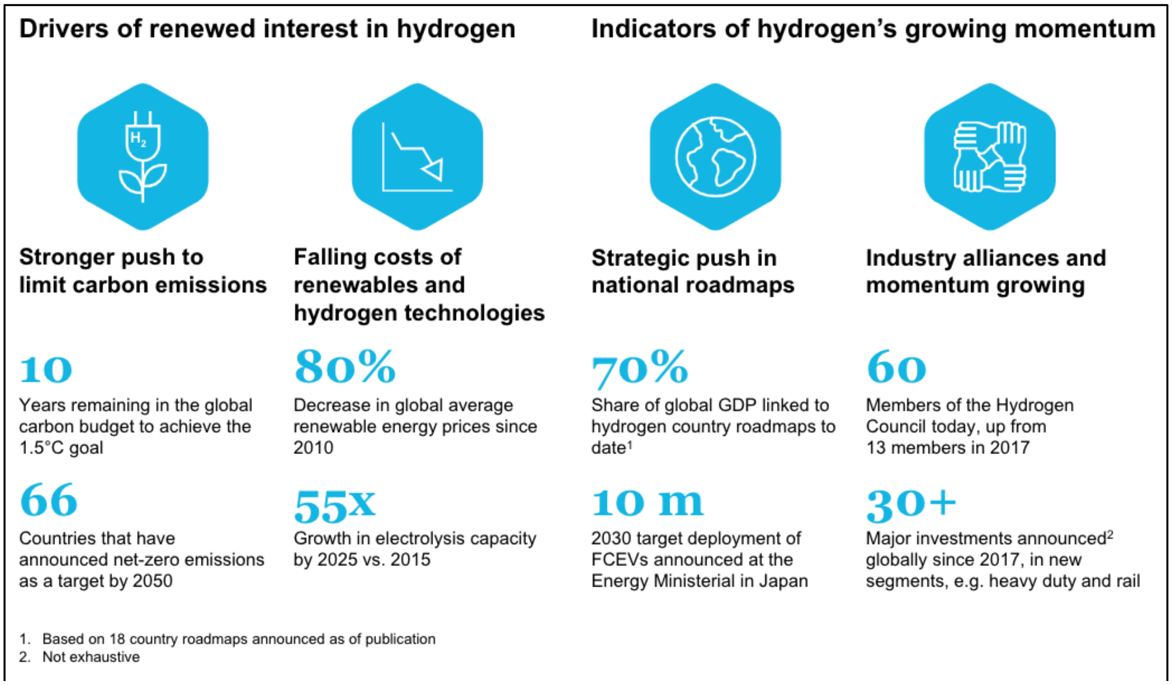


Figure 9.6 Drivers and Indicators of Hydrogen's Momentum [Hydrogen Council 2020]

Hydrogen use and research has been extensive across Europe in particular. In May 2020, Germany announced a plan to covert 1,200 kilometers of gas pipelines to a hydrogen pipeline network by 2030 at a cost of $715.8 million. Roughly 90% of the 1,200 kilometers of pipeline network will be converted and the remainder will be newly built pipelines [RECHARGE News 2020]. Canada's Enbridge Gas also recently announced a $5.2 million project that produces green hydrogen gas using electrolysis and injects it into the existing natural gas network in Ontario. The project is financially supported by the Canadian government as an effective solution to storing excess electrical energy using existing pipeline infrastructure [Enbridge 2020]. Oher countries with recently published national hydrogen strategies include Japan, South Korea, New Zealand, Australia, Netherlands, Norway, Portugal, and the European Commission [ACER 2021]. Domestically, there is widespread support for green hydrogen as a long-term alternative to fossil fuels [IRENA 2020]. According to an American survey of 1,000 senior oil and gas professionals administered by DNV in 2020, 21 percent of respondents indicated their organization was already actively engaged in the hydrogen market, and 42 percent indicated their organization intended to invest in hydrogen [Blanton, et al. 2021].

9.3 Guidance for Including Hydrogen in Decarbonization Plans

Hydrogen blending can be included in decarbonization plan with the inclusion of defined plans for the scale-up to 100 percent renewable hydrogen if it is safe to do so. It is important to identifying which sections of pipeline can most easily become hydrogen compatible. Using these network sections, smaller modifications can be made quickly to start implementing hydrogen blends and lowering carbon emissions now. Though, cast-iron pipes are not compatible with hydrogen gas and are prevalent in the Northeast, hydrogen blends can be put into place in areas with existing hydrogen compatible pipes. Materials that are compatible with hydrogen include lower carbon grade or stainless-steel pipes and polythene pipes. These pipes can be modified over time with protective coating to carry higher percentages of hydrogen in the future [Blanton, et al. 2021; Staffell, et al. 2019; IEA 2019; Dodds, Hawkes 2014]. There are still concerns with higher blend rates and durability of pipes, therefore, there should be increased pilot projects to examine hydrogen blending and not to immediately blend hydrogen into natural gas pipelines that are not suited for such a gas mixture. Once additional research and pilot studies have been conducted on how high blends of hydrogen effects steel and pipeline infrastructure then an assessment can be made on whether it is safe to increase the blend percentage of hydrogen in the natural gas pipelines system. In addition, customer rate add-ons can start now to cover pipeline modifications and spread costs to ratepayers over time instead of imposing large rate-changes all at once. Governments can also mandate that any current pipeline replacements use hydrogen-compatible plastic pipes [Blanton, et al. 2021; Dodds, Hawkes 2014].

A transition away from natural gas can be supported with a managed transition from blue hydrogen to green hydrogen. As the cost of CO_2 emissions increase, all low-carbon alternatives are expected to be least-cost options by 2040 [Hydrogen Council 2020]. More optimistically, blue hydrogen, produced using SMR with CCUS is expected to reach cost parity with electrolysis by 2035 [IEA 2019; Tlili et al., 2019]. Blue hydrogen has the potential to capitalize the current cost advantage of natural gas as a production input. In addition, expanding CCUS would not require a significant change in funds already devoted to pipeline infrastructure. It would cost an estimated $16.3 billion to build out roughly 29,700 miles of CO_2 pipelines in order to transport and capture the amount of CO_2 required for decarbonization. Comparatively, in one year (2019) the US natural gas industry invested $30.5 billion into gas transmission and distribution [Blanton, et al. 2021]. Although blue hydrogen may achieve cost parity in the future, further advancements in technology and pilot studies are required to demonstrate effectiveness before widespread implementation is possible.

9.4 Government's Role in Supporting Hydrogen Markets

9.4.1 Broad Overview

To capitalize on the benefits of hydrogen most expediently, policy support is critical. The public sector must promote investment in hydrogen production technology research, demonstration, and use. Without government support, it is highly unlikely the US will reach net-zero by 2050 [Blanton, et al. 2021]. The overarching role for governments is to clearly identify and coordinate long-term policy goals. Coordination requires defined scale-up goals for electrolyzer capacity for green hydrogen production in order to provide a signal to investors. Governments also play a key role in implementing policies that remove barriers to hydrogen growth and development [Blanton, et al. 2021; IRENA 2020]. In addition, it is important for governments to knowledge-share across national and international projects, polices and studies to streamline information for industry and other stakeholders. Communications with the public should assuage safety and misinformation concerns. In 2020, the DOE announced such an effort by collaborating with the Netherlands on hydrogen research. Research support should encourage transparency and disclosures regarding any knowledge attainted through projects being publicly supported. The US is already investing in such programs including the 2019 H2@Scale program which dedicates with $100 million over five years to hydrogen research in the US. The DOE is supporting the H2@Scale program by providing $64 million of funding for 18 projects to explore hydrogen production, storage, distribution and use [Blanton et al., 2021; IRENA, 2020].

Another way governments can promote hydrogen development is by providing market support on the demand- and supply-side. As with most industries, sector coupling and economy of scale will help in lowering costs for hydrogen production and use. To reduce production costs, market demand must be stimulated. Using low blends early on can help stimulate demand for hydrogen [Siemens 2021; IRENA 2020; IEA 2019]. On the supply-side, support is needed for the development of supply chains that can scale quickly to meet changes in demand [Siemens 2021]. Governments can publicly fund accelerated research and development to reduce uncertainties in demand, technological development and regulatory futures. This increases the incentives for private investment by reducing risk. To further reduce investment risk, governments need to set consistent blending standards to ensure safety of hydrogen use in end-use appliances. Public safety concerns or adverse events would be a large barrier to investment [IRENA 2020; IEA, et al. 2019; Tlili, et al. 2019]. To stimulate hydrogen supply, it is particularly important to reduce risk for first-movers [Hydrogen Council 2020; IRENA 2020; IEA 2019]. As with demand support, growth in hydrogen supply can be bolstered by the creation of timelines and roadmaps with key milestones for large-scale, long-term upgrade and conversion programs [Hydrogen Council, 2020; IEA, 2019].

9.4.2 Specific Policies to Support Scale-up of Hydrogen Production

There are several policies that can support an efficient transition to hydrogen. These include: 1) green procurement programs, 2) clean energy standards and renewable portfolio standards, 3) market-based approaches such as taxes and subsidies, and 4) other government support mechanisms like direct grants, conditional and convertible loans, and feed-in-tariffs [Bartlett, Krupnick 2020a; IRENA, 2020; Hydrogen Council, 2020].

With green procurement, the government sets up programs to purchase products that are standardized or certified sustainable and recommends these products to the private sector. These programs are easy to implement, can be complementary to other polices, and can create a demand pull on the market, lowering costs. For example, the US Department of Defense purchases four percent of US fuels and could switch to purchasing zero-carbon hydrogen fuels and other goods produced with zero-carbon hydrogen like steels and chemicals [Blanton, et al. 2021]. However, these programs are costly to the government and have some disadvantages. The product standards or certifications set by the government can be inflexible, leading to inefficient production decisions compared to those that would be made using market price signals. Also, if the government's procurement is on a small-scale and there are issues with coordinating demand and rules, green procurement may be inefficient and ineffectual [Bartlett, Krupnick 2020a].

Alternative approaches include clean energy standards (CES) and renewable portfolio standards (RPS). CES could require benchmark firm-level carbon emissions or emissions intensities [Bartlett, Krupnick 2020]. For instance, the government could require industrial hydrogen producers to use a specified amount of green hydrogen or require that the power sector meet gas demand with a specified amount of green hydrogen [IRENA, 2020]. Similarly, RPS could require retail electricity suppliers to increase use of renewable power overtime. RPS, however, are less appealing as other policy options due to a number of disadvantages. First, costs to suppliers of switching to renewable electricity can be passed on to electricity consumers. Second, RPS is limited in its application to sectors where suppliers and customers have little flexibility in purchasing or choosing low-carbon fuel alternatives. This is particularly true in the industrial sector, for which RPS can force firms to produce using costly inputs priced above existing and viable least-cost options. Though producers incur higher costs of production, customers of industrial goods are not required to purchase goods from specific firms and can turn to cheaper international products, potentially resulting in domestic job losses. On the other hand, RPS in the power sector is easy to implement with little concern of job losses, but it can still be costly for firms to meet the standard, making it unpopular politically [Bartlett, Krupnick 2020a].

Market-based solutions can more effectively incentivize hydrogen use and production compared to command-and control policies. Market-based policies include: 1) cap-and-trade programs, 2) carbon taxes, and 3) subsidies (tax credits). Cap-and-trade programs implemented in the power sector is a promising policy option. The program would work by requiring a certain level of hydrogen blending for utilities. The government then gives permits to firms that grant the right to use blends below the standard. The permits can be traded between firms. Utilities that satisfy blending requirement will sell permits to those that do not. In this way, firms that can meet or exceed hydrogen blend standards at lower costs do so and benefit more from selling their permits. Firms that cannot meet the blending standard will find it cheaper to buy to permits and not meet the standard.

The second market-based approach, carbon taxes, is favored by economists as the most efficient and cost-effective policy instrument to support decarbonized hydrogen. However, the implementation of carbon taxes is politically very difficult, and therefore, the remaining discussion focuses on hydrogen tax credits, which are the second-best option. Tax credits are a more practical and efficient incentive relative to command-and-control approaches and are politically favored over taxes [Bartlett, Krupnick 2020a]. Another support for tax credits over carbon taxes is that, with a carbon tax, firms are incentivized to move production with carbon byproducts to countries with less stringent carbon regulation, resulting in no net global carbon reduction and domestic job losses [Bartlett, Krupnick 2020a].

Hydrogen tax credits have been historically successful policy instruments and allow flexibility in an environment characterized by several applications, uncertainty in cost trajectory, and concerns about safety and job losses. Production tax credits (PTC) have been successful in supporting demand for wind energy, and investment tax credits (ITC) have spurred demand for solar power. Tax credits have also been successful in other countries such as the Netherlands, which subsidizes hydrogen produced by electrolysis with the SDE++ program [Bartlett, Krupnick 2020a; IRENA 2020]. In addition, the implementation of tax credits faces a relatively easier process than other policies as tax credit programs can pass through the budget reconciliation process. Once a tax credit program is passed, firms have a 10-year window to claim the credit, allowing time for decarbonized hydrogen projects to start up. The downside of a tax credit is the cost incurred by the government [Bartlett, Krupnick 2020a].

Tax credits can stimulate cost reductions in hydrogen production, which will likely not occur quickly without government support [Hydrogen Council 2020; Tlili 2019]. Tax credits should start with a high credit to speed up demand initially and gradually decrease over time as the price of decarbonized hydrogen falls. A tax credit can speed up hydrogen's ability to become competitive. For instance, a \$50/tCO_2 tax credit (equal to the marginal abatement cost of emission capture up to 60%) would make blue hydrogen (with up 60 percent CO_2 capture) competitive with grey hydrogen. \$50/tCO2 is also consistent with the global social cost of carbon (SCC) and the 45Q tax credit for CCUS. However, a tax credit of \$100/tCO2 (equal to the marginal cost of emissions capture of around 90%) would be needed make grey hydrogen with 90 percent capture competitive [Blanton, et al. 2021; Bartlett, Krupnick 2020a].

The design of tax credit policies must consider many different factors. Blanton et al. [2021] and Bartlett and Krupnick [2020a] suggest a hydrogen tax credit policy could be modeled after the 45Q tax credit for CCUS. 45Q offers a tax credit of 50/tCO2 (based on the current SCC) for carbon abatement through CCUS. For example, an ammonia plant making H_2 using CCUS to abate CO_2 byproducts can apply for 45Q tax credit. 45Q is currently active though 2025 but an amendment has been proposed to extend the credit through 2030. Bills have also been introduced to increase the value of the tax credit to \$60-\$110/tCO_2 captured. [Bartlett, Krupnick 2020a]. As with 45Q, defining an appropriate duration for a hydrogen tax credit is important. To support green hydrogen, a credit must last for a long enough duration considering the slow development of new hydrogen production technologies, CCUS projects and large-scale renewable energy projects. Bartlett and Krupnick [2020a] suggest a 10-12 year duration for a decarbonized hydrogen tax credit.

The design of a hydrogen tax credit also requires the choice between a PTC and an ITC. ITCs provide a credit for investing in expensive decarbonized hydrogen technology. The credit is the difference in investment cost in the more expensive hydrogen technology and the less expensive, higher carbon technology choice. This type of credit is useful when large capital expenditures are required and has been successfully used to promote investment in renewable technologies. An advantage of ITCs over PTCs is that they have a higher present value as they are given in the first year of the project. Production tax credits are given only after the project begins. In addition, as ITCs are a percentage of the capital cost, the ITC falls with falling capital costs without any government intervention [Bartlett, Krupnick 2020a]. Another advantage of ITCs over PTCs is that PTCs will not necessarily influence consumer choices. With just a PTC in place, it may be necessary to give an ITC to consumers to incentivize investments in hydrogen-compatible end-use appliances [Blanton, et al. 2021; Bartlett, Krupnick 2020a; Dodds, Hawkes 2014]. It is reasonable to have two tax credits, one for consumers and one for producers; however, care must be exercised to avoid 'double counting' of tax credits [Bartlett, Krupnick 2020a]. A disadvantage of an ITC relative to PTC is that ITCs reduce the capital costs of hydrogen production, encouraging producers to underutilize electrolyzers. PTCs allow producers to tradeoff between electrolyzer utilization and power costs. Higher utilization is more costly due to unavoidably high-power prices, but to capitalize on low power prices, the efficiency of higher utilization must be sacrificed.

As of June 2020, the House Select Committee on the Climate Crisis announced their intention to implement both an ITC and PTC in the industrial hydrogen sector. In the design of the PTC, they suggest that credits must be at least \$0.70/ kg for blue hydrogen and \$1.00-1.50/kg for green hydrogen [Blanton, et al. 2021]. Choosing the correct credit price is crucial. There are generally two options for setting the PTC credit. The first is setting a price based on the SCC, which is currently about \$50/tCO_2 and estimated to increase to \$84/tCO_2 in 2050. Using the SCC requires evaluation of whether the SCC is below the cost of low-carbon hydrogen production. If this is the case, the incentive will not work until the SCC rises above the cost of low-hydrogen production. Another option is to set the credit based on the cost of hydrogen production and distribution. The tax credit is the value that incentivizes hydrogen projects and falls over time to reflect decreasing production costs. It is also important to build plans for monitoring, reporting, and verification (MRV) into a tax credit design so that credit amounts are accurately determined [Bartlett, Krupnick 2020a].

With PTCs or ITCs for hydrogen production, these designs must also consider how hydrogen tax credits will work simultaneously with the existing 45Q tax credit. The 45Q credit is likely to exist at the time of implementation of a decarbonized hydrogen tax credit. Since the 45Q credit subsidizes CCUS, it already provides a credit for blue hydrogen production. To avoid 'double counting', blue hydrogen production should be allowed to claim either the hydrogen tax or the 45Q tax credit. However, if companies use hydrogen to displace carbon inputs in the production process, it is possible to allow claims to both tax credits. Policymakers should also be aware of the perverse incentive 45Q creates for firms to not transition from blue hydrogen to green hydrogen production. The problem is that the 45Q tax credit rewards carbon capture. For example, blue hydrogen with 60 percent capture gets a smaller credit than blue hydrogen with 90 percent capture. This incentivizes firms to deliberately use higher carbon input fuels in blue hydrogen production, creating more tCO_2 to capture and receive the largest credit.

Appendix 10. References

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