Final Report

The Development of Lifecycle Data for Hydrogen Fuel Production and Delivery

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Disclaimer

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ABSTRACT

An evaluation of renewable hydrogen production technologies anticipated to be available in the short, mid and long term timeframes was conducted. The conversion technologies included thermal processes, electrolytic processes, photolytic processes, and biochemical processes. A Life Cycle Analysis using the CA-GREET Tier 2 model was performed on a subset of the production technologies for both centralized and distributed pathways, including hydrogen production via electrolysis, by biomass gasification, and by biogas reforming. An economic analysis using the H2A model was performed for these pathways. The resulting greenhouse gas emissions (gCO_2e/MJ H2) and hydrogen cost ($/kg) are reported. Sensitivity analyses were performed for both the cost and emissions. A review of the potential to inject hydrogen into natural gas pipelines for distribution was performed. The review considered issues such as safety, hydrogen leakage, embrittlement of pipelines, general risk, and extraction of hydrogen. The potential hydrogen demand from off-road transportation fuel cell markets was estimated over a ten year timeframe. Specific markets considered were material handlers (forklifts), transport refrigeration units, airport ground support equipment, and telecommunications backup power.

EXECUTIVE SUMMARY

An evaluation of renewable hydrogen production technologies anticipated to be available in the short, mid and long term timeframes was conducted. Renewable conversion pathways often rely on a combination of renewable and fossil energy sources, with the primary conversion step relying on a completely renewable source and the auxiliary steps using a more readily available energy mix such as grid electricity.

The conversion technologies can be broadly classified into four categories based on the primary conversion mechanism: thermal processes, electrolytic processes, photolytic processes, and biochemical processes. Based on anticipated technology readiness, water electrolysis and biogas reforming pathways will be available in the near term whereas biomass gasification and bio-derived liquids reforming pathways are expected to be available in the mid-term. Photolytic and dark fermentation approaches are still in the research stage and must go through significant development and demonstration.

Life Cycle Analysis using the CA-GREET Tier 2 model was conducted for select centralized and distributed hydrogen production pathways. Fossil natural gas reforming, the dominant industrial hydrogen production technology, is used as the baseline against which renewable hydrogen production technologies are compared. Electrolysis using renewable power from a solar PV facility results in the lowest GHG emissions among centralized production pathways. The grid electricity based hydrogen production uses the highest amount of total and fossil energy and results in significantly higher GHG emissions compared to the baseline.

An economic analysis of select pathways was also conducted using the H2A model. Fossil natural gas reforming offers the most cost effective production option through central & distributed production. Electrolysis using renewable electricity (solar PV) results in the highest production costs through a centralized pathway whereas centralized biomass gasification offers the most cost effective production method using a renewable feedstock. Based on the life cycle GHG emissions and cost performance, centralized biomass gasification pathway offers the most cost effective option to reduce GHG emissions.

A review of studies focused on blending hydrogen into natural gas pipelines was conducted. The review focused on issues that impact the viability of blending. Those issues include effects on public safety, potential gas leakage from pipelines, durability of the pipeline networks, and effects on end-use equipment such as stoves or boilers.

The studies indicate that hydrogen blends up to 15% by volume appear viable without increasing risk. There is significant variable in pipeline operating conditions such as pressure, temperature, pipeline materials, and natural gas composition. This variation requires case specific analysis to determine the ideal blend percentage. Hydrogen can damage pipelines by degrading materials. Integrity management programs must be modified to properly monitor and maintain the pipelines one hydrogen is introduced.

During the early stages of fuel cell electric vehicle (FCEV) market penetration, hydrogen demand may be low to modest due to low sales. Off-road vehicle fuel cell markets could potentially increase the hydrogen demand easing the path to commercialization for hydrogen producers. An analysis of the potential for hydrogen demand in off-road transportation markets was performed. Potential markets include material handlers (forklifts), airport ground support equipment, and transport refrigeration

units. Telecommunications (backup power) was also considered as a potential hydrogen market. Each market was analyzed to understand the fleet stock, to determine the status of fuel cell applications, and to estimate market penetration for fuel cell equipment over a 10 year timeline. The fleet stock was projected out through 2026 based on macroeconomic projections of the California gross state product. The yearly energy usage for equipment in these markets was estimated based on reports and discussions with fuel cell companies producing equipment. The potential for hydrogen demand (kg/year) was then calculated for each market.

The potential off-road transportation hydrogen demand is dominated by the forklift market. The present stock of forklifts is significantly higher than the total stock of other off-road vehicle markets considered. In addition forklifts use more energy per year than other markets, and fuel cell forklifts have been recently commercialized. It’s estimated that roughly 7,700 fuel cell forklifts are operating in the US. While the telecommunications market for fuel cells is growing, the actual hydrogen usage is insignificant. The grid reliability is so high that backup power units are rarely required to supply power for telecommunications equipment. Both fuel cell transport refrigeration units (TRUs) and airport ground support equipment are in the demonstration phase. It’s unclear when fuel cells will begin entering these markets. The potential market penetration for forklifts was estimated to be 30% of new sales by 2026 while the market penetration for TRUs and airport ground support equipment is not expected to exceed 5% of sales by that time.

The total hydrogen demand from off-road Transportation markets through 2026 was estimated to be over 18 million kg/year. Fuel cell TRUs and airport ground support equipment contribute less than 1 million kg/year to that total. As a comparison, estimates of hydrogen demand from light-duty fuel cell electric vehicles (FCEVs) are in the range of 30 million kg/year by 2026.

1. INTRODUCTION

The California Air Resources Board (CARB) developed the Low Carbon Fuel Standard (LCFS) to reduce lifecycle greenhouse gas (GHG) emissions in the transportation sector. The regulation identifies lifecycle pathways for each fuel and assesses a carbon intensity score. The LCFS regulation requires fuel providers to meet carbon intensity targets each year. These targets are reduced over time; therefore, overall GHG emissions from the California transport sector decrease as well. CARB has performed lifecycle assessments of many transportation fuel pathways, but important additional pathways have not yet been analyzed and currently have no carbon intensity scores.

Zero emission vehicles (ZEVs) represent a critical component of plans to meet GHG reduction goals. Hydrogen fuel cell electric vehicles (FCEVs) may contribute significantly to the future ZEV market. While FCVs have no tailpipe emissions, the upstream processes which produce and deliver the fuel may have substantial emissions. To minimize upstream emissions, hydrogen production from low-emitting and renewable sources is a high priority. While CARB has analyzed and published some hydrogen pathway carbon intensities scores, many renewable pathways have not been assessed. The Air Resources Board (ARB) staff requires lifecycle data to be collected and evaluated for these critical hydrogen renewable pathways.

While hydrogen can be produced locally and doesn't necessarily require distribution across large distances, it is expected that a significant amount of hydrogen produced for both transportation and off-road Transportation applications will be produced in regions that require distribution networks. There exist some dedicated hydrogen pipelines in the US, but the size of these networks is small. Building a dedicated hydrogen infrastructure of pipelines would require significant funding that would likely be beyond the means of small initial hydrogen markets. Other distribution technologies such as liquid tanker trucks could be used to distribute hydrogen, but the most cost-effective way of distributing hydrogen may be blending the hydrogen with natural gas in the existing natural gas pipeline infrastructure. While the natural gas infrastructure already exists, the blending strategy would require additional costs such as the hardware for injection and extraction and costs to modify the existing pipeline integrity management systems. Understanding the potential for hydrogen injection into, distribution through, and extraction from the present natural gas pipeline infrastructure is necessary to evaluate the possibility of using this infrastructure to distribute hydrogen for use in transportation.

During the early introduction of FCEVs, the market for hydrogen fuel is expected to be modest. The business case for hydrogen production could then suffer from lack of sufficient demand. If off-road transportation markets existed for hydrogen, the demand from those markets could reduce the market uncertainty for near- and mid-term hydrogen producers.

The purpose of this project is to address three distinct but related hydrogen issues – lifecycle analysis of renewable hydrogen pathways, the potential for hydrogen injection and distribution through natural gas pipeline infrastructure, and the potential demand for hydrogen from off-road Transportation markets. The specific objectives are described below.

- Review the available literature to assess the most effective combinations of alternative fuels, fuel infrastructure, and vehicle powertrain technology to reduce GHG and criteria air pollutant emissions in hydrogen fuel pathways.
- Perform lifecycle analyses to determine pathways with the lowest greenhouse gas and criteria pollutant emissions for the production, distribution, and storage of hydrogen.
- Estimate the costs of each potential hydrogen pathway to determine the most cost-effective options for reducing greenhouse gas and criteria pollutant emissions.
- Assess the potential for using the current natural gas infrastructure in renewable hydrogen fuel pathways.
- Identify potential hydrogen markets in the off-road Transportation sector that could increase overall hydrogen demand and identify barriers to growth and strategies to overcome these barriers in these markets.

1.1 HYDROGEN LIFECYCLE ANALYSIS (LCA) LITERATURE REVIEW

There have been many LCA studies of hydrogen production over the past 15 years. These studies include a variety of advanced pathways such as biomass gasification, wind and solar electrolysis, nuclear based high temperature electrolysis, and coal gasification with carbon capture and sequestration (CCS). Bhandari et. al. reviewed 21 such studies covering 14 production technologies and compare the global warming potential (GWP) using the metric $kgCO_2e/kgH_2$ (Bhandari 2014). Grid based electrolysis has by far the highest GWP with steam methane reformation and coal gasification without CCS significantly higher than the remainder. The vast majority of production technologies have a small range of GWPs with the exception of solar PV electrolysis, steam methane reformation, and steam reformation of vegetable oil. The small variation indicates fairly high consistency in assumptions for the pathways.

Several recent studies are briefly discussed below. The review indicates that the pathways included in the studies, some basic assumptions, and results for hydrogen production cost and GHG emissions. This review focuses on advanced production pathways and does not show results for steam reformation of natural gas.

1.1.1 NUCLEAR HYDROGEN PRODUCTION

El-Eman et. al. conducted a comparative cost assessment of hydrogen production using nuclear power (El-Emam 2015). They considered 3 nuclear power reactors: Prismatic core (PMR), Pebble bed (PBR), and High Temperature Gas Reactor (HTGR). The HTGR case included one configuration with 4 nuclear units and one configuration with 6 units. The 6 unit case had a higher capital cost but a significantly lower electrical energy cost. The hydrogen production plant consisted of a hybrid sulfur thermochemical plant. The PMR and PBR reactors supplied heat used in the thermochemical process. The HTGR reactors supplied both heat and electricity for the hydrogen production process. The study used the

Hydrogen Economy Evaluation Program (HEEP) to calculate hydrogen production costs. Table 1 shows the cost results for hydrogen production from the 4 cases.

Table 1. Hydrogen production costs from nuclear power.

Nuclear reactor type	Hydrogen production cost ($/kg)
PMR	5.40
PBR	4.32
HTGR (4 units)	4.30
HTGR (6 units)	3.41

Source: El-Emam 2015

The International Atomic Energy Agency used the HEEP program to estimate hydrogen production costs using nuclear power (IAEA 2013). They considered 4 reactor cases – four modules of 600 MW PMR, four modules of 200 MW PMR, ten modules of 250 MW PBR, and four modules of 200 MW PBR. The hydrogen production plant used a sulfur-iodine thermochemical process. The reactors were assumed to generate no electricity and all the heat generated from the nuclear reactions would be utilized by the thermochemical plant. Table 2 shows the production costs for the four nuclear cases.

Table 2. Hydrogen production costs from nuclear power.

Nuclear reactor case	Hydrogen production cost ($/kg)
PMR (4 modules 600 MW)	4.25
PMR (4 modules 200 MW)	5.00
PBR (10 modules 250 MW)	4.53
PBR (4 modules 200 MW)	5.19

Source: IAEA 2013

Hacatoglu et. al. performed a streamlined LCA of a nuclear based, copper-chlorine thermochemical hydrogen production cycle (Hacatoglu 2012). The analysis considered production, compression, and distribution. The production component includes fuel processing, supercritical water reactor (SCWR) nuclear plant construction and operation, and hydrogen plant construction and operation. The analysis assumed compression of hydrogen from 1 to 200 atm for transport. The compressed hydrogen is then transported 300 km to fueling stations by diesel truck. GHG emissions were calculated to be 27 gCO_2e / MJ of produced hydrogen. The analysis assumed utilization in a FCEV. Overall emissions were then 67 gCO_2e / MJ (40% efficient fuel cell) and 45 gCO_2e / MJ (60% efficient fuel cell).

1.1.2 ELECTROLYSIS

Ainscough et. al. investigated the hydrogen production cost using proton exchange membrane (PEM) electrolysis (Ainscough 2014). They considered both distributed forecourt and centralized production, and for each case they looked at current year production (2013) and future production (2025). They assumed that the distributed forecourt systems produced 500 kg/day in 2013 and 1,500 kg/day in 2025 and that the centralized systems produced 50,000 kg/day. They used the Hydrogen Analysis version 3 (H2A v3) model for their economic calculations. Electricity was supplied by the grid with average levelized prices varying from \$6.12 - \$6.89. The cost results for hydrogen production are given in Table 3.

Table 3. Hydrogen production costs from PEM electrolysis from Ainscough et. al..

Electrolysis Case	Hydrogen production cost ($/kg)
Forecourt 2013	5.14
Forecourt 2025	4.23
Centralized 2013	5.12
Centralized 2025	4.20

Source: Ainscough 2014

Suleman et. al. performed an LCA analysis on serval hydrogen production pathways including wind and solar PV electrolysis (Suleman 2015). The wind power plant had a rating of 800 MW. The GWP analysis does not include distribution or compression of the hydrogen. The GHG emissions for each pathway are shown in Table 4.

Table 4. Hydrogen GWP emissions from wind and solar PV electrolysis from Suleman et. al..

Pathway	GWP ($gCO_2e/MJ\ H_2$)
Wind electrolysis	0.3
Solar PV electrolysis	3-9

Source: Suleman 2015

Harvego et. al. analyzed several high temperature electrolysis systems for hydrogen production (Harvego 2012). The reference system uses natural gas fired heaters to supply heat and grid electricity to power system components for a 1,500 kg/day forecourt facility operating at 800 °C. The electrolyser is operated in thermal neutral mode. One variation replaces the natural gas heaters with electrical resistance heaters. Another variation operates the electrolyzer below thermal neutral mode to reduce the electrical power requirements. The forecourt systems include compression, storage, and dispensing

In addition the study considers two scenarios with a 50,000 kg/day central production plant operating in thermal neutral mode with natural gas heaters. One scenario includes carbon sequestration of the natural gas combustion products while the other scenario does not. These analyses do not consider distribution, compression, storage and dispensing.

Table 5 shows the total production cost with and without compression, storage, and dispensing for the forecourt systems as well as the production cost for the central production facilities.

Table 5. Hydrogen production cost for HTE hydrogen production systems from Harvego et. al.

Pathway	Production Cost (2010$)	Production Cost with compression, storage, and dispensing (2010$)
Reference Forecourt	3.12	4.87
Forecourt with electric heaters	3.26	5.01
Forecourt operated below thermal neutral	4.89	6.64
50,000 kg/day central facility with no sequestration	2.68	
50,000 kg/day central facility with sequestration	3.08	

Source: Harvego 2012

1.1.3 BIOMASS GASIFICATION

Susmozas et. al. analyzed hydrogen production from gasification of poplar feedstock coupled with a carbon capture system (Susmozas 2016). The syngas from the process is fed to a pressure swing adsorption (PSA) unit to separate the hydrogen. The PSA off-gas is combusted to produce electricity in a steam cycle. The exhaust gas is fed to a two-stage gas separation polymeric membrane separation process to capture the CO_2. The analysis does not include distribution and compression of hydrogen. The resulting GWP for the three processes, poplar production and transport, hydrogen production, and carbon capture, along with the total is shown in Table 6.

Table 6. Hydrogen production GHG emissions for poplar gasification and carbon capture

Process	GWP ($gCO_2e/MJ\ H_2$)

Poplar production and transport	-274
Hydrogen production	106
CO_2 capture	45
Total	-122

Source: Susmozas 2016

1.1.4 MULTIPLE PATHWAYS

Ramsden et. al. conducted a life-cycle assessment of 10 hydrogen production pathways evaluating the cost and GHG emissions (Ramsden 2013). They addressed well-to-wheel transportation fuel cycle as well as the vehicle production and disposal/recycling. The 10 pathways are distributed natural gas, distributed ethanol, distributed grid electricity, four central biomass cases with different distribution methods, central natural gas, central wind electrolysis, and central coal with carbon sequestration. The study utilizes the hydrogen Macro-System Model which links the H2A Production models, the Hydrogen Delivery Scenario Analysis Model, the Greenhouse Gas, Regulated Emission, and Energy for Transportation (GREET) Model, and the Cost-per-Mile Tool. The end use vehicles were FCEVs with an on-road fuel economy of 48 miles per gasoline gallon equivalent (mpgge). Each pathway utilizing an electrolyzer or biomass is described below.

Distributed grid electricity – Hydrogen is produced locally using a 1,500 kg/day grid electrolyzer. The hydrogen is compressed and stored at 875 bar for dispensing.

Centralized wind electrolyzer – Hydrogen is produced at a centralized grid-powered electrolyzer with a capacity of 52,300 kg/day. The facility purchases wind credits for all the electricity used in production. Hydrogen is compressed to 69 bar and distributed by pipeline to a 1,000 kg/day forecourt refueling station where it is compressed to 875 bar.

Central biomass - Woody biomass (poplar) is transported by truck to a production facility with a capacity of 155,000 kg/day. The biomass is converted to biogas using a gasifier and to hydrogen using a catalytic steam methane reformer with a water shift gas reaction. There are four delivery options for this pathway. For each case the hydrogen is compressed to 875 bar for storage and dispensing at 700 bar.

- Pipeline delivery: Hydrogen is compressed to 69 bar and transported by pipeline to a 1,000 kg/day forecourt refueling station.
- Gaseous truck delivery: The hydrogen is transported using tube trailers to an 800 kg/day forecourt refueling station.
- Liquid truck delivery with gaseous dispensing: Hydrogen is liquefied and transported by tube trailer to a 1,000 kg/day forecourt refueling station where it is vaporized for dispensing.

- Liquid truck delivery with cyro-compressed dispensing: Hydrogen is liquefied and transported by tube trailer to a 1,000 kg/day forecourt refueling station where it is dispensed using a cryogenic pump.

The hydrogen cost and GHG emissions for each pathway are shown in Table 7.

Table 7. Hydrogen production costs and GHG emissions from the six electrolysis or biomass pathways from Ramsden et. al..

Pathway	Hydrogen Cost (2007$)	GHG emissions (gCO_2e/MJ H_2)
Distributed grid electricity	6.75	354
Centralized wind electrolyzer		33
Central biomass, pipeline delivery	6.32	49
Central biomass, gaseous truck delivery	5.74	45
Central biomass, liquid truck delivery, gaseous dispensing	5.12	10
Central biomass, liquid truck delivery, cryo dispensing	5.73	81

Source: Ramsden 2013

Cetinkaya et. al. assessed coal gasification without carbon capture, water electrolysis using wind and solar power, and nuclear thermochemical water splitting (Cetinkaya 2012). The analysis included construction of equipment and production plants, transportation of raw inputs, and plant operation. Distribution of hydrogen to refueling stations was not analyzed. The plant sizes considered were 284 tonnes/day hydrogen output for the coal gasification plant, 30 Nm^3/hr for the wind electrolyzer, 8 kW PV system for the solar electrolysis, and the thermochemical plant size is not given. The GHG emissions for each pathway are shown in Table 8.

Table 8. Hydrogen GHG emissions from the pathways analyzed in Cetinkaya et. al..

Pathway	GHG emissions (gCO_2e/ MJ H_2)
Coal gasification	94
Water electrolysis from wind	8

Water electrolysis from solar PV	20
Thermochemical water splitting via Cu-cl cycle	102

Source: Cetinkaya 2012

Reiter and Lindorfer considered power to gas (PtG) production of hydrogen using wind or solar PV to power electrolyzers (Reiter and Lindorfer 2015). They considered? PtG plants which produce both hydrogen and methane. The hydrogen production utilizes alkaline or PEM electriolyzers sized at several MW_{el}. The GWP analysis does not include distribution or compression of the hydrogen. The GHG emissions for each pathway are shown in Table 9.

Table 9. Hydrogen GHG emissions from the pathways analyzed in the PtG Reiter and Lindorfer study.

Pathway	GHG emissions (gCO_2e/ MJ H_2)
Wind electrolysis	5
Solar PV electrolysis	25

1.2 TECHNOLOGY AVAILABILITY ASSESSMENT

Hydrogen can be produced from a range of feedstocks using a number of technology options. The predominant hydrogen production pathway is the steam reforming of fossil natural gas in centralized facilities. The technology is commercially mature and the energy consumption, and emissions have been studied in detail for this scenario. This section provides a list of different renewable hydrogen production technologies along with a discussion of the most important pathways. Fossil fuel based technologies (ex. coal gasification with carbon capture and sequestration) and nuclear energy based processes (ex. nuclear waste heat driven water splitting) are not considered.

Hydrogen production technologies can be broadly classified into four categories.

- Thermal processes
- Electrolytic processes
- Photolytic processes
- Biochemical processes

1.2.1 THERMAL PROCESSES

This group of technologies convert the raw materials into hydrogen through the use of thermal energy, either derived from the feedstocks or from external sources. Most well-known among thermal processes are 'thermochemical' pathways such as steam reforming, and gasification that produce hydrogen through chemical conversion of the feedstocks.

Other thermal processes include reforming of renewable liquid fuels such as ethanol and high temperature water splitting. Most important categories of thermal conversion processes are:

1. Biomass gasification and pyrolysis
2. Bio-derived liquids reforming
3. Biogas reforming
4. Thermochemical water splitting

1. Biomass Gasification and Pyrolysis

Carbonaceous renewable feedstocks such as biomass, biosolids, and waste matter can be converted into hydrogen through thermochemical processes such as gasification and pyrolysis. Direct thermochemical conversion can enable the use of significant quantities of sustainable carbonaceous resources including waste streams such as Municipal Solid Waste (MSW), agricultural residue, etc. and energy crops. Gasification is the best-known pathway among thermochemical conversion technologies. Several gasification technologies are currently under development although successful commercialization has not been achieved. Besides issues related to gasification technology itself, there are significant additional barriers such as feedstock availability, collection and transportation costs, feedstock pretreatment, tar formation, gas cleanup, and high capital costs. Many of these challenges are unique to renewable feedstock conversion.

An attractive feature of gasification is that the feedstock can be any type of biomass including agricultural residues, forestry residues, byproducts from chemical processes, and even organic municipal wastes. Moreover, gasification typically converts most of the carbon in the feedstock, making it more attractive than enzymatic ethanol production or anaerobic digestion where only portions of the biomass material are converted to fuel. The second advantage is that the product gas can be converted into a variety of fuels (H_2, RNG, synthetic diesel,gasoline, etc.) and chemicals (methanol, acetic acid).

Gasification processes are primarily designed to produce synthesis gas (syngas, a mixture of hydrogen and carbon monoxide) by converting the feedstock under reducing (oxygen deficient) conditions in the presence of a limited amount of gasifying agent such as air, steam or oxygen (Higman 2003, Kumar 2017). Gasification consists of 3 major steps. The first step is devolatilization of the dried feedstock to produce the fuel gas for the second step, which is combustion. The combustion step produces the necessary heat and reducing environment required for the final step. The final step (so-called reduction step, char gasification step or syngas production step), is the slowest reaction phase in gasification, and often governs the overall gasification reaction rate. These 3 steps can be shown as:

Devolatilization: Feedstock → Fuel gas +Char
Combustion: Fuel gas + Air → Flue gas + Heat (~25% of carbon)
Reduction: Fuel gas, Char + Heat → Syngas (~75% of carbon)

Gasification: Feedstock + Air → Syngas + Flue gas + Ash

Approximately 25% of carbon in the feedstock is consumed in the combustion step to provide the heat and reducing environment for the reduction step. A detailed discussion of gasification, including minor steps and considerations is available elsewhere (Higman 2003).

Gasification technologies for renewable hydrogen production can be broadly classified into two categories (Albrecht, 2015).

a. Directly heated gasifiers
b. Indirectly heated gasifiers

a. <u>Directly Heated Gasifiers</u>: Oxygen or air blown gasifiers, commonly referred to as partial oxidation gasifiers, derive the heat necessary to convert the feedstock through combustion of a portion of the feedstock in the gasifier and are therefore 'directly' heated. External heat supply is not required. Partial oxidation is the most well-known approach to gasification and several technology options are available. Commercial success has been achieved with fossil feedstocks such as coal and petcoke. However, oxygen production through cryogenic air separation is capital intensive, especially in small scales (ex., less than 500 Tons Per Day of feedstock throughput), especially in the small to medium scales necessary for biomass gasification. Air blown gasifiers on the other hand produce a syngas diluted with nitrogen.

b. <u>Indirectly Heated Gasifiers</u>: Steam and/or hydrogen are often used as the gasifying agent and the process needs external heat supply. This is typically achieved by using a dual fluidized bed configuration. The dual fluidized bed reactor configuration is a well-known option for the gasification of biomass feedstock. This configuration uses two separate reactors, one for the combustion and the other for the reduction reaction. The heat required for the reduction reaction is supplied through the bed material (typically sand) from the combustion reactor. The bed material is continuously circulated between the two reactors while the ash is removed from the bed material using cyclones and the gases from the two reactors are not allowed to mix. The Milena project gasifier uses the two reactor configuration (Van der Meijden 2008). Dual bed gasifiers are particularly attractive for biomass gasification since oxygen is not needed. Benefits of the dual bed configuration for biomass gasification include (Basu 2010):

- Provides improved process efficiencies and avoids the challenges related to ash melting by operating at lower gasification temperatures (normally greater than 800°C but below the ash softening point).
- Air is only used in the combustion reactor and does not enter the reduction reactor, thereby preventing nitrogen dilution of syngas, a major problem in air blown gasifiers.

A major challenge of biomass gasification is to overcome the higher specific capital and operating costs. This is due to the much smaller plant sizes (normally less than five hundred tons per day of feedstock throughput) compared to coal gasification plants (tens of thousands of tons per day). The plant size is determined by biomass availability and related logistic issues and transportation costs inherent to any distributed resource. Other challenges include the presence of undesirable species such as alkali compounds in biomass ash. Alkali materials such as sodium and potassium cause slagging and fouling problems (Huber 2006).

Most biomass gasifiers operate below the ash softening temperature to avoid ash melting. The lower temperatures also lead to lower capital cost requirement, resulting in favorable process economics. However, lower temperatures often result in the formation of undesired tar, which leads to severe operational problems. A number of catalysts and process configurations have been developed to address this issue, but tar problems still persist (Knoef, 2012). Addition of a catalytic tar cracker to the outlet of the gasifier to decompose the tars into smaller molecules has been considered (Milne 1997). Washing out the tars while the product gas is cooling down has also been proposed, but this approach requires rigorous treatment of the washing water. Tar formation is still a major challenge and is regarded as the "Achilles heel" of biomass gasification processes. These issues are not to be underestimated and careful attention is required in the design and operation of biomass gasifiers.

Technology Status: Gasification has been practiced for decades and can be considered commercially viable for fossil feedstocks, under select circumstances. However, commercially mature gasification technologies that convert renewable feedstocks into fuels are not available. Continued operation in pre-commercial scales has been achieved using renewable feedstocks. The Technology Readiness Level (TRL) for hydrogen production from renewable feedstocks through gasification is estimated to be 7 (Albrecht 2015). With sufficient investment and continued technology demonstration, TRL 9 could be reached by 2025.

Supercritical Gasification

Supercritical gasifiers offer an alternate gasification route that is attractive for biomass conversion. Under supercritical conditions for water (combination of $T > 374°C$ and $P > 218$ atm), distinct liquid and vapor phases do not exist and water exists as a single phase fluid (Peterson et al., 2008). The supercritical conditions result in rapid hydrolysis of biomass and high solubility of intermediate reaction products including gaseous species (*Valorization of Lignocellulosic Biomass in a Biorefinery: From Logistics to Environmental and Performance Impact*, 2016). However, there are several technological barriers that must be addressed. These include the large heat input requirement, and high capital costs due to high operating pressures. Other issues such as fouling, plugging of the feedstock, and corrosion also exist (Marrone & Hong, 2008) (Kumar 2017).

The TRL for supercritical biomass gasification for hydrogen production is 4. Notable projects include the pilot plants at the University of Twente (Knezevic, 2009) and the VERENA group Karlsruhe, Germany (Fritz, 2009).

Plasma Gasification

Plasma gasification developers often target waste disposal as the primary goal but the technology can be used to convert other carbonaceous feedstocks including biomass. The extreme conditions of the plasma result in complete conversion of even the most difficult feedstocks. However, the conditions also lead to operational challenges and increased costs. Although the technology is advanced, with an estimated TRL of 8, it is not considered a viable approach for renewable hydrogen production due to these issues (Albrecht 2015).

Biomass Pyrolysis

Pyrolysis is the thermal decomposition of the feedstock in the absence of oxygen. The products of biomass pyrolysis are char, bio-oil (also referred to as bio-crude) and gases including methane, hydrogen, carbon monoxide, and carbon dioxide. Pyrolysis can be further classified into slow and fast pyrolysis based on the residence time of the solid biomass in the reactor. Fast pyrolysis, also known as flash pyrolysis, is normally conducted under medium to high temperatures (usually 450°C to 550°C) at very high heating rates and a short residence time (e.g., milliseconds to a few seconds) and maximizes liquids production. Hydrogen production through reforming of the bio-oil has been explored but only in research scale. Direct pyrolysis based hydrogen production is not sufficiently advanced to merit further consideration.

2. Bio-derived Liquids Reforming

Hydrogen can be produced by reforming hydrocarbon liquids derived from biomass. These liquids include ethanol, aqueous sugars, flash pyrolysis based bio-oil, etc. The aqueous sugars or ethanol are often produced through biological processing of biomass. The reforming technology is similar in concept to natural gas reforming but converts heavier hydrocarbons into hydrogen. This approach eliminates some of the key challenges associated with biomass conversion through gasification: the capital intensive gasification step is eliminated and many of associated problems such as tar formation are avoided. However, it should be noted that additional steps may be required that may offset some of the cost benefits. The technology can also improve process economics by using a central reformer that receives the liquid feedstock from distributed processing plants. The liquids can be transported by trucks or through purpose built pipelines.

Conversion of cellulosic biomass to sugars through aqueous processes is well established, especially in the context of cellulosic ethanol production. Several pretreatment processes exist that can convert the polysaccharides in lignocellulosic biomass into monomeric sugars through hydrolysis. Well known pathways include acid pretreatment, ammonia soaking and steam explosion and often involve biomass preparation steps such as size reduction. The sugars can be further dehydrated into drop-in fuels reactive intermediates such as furfural, 5-hydroxymethylfurfural, and levulinic acid that are viable hydrogen precursors (Wyman 2005).

Reforming of flash pyrolysis has also been proposed as an alternative to gasification. The most important advantage of flash pyrolysis is low capital costs and also the ability to operate facilities at much smaller scales and still retain commercial viability. However, bio-oil is extremely corrosive and poses serious handling and transportation challenges. The Total Acid Number (TAN) required for crude oil refineries is normally less than 2. Typical bio-oil TAN values range from 50 to as high as 200 (Brown 2009). Bio-oil exhibits an acidic pH in the range of 2.0 to 3.0 and hence is extremely corrosive (Mohan 2006). Bio-oil typically contains 15-30 % of water. Besides the water, the components of highest concentrations present in bio-oil are hydroxyacetaldehyde and acetic and formic acids. These oxygenated compounds along with various other species such as phenolic compounds contribute towards the acidity of the bio-oil. Bio-oil also poses storage challenges and local upgrading is often necessary in order to allow storage and transportation. The viscosity of bio-oils increases during storage and the physical properties undergo considerable changes due to the self-reaction of various compounds including polymerization reactions (Diebold 2000, Jones 2009, Oasmaa 2001). These reactions, occurring during storage, increase the average molecular weight of the bio-oil and also lead to other storage related issues such as phase separation.

Technology Status: Bio-derived liquids are typically easier to transport than biomass and can enable semi-central production. The liquids are converted using catalytic steam reforming followed by the water gas shift reaction. The reforming process requires improved catalysts due to the heavier hydrocarbons in the liquids. Although technology components are available, integrated process demonstration is still ongoing (Argonne GREET Publication 2016). The TRL for these technologies is around 4-5.

3. Biogas Reforming

Renewable methane from biogas sources including landfills, waste water treatment plants and dairy digesters can be reformed to produce hydrogen. Regardless of the source, the biogas must be subjected to considerable upgrading before reforming. The most common contaminants are discussed below.

Sulfur Compounds: Biogas streams, including landfill gases, often contain sulfur compounds such as sulfides, disulfides, and thiols. While plant and vegetable biomass based biogas sulfur content is negligible, gas from waste matter can exhibit a higher sulfur content. Sulfur compounds are corrosive and can be harmful to downstream equipment and materials including catalysts and must be reduced to acceptable levels depending on the intended application.

Halogenated Compounds: Halogenated compounds such as carbon tetrachloride, chlorobenzene, chloroform and trifluoromethane are often found in landfill gases and occasionally in other biogas sources. Halogen species can lead to the formation of acid gases such as hydrochloric acid and hydrofluoric acid that can lead to corrosion and other issues.

Ammonia: Ammonia is formed from nitrogen containing species and must be under specified levels. Ammonia forms nitrous oxide upon combustion.

Siloxanes and other Silicon Compounds: Siloxanes and silicon species are primarily found in landfill gas and are derived from silicon containing consumer product wastes including cosmetics. Siloxanes are recognized as a major problem and often form harmful deposits in downstream equipment.

Particulate Matter: Different types of particulate matter are found in landfill gases and biogas streams and often removed by means of filters or cyclones.

Moisture Content: Biogas streams, including landfill gases, often contain significant quantities of moisture that can have a detrimental effect on pipes, lines and other equipment. Gas streams are often passed through knockout drums that reduce the gas velocity so that any liquid drops out and can be drained. The next step in moisture removal is to eliminate foam from gas streams by means of coalescing meshes. Cyclones can also be used to capture liquid droplets. Uncondensed water vapor in the gas stream is eliminated using one of the dehumidification methods listed below (Deed 2004, Dudek 2010).

1. Refrigeration drying
2. Deliquescent bed absorption
3. Glycol stripping

Refrigeration is the most common technique used to eliminate water vapor from biogas streams. The gas stream is chilled to temperatures as low as 2 ºC in a heat exchanger causing the water to condense. The condensed liquid is separated from the gas stream. More effective drying can be achieved by cooling gas streams to -18 ºC, but glycol must be used to prevent ice formation in the pipework. The glycol must then be removed from the dry gas stream.

Alternatively, deliquescent dryers containing moisture absorbing materials such as common salt, silica gel or aluminium oxide can be used to remove moisture from the gas streams. The drying agents are loaded in towers and are regenerated during the process using appropriate techniques. These processes can be conducted at elevated pressures to improve the capture efficiency. Glycol stripping techniques are primarily used in facilities that produce large quantities of gas. The gas stream is passed through a contact tower containing material such as triethylene glycol that can be recovered for reuse. The water recovered from the gas streams are often acidic and require treatment before disposal.

CO_2 Removal: Biogas sources typically contain 40-60% CO_2 that is removed before reforming. Several CO_2 removal technologies have been developed and can be broadly classified into the following categories:

1. Physical and chemical absorption methods
2. Membrane separation methods
3. Pressure Swing Adsorption (PSA), and
4. Cryogenic separation

Physical and Chemical Absorption Methods: A number of organic solvents have been developed for the physical absorption based removal of CO_2 and other contaminants from gas streams. Well-known solvents include Selexol, derived from the dimethyl ether of polyethylene glycol, and amine based solvents such as Diethanolamine (DEA) and Monoethanolamine (MEA).

Water Scrubbing Techniques: CO_2, along with hydrogen sulfide, exhibits a higher degree of solubility in water compared to methane. This property is used to remove water from the gas stream in scrubbers. The compressed gas stream is brought into contact with water in countercurrent columns designed to maximize the contact surface area between the gas and the liquid. The enriched gas stream is then dried to remove the residual water. The CO_2 enriched water is then passed through flash tanks where depressurization results in the release of the CO_2.The process can be enhanced by air stripping or by vacuum. Water scrubbing is an attractive method for small scale projects due to the absence of expensive organic solvents (Rasi 2008). However, water scrubbing is often associated with high levels of power consumption necessary to handle the circulating flows.

Membrane Separation: The differential permeability of CO_2 and methane through polymeric membranes can be used to enrich the gas stream. The membranes can be operated with gas phase on both sides or by using a liquid such as a solvent to absorb the CO_2 that permeates through the membrane. Membranes with gas phase on both sides are referred to as dry membranes. Single stage membranes typically result in low levels of methane recovery and multistage processes are often needed.

Pressure Swing Adsorption (PSA): PSA processes remove the CO_2 from the gas stream by means of selective adsorption on the surface of porous solid adsorbents. The adsorption takes place under elevated pressures and the CO_2 is released during depressurization. The process involves four steps:

- High pressure adsorption
- Depressurization
- Vacuum stripping of CO_2
- Product repressurization

Two types of sorbents have been used in landfill gas cleanup projects: molecular sieve type materials and activated carbon beds. PSA processes require a dry gas stream and the removal of hydrogen sulfide beforehand.

Cryogenic Separation: The boiling point of methane under atmospheric pressure is -160 ºC whereas the boiling point of CO_2 is -78 ºC. Cryogenic processes cool the gas stream to temperatures low enough to allow the separation of CO_2 as a liquid. The methane is recovered either as a gas or as a liquid. Compression and refrigeration is normally achieved in several steps. Although the process yields a highly enriched gas stream, it is energy intensive and is not suited for small scale projects.

Once the biogas is upgraded, the reforming process is identical to that of fossil methane reforming, albeit in smaller scales. If the reformer is located onsite, upgrading to pipeline quality natural gas is not needed and steps such as CO_2 removal may be eliminated. Therefore, this option is attractive compared to transportation to the reformer through a natural gas pipeline.

Technology Status: The technology is mature since all the cleanup processes are commercially available or are demonstrated in commercial scales and the reforming step is also commercial. The major challenge is project economics due to the small scales. The TRL level for biogas reforming is 8 and commercial implementation is possible from a technology perspective. However, commercial activity is not anticipated due to the extremely poor economics.

4. Thermochemical Water Splitting

Water can be split into hydrogen and oxygen through chemical reactions with a metal oxide or an oxidizable fluid. The chemicals used are often recycled, resulting in a cyclic process that consumes water and produces hydrogen. The resulting hydrogen can have a very low carbon intensity if the thermal energy required to drive the reactions is derived from renewable sources. The preferred thermal energy source for this pathway is concentrated solar thermal energy. Numerous cycles have been studied at both lower (850-950 °C) and higher (1600-1800 °C) operating temperatures (Albrecht 2015).

<u>Technology Status</u>: Technologies to concentrate solar power have improved significantly over the last decade. Several of the chemical cycles have also been well studied, although mostly in bench scale or in small pilot scales. The TRL for this pathway is estimated to be 4-5.

1.2.2 ELECTROLYTIC PROCESSES

Hydrogen production through water electrolysis using renewable electricity can eliminate carbon emissions in transportation and other sectors. Although water electrolysis was commercialized decades ago, it only accounts for approximately 4% of world hydrogen production (Kelly 2014). This is primarily due to the higher cost of production through electrolysis and the fact that hydrogen consumption is dominated by large scale industrial processes that require centralized production in high volumes, something electrolysis is not capable of. However, electrolysis using renewable electricity offers an important pathway towards carbon free energy production and usage. Electrolysis also generates very high purity hydrogen and technology options exist for hydrogen production at very high pressures.

Electrolyzers are essentially reverse fuel cells and split water into hydrogen and oxygen using DC electricity. The oxygen is typically vented while the hydrogen is captured and stored. The major components of an electrolyzer are an anode, cathode, and the electrolyte. Electrolyzers can be classified into two categories based on the electrolyte pH: acidic and basic.

Alkaline electrolyzers have been developed much more rapidly due to the advantage of not requiring noble metal electrodes to prevent corrosion. Acid water electrolysis technology is feasible through the use of Solid Polymer Electrolytes (SPE) instead of liquid acids (Elder 2015, Millet 2013). A well-known example is the Nafion® membrane developed by DuPont. Proton Exchange Membrane (PEM) electrolyzers use a highly acidic polymer membrane as the electrolyte and are commercially available.

The standard potential for water electrolysis can be estimated using the standard potentials for the two half reactions happening at the two electrodes.

$$2H_2O \leftrightarrow 2H_{2(g)} + O_{2(g)} \qquad E^0 = -1.23V \qquad (1)$$

Under the standard conditions of 298 K and 1 bar, the equilibrium potential, i.e. the voltage needed to decompose water through electrolysis is 1.23 V. This voltage is the same for both acidic and alkaline electrolyzers. The effect of pressure on the electrolysis voltage is estimated using the Nernst equation (Kelly 2012, Kelly 2014). The electrolysis voltage increases only slightly with increasing pressure and this is the primary incentive for operating electrolyzers at high pressures when possible. Hydrogen almost always has to be compressed to high pressures for storage and transportation and mechanical compressors consume significantly higher energy than required by electrolyzers.

The effect of temperature on the electrolysis voltage can be estimated using thermodynamic correlations and is shown in Figure 1 (Mougin 2015). As the operating temperature increases, the required electrical energy input decreases and the thermal energy input increases. At high operating temperatures (800-1000 °C), approximately two thirds of the required energy must be supplied as electrical energy and the rest as thermal energy. Therefore, electrolyzer efficiency increases at higher temperatures since thermal energy is almost always less expensive than electrical energy.

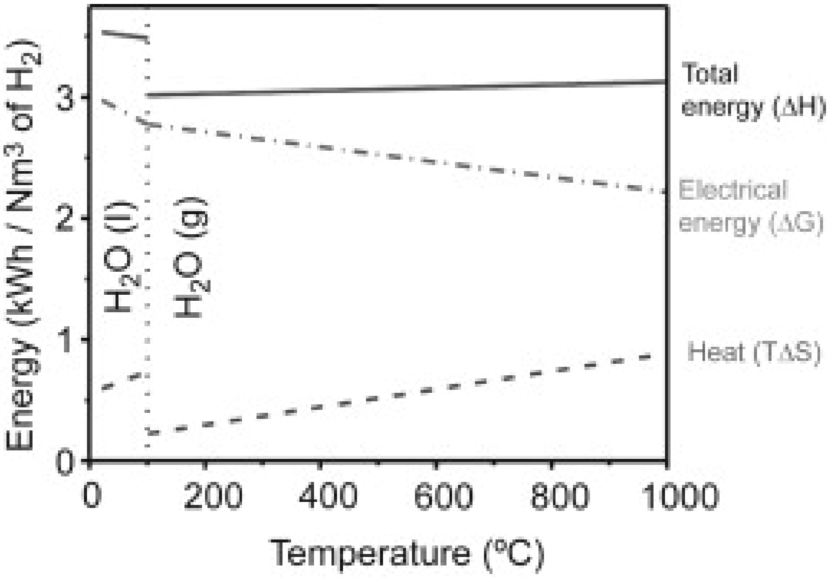

Figure 2 Effect of temperature on the thermodynamic parameters of water electrolysis

High temperature water electrolysis yields higher efficiencies and is a major area of research focus as discussed later. Several challenges remain, most related to material constraints (Kelly, 2014).

Water electrolysis in practice requires a higher voltage than 1.23 V and the difference is the overpotential required to drive the process. The overpotential has three components: the activation overpotential caused by rate limiting steps, the concentration overpotential caused by a drop in concentration at the electrode surface relative to the bulk phase due to mass transport limitations, and the ohmic overpotential primarily caused by the resistivity of the electrolyte (Kelly 2014). The ohmic overpotential can be minimized by using an electrolyte with the maximum conductivity and the concentration overpotential can be minimized by stirring or vibrating the electrodes and electrolyte to enhance mixing and bubble detachment from the surfaces. The activation overpotential is the main overpotential in water electrolysis and can be minimized by using catalytic materials.

A comparison of different water electrolysis technologies including high temperature electrolysis is given in Table 10 (Cerri 2012). The overall efficiency of alkaline and SPE processes range from 60-85%. This efficiency decreases further if the electricity generation efficiency is also taken into account. If the hydrogen is used as an energy carrier, then the ‘round trip’ efficiency for electrical energy storage must include the fuel cell or hydrogen engine efficiency and is only around 30% (Kelly 2014). Detailed reviews of alkaline and SPE electrolyzers are available in the literature (Kelly 2014, Millet 2013, Rashid 2015).

Table 20 Comparison of Water Electrolysis Technologies (Cerri 2012)

Technology status	Mature technology		Lab-scale, R&D	
	Alkaline	PEM	Medium T	Solid Oxide
T range (°C)	Ambient/120	Ambient/90	250/600	800/1000
Electrolyte/pH	25-30 wt% $(KOH)_{aq}$	PFSA*	Ploymer or $Sr[Ce_xZr_{1-x}]_{0.95}Yb_{0.05}O_3$,[5] $La_{0.6}Ba_{0.4}ScO_{2.8}$	Y_2O_3-ZrO_2, Sc_2O_3-ZrO_2, MgO-ZrO_2, CaO-ZrO_2
Mobile species	OH^-	H_3O^+	H_3O^+	O^{2-}
Cathode catalyst	Nickel foam/Ni-SS[†]	Platinum	Ni-YSZ or Ni-GDC Cermet with proton-conducting electrolyte	Ni-YSZ or Ni-GDC Cermet
Cathode carrier	Nickel foam/Ni-SS; Ni-MO/ZrO_2-TiO_2	Carbon		
Anode catalyst	Ni_2CoO_4, La-Sr-CoO_3, Co_3O_4	Ir/Ru oxide	$(La,Sr)MnO_3$, $(La/Sr)(Co,Fe)O_3$	$(La,Sr)MnO_3$, $(La/Sr)(Co,Fe)O_3$
Anode carrier	-	-	-	Gd-dopped ceria
Separator	Asbestis, PAM[‡], ZrO_2-PPS[§],NiO, Sb_2O_5-PS[¶]	Electrolyte membrane	Electrolyte membrane	Electrolyte membrane
Sealant	Metallic	Synthetic rubber or fluoroelastomer	Glass and vitro-ceramics	Glass and vitro-ceramics

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Current distributor	Ni	Titanium		Ferritic SS (Crofer APU**)
Contaminant material	Nickel-plated steel	Stainless steel	Stainless steel	Stainless steel
P range (bar)	1-200	1-350 (700)	1	1-5
Conventional current density (A/cm^2)	0.2-0.5	0-3	0-0.1	0-2
Efficiency (%) (at I A/cm^2/U_{cell} V/T°C)	60-80;0.2-0.5/20/80	80; 1.0/1.8/90	Lab scale tests	100;3.6/1.48/950
Capacity (Nm^3/h)	1-500	1-230	1	1
Durability (h)	100,000	10,000-50,000	500	500-2000
H_2O specification	Liquid	ρ>10 MΩcm	Steam	Steam
Load cycling	Medium	Good	No data av.	No data av.
Stop/go cycling	Weak	Good	No data av.	Weak

*Perfluorosulforic acid

**Auxiliary power unit

ł Stainless steel

ǂ Polysulfone-bonded polyantunoiac acid

§ ZrO_x-PPS-ZrO_2 on polyphenylsulfone

¶ Sb_2O_5-PS-polysulfone impregnated with Sb_2O_5 polyoxide

Technology Status: There are several commercial electrolysis technology providers with most of them being alkaline or PEM electrolyzers. Reviews of select commercial electrolyzers including technical and commercial evaluations are available in the literature (Harrison 2010, Ivy 2004). The TRL for electrolysis based pathways is estimated to be 8. The lack of market penetration is primarily due to the higher production cost and the lower system throughputs compared to fossil hydrogen production plants. The cost of hydrogen depends heavily on the cost of electricity in addition to the electrolyzer capital costs. Transportation costs and infrastructure availability/compatibility issues also pose a major challenge to projects where the hydrogen is not intended for ‘captive use’.

1.2.3 PHOTOLYTIC PROCESSES

Photolytic processes produce hydrogen by splitting water using light energy. Photobiological pathways use specific algae or bacteria to split the water whereas photoelectrochemical pathways rely on a special class of semiconductors. Photofermentation pathways convert an organic substrate into hydrogen using photosynthetic bacteria. Photolytic processes have the potential to achieve zero GHG emissions. Photolytic pathways are in the research stage and are part of the 'long term' prospective technologies with a TRL of between 1 and 3 (Albrecht 2015).

1.2.4 BIOCHEMICAL PROCESSES

Hydrogen can be produced through fermentation of organic substrates in an approach similar to methane production via anaerobic digestion. Unlike photobiological pathways, these processes operate in the absence of light and are referred to as dark fermentation technologies. These processes offer the same advantages as traditional fermentation methods, including simple, lower cost reactor technology and waste disposal capabilities. Challenges include low yield and productivity. The dark fermentation pathways are in the research stage and are part of the 'long term' prospective technologies with a TRL of between 1 and 3 (Albrecht 2015).

Technology Availability Matrix

Hydrogen can be produced from renewable resources using a wide range of technology options. The raw materials for these processes fall under two categories:

- Renewable carbonaceous matter (biomass, biogas, or waste)
- Water

A key parameter that determines the carbon intensity of the product hydrogen is the energy source used to drive the conversion process. The major renewable energy sources include:

- Renewable carbonaceous matter (partial combustion of the raw material to drive the conversion)
- Solar energy
- Wind, geothermal and other renewable electricity production sources

Renewable conversion pathways often rely on a combination of renewable and fossil energy sources, with the primary conversion step relying on a completely renewable source and the auxiliary steps using a more readily available energy mix such as grid electricity.

The conversion technologies can be broadly classified into four categories based on the primary conversion mechanism:

- Thermal processes
- Electrolytic processes
- Photolytic processes
- Biochemical processes

As detailed in the discussion, a number of pathways are ready for commercial implementation. The matrix below shows the anticipated commercialization timeframes for the most important pathways. The pathways are divided into three groups based on their anticipated commercialization timeframes:

- Near Term: 5 years (commercially available by 2020)
- Mid Term: 10 years (commercially available by 2025)
- Long Term: 20 years (commercially available by 2035)

The anticipated commercialization timeframes are based only on technology readiness. Market forces and the regulatory environment often decide which technologies are commercially deployed. Technologically mature processes that are not competitive with existing processes will likely not be deployed without significant government incentives or mandates. The technology readiness level and commercialization timeframe options are presented in Table 11.

Table 11. Technology Availability Matrix

	Technology	TRL	Commercialization Timeframe
1	Water electrolysis	8	N
2	Biogas reforming	8	N
3	Biomass gasification	7	M
4	Bio-derived liquids reforming	4-5	M-L
5	Thermochemical water splitting	4-5	M-L
6	Photolytic conversion	1-3	L
7	Dark fermentation	1-3	L

Note: N: Near term; M: Mid term; M-L: Mid to long term; L: Long term

1.3 BLENDING HYDROGEN WITH NATURAL GAS

While hydrogen can be produced locally for use at forecourt stations, much hydrogen will likely be produced in regions that require distribution networks. There exist some dedicated hydrogen pipelines in the US, but the size of these networks is small. Building a dedicated hydrogen infrastructure of pipelines would require significant funding that would likely be beyond the means of small initial hydrogen markets. Distribution by liquid tanker trailers could serve to transport centrally produced hydrogen, but the possibility of using the existing natural gas pipeline infrastructure could provide many benefits.

The benefits of blending hydrogen with natural gas include:

- Potential reductions in GHGs emissions by combining hydrogen produced from renewable sources to fossil natural gas.
- Reduction in the cost of hydrogen distribution through bypassing the need to build expensive dedicated hydrogen pipelines.

- Injecting hydrogen in natural gas pipelines can reduce the need to build hydrogen storage systems.
- Increasing the availability of hydrogen can accelerate the introduction of pure hydrogen applications.

Blending hydrogen with natural gas raises a variety of issues which must be understood. These issues include:

- Safety concerns – adding hydrogen can increase the probability of explosions or the possibility of ignition events.
- Leakage – hydrogen is a much smaller molecule than natural gas and can more easily leak through pipeline walls or joints.
- Durability – the physical and chemical interaction between the hydrogen gas and the pipeline material can lead to degradation.
- Extraction – blending hydrogen with natural gas can provide a low cost distribution system, but unless the blended gas will be used in end-use products, the hydrogen must be extracted with high purity. Extraction systems are costly and can lead to hydrogen losses.

A large project, known as NaturalHY, aimed at assessing the effects of blending hydrogen in the natural gas pipeline infrastructure was originated in Europe (Tiekstra and Koopman 2008). The project studied many issues related to blending hydrogen and natural gas and produced many papers. The Gas Technology Institute later reviewed these papers and others to assess the following issues – Life Cycle Assessment, safety, leakage assessment, durability, integrity, end use, and environmental and macroeconomic impacts (GTI 2010).

Melaina et. al. reviewed prior work including the NaturalHY and GTI reports to investigate blending hydrogen into natural gas pipelines (Melaina 2013). The study considered seven key issues:

- Benefits of blending
- Extent of the US natural gas pipeline network
- Impact on end-use systems
- Safety
- Material durability and integrity management
- Leakage
- Downstream extraction

These studies generally conclude that blends of 5-15% of hydrogen in natural gas will result in no safety or system issue. Further, these blend levels require no significant modifications to pipeline systems or end-use applications. Higher blend levels require modifications to allow for safe and efficient operation.

This report will summarize the relevant studies and give conclusions and recommendations relevant to hydrogen blending in natural gas pipelines.

1.4 HYDROGEN DEMAND IN OFF-ROAD TRANSPORTATION MARKETS

During the early FCEV market phase, hydrogen demand may be low to modest due to slow market penetration. Off-road Transportation hydrogen fuel cell markets could increase the demand easing the path to commercialization for hydrogen producers. Off-road Transportation markets that have either grown recently or shown potential include material handlers (forklifts), backup power/telecommunications, transport refrigeration units (TRUs), and airport ground support equipment (GSE).

Several recent assessments of the fuel cell industry describe fuel cell applications, provide an overview of the fuel cell market, identify fuel cell manufacturers supplying these markets, and list example installations. A brief description of these fuel cell market assessments is given below.

The US Department of Energy (USDOE) issues a yearly State of the States fuel cell assessment (USDOE 2015). The assessment gives detailed information about individual state fuel cell policies, funding programs, and businesses. The report lists recent deployments of fuel cell material handlers and telecommunications backup power and lists DOE fuel cell funding on a state by state basis.

The Fuel Cell and Hydrogen Energy Association released their yearly business case for fuel cells (FCHEA 2015). The report provides an overview of business installations for fuel cells. It identifies 23 companies in the Fortune 500 Top 50 companies operating or developing fuel cells. The report lists benefits of using fuel cell for material handlers and gives details of their usage in various corporate warehouses. The assessment also lists telecommunication companies that have purchased fuel cells during 2014 and 2015.

The USDOE issued a report documenting fuel cell technologies and products supported by the Fuel Cell Technologies Office (USDOE 2016). The report identifies commercial and emerging fuel cell technologies and products. Examples of such products are:

- GenDrive Fuel Cell power system for forklifts (Plug Power)
- PowerEdge Fuel Cell system for forklifts (Nuvera Fuel Cells)
- Low cost metal hydride storage system for forklifts (Hawaii Hydrogen Carriers)
- Ground support equipment for baggage tractors at airports (Plug power)

Fourth Energy Wave released its annual fuel cell and hydrogen review (Fourth Energy Wave 2016). The scope of the report includes worldwide markets with information broken down by regions. Megawatt shipments of both telecommunications fuel cells and forklifts have increased every year since 2013.

E4tech produced an analysis of the fuel cell industry detailing shipments of fuel cells in the stationary, transport, and portable markets and discussing companies that have moved into or out of various markets. After a modest reduction of units and MWs shipped in 2014 compared to 2013, both units and MW production increased above 2013 values in 2015. This report focuses on worldwide markets.

1.4.1 MATERIAL HANDLERS (FORKLIFTS)

Forklifts are used in industrial, agricultural, and commercial establishments to move heavy loads. An ITA Market Intelligence report shows data from recent forklift sales that indicate a slight trend towards increased purchases of electric forklifts over conventional fueled forklifts (ITA 2016). The market for electric forklifts is expanding and fuel cells could capture a significant portion of this market.

By 2015 there were over 7,700 fuel cell forklifts in operation at warehouses across the country. Fuel cell forklifts have several advantages over battery powered forklifts (FCHEA 2015).

- Faster charging: fuel cells can be refueled much faster than batteries can be charged so facilities can improve their productivity.
- Constant power: fuel cells provide continuous power without sagging as batteries do when they are depleted.
- Lower cost: fuel cell forklifts cost less to operate and maintain than battery powered forklifts.
- Space savings: hydrogen refueling infrastructure requires a much lower footprint than battery charging equipment.

1.4.2 BACKUP POWER (TELECOMMUNICATIONS)

Telecommunications applications at phone towers use fuel cells for backup power during grid outages. The fuel cells are longer lasting and lighter than batteries, and they are quieter are more reliable than diesel generators. US companies AT&T, T-Mobile/MetroPCS, SouthernLINC, Sprint, and Verizon use fuel cells for backup at thousands of locations across the country (UCDOE 2015). In 2013 Sprint partnered with DOE to deploy fuel cell backup power systems for rooftop telecommunications equipment (FCHEA 2015)

While the market for fuel cell backup power at telecommunications sites is growing, hydrogen demand from this market will be insignificant. Grid power is so reliable that backup power is rarely needed. Thus, this market will contribute little to potential off-road Transportation hydrogen usage, and the market is not explored further in analysis.

1.4.3 TRANSPORT REFRIGERATION UNITS (TRUS)

Presently fuel cell TRUs are in the demonstration phase. The California Air Resources Board considers them one of the three most promising technologies for TRUs along with plug-in battery TRUs and cryogenic TRUs (CARB 2015). The reasons for the promising assessment are:

- Significant potential emissions reductions
- May be commercially available within 5 years with proper funding of next generation demonstrations,
- Duty cycle, noise, and payload impacts do not appear to be issues

The US DOE funded a demonstration with project partners Nuvera Fuel Cell, Thermo King, Sysco Foodservices and H-E-B Groceries to be operated in Riverside, Ca (PNNL, 2013). Sandia National Laboratories has funded a portable containerized hydrogen system to power refrigerated shipping containers at the Port of Honolulu. The fuel cell supplier is Hydrogenics (Sandia, 2014).

The capital cost of fuel cell TRUs is expected to be high, but the increased efficiency can result in lower fuel costs. A fuel cell TRU can be more cost effective than a diesel TRU if diesel fuel cost $4/gallon and hydrogen cost $5/kg (CARB 2015). Hydrogen costs are expected to be higher in the near to mid-term, but if fuel cell TRUs are operated near facilities with many fuel cell forklifts the infrastructure costs could be spread over more equipment. The hydrogen cost might then be the incremental cost of generation and potentially low enough to make the fuel cell TRUs cost effective.

1.4.4 AIRPORT GROUND SUPPORT EQUIPMENT (GSE)

There exists considerable interest in electrifying airport GSE. A report from the Los Angeles World Airports Environment & Land Use Planning Division investigated the potential to electrify airport GSE (LA Airports 2015). Presently roughly 37% of the GSE at the LA airport are electrified using batteries. The report recommends electrifying most of the GSE vehicle types in order to reduce emissions. Other airports have moved to electrify GSE with Ontario airport 100% electrified (LA World Airports 2008) and San Jose International Airport roughly 50% electrified (ICF 2014). The electrified GSE at these airports are currently battery electric equipment, but fuel cells could penetrate this market.

Recently DOE sponsored a fuel cell GSE project at the Memphis International Airport. Fifteen fuel cell cargo tractors went into service at the Federal Express facility in April 2015. The fuel cells were supplied by Plug Power. The program will operate for two years and is expected to save over 175,000 gallons of diesel fuel and reduce carbon dioxide emissions by over 1,700 metric tons (FCHEA 2015).

2 METHODS

2.1 HYDROGEN LIFECYCLE ANALYSIS: TECHNICAL ASSESSMENT

Conventional methods of process evaluation are often focused on a limited number of steps in a production pathway and are inadequate in their ability to quantify the "cradle-to-grave" energy use and emissions. For example, emission reductions in one section of the pathway may cause increased emissions in a different section. LCAs overcome such limitations by evaluating the energy consumption, emissions, and other characteristics of a pathway by using a boundary line that typically begins at the resource extraction step and accounts for all emissions, including those associated with waste disposal.

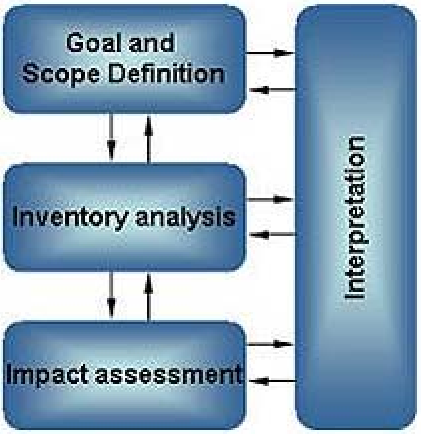

Figure 2. Phases of Life Cycle Analysis

Life Cycle Analysis is the compilation, quantification, and evaluation of the environmental and in some cases the human health impacts of a product or process across its life cycle (US DOE 2009). According to the International Organization for Standardization (ISO) (ISO 2010), an LCA consists of four phases:

(a) The goal and scope definition phase
(b) The inventory analysis phase
(c) The impact assessment phase
(d) The interpretation phase

Figure 2 shows the four phases as they interrelate to each other (LCA 2017). Although all LCAs must consist of the above phases, the scope and focus of specific studies vary widely based on the objectives and available data. LCAs can be broadly classified in Attributional LCA (A-LCA) studies and Consequential LCA (C-LCA) studies. A-LCAs focus on the components/stages that are directly linked to the fuel or products life cycle whereas C-LCAs focus on the impacts other than those caused by the direct relationships that are part of A-LCAs (Rehl 2012, Vázquez-Rowe 2014).

LCAs are necessitated by a number of factors, including the complexity of industrial processes and pathways that involve multiple and diverse blocks or sub-processes, evolving awareness of long term environmental impacts of resource harvesting and waste disposal from even advanced, commercially mature technologies, and the need for comprehensive quantification of the environmental impacts of different products to guide policy makers and regulatory agencies, manufacturers, and the general public.

LCA models iteratively calculate the energy use and emissions associated with specific pathways using large databases consisting of information on various stages of the pathways and some user-specified input values. Although the definition is the same, in practice LCAs evaluate the environmental impacts of a particular process using a wide range of parameters. LCAs involve the estimation of a large number of variables and several assumptions must be made. The parameters involved include, but are not limited to, the fuel/engine type and emissions of equipment used during the feedstock production and transportation stages, the efficiency of the fuel production technology and the various associated emissions the mode and efficiency of transportation of the fuel to the consumer, the efficiency of the vehicle type considered, etc. There are also numerous vehicle/fuel pathways that can be considered and all the available options cannot be evaluated in a single study. The scope and the options considered in each study are dictated by the objectives of the specific study and the development potential of the available pathways (ISO 2010, Curan 2012).

The LCA for fuels is typically performed in two parts, the Well-to-Tank (WTT) and Tank-to-Wheels (TTW) estimates. The final full life cycle emissions and energy consumption information, i.e., Well-to-Wheels (WTW), is obtained by adding the two parts. The Well-to-Tank section accounts for all the fuel production steps such as resource extraction, fuel production, transport, storage, distribution, and marketing. Facility fabrication and facility decommissioning during these steps are not typically taken into account. The Tank-to-Wheels part takes into account the emissions during the vehicle operation. Vehicle manufacturing and vehicle decommissioning are not taken into account for fuel LCA studies. Current LCA studies overwhelmingly focus on performance per unit of fuel produced, e.g. MJ, of fuel instead of performance per hectare or other units of the land used. Conventionally, demolition and recycling of the process plants have not been studied in detail (Patel 2016). Economic assessment of pathways or technologies is typically not considered to be a part of LCAs.

Greenhouse gases. The key GHGs considered by the LCA and their Global Warming Potential (GWP) compared to CO_2 are given in Table 12. The GWPs are the 100 year warming potential values published by the Intergovernmental Panel on Climate Change (IPCC) in 2007 and are often referred to as the IPCC 2007 GWPs (IPCC 2007).

Table 12. Global Warming Potentials of the key GHGs (IPCC 2007)

GHG Name	100 Year GWP
Carbon dioxide (CO_2)	1
Methane (CH_4)	25
Nitrous Oxide (N_2O)	298
Chlorofluorocarbons(CFC-12)	10,900
Hydrofluorocarbons (HFC-134a)	1,430

The GHG emissions for each pathway are calculated for each GHG and are reported on a carbon dioxide equivalent (CO_2e) basis using the GWPs. LCAs also typically calculate the net emissions of select criteria pollutants. This study presents the emission values for the following criteria pollutants: VOCs, CO, NOx, PM_{10}, $PM_{2.5}$, and SOx.

Energy use. The following categories of energy use are calculated by CA-GREET.

- Total and fossil energy used per unit of energy produced for each stage of the fuel production step
- Total energy used per mile driven for the fuel used in vehicles
- Fossil energy used per mile driven for the fuel used in vehicles
- The proportions of types of energy used for each stage of the fuel production cycle

A number of software packages are available that include extensive databases and 'pathways' that can be used to evaluate most of existing technology/pathway options. The Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model is one such model that is widely used in academic studies, especially in the United States (***IEA 2016***). Other models include GHGenius, LEM, and GEMIS. This study is conducted using the CA-GREET 2.0 Tier 2 model (CA-GREET 2017). The CA-GREET model is a modified version of the GREET model consisting of California specific assumptions.

2.1.1 Pathways Studied

The objective of this study is to evaluate the life cycle energy use and GHG emissions of select hydrogen production pathways using the CA-GREET 2.0-T2 model. The pathways evaluated are listed below along with a description of each pathway. The pathways are selected based on their near term availability and the availability in the CA-GREET model.

- Natural gas reforming
- Electrolysis with grid and renewable power
- Biomass gasification
- Biogas/landfill gas reforming

A description of these pathways is provided below.

Natural gas reforming and biogas reforming

Fossil natural gas reforming is the major industrial hydrogen production pathway, accounting for more than 95% of current production. The centralized and distributed natural gas reforming pathways are considered the baseline and use steam methane reforming (SMR) and water gas shift (WGS) reactions. Pressure swing adsorption is used to separate hydrogen from the other species. The hydrogen produced at a central facility is compressed and injected into a pipeline, through which it is transported to the refueling station. There the hydrogen is further compressed and dispensed as a gaseous fuel to the vehicle fuel tank (Ruth 2009). The distributed production pathway assumes that the reforming takes place at the forecourt refueling facilities.

The feedstock for both pathways is North American Natural gas (NA NG) consisting of a high methane percentage (94.9%) and varying ethane, propane, butane and inert gas composition (NAESB 2017). The approximate gross heating value of the natural gas is 1014.5 Btu/ft^3. Thermal efficiency of natural gas reforming to produce hydrogen (LHV of

H_2 to the total energy input of the system including NG) is assumed to be 72% for gaseous hydrogen production.

Natural gas is fed to the plant from the pipeline and is generally sulfur-free, but odorizers with mercaptans must be cleaned from the gas to prevent contamination in the reformer (Ruth 2009). The desulfurized natural gas feedstock is mixed with process steam and is reacted inside the reformer to produce syngas. The reforming process is performed at high-temperatures (800°C–1,000°C) in the presence of a catalyst, for ex. nickel. The syngas is further processed in a shift reactor to increase the hydrogen concentration. The H_2 is purified and then compressed and/or liquefied as required. The process flow diagram for natural gas reforming process is shown in Figure 3.

The biogas reforming pathway assumes that biomethane, i.e., methane from a renewable resource such as digestor gas, is reformed to produce hydrogen. Biogas contains mostly CH_4 and CO_2 and can be produced from various sources. This study assumes that the biogas is obtained from a digestor at a waste water treatment plant (WWTP) or animal manure or directly from the landfill gas source. The process flow diagram in Figure 4 shows the biogas processing steps involved in upgrading the biogas to biomethane before reforming. The biomethane is also produced from the anaerobic digestion of animal manure requires similar steps. Therefore, biomethane is obtained from either of these three source (WWTP sludge, animal manure or landfill gas) and the upgraded biogas (biomethane) is assumed to have similar properties as NA NG and the gaseous hydrogen production efficiency (ratio of energy output in form of hydrogen and total energy input) from the biomethane is assumed to be 72%. The process efficiencies for the other major process units include is 99.54% waste collection efficiency, 89% biogas processing efficiency, and 92% efficiency (ratio of energy of separated gas and energy input) for the gas separation step using pressure swing adsorption.

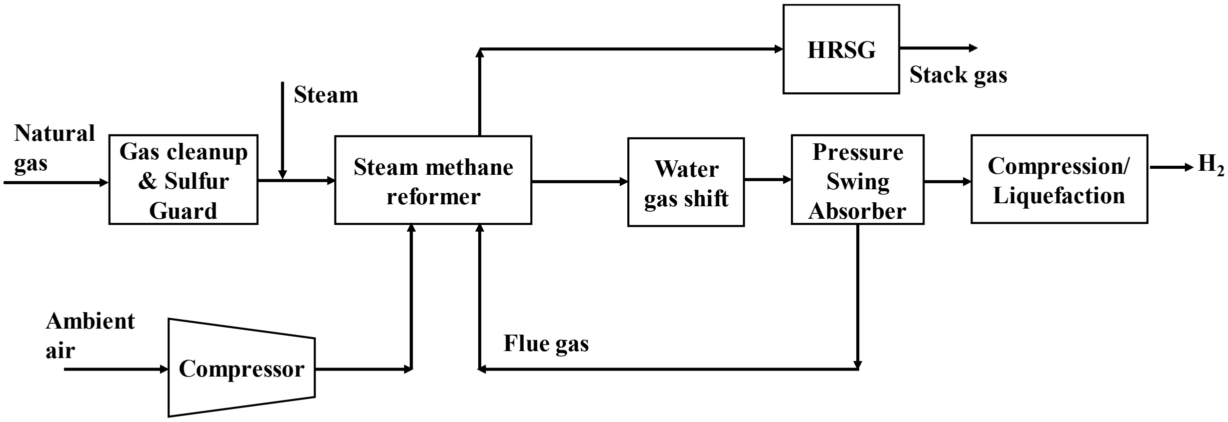

Figure 3. Hydrogen production via steam reforming of natural gas (HRSG: Heat Recovery Steam Generator)

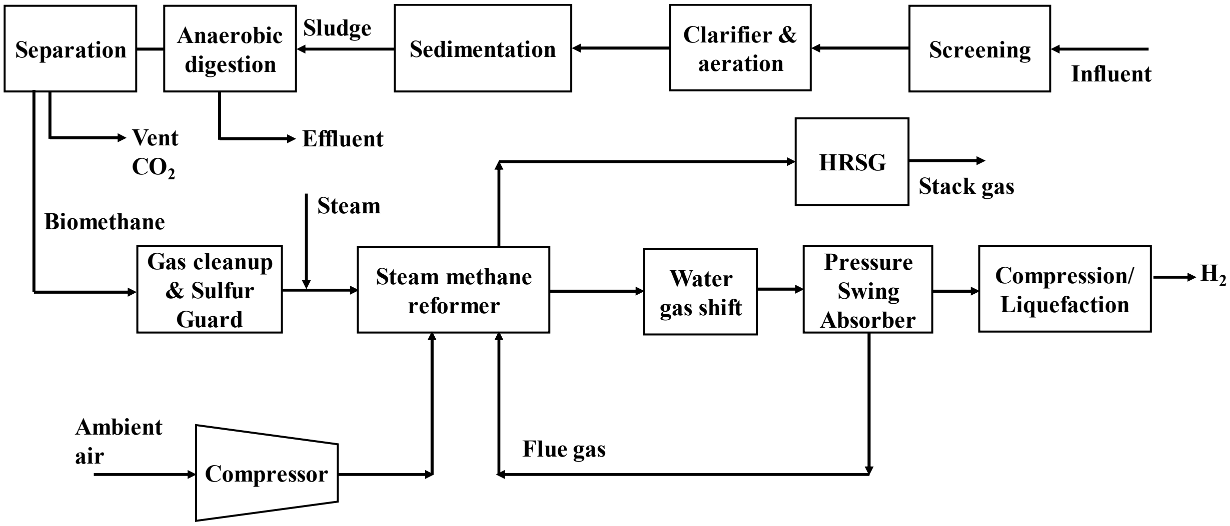

Figure 4. Hydrogen production via steam reforming of biogas produced from a WWTP

2.1.2 ELECTROLYSIS

The centralized hydrogen production pathway assumes that renewable power from a solar PV power plant is used to electrolyze water whereas the distributed pathway assumes the use of grid power. A scrubber is used to obtain the required hydrogen purity. The centrally produced hydrogen is compressed and injected into a pipeline, through which it is transported to the refueling station (Ruth 2009). The distributed pathway assumes that the electrolyzers are located at the forecourt refueling facilities and are connected to the electric grid. The electrolyzer system requires high-purity water to avoid deterioration in performance.

The electrolyzer produces hydrogen and oxygen from feed water. The hydrogen and oxygen are separated using gas/lye (KOH) separators. The oxygen is released to the atmosphere, and the hydrogen is fed to the gas scrubber subsystem, which purifies the hydrogen. The purity of the hydrogen coming off the electrolyzer stack is 99.9 % (Ruth 2009). The process thermal efficiency (ratio of LHV of H2 and total energy input to the system) is assumed to be 66.8% for this system. For the distributed pathway the electricity is taken from the CAMX grid and for central facility the electricity is assumed to be from a generic solar PV generation facility. The CAMX grid electricity mix consists of: 56.2% from natural gas, 28% renewable, 11.5% hydroelectricity, 3.1% nuclear and 2.2% from other sources (California ISO 2017). The process flow diagram for renewable power based electrolysis process is shown in Figure 5.

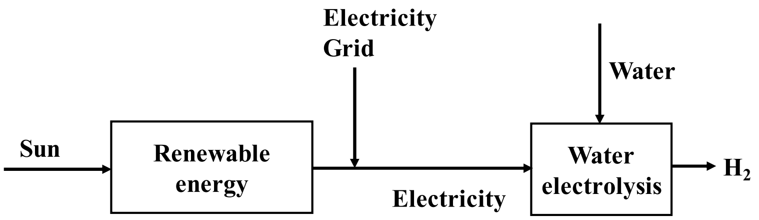

Figure 5. Hydrogen production via water electrolysis using renewable power

2.1.3 BIOMASS GASIFICATION

The biomass gasification pathway assumes that a biomass feedstock within a 50-mile radius is collected and transported via truck to the hydrogen production facility. A biomass gasifier converts the biomass to syngas, which is then upgraded to hydrogen. PSA is used to obtain the required hydrogen purity (Ruth 2005). During the upgrading step, the syngas generated from the gasification process is cleaned up and subjected to the water gas shift reaction. The product gas is sent to a gas cleanup unit and a hydrogen separator to achieve the required hydrogen purity. The hydrogen is then subject to compression and/or liquefaction for storage. The process flow diagram for the biomass gasification to hydrogen is shown in Figure 6. The biomass source for this study is assumed to be switchgrass and the overall thermal efficiency of biomass gasification to gaseous hydrogen is assumed to be 57%.

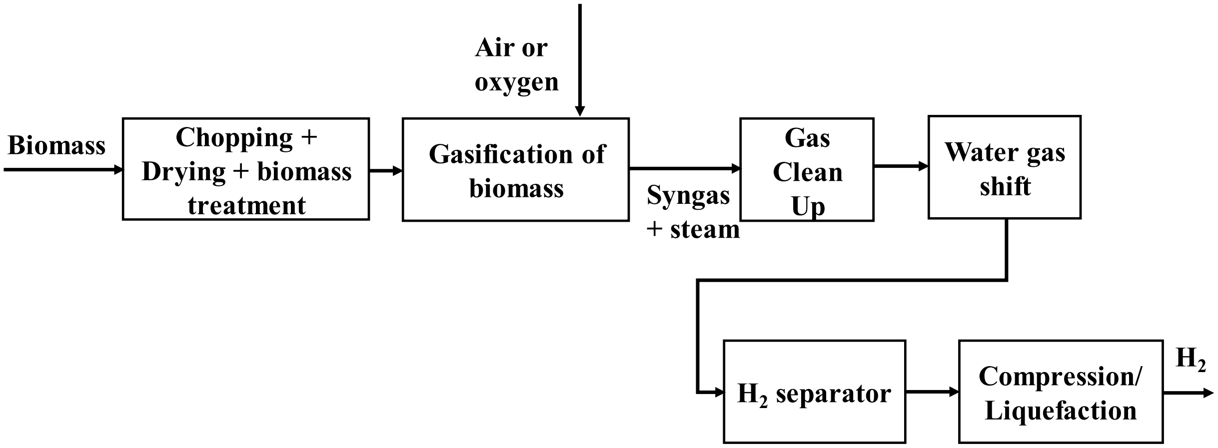

Figure 6. Hydrogen production via biomass gasification

2.2 HYDROGEN LIFECYCLE ANALYSIS: ECONOMIC ANALYSIS

The two major barriers to widespread replacement of fossil fuels with renewable alternatives are the high costs and lack of infrastructure and mature end use technologies. An important advantage of fossil fuels is that they exist underground in near-final forms and are simply extracted and refined, as opposed to renewables that must be synthesized from raw materials. As a result, the production step is often the most energy intensive in the life cycle of renewable fuels. This step directly translates into additional costs. The distributed nature of renewables also does not lend itself to very large scale centralized facilities, thereby forfeiting the significant benefits that can result from economies of scale. These two factors often result in renewable alternatives being prohibitively expensive, requiring support from the government including investment and incentives.

Hydrogen has been an attractive alternative fuel for decades but high costs and the lack of a mature infrastructure have prevented large-scale adoption as an energy carrier or fuel. Hydrogen produced from renewable sources cannot compete with fossil hydrogen prices although technological advances have significantly reduced the costs. The U.S. Department of Energy (US DOE)'s Hydrogen and Fuel Cells Program has made substantial investments in hydrogen related research and has set renewable hydrogen cost targets for the near and long term. According to the DOE, "*the Hydrogen Production sub-program supports research and development (R&D) of technologies that will enable the long-term viability of hydrogen as an energy carrier for a diverse range of end-use applications, including transportation (e.g., specialty vehicles, cars, trucks, and buses), stationary power (e.g., backup power and combined heat and power systems), and portable power. The goal of the Hydrogen Production sub-program is to develop low cost, highly efficient hydrogen production technologies that utilize diverse domestic sources of energy, including renewable resources, coal with sequestration, and nuclear power (US DOE 2015).*

The specific cost objectives set by the USDOE provide a baseline against which the performance of specific pathways can be compared. The objective of the Hydrogen Production sub-program is to "*reduce the cost of hydrogen dispensed at the pump to a cost that is competitive on a cents-per-mile basis with fuels used in competing vehicle technologies. Based on current analysis, this translates to a hydrogen cost target of <$4/kg hydrogen (produced, delivered, and dispensed, but untaxed) by 2020* (Ruth 2011), *with <$2/kg apportioned for production only* (Weil 2012)." Specific cost objectives from the DOE Fuel Cell Technologies Office's Multi-Year Research, Development, and Demonstration Plan (US DOE 2012) are listed below. The energy content of a kilogram of hydrogen and a gallon of gasoline are approximately equal on an LHV (Lower Heating value) basis. So per kilogram and per gge (gasoline gallon equivalent) costs are used interchangeably.

- By 2020, reduce the cost of distributed production of hydrogen from biomass-derived renewable liquids to <$2.30/gge (≤$4.00 delivered and dispensed).
- By 2020, reduce the cost of distributed production of hydrogen from water electrolysis to <$2.30/gge (≤$4.00 delivered and dispensed).
- By 2015, reduce the cost of central production of hydrogen from water electrolysis using renewable power to $3.00/gge at plant gate. By 2020, reduce the cost of central production of hydrogen from water electrolysis using renewable power to ≤$2.00/gge at plant gate.
- By 2020, reduce the cost of hydrogen produced from biomass gasification to ≤$2.00/gge at the plant gate.
- By 2015, verify the potential for solar thermochemical (STCH) cycles for hydrogen production to be competitive in the long term and by 2020, develop this

technology to produce hydrogen with a projected cost of \$3.00/gge at the plant gate.

- By 2020, develop advanced renewable photoelectrochemical hydrogen generation technologies to produce hydrogen with a projected cost of \$4.00/gge at the plant gate.
- By 2020, develop advanced biological generation technologies to produce hydrogen with a projected cost of \$10.00/gge at the plant gate.
- By 2017, develop technologies for direct solar-to-hydrogen (STH) production at centralized facilities for ≤\$5.00/gge at the plant gate.
- By 2020, demonstrate plant-scale-compatible photoelectrochemical water-splitting systems to produce hydrogen at solar-to-hydrogen energy conversion efficiencies ≥15%, and plant-scale-compatible photobiological water-splitting systems to produce hydrogen at solar-to-hydrogen energy conversion efficiencies ≥5%.

The cost targets are shown in the graphs below (US DOE 2015) in Figure 7. At present, natural gas reforming is the only technology that can meet the target cost of \$2/gge.

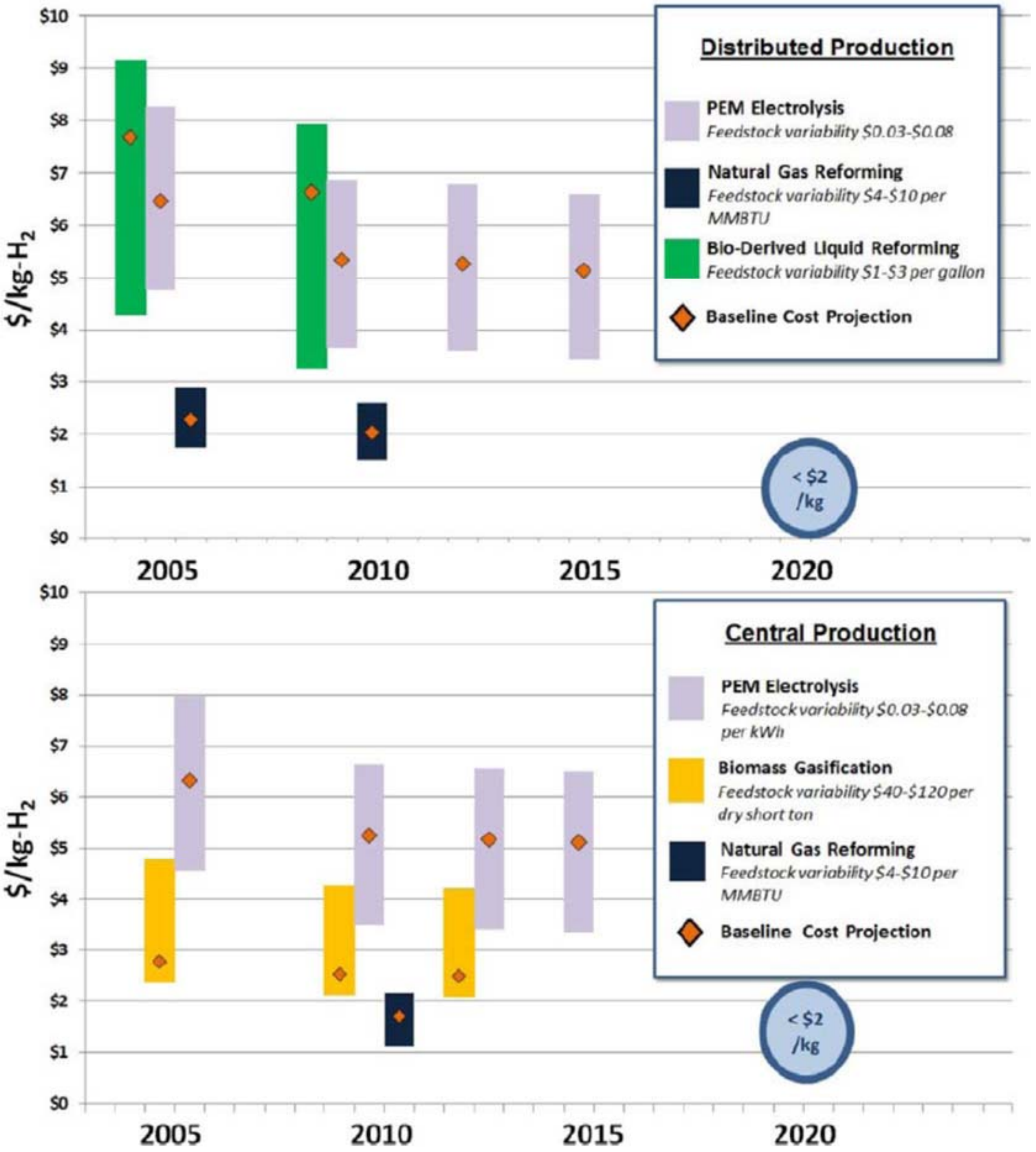

Figure 7. US DOE's hydrogen production cost target ranges, untaxed, for near- to mid-term distributed and centralized pathways. The high end of each bar represents a pathway-specific high feedstock cost as well as an escalation of capital cost, while the low end reflects a low feedstock cost and no capital escalation (PEM = Polymer Electrolyte Membrane) (U.S.D.o.Energy 2015).

Process economic assessment was conducted for select central and distributed pathways using the H2A model (Version 3.1) developed by the DOE Hydrogen and Fuel Cells Program. A description of the model is available in the user guide (Weli 2012): The H2A Production Model is excel based and analyzes the technical and economic aspects of central and distributed (forecourt) hydrogen production technologies. Using a standard discounted cash flow rate of return methodology, it determines the minimum hydrogen selling price (or levelized cost), including a specified after-tax internal rate of return from the production technology. The model has default technology input values for established production technology cases. The users have the option to accept the default values or use custom values.

The model is actually two models: one Microsoft Excel spreadsheet to analyze central hydrogen production technologies and another to analyze forecourt hydrogen production technologies. The two models are very similar; the primary difference is that the central model performs carbon sequestration calculations, whereas the forecourt model performs refueling station compression, storage, and dispensing calculations. The basic architecture of the model is shown in Figure 8 (Steward 2008).

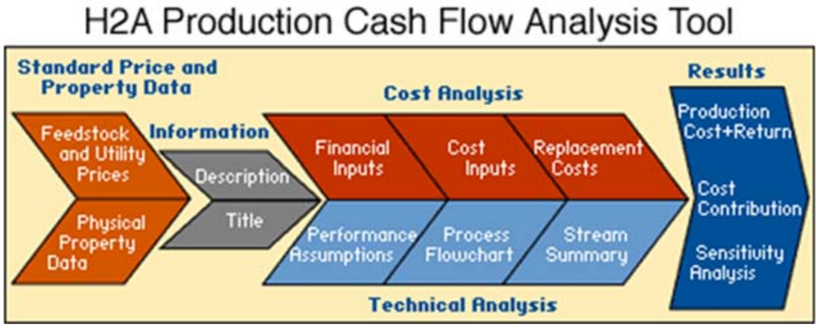

Figure 8. H2A model basic architecture (Steward 2008).

The assumptions used in the economic analysis and the results are discussed below. The pathways analyzed are:

- Natural gas reforming
- Electrolysis with grid and renewable power
- Biomass gasification
- Biogas reforming

The economic analysis for both centralized and distributed pathways were conducted using the H2A cost analysis model. Technology descriptions for specific pathways are provided in the previous section (Task 2b). The basic assumptions common for centralized and distributed pathways are listed below.

Common Assumptions:

- Plant startup year: 2018
- Analysis Methodology — Discounted Cash Flow (DCF)
- Technology Development Stage — All Central and Forecourt cost estimates are based on mature, commercial facilities
- Equity financing: 20%
- Debt: 80%
- Interest rate on debt: 6%
- Depreciation schedule length: 20 years

- Depreciation type: MACRS
- Decommissioning cost: 10 % of depreciable capital investment
- Salvage value: 10% of total capital investment
- Internal rate of return (IRR): 10%
- Inflation rate: 1.9%
- Total tax rate: 38.9%
- Sales Tax — Not included
- Hydrogen Pressure at Gate – 1 bar
- Working capital: 15 % of yearly change in operating costs
- Industrial electricity (US grid mix)
    - Price Conversion Factor: 0.0036 GJ/kWh
    - Price in Startup Year: 0.06714 \$(2012)/kWh
- Industrial Natural gas
    - Price Conversion Factor: 1.055 GJ/mmBtu
    - Price in Startup Year: 7.65 \$(2012)/mmBtu (EIA 2017)
- Cooling water
    - Price \$(2012)/ Mgal: 86.28
- Process water
    - Price \$(2012)/ Mgal: 1,807.67

The default assumptions from the H2A model are used except for the industrial natural gas price and equity value. The equity is assumed to be 20% and the industrial natural gas price is from the EIA's California natural gas prices database.

2.2.1 CENTRALIZED PATHWAYS

The centralized pathways studied are:

- North American natural gas reforming
- Electrolysis using renewable power (solar PV)
- Biomass gasification

The assumptions common to all centralized pathways are listed below.

- Length of construction period
    - One year (Electrolysis)
    - % of Capital Spent in 1st year of Construction: 100%
    - Length of construction period: 3 year (Natural gas reforming and Biomass gasification)
    - % of Capital Spent in 1st year of Construction: 8%
    - % of Capital Spent in 2nd year of Construction: 60%
    - % of Capital Spent in 3rd year of Construction: 32%
- Debt period: 20 years
- Plant life: 40 years
- Analysis period: 40 years
- Depreciation schedule length: 20 years

The specific assumptions for each centralized pathway along with the hydrogen production costs are listed in Table 13 (Ramsden 2009).

Table 13. Specific assumptions used in centralized pathway analysis

Components	Natural gas reforming	Solar electrolysis	Biomass gasification
Plant design basis (kg/day)	379,000	50,000	50,000
Operating capacity factor (%)	90	97	90
Reference year	2010	2012	2012
Basis year	2005	2012	2005
Primary feed	Natural gas, Water	Electricity, Water	Woody biomass, Water
Operation type	Reforming with CO_2 sequestration	PEM electrolyzer	Gasification
Primary feed usage	Industrial natural gas: 0.15598 mmBtu/kg H_2 Demineralized water: 3.355 gal/kg H_2	Electricity: 54.3 (kWh/kg H_2)	Biomass Feedstock: 12.8 kWh/kg H_2 Biomass feedstock price: 0.1 $(2012)/kg (Webb 2015) Process water: 1.321 gal/kg H_2
Utility usage	Industrial electricity, plant operation: 0.6 kWh/kg H_2 Industrial electricity, CO_2 sequestration: 0.8 kWh/kg H_2 Cooling water: 1.495 gal/kg H_2	Cooling water: 290 gal/kg H_2	Commercial Natural gas: 0.2 Nm^3/kg H_2 Industrial electricity: 1 kWh/kg H_2 Cooling water: 79.26 gal/kg H_2
Indirect Depreciable Capital Costs	Site preparation: $2,220,600 Engineering & design: $25,200,000 Project contingency: $ 37,800,000 Up-Front Permitting Costs (legal and contractors fees included here): $ 16,600,000	Site preparation: $2,280,600 Engineering & design: $11,403,000 Process contingency: $ 8,008,000 Up-Front Permitting Costs (legal and contractors fees included here): $ 17,104,500	Site preparation: $1,100,000 Engineering & design: $14,500,000 Project contingency: $ 16,800,000 Up-Front Permitting Costs (legal and contractors fees included here): $ 10,100,000
Non-Depreciable Capital Costs	Cost of land: $50,000/acre	Cost of land: $50,000/acre	Cost of land: $50,000/acre

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	Land required: 20 acres	Land required: 5 acres	Land required: 50 acres
Fixed Operating Costs	Total plant staff: 25 Burdened labor cost, including overhead ($/man-hr): 50 Material costs for Maintenance and Repairs: $1,000,000/year	Total plant staff: 15 Burdened labor cost, including overhead ($/man-hr): 50 Production Maintenance and Repairs: $3,421,000/year	Total plant staff: 60 Burdened labor cost, including overhead ($/man-hr): 50 G&A rate: 20% of labor cost Property tax and Insurance rate: 2% of total capital investment Material costs for Maintenance and Repairs: $600,000/year
Other Variable Operating Costs (for the first year)	-	-	Other variable operating costs (e.g. environmental surcharges): $100,000/year Other Material Costs: $7,400,000/year Waste treatment costs: $1,300,000/year Solid waste disposal costs: $800,000/year
Unplanned Replacement Capital Cost Factor	0.5%	0.5%	0.5%
Capital cost	Total: $ 156,200,000 Process Plant Equipment (Reformer): $95,900,000 Balance of Plant and Offsites: $38,300,000 Process CO_2 Removal: $11,700,000 Stack CO_2 Removal: $10,300,000	Total: $101,812,500 Electrolyzer Stack: $47,852,000 Electrolyzer BoP: $53,961,000	Total: $ 111,900,000 Feed Handling & Drying: $20,100,000 Gasification, Tar Reforming, & Quench: $17,800,000 Compression & Sulfur Removal: $16,600,000 Steam Methane Reforming, Shift,

	CO_2 Compressor: $33,700,000 CO_2 Injection (Site and wells): $2,500,000 CO_2 Pipeline: $76,300,000		and PSA: $32,100,000 Steam System and Power Generation: $15,300,000 Cooling Water and Other Utilities: $3,600,000 Buildings & Structures: $6,400,000
Installation cost factor	Included in the capital cost	12% of the capital cost	Included in the capital cost
Replacement cost	-	15% of the capital cost Interval: 7 years	$5,900,000
Hydrogen production cost ($/kg H_2)	**1.89**	**6.16**	**2.49**

2.2.2 DISTRIBUTED PRODUCTION PATHWAYS

The distributed pathways studied are:

- North American natural gas reforming
- Electrolysis using grid power
- Biogas reforming

The assumptions common to all distributed pathways are listed below.

- Summer Surge (% Above the System Average Demand): 10%
- Friday Average above Weekly Average (%): 8%
- Hours per unplanned outage:14
- Number of outages per year: 10
- Days per planned outage: 5
- Number of planned outages per year: 1
- Operating capacity factor: 86%
- Length of construction period: 1 year
- % of Capital Spent in 1st Year of Construction: 100%
- Debt period: 7 years
- Plant life: 20 years
- Analysis period: 20 years
- Depreciation schedule length: 7 years

The specific assumptions for each distributed pathway along with the hydrogen production costs are listed in Table 14 (Ramsden 2009).

Table 14. Specific Assumptions used in distributed pathway analysis

Components	Natural gas reforming	Grid electrolysis	Biogas reforming
Plant design basis (kg/day)	1,500	1,500	1,500
Reference year	2010	2012	2010
Basis year	2005	2012	2005
Primary feed	Natural gas, Water	Electricity, Water	Biogas upgraded to natural gas, Water
Operation type	Reforming without CO_2 sequestration	PEM electrolyzer	Reforming without CO_2 sequestration
Primary feed usage	Commercial natural gas: 0.15598 mmBtu/kg H_2 Process water: 5.77 gal/kg H_2	Electricity: 54.3 (kWh/kg H_2) 1. Grid Electricity 2. Wind Electricity: 0.0583 \$(2015)/kWh 3. Solar PV Electricity: 0.0808 \$(2015)/kWh	Upgraded Biogas Price in Startup Year: 15.77 \$(2010)/mmbtu Usage: 4.5 Nm^3/kg H_2 Process water: 5.77 gal/kg H_2
Utility usage	Industrial electricity: 1.11 kWh/kg H_2	Cooling water: 290 gal/kg H_2	Industrial electricity: 1.11 kWh/kg H_2
Indirect Depreciable Capital Costs	Site preparation: \$240,000 Engineering & design: \$350,000 Project contingency: \$ 210,000 Up-Front Permitting Costs (legal and contractors fees included here): \$ 130,000	Site preparation: \$673,500 Engineering & design: \$50,000 Project contingency: \$ 536,000 Up-Front Permitting Costs (legal and contractors fees included here): \$ 30,000	Site preparation: \$240,000 Engineering & design: \$350,000 Project contingency: \$ 210,000 Up-Front Permitting Costs (legal and contractors fees included here): \$ 130,000

Fixed Operating Costs	Total plant staff: 0 Burdened labor cost, including overhead ($/man-hr): 50 Production Maintenance and Repairs: $280,000/year	Total plant staff: 0 Burdened labor cost, including overhead ($/man-hr): 50 Production Maintenance and Repairs: $200,000/year	Total plant staff: 0 Burdened labor cost, including overhead ($/man-hr): 50 Production Maintenance and Repairs: $280,000/year
Capital cost	Total: $960,000 Primary feed system: $10,000 Boiler: $30,000 Superheater: $10,000 HDS & absorbent bed: $10,000 Reformer: $200,000 Water gas shift: $170,000 Reformate cooler: $30,000 Condenser: $40,000 PSA unit: $70,000 Water purification: $30,000 Structural supports: $20,000 Controls system: $40,000 System assembly: $210,000 Miscellaneous: 90,000	Total: $ $3,190,125 Electrolyzer Stack: $1,310,000 Electrolyzer BoP: $1,884,000	Total: $960,000 Primary feed system: $10,000 Boiler: $30,000 Superheater: $10,000 HDS & absorbent bed: $10,000 Reformer: $200,000 Water gas shift: $170,000 Reformate cooler: $30,000 Condenser: $40,000 PSA unit: $70,000 Water purification: $30,000 Structural supports: $20,000 Controls system: $40,000 System assembly: $210,000 Miscellaneous: 90,000

Installation cost factor	10% of the capital cost	12% of the capital cost	10% of the capital cost
Replacement cost	15% of the capital cost Interval: 7 years	15% of the capital cost Interval: 7 years	15% of the capital cost Interval: 7 years
Hydrogen production cost (\$/kg H_2)	**2.03**	**5.75**	**3.32**

2.3 BLENDING HYDROGEN WITH NATURAL GAS

Several potential benefits of blending hydrogen with natural gas have been suggested.

- Possibility for reduction in fuel gas GHG emissions by blending “green” hydrogen (produced from renewable sources) with fossil natural gas.
- Having a hydrogen blend available would help encourage a transition to pure hydrogen end-use systems on an industrial and private scale (such as heating systems, burners).
- Lower the cost of making a transition to hydrogen transportation, by using the existing natural gas pipeline infrastructure to distribute NG/H2 blends instead of building a costly new dedicated hydrogen system.
- Hydrogen could be “stored” by introducing it into natural gas pipelines, rather than building dedicated hydrogen storage systems.

Blended delivery without recovering hydrogen is theoretically appealing as it has a large overlap with existing natural gas equipment and infrastructure and might enable reuse of existing equipment. However, transporting a NG/H2 blend in the natural gas system raises multiple questions.

- Will addition of hydrogen affect the integrity and safety of the natural gas delivery system? For example, will hydrogen “embrittle” pipeline or storage materials designed for use with natural gas?
- How will energy flow rate be affected by addition of hydrogen?
- Will natural gas end-use systems such as CNG vehicles, home appliances or heating systems still operate safely and efficiently with hydrogen blended in?
- How much will blending add to overall system cost?
- What are the potential greenhouse gas benefits of blending “green hydrogen” with natural gas?

To study these questions we reviewed recent papers and studies focusing on hydrogen injection and distribution in the natural gas infrastructure.

2.4 HYDROGEN DEMAND IN OFF-ROAD TRANSPORTATION MARKETS

The methodology used to estimate the potential hydrogen demand from off-road Transportation markets in California requires determining the fleet stock in each sector for ten years through 2026, estimating the potential percentage of stock which will be powered by fuel cells, and determining the yearly hydrogen usage for each vehicle or piece of equipment.

For each sector (forklifts, TRUs, and airport GSE) the present fleet stock is determined. The size of the fleet stock is then projected out each year through 2026 based on macroeconomic projections for the California gross state product (GSP). The sectors are comprised of more than a single type of vehicle or equipment; for example, forklifts fall into five classes. The fleet stock for each type was independently determined and projected for 10 years. The percentage of fuel cell units in the fleet stock was estimated based on discussions with stakeholders and information from relevant reports.

For each fuel cell in the fleet the yearly hydrogen usage was calculated. If the vehicle activity (hours) and average power are known, the energy usage for the year can be calculated. The hydrogen usage can then be calculated using the fuel cell efficiency. The fuel cell efficiency is assumed to be 50% for all markets. Some studies directly estimate the energy usage so activity and average power are not necessary.

The projected fleet stock is based on macroeconomic data from the US Bureau of Economic Analysis, Moody's Analytics (Moody's Analytics 2015). The projected average percentage increase for the baseline GSP over the next 10 years is 2.3%. Once the populations for each sector are determined for the base year (2016), the populations are projected through 2026 by increasing the numbers by the average percentage GSP.

The following sections give detailed specifics of the inputs and assumptions for each off-road Transportation sector.

2.4.1 AIRPORT GSE

Data for 2012 from an Airport Cooperative Research Program Report was used to estimate the number of pieces of GSE at US airports (ACRP 2012). Federal Aviation Administration (FAA) enplanement data allowed scaling the US data to California (FAA 2016). Roughly 11% of US enplanements occur in California. It is assumed that the cargo handling equipment requirements for California are similar to those of all US airports.

A Los Angeles World Airports Environment & Land Use Planning Division report used data from LAX to estimate the fuel costs for electric GSE (LA World Airports 2015). The data includes a yearly cost along with the assumed price of electricity. Using these numbers the estimated yearly fuel usage for each type of equipment was calculated. The fuel usage is shown in Table 15.

Table 15: Estimates for Airport GSE Fuel Use for Both Diesel and Electric Versions

GSE Type	Electricity (kWh/year)
A/C Tug Narrow Body	9493
A/C Tug Wide Body	9493
Baggage Tug	10280
Belt Loader	4207

Cargo Tractor	10280
Forklift	8540
Lift	9493
Passenger Stand	10280
Other GSE	7247

Source: LA World Airports 2015

The GSE type "other" includes cargo loaders, carts, hydrant carts, lavatory carts, and sweepers.

Demonstration programs for fuel cell GSE focus on cargo tractors. While these are likely to be the first GSE commercialized with fuel cells, other GSE could potentially use fuel cells as well. Given that fuel cell GSE are still in the demonstration phase, the percentage of FCEVs in the market is expected to be small. Discussions with stakeholders suggest that a maximum market penetration percentage for fuel cell tractors would be roughly 5% by 2026 and initial commercial units might enter the market after five years (2022). It's assumed GSE other than cargo tractors could reach 2% of the market after 10 years.

2.4.2 MATERIAL HANDLERS (FORKLIFTS)

Forklift sales data was taken from an ITA Market Intelligence report showing factory shipments for forklifts in the US from 1990 through 2012 (ITA 2012). The sales are broken into three groups – class 1 & 2 (electric rider), class 3 (motorized hand electric), and class 4 & 5 (internal combustion engine). Using the estimate of forklift lifetimes for electric and internal combustion of 8 and 7 years respectively along with the sales data, an estimate for the 2013 fleet size for each class was calculated (CTEA 2014). The fleet sizes for California were estimated by assuming forklift sales mirror state populations and using 12% as the percentage of US population in California.

Macroeconomic projections for California GSP are used to project forklift populations through 2026 for classes 1-3. Class 4 and 5 fleet projections assume that the percentage of internal combustion forklifts to total forklifts stays constant at 45%.

The fleet stock projections assume that a percentage of projected class 4 and 5 forklifts will be purchased as class 1, 2, or 3 and be electric. There is some indication from the sales data that the percentage of internal combustion engine forklifts has decreased since 2007 from 45% of the total to roughly 35%. That trend would indicate that perhaps 20% fewer internal combustion engine forklifts are being sold recently. The projections assume that 15% class 4 and 5 forklifts will be purchased as class 1 or 2 forklifts by 2026.

To determine the electricity usage in the forecast from shifting sales from internal combustion engine to electric forklifts, it was assumed that gasoline forklifts < 120 hp would shift to electric forklifts in the 6000-8000 lb range and diesel forklifts > 120 hp would shift to 19,800 lb electric forklifts. All forklifts originally projected as class 1 and 2 are assumed to be 6000-8000 lb. The CARB forklift populations show roughly 86% of conventional forklifts are < 120 hp and roughly 14% of conventional forklifts are > 120 hp. The energy usage for 6000-8000 lb forklifts is 18.3 MWh/year, 19,800 lb forklifts is 52.8 MWh/year, and class 3 forklifts is 5.2 MWh/year (CTEA 2014).

Discussions with stakeholders indicate that an upper limit on fuel cell forklift market penetration would be roughly 10% of the electric forklifts sold in 2019 and 30% of electric forklifts sold in 2026.

2.4.3 TRANSPORT REFRIGERATION UNITS

The fleet population for 2015 and projections for TRUs were taken from the California Air Resources Board TRU emissions inventory database (CARB 2011).The database includes four classes of TRU - < 11 hp, 11-25 hp, > 25 hp, and out-of-state. The out-of-state TRUs are assumed to all be large or > 25 hp. The hours of operation comes from the emissions inventory database.

The electricity and diesel fuel usage for operating eTRUs and TRUs is taken from the California Transportation Electrification Assessment and discussions with CARB personnel (CTEA 2014). The values are given in Table 16 and assumed constant through 2026.

Table 16: Electricity and Diesel Fuel Usage for TRUs

TRU Size	**Electric Power (kW)**
< 11 hp	2.3
11 – 25 hp	6
> 25 hp	10
Out-of-state	10

Source: CTEA 2014

The present price of diesel fuel coupled with the high price of hydrogen makes fuel cell TRU commercialization difficult. If conditions exist such that hydrogen can be produced at relatively low cost, the potential for market penetration increases. The section on barriers suggests strategies to lower the hydrogen cost for TRUs. Discussions with stakeholders indicate that an upper limit on market penetration might be 5% of sales in 2026. Given that incentives and commercialization strategies will likely focus on in state TRUs, the market penetration for out-of-state TRUs was assumed to be 0%.

3 RESULTS

3.1 HYDROGEN LIFECYCLE ANALYSIS

The basic assumptions used in the CA-GREET Tier2 model for all the process pathways are listed below:

- Analysis year: 2015
- Both gaseous and liquid hydrogen production processes are considered
- Central or distributed pathways are selected as required
- CAMX grid (California-Mexico grid) mix is considered as regional electricity mix for utility supply for all the cases except solar or wind.
- CA Crude is selected for regional crude oil use
- H2A model by NREL is selected for the Hydrogen production process
- Scenarios for H2A Model Cases: Future scenario. The assessment is performed for the future (2025-2030) technologies.
- For the gaseous and liquid hydrogen production plants the feedstock sources are dependent on the production pathway
- Natural gas (NG) feedstock is considered as North American (NA) NG
- Final product hydrogen use: passenger car with 24.81 MPGGE
- NG transmission distance: Interstate pipeline: 1000 miles; Instate mile: 0 miles
- Electric Transmission and Distribution Loss: 6.5%
- Co-product credits: none
- Steam/electricity export credits: none

The WTW results of the gaseous hydrogen life cycle analysis, including the energy consumption per mile driven and the GHG emissions are presented in Figures 9-11 and Table 17. The results include the total (Well to Wheels) energy use per mile driven using the specified fuel and vehicle technology. The fossil energy use is also listed which is further split into petroleum, coal and natural gas. The table also presents the emissions for the GHGs considered. The GHG emission and energy usages for Well to Tank analysis is shown in Figures 12-14 and Table 18. The WTW and WTT analysis for liquefied hydrogen production is shown in Table 19 and Table 20 and Figures 15-19.

The detailed emission and energy uses of both Well to Tank and Well to Wheel analysis for all the pathways are listed in Appendix A. Information listed in Appendix A includes:

- Energy consumption data, GHG emissions, criteria pollutant emissions for the different hydrogen production pathways for both gaseous and liquid hydrogen production (Table A1-Table A27).

The GHG emissions and the energy consumption during the TTW step are primarily based on the vehicle technology used and the efficiency of the specific vehicle type. All calculations are performed for passenger cars with 24.81 gasoline equivalent miles per gasoline gallon equivalent (MPGGE).

The total energy consumed per mile of the vehicle driven for each gaseous hydrogen pathway is shown in Figure 9. The renewable hydrogen production pathways, biomass gasification, biogas reforming, and grid electrolysis, consume more energy than the baseline natural gas reforming pathway. The fossil energy consumption results demonstrate the characteristic differences between these pathways except grid electrolysis, as shown in Figure 10.

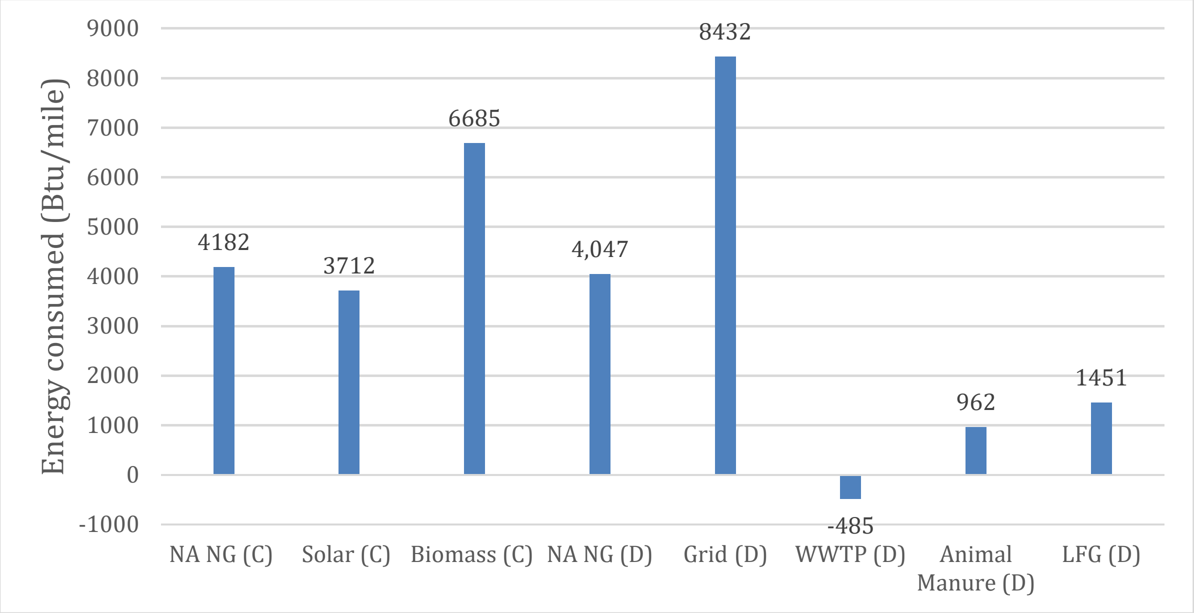

Figure 9. Total Energy consumed per mile driven for gaseous hydrogen production by each fuel pathway (Well to Wheel) (C - Centralized production pathway; D - Distributed production pathway)

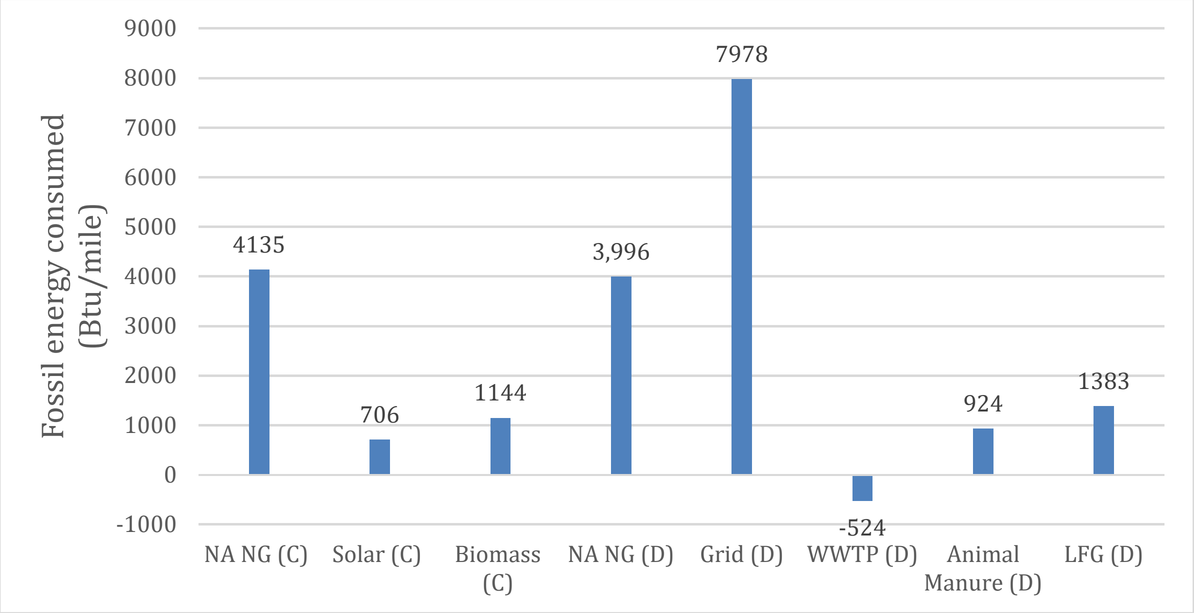

Figure 10. Fossil energy consumed per mile driven for gaseous hydrogen production by each fuel pathway (Well to Wheel) (C - Centralized production pathway; D - Distributed production pathway)

The WTW GHG emission results shown in Figure 11 demonstrate significant differences between the pathways. The grid electrolysis pathway results in the highest GHG emissions whereas biogas reforming offers the least carbon intensive approach to hydrogen production. Based on the GHG emission results, biogas reforming is the best distributed production pathway (with waste water treatment plant sludge) whereas electrolysis using solar power is the best centralized production pathway.

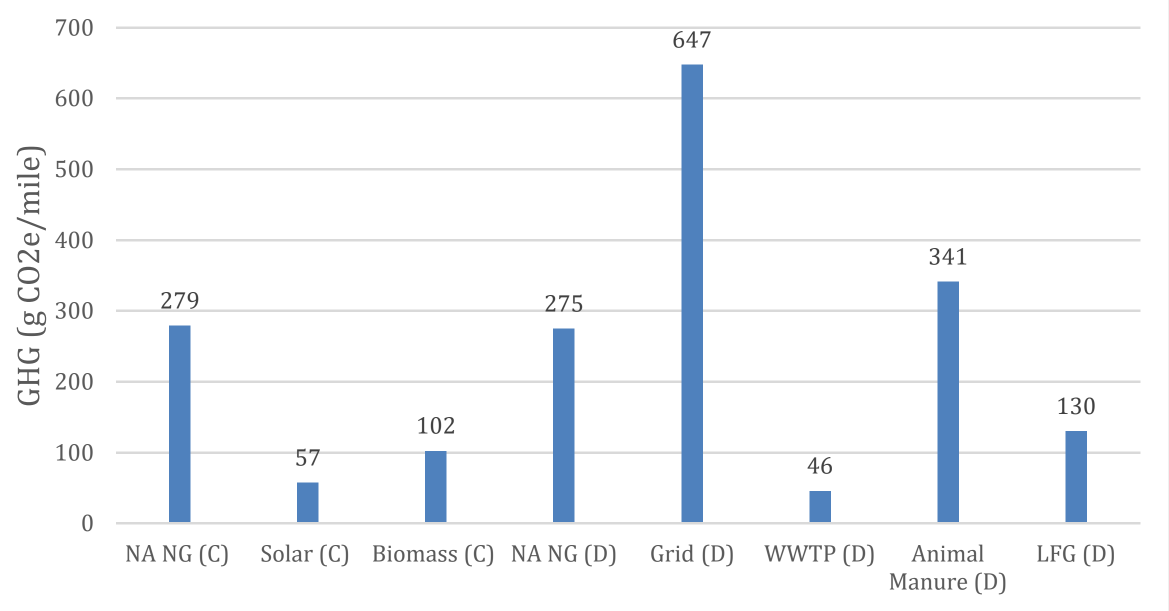

Figure 11. Greenhouse Gas emissions results for gaseous hydrogen production pathways (Well to Wheel) (C - Centralized production pathway; D - Distributed production pathway)

The Well to Tank analysis data for gaseous hydrogen production is shown in Figures 12-14. The total energy, fossil energy and GHG emissions data show a similar trend as in the WTW analysis.

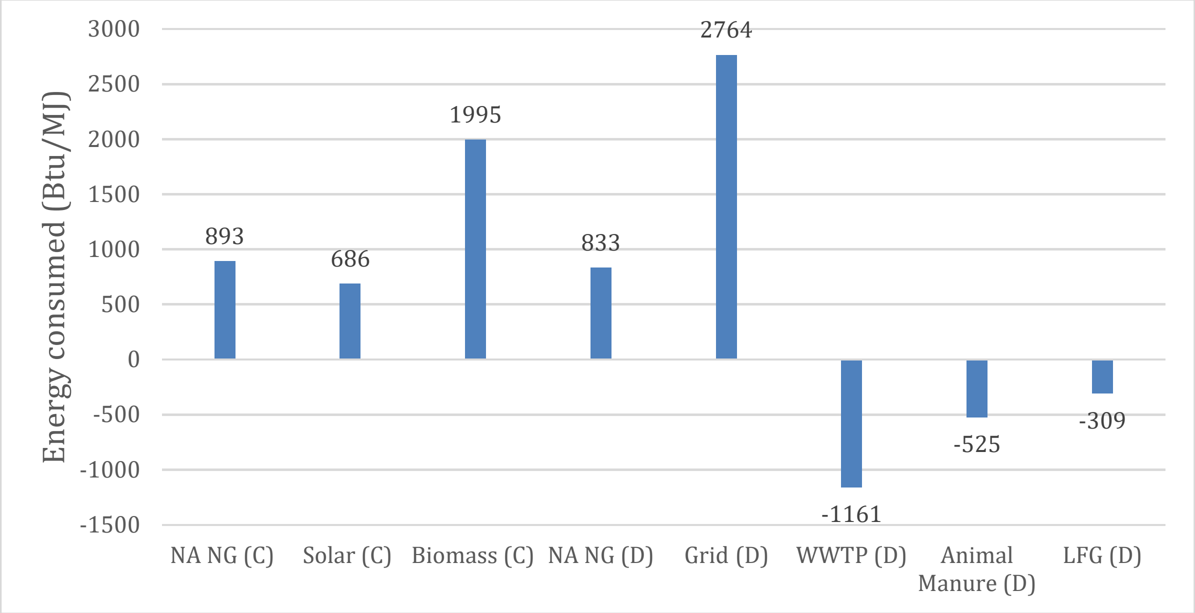

Figure 12. Total Energy consumed in hydrogen fuel generation for gaseous hydrogen production by each fuel pathway (Well to Tank) (C - Centralized production pathway; D - Distributed production pathway)

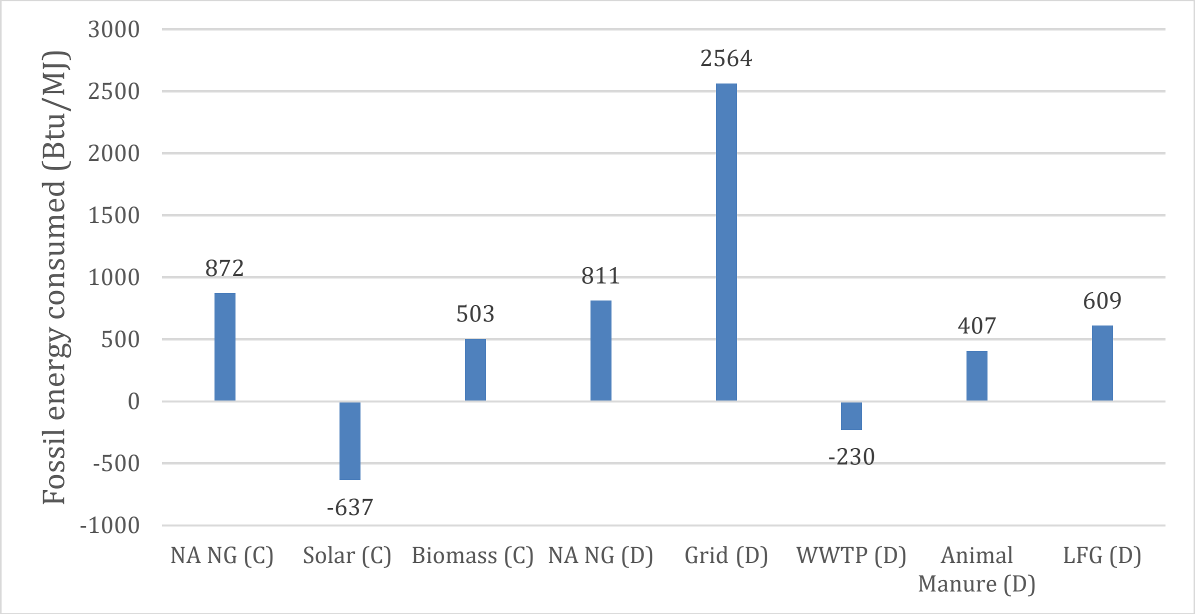

Figure 13. Fossil energy consumed for hydrogen fuel generation for gaseous hydrogen production by each fuel pathway (Well to Tank) (C - Centralized production pathway; D - Distributed production pathway)

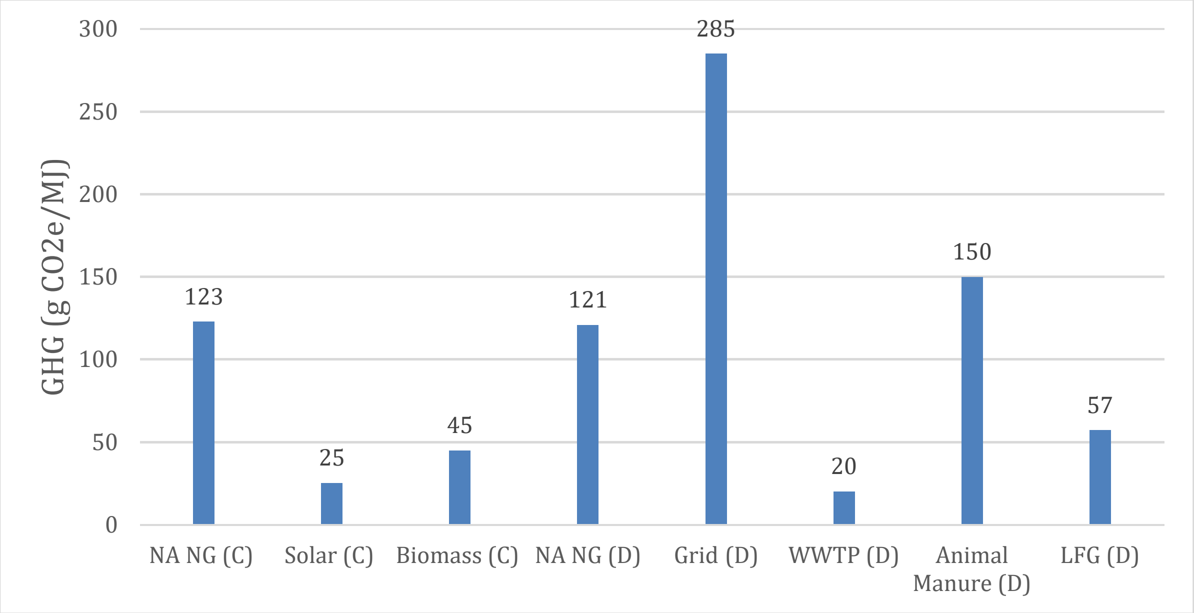

Figure 14. Greenhouse Gas emissions results for gaseous hydrogen production pathway (Well to Tank) (C - Centralized production pathway; D - Distributed production pathway)

Table 17: Summary of life cycle analysis results for gaseous hydrogen production [Well to Wheel]

Item	Units: g/mile for emissions and btu/mile for energy							
	Central pathway			Distributed pathway				
	Natural gas reforming	Solar electrolysis	Biomass gasification	Natural gas reforming	Grid Electrolysis	WWTP reforming	Aminal Manure digestion	LFG reforming
Total Energy	4182	3712	6685	4047	8432	-485	962	1451
Fossil Fuels	4135	706	1144	3996	7978	-524	924	1383
Coal	315	270	79	342	3056	-208	335	523
Natural Gas	3751	387	917	3582	4377	-279	497	742
Petroleum	69	48	148	73	545	-37	92	118
CO_2	258	54	77	250	610	-52	269	103
CH_4	1	0	0	1	1	4	3	1
N_2O	0	0	0	0	0	0	0	0
GHGs	279	57	102	275	647	46	341	130

Table 18. Summary of life cycle analysis results for gaseous hydrogen production [Well to Tank]

Item	Units: g/MJ for emissions and btu/MJ for energy							
	Central pathway			Distributed pathway				
	Natural gas reforming	Solar electrolysis	Biomass gasification	Natural gas reforming	Grid Electrolysis	WWTP reforming	Animal Manure digestion	LFG reforming
Total Energy	893	686	1995	833	2764	-1161	-525	-309
Fossil Fuels	872	0	503	811	2564	-230	407	609
Coal	139	0	35	150	397	-91	147	230
Natural Gas	703	1,118	404	629	2874	-123	219	327
Petroleum	30	0	65	32	0	-16	40	52
CO_2	113	24	34	110	269	-23	119	45
CH_4	0	0	0	0	1	2	1	0
N_2O	0	0	0	0	0	0	0	0
GHGs	123	25	45	121	285	20	150	57

Table 19: Summary of life cycle analysis results for liquid hydrogen production [Well to Wheel]

Item	Units: g/mile for emissions and btu/mile for energy							
	Central pathway			Distributed pathway				
	Natural gas reforming	Solar electrolysis	Biomass gasification	Natural gas reforming	Grid Electrolysis	WWTP reforming	Animal Manure digestion	LFG reforming
Total Energy	5743	5333	8252	6238	10513	870	2476	3020
Fossil Fuels	5616	2120	2460	6070	9947	819	2426	2935
Coal	853	806	210	1126	3810	245	848	1057
Natural Gas	4584	1156	2043	4733	5458	514	1376	1648
Petroleum	179	158	208	212	679	59	202	231
CO_2	373	162	160	400	761	43	400	216

CH_4	1	0	0	1	2	5	4	2
N_2O	0	0.0	0	0	0	0	0	0
GHGs	381	172	193	434	807	171	498	264

Table 20. Summary of life cycle analysis results for liquids hydrogen production [Well to Tank]

Item	Units: g/MJ for emissions and btu/MJ for energy							
	Central pathway			Distributed pathway				
	Natural gas reforming	Solar electrolysis	Biomass gasification	Natural gas reforming	Grid Electrolysis	WWTP reforming	Animal Manure digestion	LFG reforming
Total Energy	1580	1400	2684	1798	3679	-565	142	381
Fossil Fuels	1524	0	1083	1724	3430	360	1068	1292
Coal	375	0	92	496	729	108	373	465
Natural Gas	1070	0	899	1135	3350	226	606	725
Petroleum	79	0	91	93	0	26	89	102
CO_2	164	71	71	176	335	19	176	95
CH_4	1	0	0	1	1	2	2	1
N_2O	0	0	0	0	0	0	0	0
GHGs	181	76	85	191	385	75	219	116

The negative energy uses for H_2 production from wastewater treatment plant sludge whereas the animal manure and RNG pathways are different due to the energy credits given to these pathways. The major credits given for these pathways for energy uses are listed in Table 21.

Table 21: Energy credits for the wastewater treatment plant sludge, animal manure and RNG based H_2 production pathways.

		Transportation of Animal Waste	Anaerobic Digestion of Animal Waste/ Wastewater Sludge and RNG Production	RNG Upgrading	Electricity Exported/Imported	Energy and Emission Credits for CNG and Electricity	Energy and Emission Credits for Displaced N Fertilizer
Wastewater Treatment	Total energy		1,718,498	83,691	0	-3,314,327	

to Natural Gas	Fossil energy		0	0	0	-511,848	
Animal Waste to Natural Gas	Total energy	12,876	150,181	548,563	0	-1,698,744	-1561
	Fossil energy	13,290	0	0	0	0	-1559
Landfill Gas to Natural Gas	Total energy		157,572	184,671	0	-1,154,210	
	Fossil energy		149,313	28,294	0	0	

All the units are in Btu/mmBtu

The table shows that the total and fossil energy use are different for different pathways. Out of the different pathways considered for the H_2 production the grid electricity based electrolysis process consumes highest amount of total energy and fossil energy. This is due to the significant contribution of natural gas and coal based power to the US grid mix. The H_2 production process using grid electricity results in reduced overall energy efficiency. Thus, the grid electricity based hydrogen production process requires the highest amount of energy for H_2 production. Wastewater treatment plant sludge based H_2 production process uses the lowest amount of energy for RNG upgrading and receives the highest total and fossil energy credit. This pathway results in the lowest energy use with the least amount of GHG emission.

Biogas flaring credit for manure based pathway:
Biogas flaring credit is given to manure based pathways since animal manure is currently not converted to biogas and required to be flared. The credit for biogas flaring does not affect the energy use value results in significantly reduced emissions. The number value used for biogas flaring credit is 253, 849 Btu/mmBTU. The emission values incorporating the credit are listed in Table 22.

Table 22. Emission from animal manure based H_2 production pathway.

	Biogas flaring credit: 253, 849 Btu/mmBTU		
Item	Feedstock	Fuel	Total
CO2 (w/ C in VOC & CO)	30.299	239.055	269.355
CH4	2.457	0.835	3.292
N2O	-0.030	-0.007	-0.036
GHGs	82.937	257.923	340.860
VOC: Total	0.068	0.033	0.101
CO: Total	0.357	0.168	0.526
NOx: Total	0.022	0.150	0.172
PM10: Total	0.008	0.043	0.069

PM2.5: Total	0.008	0.037	0.049
SOx: Total	0.000	0.147	0.147
VOC: Urban	0.034	0.014	0.048
CO: Urban	0.177	0.076	0.253
NOx: Urban	0.008	0.052	0.060
PM10: Urban	0.004	0.023	0.039
PM2.5: Urban	0.004	0.022	0.029
SOx: Urban	0.000	0.042	0.042

All units are in g/mile

The Well to Wheel analysis results for the liquid hydrogen production pathways are presented in Figure 15, 16, and 17. The Well to Tank analysis for the liquid hydrogen production pathways are presented in Figure 18, 19, and 20. The results show similar trends and are comparable with the gaseous hydrogen production pathways.

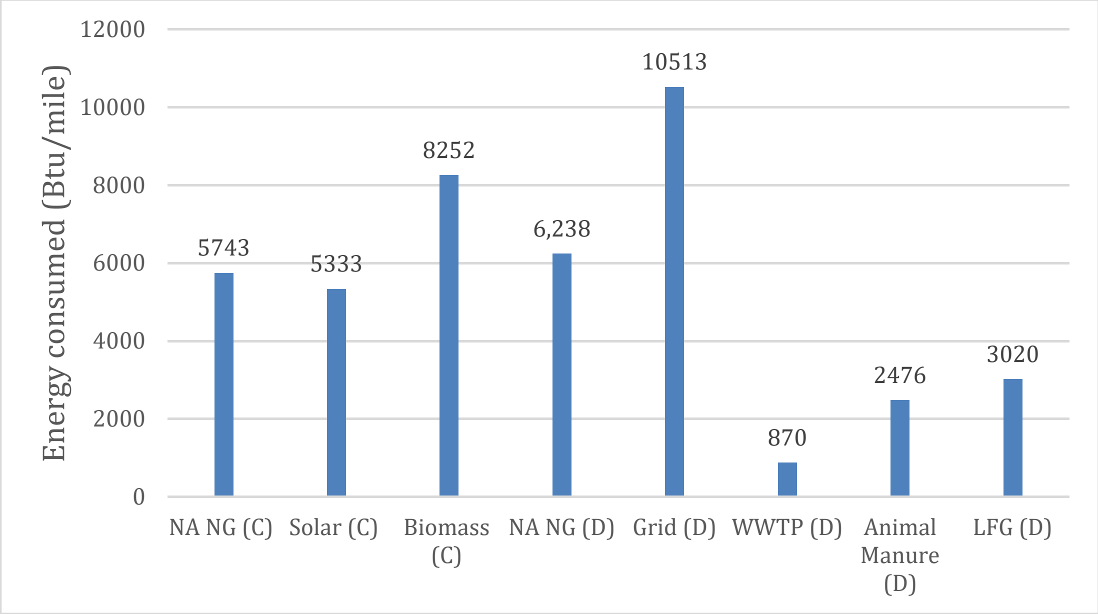

Figure 15. Total Energy consumed per mile driven for liquid hydrogen production by each fuel pathway (Well to Wheel) (C - Centralized production pathway; D - Distributed production pathway)

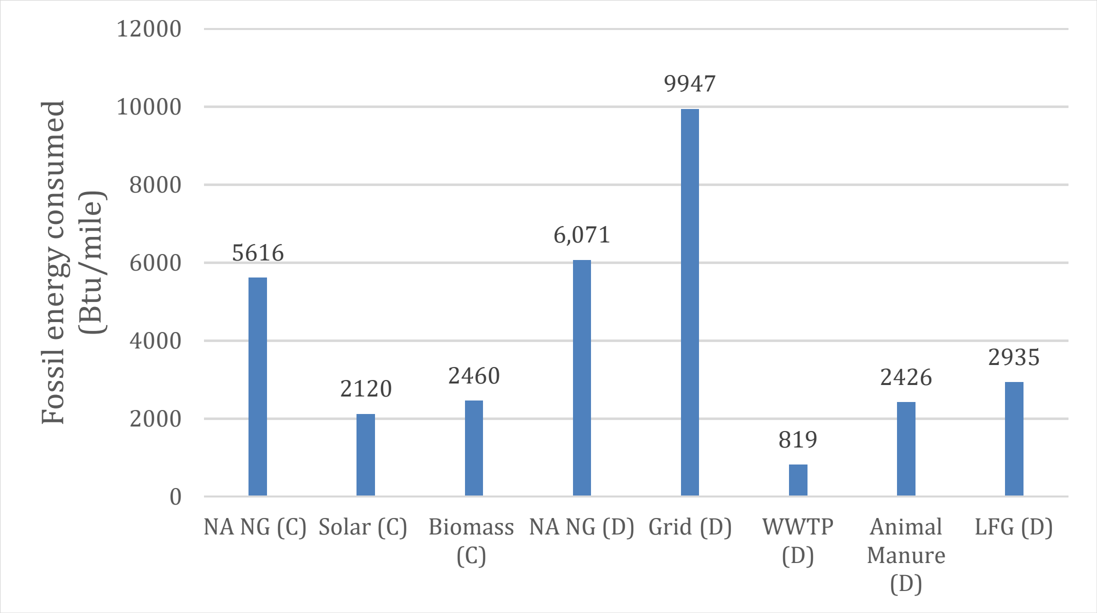

Figure 16. Fossil energy consumed per mile driven for liquid hydrogen production by each fuel pathway (Well to Wheel) (C - Centralized production pathway; D - Distributed production pathway)

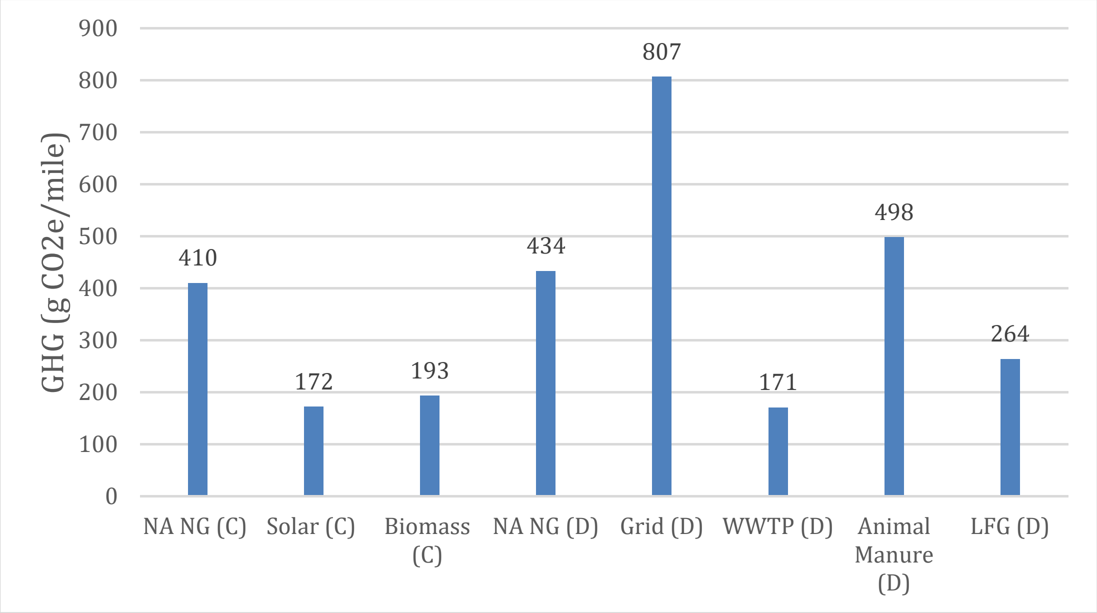

Figure 17. Greenhouse Gas emissions results for liquid hydrogen production pathway (Well to Wheel) (C - Centralized production pathway; D - Distributed production pathway)

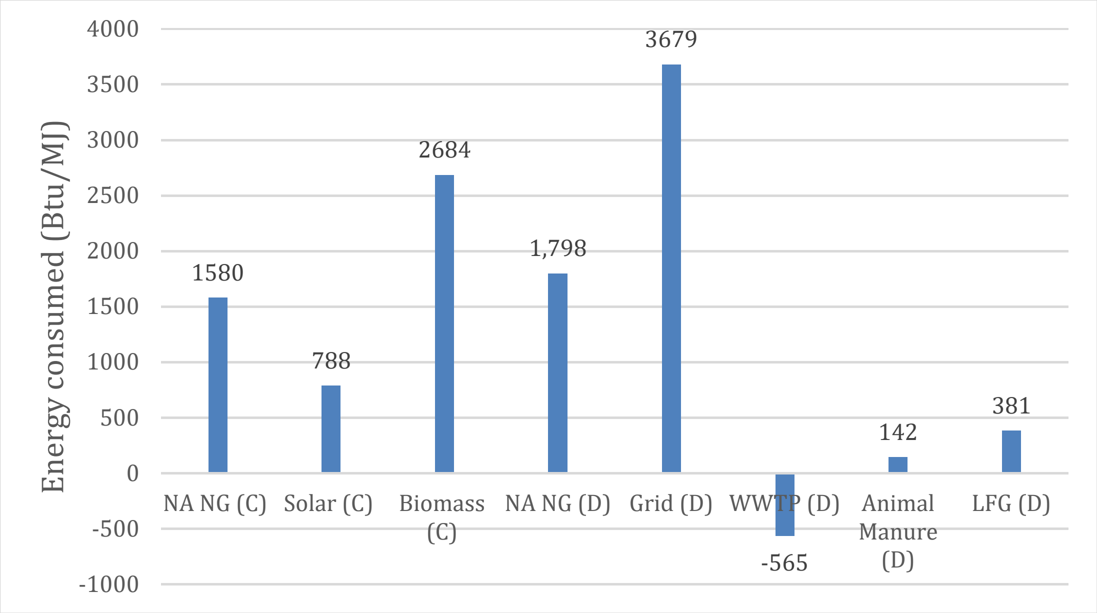

Figure 18. Total Energy consumed hydrogen fuel generation for liquid hydrogen production by each fuel pathway (Well to Tank) (C - Centralized production pathway; D - Distributed production pathway)

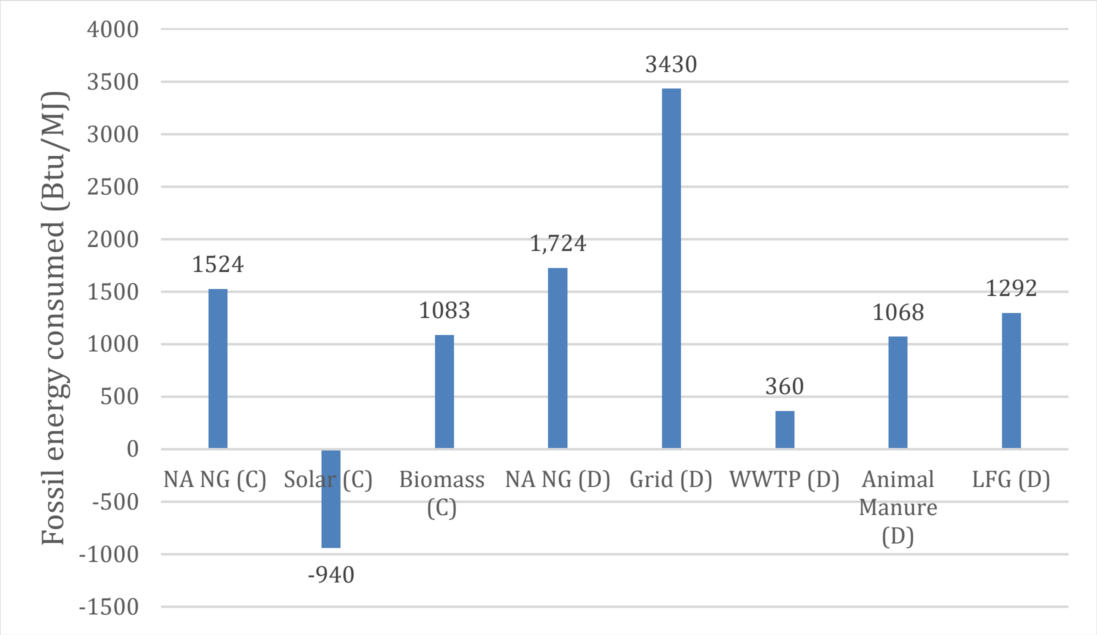

Figure 19. Fossil energy consumed for hydrogen fuel generation for liquid hydrogen production by each fuel pathway (Well to Tank) (C - Centralized production pathway; D - Distributed production pathway)

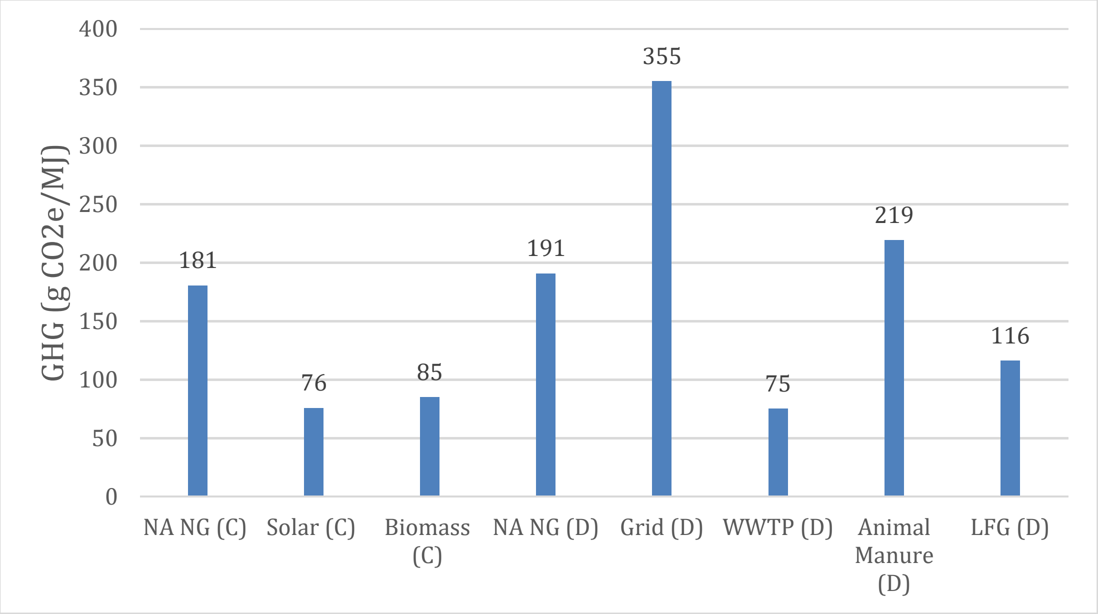

Figure 20. Greenhouse Gas emissions results for liquid hydrogen production pathway (Well to Tank) (C - Centralized production pathway; D - Distributed production pathway)

3.2 HYDROGEN LIFECYCLE ANALYSIS: ECONOMIC ANALYSIS

Figure 21 shows the H_2 production cost results for all the pathways studied. The NANG reforming pathways are the most cost effective for both centralized and distributed production. Grid powered and renewable electrolysis based pathways are the most expensive followed by biogas reforming. Centralized production through biomass gasification offers the lowest cost option using a renewable feedstock. The feedstock cost is the largest cost component for all pathways followed by capital costs. The feedstock for the electrolysis pathways is electricity. Natural gas, biomass or upgraded biogas are the feedstocks for respective pathways whereas electricity is considered as utility for these processes.

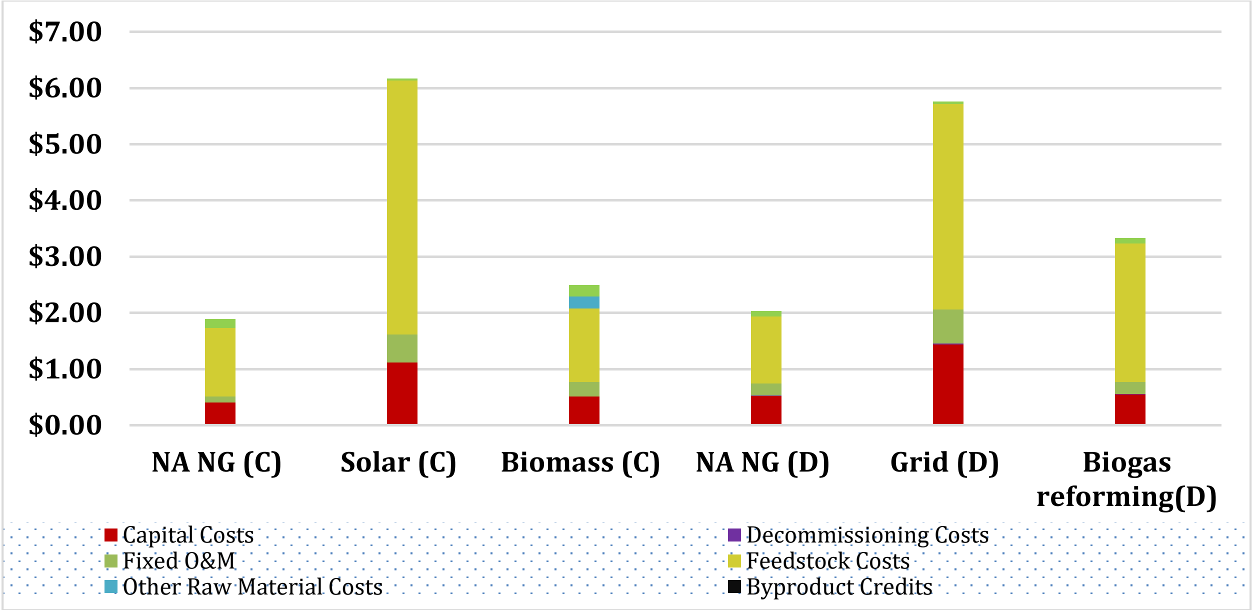

Figure 21. Real levelized H_2 production cost values ($/kg H_2) (C - Centralized production pathway; D - Distributed production pathway)

3.2.1 SENSITIVITY ANALYSIS

Sensitivity analysis for the hydrogen production cost were performed and are shown in Tornado charts (Figure 22). The parameters with the largest effect on the production cost were selected and are shown in the charts. The production cost is most sensitive to feedstock costs, capital costs, and the operating capacity factor in that order. The feedstock costs and capital costs are varied in a ±30% range of the baseline cost. Plant design capacity and fixed operating costs are assumed to vary by ±25% of the baseline cost. The rest of the costs are assumed as ±10% of the baseline cost. The sensitivity analysis results for all the pathways are presented in figures 23 to 27.

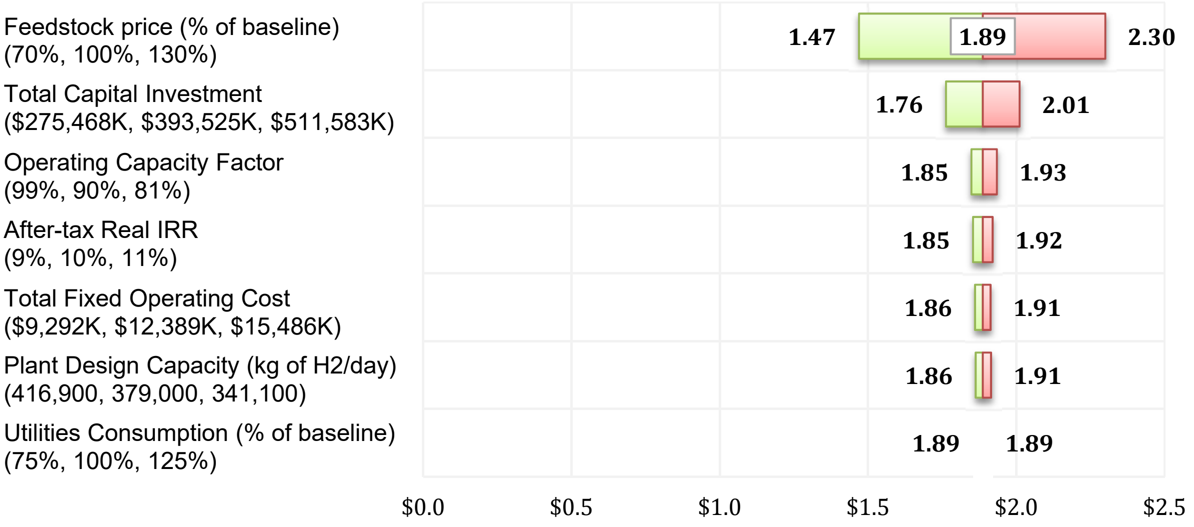

Figure 22. Sensitivity analysis for central natural gas based hydrogen production

Figure 23. Sensitivity analysis for central solar electrolysis based hydrogen production

Figure 24. Sensitivity analysis for central biomass gasification based hydrogen production

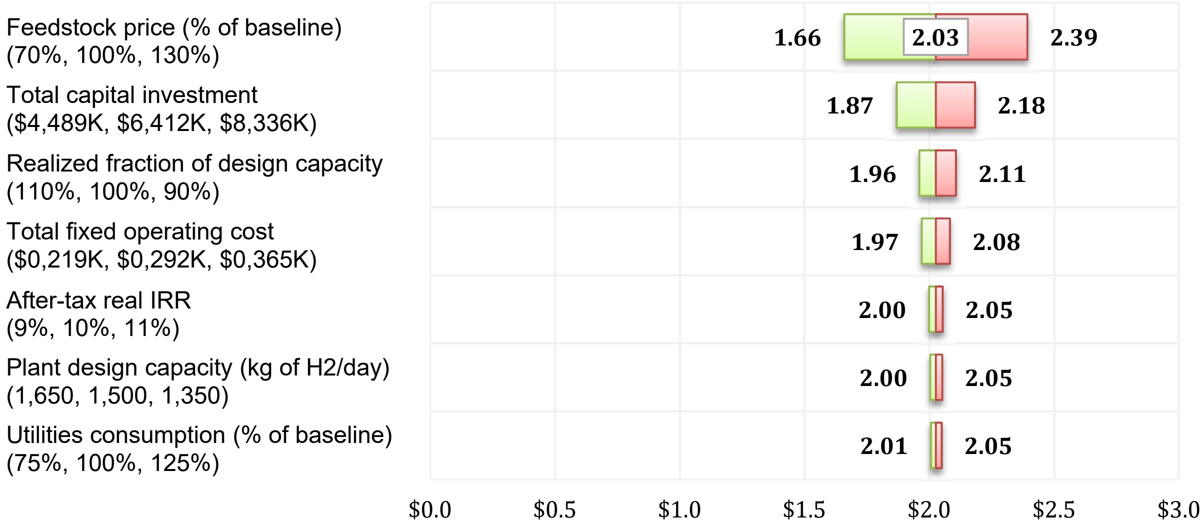

Figure 25. Sensitivity analysis for distributed natural gas based hydrogen production

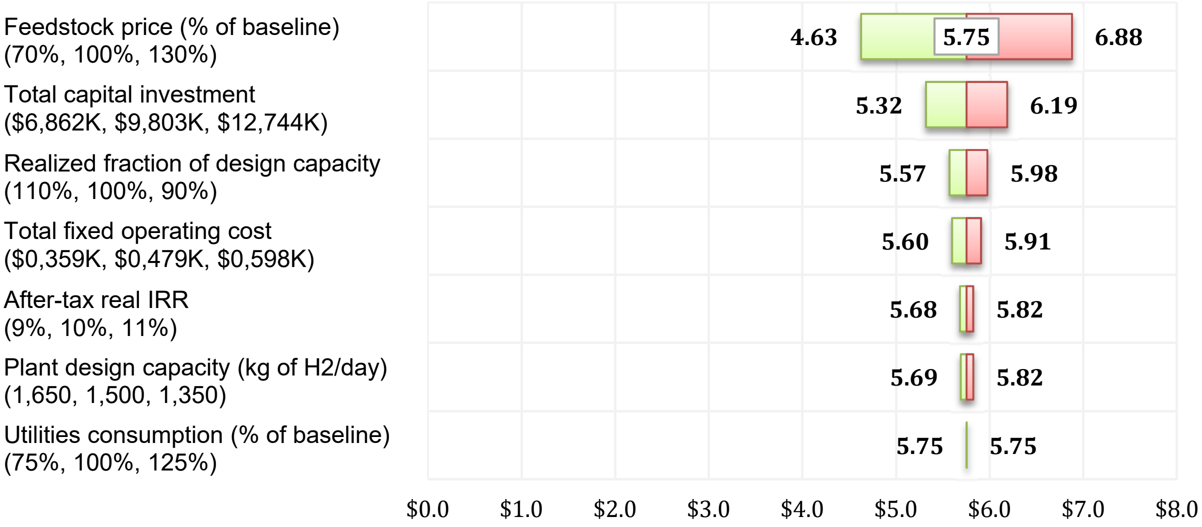

Figure 26. Sensitivity analysis for distributed grid electrolysis based hydrogen production

Figure 27. Sensitivity analysis for distributed biogas based hydrogen production

3.3 BLENDING HYDROGEN WITH NATURAL GAS

To assess the effect of blending hydrogen into natural gas pipeline networks the following issues are evaluated:

- Safety
- Leakage
- Durability

- Hydrogen extraction
- End use applications

3.3.1 SAFETY

Several papers have investigated the safety aspects of blending hydrogen in natural gas pipeline networks (GTI 2010, Melaina 2013, Messaoudani 2016, Hodges 2015, Florisson 2009). Three identified risks are gas buildup, explosions in enclosures, and risk from failure of transmission pipelines.

Gas Buildup
Two experimental releases demonstrated that the gas buildup behavior of blended fuels is similar to that of pure natural gas. The steady state concentration for hydrogen blends up to 50% is not significantly higher than for pure natural gas.

Explosions in enclosures
Measurements of the severity of confined vented explosions with blends up to 20% showed only a modest increase compared to pure natural gas. Blends over 50% show a significant increase of overpressure.

Risk from failure of transmission pipelines
This risk is the product of the frequency of pipeline failure, the probability of ignition, and the consequences of fire. The frequency of pipeline failure (rupture) dominates the overall risk (Florisson 2009). The analysis shows that risk declines as one moves away from the pipeline, and that the risk approaches zero closer to the pipeline as the hydrogen concentration increase. Higher hydrogen concentrations yield greater risks closer to the pipeline.

The main failure mode for natural gas distribution pipelines involves leaks. The Gas Technologies Institute analyzed risk associated with eight failure modes (GTI 2010).

- Corrosion leading to leakage
- Material defect whether from component defects or construction (e.g. welding).
- Natural force such as earthquakes
- Excavation damage
- Other forces not including natural forces or excavation
- Equipment malfunction
- Incorrect operations
- Other

GTI concluded that risk increased when hydrogen was added to natural gas, and the impact depends on the hydrogen concentration. Risk is not significant for blends of 20% or less hydrogen. If the hydrogen concentration exceeds 20% the risk in service lines, which are generally installed in confined spaces, can increase significantly. The risk is considered unacceptable when the hydrogen concentration exceeds 50%.

3.3.2 LEAKAGE

Because hydrogen molecules are significantly smaller than natural gas molecules, hydrogen leakage rates can be larger than rates for natural gas. Studies of permeation through plastic pipes indicate that hydrogen's permeation coefficient is 4-5 time higher than permeation for natural gas. In steel or iron pipes hydrogen leakage occurs primarily through threads or mechanical joints. Leakage rates for hydrogen were three times higher than rates for natural gas (Melaina 2015).

Adding 20% hydrogen to natural gas in distribution lines can double the total gas loss. Higher concentrations will result in higher losses. Losses from service lines which operate at lower pressures will be lower. The measured loss at 20% concentrations is economically insignificant (Melaina 2015).

3.3.3 DURABILITY

Material durability refers to the effect hydrogen can have on pipeline materials. Hydrogen can degrade pipeline materials through physical or chemical processes. An important degradation process is embrittlement of steel. Hydrogen atoms can diffuse into steel and recombine to form molecules creating pressure inside the metal. The pressure can reduce the material's ductility and tensile strength leading to fracture. Because hydrogen can degrade pipeline materials, pipeline operators must inspect, maintain, and assess natural gas pipelines, a process known as integrity management.

The degradation to pipeline materials caused by hydrogen depends on the type of materials, hydrogen concentration, and operating parameters such as pressure and temperature. Hydrogen does not appear to damage iron or copper in natural gas pipelines. The magnitude of hydrogen embrittlement depends on the type of steel. Hydrogen has a larger effect on high strength steels potentially inducing cracking and fracture while low strength steels may only lose tensile ductility. Hydrogen does not degrade polymer materials such as polyethylene.

Since hydrogen can degrade natural gas pipelines, operators must institute an integrity management program to determine when damage to pipelines can become problematic. There are a number of inspection tools used to find critical defects in the pipeline. The proper inspection interval depends on pipeline materials, and environmental conditions. Inspection intervals will be shorter for higher hydrogen concentrations

The cost of integrity management programs depends on operating conditions. Increases in program cost will generally be kept lower than 10% if hydrogen concentrations remain below 50%, operating pressures do not exceed 66 bars, and the system design life is under 50 years (GTI 2010).

3.3.4 HYDROGEN EXTRACTION

Hydrogen blended with natural gas in pipelines may be used for applications that do not require high purity such as domestic appliances, but an important application is use in fuel cell cars where the hydrogen must be extracted from the natural gas and processed to a high purity. There are several technologies which can be used to extract and purify hydrogen (Melaina 2013).

Pressure swing adsorption (PSA)

PSA operates by preferentially adsorbing some molecules while allowing other species to pass through. The adsorption probability is a function of the material type and the partial pressure. PSA units use multiple materials and layers designed for the gas concentration entering the unit.

If very high purity is needed, PSA units can be operated with more frequent cycling of the bed of materials. As the gas passes through the bed multiple times, more impurities are removed, but also some hydrogen is lost. This mode of operation sacrifices recovery rate for purity.

Membrane separation

Membrane separation operates by utilizing differential partial pressures on each side of the membrane. The pressure differential moves molecules from the side of higher partial pressure to lower partial pressure. Membranes separation technologies work efficiently for high concentrations of hydrogen. The purity of the hydrogen gas increases as the recovery rate decreases. In general membrane separation can produce hydrogen with 95-99% purity. Palladium membrane can achieve very high purities (e.g. 99.9999999%).

Electrochemical hydrogen separation

Electrochemical separation uses fuel cells passing process gas across one side of the stack. An electric current causes the hydrogen electron to dissociate from the proton. The proton passes through the stack and recombines with the electron at the other electrode. Low hydrogen partial pressures require high fuel cell powers to operate.

NREL estimated the cost for hydrogen extraction from a natural gas pipeline using PSA units. Assuming a recovery factor of 80%, hydrogen blended at 10% concentration can be extracted at \$3.3 - \$8.3/ kg depending on the volume recovered (100-1000 kg/day). As the recovered volume increases, the cost decreases. For a hydrogen concentration of 20% the cost drops to \$2.0-\$7.4. This cost can be significantly reduced if the hydrogen is extracted at a pressure reduction facility where the natural gas does not need to be recompressed. At pressure reduction facilities the extraction cost could be reduced to \$0.3-\$1.3 (Melaina 2013).

3.3.5 END USE

Even if the intent of blending hydrogen in natural gas pipeline networks is to extract and utilize the hydrogen in pure form, separation technology cannot recover all the hydrogen. Therefore, systems that operate on natural gas will be feed a blend of hydrogen and natural gas. An important consideration is the effect of hydrogen concentration on these end-use systems such as boilers, stoves, or power generation equipment.

The conditions that determine the maximum blend percentage without adversely effecting end-use systems vary considerably. The composition of the natural gas, the type of appliance or engine, and even the age of the appliance all effect the maximum blend percentage. Stationary natural gas engines likely will require modifications to the control strategy.

The acceptable range of hydrogen concentration without requiring modifications to end-use applications is roughly 5-20% hydrogen by volume. Higher concentrations require changes or precautions and may entail costs as well (Melaina 2013).

3.4 HYDROGEN DEMAND IN OFF-ROAD TRANSPORTATION MARKETS

3.4.1 HYDROGEN DEMAND

The hydrogen demand for the off-road Transportation fuel cell applications considered in this analysis is shown in Figures 28-31.

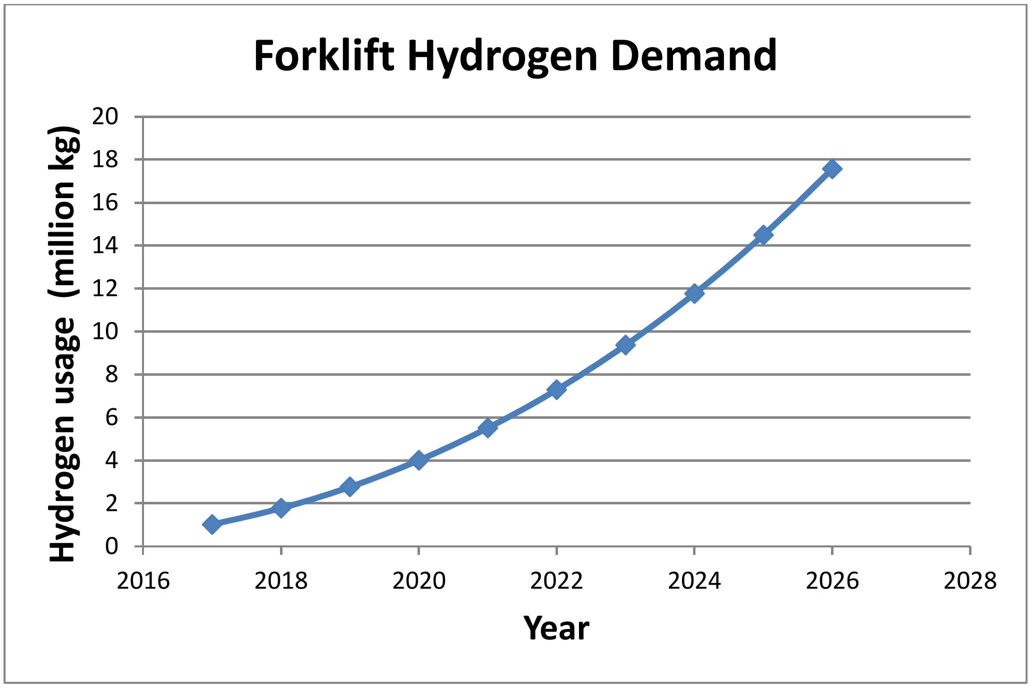

Figure28. Hydrogen demand for fuel cell forklifts in California

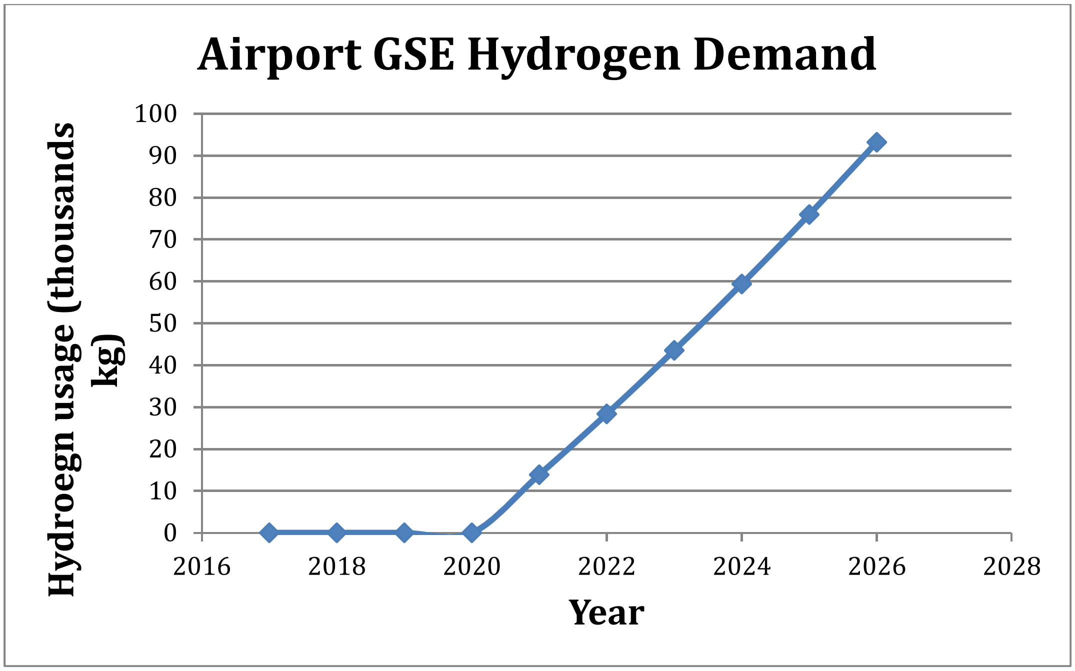

Figure 29. Hydrogen demand for fuel cell airport GSE in California

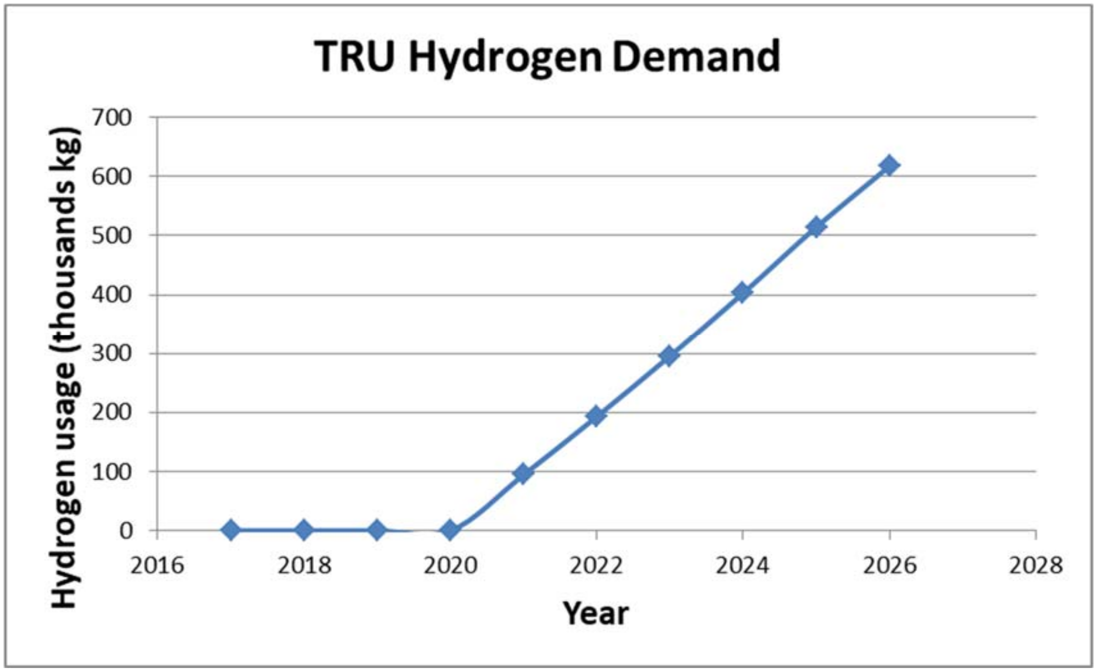

Figure 30. Hydrogen demand for fuel cell TRUs in California

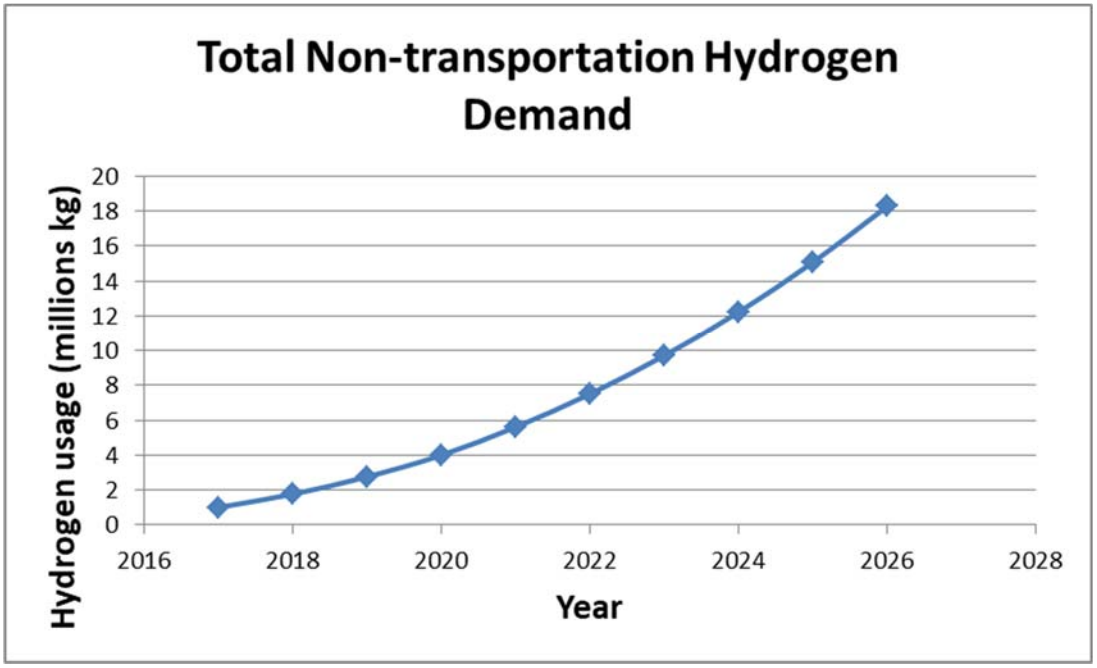

Figure 31. Total Hydrogen demand for fuel cell off-road Transportation applications in California

The market for fuel cell TRUs and airport GSE remains in the very early stages throughout the time period of this analysis. The market penetration for total fuel cell stock was assumed to be linear for this period, and therefore, the hydrogen usage increases linearly.

3.4.2 BARRIERS TO COMMERCIALIZATION

Cost

The major barrier to commercialization in off-road transportation markets is cost. Both the fuel cell capital cost and hydrogen fuel cost are relatively high. Until volume sales increase significantly the capital cost will remain a strong barrier. Cost analyses conclude that fuel cell TRUs would not be cost effective unless diesel fuel costs near $4/gallon and hydrogen fuel is $5/kg or less. Both of these targets are unlikely to be met in the near-term unless special conditions prevail.

Companies considering purchasing fuel cell GSE or forklifts will often include the cost of adding hydrogen infrastructure in their cost calculations, but they don't include infrastructure cost for diesel stations or electrical power because that infrastructure already exists. The cost comparison is weighted against fuel cells because only incremental costs are considered.

Lack of Infrastructure

Fuel cell forklifts, TRUs, and airport GSE require hydrogen infrastructure to refuel. Any company considering fuel cell products must install potentially costly appropriate infrastructure.

Fuel cell TRU range

Due to the relative lack of hydrogen infrastructure, fuel cell TRUs will not be able to travel long distances since they cannot refuel regularly. Until hydrogen infrastructure configured for class 8 trucks is installed along major highways, long haul operations will not be viable. Fuel cell TRUs may be limited to fleets that return to base every day where they could have access to a fueling station (CARB 2015)

Uncertainty

Fuel cell forklifts have been commercialized with over 7,700 units sold. Companies interested in purchasing such products can readily see how well they perform and what operational problems exist. However, fuel cell GSE and TRUs are still in the demonstration phase where uncertainty concerning reliability, cost, and performance is high. Until these products are installed in many more locations, prospective purchasers may have significant concerns about the commercial readiness.

Competition from battery electric or electric designs

In each of the off-road Transportation sectors considered for fuel cell applications battery electric or electric designs have a significant lead in commercialization. The majority of forklifts are already powered by batteries. Airports have begun a transition to battery electric GSE with the percentage of battery electric GSE at or above 50% at some airports. Trucks are beginning to install electric TRUs (eTRUs) which can plug into power outlets when the vehicle is stopped at appropriate facilities.

Battery electric forklifts or GSE and eTRUs emit no criteria pollutants and generally can have very low lifecycle GHG emissions. In general these technologies are considered very positive from an environmental standard; nevertheless, they do act as a barrier to fuel cell market penetration in these applications. To the extent that these electric designs are considered more desirable than their fuel cell competition, hydrogen demand from these sectors will be suppressed.

Strategies to overcome commercialization barriers

Incentives and subsidies

To help mitigate the higher capital and fuel cost for fuel cell systems governments could offer incentives and subsidies. The US IRS could extend the Business Energy Investment Tax Credit for certain environmentally beneficial technologies including fuel cells. Before this credit lapsed, companies could receive a tax credit of 30% for purchasing fuel cell products. The rebate percentage was gradually stepped down after 2019 reaching 10% by 2022. The rule could be amended to extend the 30% credit after 2019 to ensure strong incentives during the period where fuel cell forklifts, GSE, and TRUs are ramping up commercialization. California could add incentives to this federal program.

Emission standards and other regulation

The emissions standard for off-road diesel engines could be lowered over time. Stricter standards could make zero emission technologies more attractive to companies considering new purchases. CARB is considering reducing the period of time that TRU diesel engines can operate while stationary. If the period were reduced over time, companies could view fuel cell operation as a path to ensure compliance.

Disseminate product information

To reduce the concerns about the reliability and performance of these new fuel cell technologies, demonstration programs could be closely monitored, and information relating to successful outcomes could be widely disseminated. Some companies may participate in demonstrating fuel cell airport GSE or TRUs, but the majority may not be aware of progress made over time. When a product has demonstrated adequate performance, extended reliability, or lower costs, CARB or the California Energy Commission could work to ensure that other companies in the same market become aware of the progress made. Industry groups such as the National Fuel Cell and Hydrogen Association, the California Hydrogen Business Council, and the California Fuel Cell Partnership could assist in disseminating appropriate information.

Industrial parks (hub and spoke)

The high cost of hydrogen fuel acts as a disincentive to purchase fuel cell technologies. The cost is generally a function of the volume produced. During the early commercialization phase, the demand for hydrogen will be relatively low. To potentially reduce this cost companies could look to locate fuel cell products near already existing markets. For example, if a warehouse that operates fuel cell forklifts is serviced by trucks with TRUs, those trucks could operate fuel cell TRUs. Both markets could utilize the same hydrogen infrastructure or portions of the same infrastructure thus reducing the cost of hydrogen.

4 SUMMARY AND CONCLUSIONS

4.1 TECHNOLOGICAL ASSESSMENT

An assessment of renewable hydrogen production pathways was conducted and a list of near, mid and long term pathways was developed based on the anticipated commercialization timeframes. The key technology pathways expected to be commercially available in the near to mid-term are:

- Near Term: 5 years (commercially available by 2020)
    - Water electrolysis based hydrogen production
    - Biogas reforming to hydrogen
- Mid Term: 10 years (commercially available by 2025)
    - Biomass gasification based hydrogen production

Life Cycle Analysis and economic analysis were conducted for select centralized and distributed hydrogen production pathways using the CA-GREET Tier 2 model. Fossil natural gas reforming, the dominant industrial hydrogen production technology, is used as the baseline against which renewable hydrogen production technologies are compared. The renewable resource based pathways such as electrolysis using solar power, biomass gasification and biomethane reforming result in reduced GHG emissions as well as reduced fossil energy consumption. The key results from the life cycle and economic analysis include:

- The Well-to-Wheel analysis has been performed for different fuel pathways and shows that the biomethane reforming pathway results in the lowest GHG emissions. Electrolysis using renewable power from a solar PV facility results in the lowest GHG emissions among centralized production pathways. Grid electricity based hydrogen production via electrolysis uses the highest amount of total and fossil energy and results in significantly higher GHG emissions compared to the baseline.

- Hydrogen production cost was evaluated for the traditional steam methane reforming process as well as other alternative pathways. As expected, natural gas reforming offers the most cost effective production option through central & distributed production. Electrolysis using renewable electricity (solar PV) results in the highest production cost through a centralized pathway, roughly 226% higher than the baseline cost. Centralized biomass gasification offers the most cost effective approach to production using a renewable feedstock. Electrolysis is the highest production cost option among distributed pathways. Grid electricity based electrolysis results in approximately 183% higher production costs whereas biogas reforming pathway results in 64% higher costs than the baseline process.

- Based on the life cycle GHG emissions and cost performance, centralized biomass gasification pathway offers the most cost effective option to reduce GHG emissions among renewable hydrogen production pathways.

Based on the technology assessment and analysis results, the following recommendations are provided.

- Although renewable hydrogen production is technologically feasible in the near to mid-term, commercial viability will be difficult to achieve without sufficient incentives and other governmental support. An assessment of the most feasible commercialization approaches and steps needed to realize commercial production is necessary.
- Many of the technologies evaluated here are under development and are evolving rapidly. Publicly available data are often out of date or are not reflective of specific technology options. A more focused analysis of select pathways using data from commercial installations or demonstration projects will result in technology specific data that can guide further research, development and commercialization strategy.

4.2 BLENDING HYDROGEN WITH NATURAL GAS

The following conclusions summarize results from the review of blending hydrogen in natural gas pipeline networks.

Safe blend percentage
Based on safety, durability, and end-use considerations, hydrogen blend percentages ranging from 5-15% of hydrogen by volume are acceptable in natural gas pipeline networks. This level does not require modifications to end-use equipment, does not reduce public safety, and does not cause damage to pipeline systems.

Case specific results
The wide range of parameters for pipeline networks including natural gas composition, pipeline pressures and temperatures, and pipeline materials may require individual analysis of each situation in order to determine appropriate hydrogen concentrations.

Integrity management programs
The potential for hydrogen to cause pipeline degradation requires modifications to integrity management programs developed for natural gas pipeline networks. Proper monitoring and maintenance can lower the probability that the introduction of hydrogen into the network will cause unacceptable damage.

High blend percentages
Caution must be exercised in utilizing blend percentages above 15%. While some situations could support increased hydrogen percentages, significant issues must be addressed.

4.2.1 RECOMMENDATIONS

Blending hydrogen in natural gas pipeline networks may provide a solution to the problem of hydrogen distribution from remote or centralized production facilities. To better understand the implications of a blended infrastructure, the following recommendations are suggested:

- Make funding available for detailed analyses of the distribution cost for hydrogen blended into natural gas pipelines. This cost should be compared to other distribution options.

- Given the wide variability of pipeline conditions, conduct studies of the necessary modifications to natural gas pipelines to allow hydrogen blending at various percentages.

- Conduct studies to understand the effect of various blend percentages on end-use equipment.

4.3 HYDROGEN DEMAND IN OFF-ROAD TRANSPORTATION MARKETS

This study estimated the potential hydrogen demand for off-road Transportation equipment. The estimate assumed that conditions for market penetration were realistic but towards the optimal side.

The hydrogen demand for off-road Transportation fuel cell markets in California is dominated by forklifts. Fuel cell forklifts are presently commercialized and stakeholders believe that market penetration could increase significantly. Most forklifts are presently battery electric and fuel cell forklifts have some significant advantages over battery powered forklifts – faster refueling, constant power output, lower cost operation and maintenance, and space savings. Potential market penetration for fuel cell forklifts could be as high as 30% of new sales by 2026.

On the other hand, both fuel cell TRUs and airport GSE are in the demonstration phase and not ready for commercialization. With the right incentives and regulation these markets could be commercialized within 5 years or so, but total market penetration is only assumed to reach roughly 2% by 2026. In addition the fleet stock of TRU and airport equipment is much smaller than the stock of forklifts. The total contribution to the hydrogen demand for fuel cell TRUs and airport GSE is negligible compared to that of forklifts.

The potential total hydrogen demand for off-road Transportation equipment in California reaches roughly 18 million kg/year in 2026. In their mid-energy demand scenario the California Energy Commission (CEC) estimates that hydrogen demand from fuel cell light-duty vehicles may reach roughly 30 million kg/year by 2026 (CEC 2016).

4.3.1 RECOMMENDATIONS

Disseminate product information

Reliability and performance may be a concern for companies considering off-road transportation fuel cell technologies. To alleviate these concerns information from successful demonstration programs could be widely disseminated. While some companies participate in these demonstrations, many others may be unaware of potential progress.

When a fuel cell product has demonstrated good performance and costs have been reduced, CARB or the California Energy Commission could disseminate these results so potentially interested companies can become aware of the progress.

Industrial parks (hub and spoke)

Hydrogen fuel cost is presently high and can result in fuel cell technologies not being cost effective. The cost generally decreases as the volume produced increases. Companies may be able to reduce hydrogen cost by locating products near existing fuel cell markets or by identifying industrial parks where products can be co-located. These industrial parks can act to increase overall hydrogen demand, and therefore, reduce the cost.

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7 GLOSSARY OF TERMS

A-LCA	Attributional Life Cycle Analysis
CA-GREET	California Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
CAMX	California-Mexico
CARB	California Air Resources Board
CCS	carbon capture and sequestration
CEC	California Energy Commision
CFC	Chlorofluorocarbons
C-LCA	Consequential Life Cycle Analysis
CO2e	Carbon Dioxide Equivalent
EIA	Energy Information Administration
eTRU	electric transport refrigeration unit
FAA	Federal Aviation Administration
FCEV	Fuel cell electric vehicle
gge	gallon gasoline equivalent
GHG	green house gas
GHG	Green House Gas
GHGenius	Greenhouse Gas Genius
GREET	Greenhouse Gas, Regulatefd Emission, and Energy for Transportation
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
GSE	ground support equipment
GSP	gross state product
GWP	Global Warming Potential
H2A	hydrogen analysis
HEEP	hydrogen economy evaluation program
HFC	Hydrofluorocarbons
HTE	high temperature electrolysis
HTGR	high temperature gas reactor
IPCC	Intergovernmental Panel on Climate Change
ISO	International Organization for Standardization
LCA	lifecycle analysis
LCA	Life Cycle Analysis
LCFS	Low Carbon Fuel Standard
LHV	Lower Heating Value
MACRS	Modified Accelerated Cost Recovery System
MPG	Miles Per Gallon
mpgge	miles per gasoline gallon equivalent
MPGGE	Miles Per Gasoline Gallon Equivalent
NA NG	North American Natural gas

NG	Natural Gas
NREL	National Renewable Energy Laboratory
PBR	peeble bed reactor
PEM	Polymer Electrolyte Membrane
PEM	proton exchange membrane
PM	Particulate Matter
PMR	prismatic core reactor
PSA	Pressure Swing Absorption
PtG	power to gas
R&D	Research & Development
RNG	Renewable Natural Gas
SMR	Steam Methane Reforming
STCH	Solar to Thermochemical
STH	Solar to Hydrogen
TRU	transport refrigeration unit
TTW	Tank- to-Wheels
US DOE	US Department of Energy
USDOE	United States Department of Energy
VOC	Volatile Organic Compound
WGS	Water Gas Shift
WTT	Well To Tank
WTW	Well To Wheel
WWTP	Waste Water Treatment Plant
ZEV	zero emissions vehicle

8 APPENDIX

8.1 CENTRAL: NATURAL GAS REFORMING

Table A1: Well-to-Tank Energy Consumption and Emissions

	FCV: G.H2, Central Plants, NA NG	FCV: L.H2, Central Plants, NA NG
	Btu/MJ or g/MJ	Btu/MJ or g/MJ
Total Energy	893	1,580
WTP Efficiency	84.3%	78.5%
Fossil Fuels	872	1,524
Coal	139	375
Natural Gas	703	1,070
Petroleum	30	79
CO2 (w/ C in VOC & CO)	113	164
CH4	0	1
N2O	0	0
GHGs	123	181
VOC: Total	11.10	13.90
CO: Total	35.67	51.45
NOx: Total	48.00	62.52
PM10: Total	1.61	1.07
PM2.5: Total	1.13	0.97
SOx: Total	21.75	14.44
VOC: Urban	0.67	0.12
CO: Urban	3.51	0.89
NOx: Urban	4.97	0.95
PM10: Urban	0.32	0.05
PM2.5: Urban	0.23	0.04
SOx: Urban	3.07	0.12

Table A2 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Central Plants, NA NG								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	280.831	1747.340	2153.472	4181.643	123.603	769.065	947.818	1840.487
Fossil Fuels	279.989	1701.283	2153.472	4134.743	123.233	748.794	947.818	1819.844
Coal	5.671	309.745	0.000	315.416	2.496	136.330	0.000	138.826
Natural Gas	264.247	1333.005	2153.472	3750.724	116.304	586.702	947.818	1650.824
Petroleum	10.070	58.532	0.000	68.603	4.432	25.762	0.000	30.194
CO2 (w/ C in VOC & CO)	15.522	242.327	0.000	257.849	6.832	106.656	0.000	113.488
CH4	0.466	0.306	0.000	0.772	0.205	0.135	0.000	0.340
N2O	0.003	0.003	0.000	0.006	0.001	0.001	0.000	0.003
GHGs	28.175	250.862	0.000	279.037	12.401	110.413	0.000	122.814
VOC: Total	0.023	0.022	0.000	0.046	0.010	0.010	0.000	0.020
CO: Total	0.075	0.099	0.000	0.174	0.033	0.043	0.000	0.077
NOx: Total	0.095	0.180	0.000	0.275	0.042	0.079	0.000	0.121
PM10: Total	0.001	0.042	0.018	0.061	0.001	0.019	0.008	0.027
PM2.5: Total	0.001	0.036	0.005	0.042	0.000	0.016	0.002	0.018
SOx: Total	0.027	0.145	0.000	0.172	0.012	0.064	0.000	0.076
VOC: Urban	0.001	0.003	0.000	0.004	0.001	0.001	0.000	0.002
CO: Urban	0.007	0.018	0.000	0.025	0.003	0.008	0.000	0.011
NOx: Urban	0.008	0.036	0.000	0.044	0.004	0.016	0.000	0.019

PM10: Urban	0.000	0.011	0.013	0.023	0.000	0.005	0.006	0.010
PM2.5: Urban	0.000	0.010	0.003	0.013	0.000	0.004	0.001	0.006
SOx: Urban	0.001	0.039	0.000	0.040	0.000	0.017	0.000	0.018

Table A3 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Central Plants, NA NG								
Btu/mile or g/mile					Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	290.874	3298.237	2153.472	5742.582	128.024	1451.669	947.818	2527.511
Fossil Fuels	290.002	3172.316	2153.472	5615.789	127.640	1396.247	947.818	2471.705
Coal	5.874	846.845	0.000	852.719	2.585	372.726	0.000	375.311
Natural Gas	273.697	2156.405	2153.472	4583.574	120.464	949.109	947.818	2017.391
Petroleum	10.430	169.066	0.000	179.496	4.591	74.412	0.000	79.002
CO2 (w/ C in VOC & CO)	16.077	357.336	0.000	373.413	7.076	157.276	0.000	164.352
CH4	0.483	0.882	0.000	1.364	0.212	0.388	0.000	0.601
N2O	0.003	0.005	0.000	0.009	0.002	0.002	0.000	0.004
GHGs	29.183	381.009	0.000	410.192	12.844	167.695	0.000	180.540
VOC: Total	0.024	0.038	0.000	0.062	0.011	0.017	0.000	0.027
CO: Total	0.078	0.172	0.000	0.250	0.034	0.076	0.000	0.110
NOx: Total	0.098	0.357	0.000	0.455	0.043	0.157	0.000	0.200
PM10: Total	0.001	0.070	0.018	0.089	0.001	0.031	0.008	0.039
PM2.5: Total	0.001	0.053	0.005	0.059	0.001	0.024	0.002	0.026
SOx: Total	0.028	0.382	0.000	0.410	0.012	0.168	0.000	0.181
VOC: Urban	0.001	0.004	0.000	0.005	0.001	0.002	0.000	0.002
CO: Urban	0.007	0.029	0.000	0.036	0.003	0.013	0.000	0.016
NOx: Urban	0.009	0.066	0.000	0.074	0.004	0.029	0.000	0.033

PM10: Urban	0.000	0.014	0.013	0.027	0.000	0.006	0.006	0.012
PM2.5: Urban	0.000	0.011	0.003	0.014	0.000	0.005	0.001	0.006
SOx: Urban	0.001	0.106	0.000	0.107	0.000	0.047	0.000	0.047

Central: Solar Electrolysis

Central: Natural Gas reforming

Table A4: Well-to-Tank Energy Consumption and Emissions

	FCV: G.H2, Central Plants, NA NG	FCV: L.H2, Central Plants, NA NG
	Btu/MJ or g/MJ	Btu/MJ or g/MJ
Total Energy	893	1,580
WTP Efficiency	84.3%	78.5%
Fossil Fuels	872	1,524
Coal	139	375
Natural Gas	703	1,070
Petroleum	30	79
CO2 (w/ C in VOC & CO)	113	164
CH4	0	1
N2O	0	0
GHGs	123	181
VOC: Total	11.10	13.90
CO: Total	35.67	51.45
NOx: Total	48.00	62.52
PM10: Total	1.61	1.07
PM2.5: Total	1.13	0.97
SOx: Total	21.75	14.44
VOC: Urban	0.67	0.12
CO: Urban	3.51	0.89
NOx: Urban	4.97	0.95
PM10: Urban	0.32	0.05
PM2.5: Urban	0.23	0.04
SOx: Urban	3.07	0.12

Table A5 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Central Plants, NA NG								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	280.831	1747.340	2153.472	4181.643	123.603	769.065	947.818	1840.487
Fossil Fuels	279.989	1701.283	2153.472	4134.743	123.233	748.794	947.818	1819.844
Coal	5.671	309.745	0.000	315.416	2.496	136.330	0.000	138.826
Natural Gas	264.247	1333.005	2153.472	3750.724	116.304	586.702	947.818	1650.824
Petroleum	10.070	58.532	0.000	68.603	4.432	25.762	0.000	30.194
CO2 (w/ C in VOC & CO)	15.522	242.327	0.000	257.849	6.832	106.656	0.000	113.488
CH4	0.466	0.306	0.000	0.772	0.205	0.135	0.000	0.340
N2O	0.003	0.003	0.000	0.006	0.001	0.001	0.000	0.003
GHGs	28.175	250.862	0.000	279.037	12.401	110.413	0.000	122.814
VOC: Total	0.023	0.022	0.000	0.046	0.010	0.010	0.000	0.020
CO: Total	0.075	0.099	0.000	0.174	0.033	0.043	0.000	0.077
NOx: Total	0.095	0.180	0.000	0.275	0.042	0.079	0.000	0.121
PM10: Total	0.001	0.042	0.018	0.061	0.001	0.019	0.008	0.027
PM2.5: Total	0.001	0.036	0.005	0.042	0.000	0.016	0.002	0.018
SOx: Total	0.027	0.145	0.000	0.172	0.012	0.064	0.000	0.076
VOC: Urban	0.001	0.003	0.000	0.004	0.001	0.001	0.000	0.002
CO: Urban	0.007	0.018	0.000	0.025	0.003	0.008	0.000	0.011
NOx: Urban	0.008	0.036	0.000	0.044	0.004	0.016	0.000	0.019

PM10: Urban	0.000	0.011	0.013	0.023	0.000	0.005	0.006	0.010
PM2.5: Urban	0.000	0.010	0.003	0.013	0.000	0.004	0.001	0.006
SOx: Urban	0.001	0.039	0.000	0.040	0.000	0.017	0.000	0.018

Table A6 Well to Wheel Energy Consumption and Emissions for liquid hydrogen production

FCV: L.H2, Central Plants, NA NG								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	290.874	3298.237	2153.472	5742.582	128.024	1451.669	947.818	2527.511
Fossil Fuels	290.002	3172.316	2153.472	5615.789	127.640	1396.247	947.818	2471.705
Coal	5.874	846.845	0.000	852.719	2.585	372.726	0.000	375.311
Natural Gas	273.697	2156.405	2153.472	4583.574	120.464	949.109	947.818	2017.391
Petroleum	10.430	169.066	0.000	179.496	4.591	74.412	0.000	79.002
CO2 (w/ C in VOC & CO)	16.077	357.336	0.000	373.413	7.076	157.276	0.000	164.352
CH4	0.483	0.882	0.000	1.364	0.212	0.388	0.000	0.601
N2O	0.003	0.005	0.000	0.009	0.002	0.002	0.000	0.004
GHGs	29.183	381.009	0.000	410.192	12.844	167.695	0.000	180.540
VOC: Total	0.024	0.038	0.000	0.062	0.011	0.017	0.000	0.027
CO: Total	0.078	0.172	0.000	0.250	0.034	0.076	0.000	0.110
NOx: Total	0.098	0.357	0.000	0.455	0.043	0.157	0.000	0.200
PM10: Total	0.001	0.070	0.018	0.089	0.001	0.031	0.008	0.039
PM2.5: Total	0.001	0.053	0.005	0.059	0.001	0.024	0.002	0.026
SOx: Total	0.028	0.382	0.000	0.410	0.012	0.168	0.000	0.181
VOC: Urban	0.001	0.004	0.000	0.005	0.001	0.002	0.000	0.002
CO: Urban	0.007	0.029	0.000	0.036	0.003	0.013	0.000	0.016
NOx: Urban	0.009	0.066	0.000	0.074	0.004	0.029	0.000	0.033

PM10: Urban	0.000	0.014	0.013	0.027	0.000	0.006	0.006	0.012
PM2.5: Urban	0.000	0.011	0.003	0.014	0.000	0.005	0.001	0.006
SOx: Urban	0.001	0.106	0.000	0.107	0.000	0.047	0.000	0.047

Central: Solar Electrolysis

Table A7: Well-to-Tank Energy Consumption and Emissions

	FCV: G.H2, Central Plants, Solar	FCV: L.H2, Central Plants, Solar
	Btu/MJ or g/MJ	Btu/MJ or g/MJ
Total Energy	686	1,400
WTP Efficiency	0.00	0.00
Fossil Fuels	-637	-15
Coal	-829	-593
Natural Gas	1,118	1,457
Petroleum	0	0
CO2 (w/ C in VOC & CO)	24	71
CH4	0	0
N2O	0	0
GHGs	25.20	75.74
VOC: Total	0.00	0.01
CO: Total	0.02	0.05
NOx: Total	0.04	0.11
PM10: Total	0.01	0.02
PM2.5: Total	0.00	0.01
SOx: Total	0.05	0.16
VOC: Urban	0.00	0.00
CO: Urban	0.00	0.01
NOx: Urban	0.01	0.02
PM10: Urban	0.00	0.00
PM2.5: Urban	0.00	0.00
SOx: Urban	0.01	0.04

Table A8 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Central Plants, Solar								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	812.743	745.846	2153.472	3712.060	357.716	328.273	947.818	1633.807
Fossil Fuels	0.000	705.651	0.000	705.651	0.000	310.582	0.000	310.582
Coal	0.000	270.312	0.000	270.312	0.000	118.974	0.000	118.974
Natural Gas	0.000	387.177	0.000	387.177	0.000	170.410	0.000	170.410
Petroleum	0.000	48.163	0.000	48.163	0.000	21.198	0.000	21.198
CO2 (w/ C in VOC & CO)	0.000	53.977	0.000	53.977	0.000	23.757	0.000	23.757
CH4	0.000	0.117	0.000	0.117	0.000	0.052	0.000	0.052
N2O	0.000	0.001	0.000	0.001	0.000	0.001	0.000	0.001
GHGs	0.000	57.263	0.000	57.263	0.000	25.204	0.000	25.204
VOC: Total	0.000	0.007	0.000	0.007	0.000	0.003	0.000	0.003
CO: Total	0.000	0.035	0.000	0.035	0.000	0.015	0.000	0.015
NOx: Total	0.000	0.084	0.000	0.084	0.000	0.037	0.000	0.037
PM10: Total	0.000	0.013	0.018	0.031	0.000	0.006	0.008	0.014
PM2.5: Total	0.000	0.008	0.005	0.013	0.000	0.004	0.002	0.006
SOx: Total	0.000	0.119	0.000	0.119	0.000	0.052	0.000	0.052
VOC: Urban	0.000	0.001	0.000	0.001	0.000	0.000	0.000	0.000
CO: Urban	0.000	0.007	0.000	0.007	0.000	0.003	0.000	0.003
NOx: Urban	0.000	0.018	0.000	0.018	0.000	0.008	0.000	0.008
PM10: Urban	0.000	0.004	0.013	0.016	0.000	0.002	0.006	0.007

PM2.5: Urban	0.000	0.002	0.003	0.006	0.000	0.001	0.001	0.003
SOx: Urban	0.000	0.034	0.000	0.034	0.000	0.015	0.000	0.015

Table A9 Well to Wheel Energy Consumption and Emissions for liquid hydrogen production

FCV: L.H2, Central Plants, Solar								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	918.823	2260.926	2153.472	5333.221	404.406	995.112	947.818	2347.336
Fossil Fuels	0.000	2120.342	0.000	2120.342	0.000	933.236	0.000	933.236
Coal	0.000	806.002	0.000	806.002	0.000	354.749	0.000	354.749
Natural Gas	0.000	1156.015	0.000	1156.015	0.000	508.803	0.000	508.803
Petroleum	0.000	158.325	0.000	158.325	0.000	69.684	0.000	69.684
CO2 (w/ C in VOC & CO)	0.000	162.250	0.000	162.250	0.000	71.412	0.000	71.412
CH4	0.000	0.351	0.000	0.351	0.000	0.154	0.000	0.154
N2O	0.000	0.004	0.000	0.004	0.000	0.002	0.000	0.002
GHGs	0.000	172.094	0.000	172.094	0.000	75.745	0.000	75.745
VOC: Total	0.000	0.023	0.000	0.023	0.000	0.010	0.000	0.010
CO: Total	0.000	0.107	0.000	0.107	0.000	0.047	0.000	0.047
NOx: Total	0.000	0.257	0.000	0.257	0.000	0.113	0.000	0.113
PM10: Total	0.000	0.040	0.018	0.058	0.000	0.017	0.008	0.025
PM2.5: Total	0.000	0.024	0.005	0.029	0.000	0.011	0.002	0.013
SOx: Total	0.000	0.355	0.000	0.355	0.000	0.156	0.000	0.156
VOC: Urban	0.000	0.002	0.000	0.002	0.000	0.001	0.000	0.001
CO: Urban	0.000	0.022	0.000	0.022	0.000	0.010	0.000	0.010
NOx: Urban	0.000	0.055	0.000	0.055	0.000	0.024	0.000	0.024

PM10: Urban	0.000	0.011	0.013	0.023	0.000	0.005	0.006	0.010
PM2.5: Urban	0.000	0.007	0.003	0.011	0.000	0.003	0.001	0.005
SOx: Urban	0.000	0.101	0.000	0.101	0.000	0.044	0.000	0.044

Central: Biomass gasification

Table A10: Well-to-Tank Energy Consumption and Emissions

	FCV: G.H2, Central Plants, Biomass	FCV: L.H2, Central Plants, Biomass
	Btu/MJ or g/MJ	Btu/MJ or g/MJ
Total Energy	1,995	2,684
WTP Efficiency	0.00	0.00
Fossil Fuels	503	1,083
Coal	35	92
Natural Gas	404	899
Petroleum	65	91
CO2 (w/ C in VOC & CO)	34	71
CH4	0	0
N2O	0	0
GHGs	45.00	85.05
VOC: Total	0.01	0.02
CO: Total	0.05	0.08
NOx: Total	0.09	0.15
PM10: Total	0.01	0.01
PM2.5: Total	0.00	0.01
SOx: Total	0.06	0.09
VOC: Urban	0.00	0.00
CO: Urban	0.01	0.02
NOx: Urban	0.01	0.02
PM10: Urban	0.00	0.00
PM2.5: Urban	0.00	0.00
SOx: Urban	0.00	0.00

Table A11 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Central Plants, Biomass								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	705.949	3825.878	2153.472	6685.299	310.713	1683.902	947.818	2942.433
Fossil Fuels	147.484	996.480	0.000	1143.964	64.913	438.585	0.000	503.498
Coal	1.758	77.467	0.000	79.225	0.774	34.096	0.000	34.870
Natural Gas	82.895	834.104	0.000	916.999	36.485	367.118	0.000	403.603
Petroleum	62.831	84.909	0.000	147.740	27.654	37.371	0.000	65.025
CO2 (w/ C in VOC & CO)	11.508	65.205	0.000	76.713	5.065	28.699	0.000	33.764
CH4	0.022	0.178	0.000	0.200	0.010	0.078	0.000	0.088
N2O	0.033	0.035	0.000	0.069	0.015	0.016	0.000	0.030
GHGs	22.014	80.222	0.000	102.236	9.689	35.308	0.000	44.998
VOC: Total	0.010	0.020	0.000	0.031	0.005	0.009	0.000	0.013
CO: Total	0.024	0.080	0.000	0.104	0.011	0.035	0.000	0.046
NOx: Total	0.062	0.144	0.000	0.206	0.027	0.063	0.000	0.091
PM10: Total	0.004	0.010	0.018	0.031	0.002	0.004	0.008	0.014
PM2.5: Total	0.003	0.008	0.005	0.015	0.001	0.003	0.002	0.007
SOx: Total	0.030	0.108	0.000	0.138	0.013	0.048	0.000	0.061
VOC: Urban	0.000	0.002	0.000	0.002	0.000	0.001	0.000	0.001
CO: Urban	0.001	0.015	0.000	0.016	0.000	0.007	0.000	0.007
NOx: Urban	0.001	0.018	0.000	0.019	0.001	0.008	0.000	0.008
PM10: Urban	0.000	0.001	0.013	0.013	0.000	0.000	0.006	0.006

PM2.5: Urban	0.000	0.001	0.003	0.004	0.000	0.000	0.001	0.002
SOx: Urban	0.001	0.002	0.000	0.003	0.000	0.001	0.000	0.001

Table A12 Well to Wheel Energy Consumption and Emissions for liquid hydrogen production

FCV: L.H2, Central Plants, Biomass								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	731.196	5367.171	2153.472	8251.839	321.825	2362.279	947.818	3631.922
Fossil Fuels	152.759	2307.576	0.000	2460.335	67.234	1015.645	0.000	1082.879
Coal	1.821	207.910	0.000	209.731	0.802	91.509	0.000	92.310
Natural Gas	85.859	1956.978	0.000	2042.838	37.790	861.334	0.000	899.124
Petroleum	65.078	142.688	0.000	207.766	28.643	62.802	0.000	91.445
CO2 (w/ C in VOC & CO)	11.920	148.425	0.000	160.345	5.246	65.327	0.000	70.573
CH4	0.023	0.416	0.000	0.439	0.010	0.183	0.000	0.193
N2O	0.035	0.039	0.000	0.074	0.015	0.017	0.000	0.032
GHGs	22.801	170.436	0.000	193.237	10.036	75.015	0.000	85.050
VOC: Total	0.011	0.036	0.000	0.047	0.005	0.016	0.000	0.021
CO: Total	0.025	0.167	0.000	0.193	0.011	0.074	0.000	0.085
NOx: Total	0.064	0.269	0.000	0.333	0.028	0.118	0.000	0.147
PM10: Total	0.004	0.019	0.018	0.041	0.002	0.008	0.008	0.018
PM2.5: Total	0.003	0.015	0.005	0.023	0.001	0.006	0.002	0.010
SOx: Total	0.031	0.181	0.000	0.212	0.013	0.080	0.000	0.093
VOC: Urban	0.000	0.004	0.000	0.005	0.000	0.002	0.000	0.002
CO: Urban	0.001	0.038	0.000	0.039	0.000	0.017	0.000	0.017
NOx: Urban	0.002	0.046	0.000	0.047	0.001	0.020	0.000	0.021

PM10: Urban	0.000	0.001	0.013	0.014	0.000	0.001	0.006	0.006
PM2.5: Urban	0.000	0.001	0.003	0.005	0.000	0.001	0.001	0.002
SOx: Urban	0.001	0.004	0.000	0.005	0.000	0.002	0.000	0.002

Distributed: Natural gas reforming

Table A13: Well-to-Tank Energy Consumption and Emissions

	FCV: G.H2, Central Plants, NA NG	FCV: L.H2, Central Plants, NA NG
	Btu/MJ or g/MJ	Btu/MJ or g/MJ
Total Energy	833	1,798
WTP Efficiency	84.3%	78.5%
Fossil Fuels	811	1,724
Coal	150	496
Natural Gas	629	1,135
Petroleum	32	93
CO2 (w/ C in VOC & CO)	110	176
CH4	0	1
N2O	0	0
GHGs	121	191
VOC: Total	11.10	13.90
CO: Total	35.67	51.45
NOx: Total	48.00	62.52
PM10: Total	1.61	1.07
PM2.5: Total	1.13	0.97
SOx: Total	21.75	14.44
VOC: Urban	0.67	0.12
CO: Urban	3.51	0.89
NOx: Urban	4.97	0.95
PM10: Urban	0.32	0.05
PM2.5: Urban	0.23	0.04
SOx: Urban	3.07	0.12

Table A14 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Distributed Plants, NA NG								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	287.030	1606.209	2153.472	4046.711	126.332	706.949	947.818	1781.098
Fossil Fuels	286.186	1556.226	2153.472	3995.884	125.961	684.949	947.818	1758.728
Coal	5.681	336.143	0.000	341.823	2.500	147.948	0.000	150.448
Natural Gas	270.410	1157.650	2153.472	3581.531	119.017	509.522	947.818	1576.357
Petroleum	10.095	62.434	0.000	72.529	4.443	27.480	0.000	31.923
CO2 (w/ C in VOC & CO)	15.552	234.913	0.000	250.465	6.845	103.393	0.000	110.238
CH4	0.586	0.309	0.000	0.895	0.258	0.136	0.000	0.394
N2O	0.003	0.003	0.000	0.006	0.001	0.001	0.000	0.003
GHGs	31.196	243.387	0.000	274.584	13.730	107.123	0.000	120.854
VOC: Total	0.024	0.020	0.000	0.044	0.010	0.009	0.000	0.019
CO: Total	0.075	0.089	0.000	0.165	0.033	0.039	0.000	0.072
NOx: Total	0.095	0.170	0.000	0.264	0.042	0.075	0.000	0.116
PM10: Total	0.001	0.042	0.018	0.061	0.001	0.018	0.008	0.027
PM2.5: Total	0.001	0.035	0.005	0.041	0.000	0.016	0.002	0.018
SOx: Total	0.027	0.155	0.000	0.182	0.012	0.068	0.000	0.080
VOC: Urban	0.001	0.004	0.000	0.006	0.001	0.002	0.000	0.003
CO: Urban	0.007	0.028	0.000	0.035	0.003	0.012	0.000	0.015
NOx: Urban	0.008	0.052	0.000	0.061	0.004	0.023	0.000	0.027

PM10: Urban	0.000	0.022	0.013	0.035	0.000	0.010	0.006	0.015
PM2.5: Urban	0.000	0.021	0.003	0.024	0.000	0.009	0.001	0.010
SOx: Urban	0.001	0.042	0.000	0.043	0.000	0.019	0.000	0.019

Table A15 Well to Wheel Energy Consumption and Emissions for liquid hydrogen production

FCV: L.H2, Distributed Plants, NA NG								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	287.551	3797.204	2153.472	6238.227	126.561	1671.282	947.818	2745.661
Fossil Fuels	286.706	3630.626	2153.472	6070.804	126.189	1597.965	947.818	2671.972
Coal	5.691	1120.261	0.000	1125.952	2.505	493.066	0.000	495.571
Natural Gas	270.902	2308.133	2153.472	4732.506	119.233	1015.890	947.818	2082.941
Petroleum	10.113	202.232	0.000	212.345	4.451	89.009	0.000	93.461
CO2 (w/ C in VOC & CO)	15.580	384.729	0.000	400.309	6.857	169.332	0.000	176.190
CH4	0.587	0.634	0.000	1.220	0.258	0.279	0.000	0.537
N2O	0.003	0.006	0.000	0.009	0.001	0.003	0.000	0.004
GHGs	31.253	402.312	0.000	433.565	13.755	177.072	0.000	190.827
VOC: Total	0.024	0.041	0.000	0.064	0.010	0.018	0.000	0.028
CO: Total	0.076	0.186	0.000	0.262	0.033	0.082	0.000	0.115
NOx: Total	0.095	0.401	0.000	0.496	0.042	0.177	0.000	0.218
PM10: Total	0.001	0.078	0.018	0.097	0.001	0.034	0.008	0.043
PM2.5: Total	0.001	0.058	0.005	0.063	0.000	0.025	0.002	0.028
SOx: Total	0.027	0.484	0.000	0.511	0.012	0.213	0.000	0.225
VOC: Urban	0.001	0.007	0.000	0.008	0.001	0.003	0.000	0.004
CO: Urban	0.007	0.048	0.000	0.055	0.003	0.021	0.000	0.024
NOx: Urban	0.008	0.101	0.000	0.110	0.004	0.045	0.000	0.048

PM10: Urban	0.000	0.032	0.013	0.044	0.000	0.014	0.006	0.020
PM2.5: Urban	0.000	0.027	0.003	0.031	0.000	0.012	0.001	0.014
SOx: Urban	0.001	0.136	0.000	0.137	0.000	0.060	0.000	0.060

Distributed: Grid Electrolysis

Table A16: Well-to-Tank Energy Consumption and Emissions

	FCV: G.H2, Central Plants, NA NG	FCV: L.H2, Central Plants, NA NG
	Btu/MJ or g/MJ	Btu/MJ or g/MJ
Total Energy	2,764	3,679
WTP Efficiency	0	0
Fossil Fuels	2,564	3,430
Coal	397	729
Natural Gas	2,874	3,350
Petroleum	0	0
CO2 (w/ C in VOC & CO)	269	335
CH4	1	1
N2O	0	0
GHGs	285	355
VOC: Total	0.04	0.05
CO: Total	0.17	0.22
NOx: Total	0.42	0.52
PM10: Total	0.07	0.08
PM2.5: Total	0.04	0.05
SOx: Total	0.59	0.74
VOC: Urban	0.00	0.00
CO: Urban	0.04	0.04
NOx: Urban	0.09	0.11
PM10: Urban	0.02	0.02
PM2.5: Urban	0.01	0.02
SOx: Urban	0.17	0.21

Table A17 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Distributed Plants, Grid Electrolysis								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	3111.945	3166.887	2153.472	8432.303	1369.675	1393.857	947.818	3711.351
Fossil Fuels	2952.826	2996.220	2028.832	7977.878	1299.642	1318.741	892.960	3511.342
Coal	1070.745	1147.753	837.564	3056.062	471.272	505.166	368.641	1345.079
Natural Gas	1665.958	1643.967	1067.380	4377.304	733.246	723.567	469.791	1926.604
Petroleum	216.124	204.500	123.888	544.512	95.124	90.008	54.527	239.659
CO2 (w/ C in VOC & CO)	610.250	0.000	0.000	610.250	268.592	0.000	0.000	268.592
CH4	1.324	0.000	0.000	1.324	0.583	0.000	0.000	0.583
N2O	0.014	0.000	0.000	0.014	0.006	0.000	0.000	0.006
GHGs	647.400	0.000	0.000	647.400	284.943	0.000	0.000	284.943
VOC: Total	0.084	0.000	0.000	0.084	0.037	0.000	0.000	0.037
CO: Total	0.397	0.000	0.000	0.397	0.175	0.000	0.000	0.175
NOx: Total	0.944	0.000	0.000	0.944	0.416	0.000	0.000	0.416
PM10: Total	0.149	0.000	0.018	0.167	0.066	0.000	0.008	0.074
PM2.5: Total	0.091	0.000	0.005	0.096	0.040	0.000	0.002	0.042
SOx: Total	1.343	0.000	0.000	1.343	0.591	0.000	0.000	0.591
VOC: Urban	0.009	0.000	0.000	0.009	0.004	0.000	0.000	0.004
CO: Urban	0.081	0.000	0.000	0.081	0.036	0.000	0.000	0.036
NOx: Urban	0.200	0.000	0.000	0.200	0.088	0.000	0.000	0.088

PM10: Urban	0.040	0.000	0.013	0.053	0.018	0.000	0.006	0.023
PM2.5: Urban	0.028	0.000	0.003	0.031	0.012	0.000	0.001	0.014
SOx: Urban	0.382	0.000	0.000	0.382	0.168	0.000	0.000	0.168

Table A18 Well to Wheel Energy Consumption and Emissions for liquid hydrogen production

FCV: L.H2, Distributed Plants, Grid Electrolysis								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	4413.427	3946.414	2153.472	10513.313	1942.503	1736.954	947.818	4627.275
Fossil Fuels	4184.170	3733.738	2028.832	9946.740	1841.599	1643.348	892.960	4377.907
Coal	1542.432	1430.272	837.564	3810.268	678.878	629.512	368.641	1677.032
Natural Gas	2341.572	2048.628	1067.380	5457.580	1030.607	901.673	469.791	2402.071
Petroleum	300.166	254.838	123.888	678.892	132.114	112.163	54.527	298.804
CO2 (w/ C in VOC & CO)	761.088	0.000	0.000	761.088	334.982	0.000	0.000	334.982
CH4	1.652	0.000	0.000	1.652	0.727	0.000	0.000	0.727
N2O	0.017	0.000	0.000	0.017	0.007	0.000	0.000	0.007
GHGs	807.421	0.000	0.000	807.421	355.374	0.000	0.000	355.374
VOC: Total	0.105	0.000	0.000	0.105	0.046	0.000	0.000	0.046
CO: Total	0.495	0.000	0.000	0.495	0.218	0.000	0.000	0.218
NOx: Total	1.178	0.000	0.000	1.178	0.518	0.000	0.000	0.518
PM10: Total	0.186	0.000	0.018	0.204	0.082	0.000	0.008	0.090
PM2.5: Total	0.114	0.000	0.005	0.118	0.050	0.000	0.002	0.052
SOx: Total	1.675	0.000	0.000	1.675	0.737	0.000	0.000	0.737
VOC: Urban	0.011	0.000	0.000	0.011	0.005	0.000	0.000	0.005
CO: Urban	0.101	0.000	0.000	0.101	0.045	0.000	0.000	0.045
NOx: Urban	0.250	0.000	0.000	0.250	0.110	0.000	0.000	0.110

PM10: Urban	0.050	0.000	0.013	0.063	0.022	0.000	0.006	0.028
PM2.5: Urban	0.035	0.000	0.003	0.038	0.015	0.000	0.001	0.017
SOx: Urban	0.476	0.000	0.000	0.476	0.210	0.000	0.000	0.210

Distributed: WWTP reforming

Table A19: Well-to-Tank Energy Consumption and Emissions

	FCV: G.H2, Central Plants, NA NG	FCV: L.H2, Central Plants, NA NG
	Btu/MJ or g/MJ	Btu/MJ or g/MJ
Total Energy	-1,161	-565
WTP Efficiency	0	0
Fossil Fuels	-230	360
Coal	-91	108
Natural Gas	-123	226
Petroleum	-16	26
CO2 (w/ C in VOC & CO)	-23	19
CH4	2	2
N2O	0	0
GHGs	20	75
VOC: Total	0.09	0.12
CO: Total	0.47	0.58
NOx: Total	-0.07	0.03
PM10: Total	0.01	0.02
PM2.5: Total	0.01	0.02
SOx: Total	-0.04	0.05
VOC: Urban	0.05	0.05
CO: Urban	0.24	0.27
NOx: Urban	-0.02	-0.02
PM10: Urban	0.01	0.00
PM2.5: Urban	0.01	0.00
SOx: Urban	-0.01	0.01

Table A20 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Distributed Plants, WWTP								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	-3251.321	612.514	2153.472	-485.336	-1431.020	269.589	947.818	-213.613
Fossil Fuels	-1089.976	566.452	0.000	-523.524	-479.737	249.315	0.000	-230.421
Coal	-423.378	215.645	0.000	-207.733	-186.343	94.913	0.000	-91.430
Natural Gas	-591.201	312.383	0.000	-278.818	-260.208	137.490	0.000	-122.718
Petroleum	-75.398	38.424	0.000	-36.974	-33.185	16.912	0.000	-16.273
CO_2 (w/ C in VOC & CO)	-220.801	168.536	0.000	-52.265	-97.182	74.179	0.000	-23.004
CH_4	2.961	0.977	0.000	3.938	1.303	0.430	0.000	1.733
N_2O	-0.002	0.001	0.000	-0.001	-0.001	0.000	0.000	-0.001
GHGs	-147.475	193.214	0.000	45.739	-64.909	85.040	0.000	20.131
VOC: Total	0.156	0.058	0.000	0.214	0.069	0.025	0.000	0.094
CO: Total	0.786	0.289	0.000	1.075	0.346	0.127	0.000	0.473
NOx: Total	-0.234	0.077	0.000	-0.157	-0.103	0.034	0.000	-0.069
PM10: Total	-0.014	0.037	0.018	0.042	-0.006	0.016	0.008	0.018
PM2.5: Total	-0.006	0.033	0.005	0.032	-0.002	0.015	0.002	0.014
SOx: Total	-0.187	0.095	0.000	-0.092	-0.082	0.042	0.000	-0.040
VOC: Urban	0.083	0.027	0.000	0.110	0.036	0.012	0.000	0.048

CO: Urban	0.408	0.141	0.000	0.549	0.180	0.062	0.000	0.242
NOx: Urban	-0.081	0.027	0.000	-0.054	-0.036	0.012	0.000	-0.024
PM10: Urban	-0.002	0.021	0.013	0.032	-0.001	0.009	0.006	0.014
PM2.5: Urban	0.000	0.020	0.003	0.023	0.000	0.009	0.001	0.010
SOx: Urban	-0.053	0.027	0.000	-0.026	-0.023	0.012	0.000	-0.012

Table A21 Well to Wheel Energy Consumption and Emissions for liquid hydrogen production

FCV: L.H2, Distributed Plants, WWTP								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	-3261.318	1977.764	2153.472	869.917	-1435.420	870.483	947.818	382.881
Fossil Fuels	-1020.798	1839.368	0.000	818.570	-449.289	809.570	0.000	360.281
Coal	-436.922	682.268	0.000	245.345	-192.305	300.290	0.000	107.985
Natural Gas	-506.447	1020.691	0.000	514.244	-222.905	449.242	0.000	226.337
Petroleum	-77.429	136.410	0.000	58.981	-34.079	60.039	0.000	25.960
CO2 (w/ C in VOC & CO)	-224.648	267.857	0.000	43.209	-98.875	117.893	0.000	19.018
CH4	3.159	1.877	0.000	5.035	1.390	0.826	0.000	2.216
N2O	0.001	0.004	0.000	0.005	0.000	0.002	0.000	0.002
GHGs	-145.460	316.086	0.000	170.626	-64.022	139.120	0.000	75.098
VOC: Total	0.171	0.093	0.000	0.264	0.075	0.041	0.000	0.116
CO: Total	0.861	0.463	0.000	1.325	0.379	0.204	0.000	0.583
NOx: Total	-0.189	0.251	0.000	0.062	-0.083	0.110	0.000	0.027
PM10: Total	-0.014	0.064	0.018	0.068	-0.006	0.028	0.008	0.030

PM2.5: Total	-0.006	0.051	0.005	0.050	-0.002	0.022	0.002	0.022
SOx: Total	-0.192	0.301	0.000	0.108	-0.085	0.132	0.000	0.048
VOC: Urban	0.087	0.035	0.000	0.122	0.038	0.016	0.000	0.054
CO: Urban	0.430	0.186	0.000	0.615	0.189	0.082	0.000	0.271
NOx: Urban	-0.076	0.034	0.000	-0.042	-0.034	0.015	0.000	-0.019
PM10: Urban	-0.002	0.013	0.013	0.024	-0.001	0.006	0.006	0.010
PM2.5: Urban	0.000	0.010	0.003	0.013	0.000	0.005	0.001	0.006
SOx: Urban	-0.055	0.085	0.000	0.030	-0.024	0.038	0.000	0.013

Distributed: Animal Manure reforming

Table A22: Well-to-Tank Energy Consumption and Emissions

	FCV: G.H2, Central Plants, Animal Manure	FCV: L.H2, Central Plants, Animal Manure
	Btu/MJ or g/MJ	Btu/MJ or g/MJ
Total Energy	-525	142
WTP Efficiency	0	0
Fossil Fuels	407	1,068
Coal	147	373
Natural Gas	219	606
Petroleum	40	89
CO2 (w/ C in VOC & CO)	119	176
CH4	1	2
N2O	0	0
GHGs	150	219
VOC: Total	0.04	0.06
CO: Total	0.23	0.31
NOx: Total	0.08	0.19
PM10: Total	0.02	0.04
PM2.5: Total	0.02	0.03
SOx: Total	0.06	0.16
VOC: Urban	0.02	0.02
CO: Urban	0.11	0.13
NOx: Urban	0.03	0.04
PM10: Urban	0.01	0.01
PM2.5: Urban	0.01	0.01
SOx: Urban	0.02	0.05

Table A23 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Distributed Plants, Animal Manure								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	-2121.617	929.782	2153.472	961.637	-933.798	409.229	947.818	423.250
Fossil Fuels	40.003	883.798	0.000	923.801	17.607	388.990	0.000	406.597
Coal	0.443	334.672	0.000	335.115	0.195	147.301	0.000	147.496
Natural Gas	14.588	482.513	0.000	497.101	6.421	212.371	0.000	218.792
Petroleum	24.972	66.613	0.000	91.584	10.991	29.318	0.000	40.309
CO2 (w/ C in VOC & CO)	30.299	239.055	0.000	269.355	13.336	105.217	0.000	118.552
CH4	2.457	0.835	0.000	3.292	1.081	0.367	0.000	1.449
N2O	-0.030	-0.007	0.000	-0.036	-0.013	-0.003	0.000	-0.016
GHGs	82.937	257.923	0.000	340.860	36.504	113.521	0.000	150.024
VOC: Total	0.068	0.033	0.000	0.101	0.030	0.014	0.000	0.045
CO: Total	0.357	0.168	0.000	0.526	0.157	0.074	0.000	0.231
NOx: Total	0.022	0.150	0.000	0.172	0.010	0.066	0.000	0.076
PM10: Total	0.008	0.043	0.018	0.069	0.003	0.019	0.008	0.030
PM2.5: Total	0.008	0.037	0.005	0.049	0.003	0.016	0.002	0.022
SOx: Total	0.000	0.147	0.000	0.147	0.000	0.065	0.000	0.065
VOC: Urban	0.034	0.014	0.000	0.048	0.015	0.006	0.000	0.021
CO: Urban	0.177	0.076	0.000	0.253	0.078	0.033	0.000	0.111

NOx: Urban	0.008	0.052	0.000	0.060	0.003	0.023	0.000	0.026
PM10: Urban	0.004	0.023	0.013	0.039	0.002	0.010	0.006	0.017
PM2.5: Urban	0.004	0.022	0.003	0.029	0.002	0.010	0.001	0.013
SOx: Urban	0.000	0.042	0.000	0.042	0.000	0.018	0.000	0.019

Table A24 Well to Wheel Energy Consumption and Emissions for liquid hydrogen production

FCV: L.H2, Distributed Plants, Animal Manure								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	-2090.068	2413.080	2153.472	2476.483	-919.912	1062.080	947.818	1089.986
Fossil Fuels	150.737	2274.790	0.000	2425.527	66.345	1001.214	0.000	1067.559
Coal	2.485	845.581	0.000	848.066	1.094	372.170	0.000	373.263
Natural Gas	121.620	1254.123	0.000	1375.743	53.529	551.983	0.000	605.512
Petroleum	26.632	175.086	0.000	201.718	11.722	77.061	0.000	88.783
CO2 (w/ C in VOC & CO)	35.686	364.614	0.000	400.300	15.706	160.479	0.000	176.186
CH4	2.636	1.682	0.000	4.318	1.160	0.740	0.000	1.901
N2O	-0.027	-0.006	0.000	-0.033	-0.012	-0.003	0.000	-0.015
GHGs	93.424	404.871	0.000	498.295	41.119	178.198	0.000	219.317
VOC: Total	0.080	0.059	0.000	0.139	0.035	0.026	0.000	0.061
CO: Total	0.416	0.298	0.000	0.715	0.183	0.131	0.000	0.315
NOx: Total	0.078	0.350	0.000	0.427	0.034	0.154	0.000	0.188
PM10: Total	0.008	0.072	0.018	0.098	0.004	0.032	0.008	0.043
PM2.5: Total	0.008	0.056	0.005	0.069	0.003	0.025	0.002	0.030
SOx: Total	0.001	0.372	0.000	0.374	0.001	0.164	0.000	0.164

VOC: Urban	0.036	0.017	0.000	0.053	0.016	0.007	0.000	0.023
CO: Urban	0.190	0.097	0.000	0.286	0.083	0.043	0.000	0.126
NOx: Urban	0.015	0.068	0.000	0.083	0.007	0.030	0.000	0.037
PM10: Urban	0.004	0.015	0.013	0.032	0.002	0.007	0.006	0.014
PM2.5: Urban	0.004	0.012	0.003	0.019	0.002	0.005	0.001	0.008
SOx: Urban	0.001	0.106	0.000	0.107	0.000	0.047	0.000	0.047

Distributed: LFG reforming

Table A25: Well-to-Tank Energy Consumption and Emissions

	FCV: G.H2, Central Plants, LFG	FCV: L.H2, Central Plants, LFG
	Btu/MJ or g/MJ	Btu/MJ or g/MJ
Total Energy	-309	381
WTP Efficiency	0	0
Fossil Fuels	609	1,292
Coal	230	465
Natural Gas	327	725
Petroleum	52	102
CO2 (w/ C in VOC & CO)	45	95
CH4	0	1
N2O	0	0
GHGs	57	116
VOC: Total	-0.01	0.00
CO: Total	0.04	0.10
NOx: Total	0.08	0.19
PM10: Total	0.02	0.03
PM2.5: Total	0.01	0.02
SOx: Total	0.10	0.20
VOC: Urban	-0.01	-0.01
CO: Urban	0.02	0.02
NOx: Urban	0.02	0.03
PM10: Urban	0.01	0.00
PM2.5: Urban	0.01	0.00
SOx: Urban	0.03	0.06

Table A26 Well to Wheel Energy Consumption and Emissions for gaseous hydrogen production

FCV: G.H2, Distributed Plants, LFG								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	-1739.618	1037.063	2153.472	1450.917	-765.666	456.448	947.818	638.599
Fossil Fuels	398.565	984.497	0.000	1383.062	175.422	433.311	0.000	608.734
Coal	147.332	375.924	0.000	523.256	64.846	165.457	0.000	230.303
Natural Gas	205.682	536.180	0.000	741.862	90.528	235.992	0.000	326.519
Petroleum	45.551	72.392	0.000	117.944	20.049	31.862	0.000	51.911
CO2 (w/ C in VOC & CO)	-99.565	202.584	0.000	103.019	-43.822	89.164	0.000	45.342
CH4	0.737	0.352	0.000	1.089	0.324	0.155	0.000	0.479
N2O	-0.002	0.001	0.000	0.000	-0.001	0.000	0.000	0.000
GHGs	-81.614	211.710	0.000	130.096	-35.921	93.181	0.000	57.260
VOC: Total	-0.033	0.004	0.000	-0.029	-0.015	0.002	0.000	-0.013
CO: Total	0.011	0.071	0.000	0.083	0.005	0.031	0.000	0.036
NOx: Total	0.024	0.150	0.000	0.174	0.011	0.066	0.000	0.077
PM10: Total	-0.003	0.041	0.018	0.056	-0.001	0.018	0.008	0.025
PM2.5: Total	-0.005	0.033	0.005	0.033	-0.002	0.015	0.002	0.014
SOx: Total	0.064	0.165	0.000	0.229	0.028	0.073	0.000	0.101
VOC: Urban	-0.014	0.000	0.000	-0.014	-0.006	0.000	0.000	-0.006
CO: Urban	0.010	0.029	0.000	0.038	0.004	0.013	0.000	0.017
NOx: Urban	0.004	0.051	0.000	0.056	0.002	0.023	0.000	0.024

PM10: Urban	-0.002	0.021	0.013	0.032	-0.001	0.009	0.006	0.014
PM2.5: Urban	-0.003	0.020	0.003	0.020	-0.001	0.009	0.001	0.009
SOx: Urban	0.018	0.047	0.000	0.065	0.008	0.021	0.000	0.029

Table A27 Well to Wheel Energy Consumption and Emissions for liquid hydrogen production

FCV: L.H2, Distributed Plants, LFG								
	Btu/mile or g/mile				Btu/MJ or g/MJ			
Item	Feedstock	Fuel	Vehicle Operation	Total	Feedstock	Fuel	Vehicle Operation	Total
Total Energy	-1694.021	2560.278	2153.472	3019.728	-745.598	1126.867	947.818	1329.088
Fossil Fuels	522.485	2412.957	0.000	2935.442	229.964	1062.026	0.000	1291.990
Coal	154.775	902.182	0.000	1056.957	68.122	397.082	0.000	465.204
Natural Gas	319.741	1327.759	0.000	1647.500	140.729	584.393	0.000	725.122
Petroleum	47.969	183.016	0.000	230.985	21.113	80.552	0.000	101.664
CO2 (w/ C in VOC & CO)	-98.954	314.573	0.000	215.619	-43.553	138.455	0.000	94.901
CH4	0.853	1.019	0.000	1.872	0.375	0.449	0.000	0.824
N2O	0.002	0.005	0.000	0.006	0.001	0.002	0.000	0.003
GHGs	-77.178	341.464	0.000	264.287	-33.969	150.290	0.000	116.322
VOC: Total	-0.026	0.019	0.000	-0.006	-0.011	0.009	0.000	-0.003
CO: Total	0.058	0.165	0.000	0.223	0.025	0.073	0.000	0.098
NOx: Total	0.079	0.350	0.000	0.430	0.035	0.154	0.000	0.189
PM10: Total	-0.003	0.068	0.018	0.083	-0.001	0.030	0.008	0.037
PM2.5: Total	-0.006	0.051	0.005	0.050	-0.002	0.022	0.002	0.022
SOx: Total	0.068	0.397	0.000	0.465	0.030	0.175	0.000	0.205
VOC: Urban	-0.013	-0.002	0.000	-0.015	-0.006	-0.001	0.000	-0.007

CO: Urban	0.016	0.032	0.000	0.048	0.007	0.014	0.000	0.021
NOx: Urban	0.012	0.067	0.000	0.079	0.005	0.029	0.000	0.035
PM10: Urban	-0.002	0.013	0.013	0.024	-0.001	0.006	0.006	0.010
PM2.5: Urban	-0.003	0.010	0.003	0.010	-0.001	0.004	0.001	0.004
SOx: Urban	0.019	0.113	0.000	0.132	0.008	0.050	0.000	0.058