Introduction to the Hydrogen Market in California

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September 2020

Summary

Hydrogen can play an important role in increasing energy security and reducing greenhouse gas emissions in California. However, until now, the uptake of hydrogen in California at scale has been limited due to high costs of production. In the United States and in California in particular, most of the current hydrogen is produced by Steam Methane Reforming (SMR) of natural gas, though several projects of renewable hydrogen plants have been announced in recent years. Previous modelling approaches have estimated that hydrogen could play an important role in decarbonization of transportation, as well as buildings and industry sectors, given supporting policy drivers and enabling infrastructure. Biomass is a potentially remarkable source for hydrogen as it could provide outsized environmental benefits, including carbon dioxide removal and support for forest restoration, at competitive costs close to those of hydrogen from natural gas or coal. This memo presents a market analysis of hydrogen in California, reviews existing literature on costs, emissions, and scale on biomass conversion to hydrogen using three hydrogen conversion platforms: biomass gasification, biomass gasification with carbon capture and storage, and pyrolysis. In the light of available biomass resources in California, this memo proposes next steps to develop, deploy and commercialize hydrogen using non-merchantable forest biomass in California.

California is likely to have plentiful biomass resource from forest residues: total biomass availability in California for the year 2025 – estimated at 24 million tons per year – is sufficient to produce 1.7 million tons of hydrogen, or 85% of current State demand and 40% of future 2050 demand of 4 million tons hydrogen per year. Hydrogen production from California's diverse biomass resource base can be accomplished with gasification, gasification with carbon capture and storage (CCS), and pyrolysis. The levelized cost of hydrogen from biomass sources using gasification are reported in the range of \$1.48 to 3.00/kg (\$3.15 to 3.6/ kg with CCS), with a mean of \$2.24/kg (\$3.37/kg

with CCS). Greenhouse gas emissions of hydrogen produced from biomass are significantly lower than hydrogen produced from natural gas and reported to be in the range of 3 to 72 gCO_2e /MJ, (-97 to -146 gCO_2e /MJ with CCS) with a mean of 22 gCO_2e /MJ (-122 gCO_2e /MJ with CCS). Pyrolysis of biomass for hydrogen production has received insufficient scholarly attention: nevertheless, we expect pyrolysis to have the lowest capital cost and operating costs compared to gasification at a capacity of 2,000 bone dry tons/day of feedstock (~600,000 bone dry tons/year). Biomass gasification demonstrates significant economies of scale in both capital and operational costs. Infrastructure needs for hydrogen distribution in California vary according to the demand and available infrastructure options. In the near-term, California could utilize truck transport for short distances and small volumes, and existing energy infrastructure such as natural gas pipelines, and railroads for the transmission of large amounts of hydrogen for longer distances. California's robust forest resource base, coupled with supportive climate policy, could play a significant role in the future hydrogen market development in order to meet California's energy and climate goals.

1 Production and Consumption

The United States currently produces about 9 million tons of hydrogen annually, about 12% of global hydrogen production (72 million tons/yr) (DOE, 2019). The main use of hydrogen is by oil refineries to remove sulfur content that is naturally contained in oil to produce cleaner fuels. Hydrogen used by refineries is largely being supplied by industrial gas companies (IGCs) that primarily use Steam Methane Reforming (SMR) of natural gas to produce hydrogen. Currently 99% of 9 million tons in the United States is supplied by fossil fuels (USEA, 2020). Table 1 provides a comparison of market size of hydrogen production in the United States and Global.

Hydrogen production can be divided into three segments (DOE, 2019):

1. “Merchant” hydrogen—hydrogen generated on site or in a central production facility and sold to a consumer by pipeline, bulk tank, or cylinder truck delivery;
2. “Captive” hydrogen—hydrogen produced by the consumer for internal use;
3. “By-product” hydrogen—hydrogen that is recovered from by-product process streams and can be consumed by the same company (as with captive) or sold to another company (as with merchant).

Table 1: Market Size of United States and Global Hydrogen Production (Million tons/year)

	United States	Global
Merchant	4.30	7.92
Captive	4.08	61.25
By-Product	0.43	3.15
Total	**8.81**	**72.32**

Source: DOE 2019

In California, 766,604 tons/year hydrogen is produced by a few large producers that have facilities across California. This constitutes roughly 40 percent of the total demand of 2 million tons/year in California (California Energy Commission, 2020). Table 2 provides data on hydrogen production by industrial gas companies to supply oil refineries and other industries.

Table 2: California IGCs Hydrogen Production Facilities[1]

Producer	City	Technology	Capacity (tons/year)	Industry
Air Products	Sacramento	SMR	2,023	Multiple
Praxair	Ontario	SMR	7,276	Multiple
Air Liquide	El Segundo	SMR	75,643	Oil Refining
Air Liquide	Rodeo	SMR	105,547	Oil Refining
Air Products	Carson	SMR	87,956	Oil Refining
Air Products	Martinez	SMR	77,402	Oil Refining
Air Products	Martinez	SMR	30,785	Oil Refining
Air Products	Sacramento	SMR	unknown	Food
Air Products	Wilmington	RFG SMR	140,730	Oil Refining
Praxair	Ontario	SMR	10,555	Multiple
Praxair	Richmond	SMR	228,687	Oil Refining
Total			**766,604**	

Source: EIN 2020

In addition, several new projects targeting the California hydrogen transportation market and capable of producing or processing renewable hydrogen have been announced since 2017 (CEC, 2020). While most facilities use electrolysis (green hydrogen), SGH2 will likely use MSW plasma gasification, and Air Liquide will use SMR with biogas. Of the following, none of the facilities will use CCS with SMR (blue hydrogen). Rather than producing hydrogen from electrolysis or steam methane reforming, it is also possible to produce hydrogen from the gasification of biomass. It is also possible to couple biomass gasification with CO2 capture and sequestration (CCS), resulting in carbon-negative hydrogen production. Hydrogen production is a relatively low-cost opportunity for carbon capture (Baker 2020).

[1] **U.S. Department of Energy** cited in the EIN Renewable Hydrogen Roadmap: https://einow.org/rh2roadmap

Table 3: Proposed Plants for Renewable Hydrogen Producers in California

Producer	City	Capacity (tons/year)	Deployment year	Technology used
Air Liquide	California (undetermined)	10,950[2]	2022	Landfill-derived methane
Air Products	California (undetermined)	Unknown	2021	Electrolysis (Wind/Solar)
Fuel Cell Energy and Toyota	Long Beach	438[3]	2020	Electrolysis
Stratos Fuels and Hydrogenics	Palm Springs	365[4]	Phase I - construction	Electrolysis
H2B2	Kings County	365[5]	2020	Electrolysis
SGH2	Lancaster	4,015[6]	2022	MSW (Recycled mixed paper waste) Gasification
Sunline	Palm Springs	328[7]	2018	Electrolysis

Production capacity of captive, on-purpose, hydrogen at California refineries has increased from 934,619 tons per year in 2015 to 1.05 million tons per year in 2019 (Table 4).

Table 4: Hydrogen Production Capacity of California Refineries (tons/year) *

Company	City	2015	2016	2017	2018	2019
Alon	Bakersfield	19,812	19,812	19,812	-	-
Chevron USA Inc	Richmond	155,913	155,913	155,913	155,913	284,262
Chevron USA Inc	El Segundo	66,328	66,328	66,328	66,328	66,328
Phillips 66 Company**	Rodeo	19,812	19,812	19,812	19,812	19,812
Phillips 66 Company	Wilmington	90,447	90,447	90,447	90,447	90,447
San Joaquin Refining Co Inc	Bakersfield	3,446	3,446	3,446	3,446	3,446
Shell Oil Products USA	Martinez	162,805	166,250	166,250	166,250	166,250
Tesoro Refining & Marketing	Martinez	70,635	70,635	70,635	70,635	74,942
Tesoro Refining & Marketing	Carson	90,447	90,447	90,447	90,447	103,368
Tesoro Refining & Marketing	Wilmington	12,921	12,921	12,921	12,921	-
Torrance Refining Co	Torrance	125,764	125,764	125,764	125,764	125,764
Valero Refining Co California	Benicia	116,289	116,289	116,289	116,289	116,289
Total		**934,619**	**938,064**	**938,064**	**918,252**	**1,050,908**

Source: EIA 2020
*Conversion Factor for Hydrogen[8]: 1Scf (standard cubic foot) = 0.00236 Kg
** Phillips 66 announced in August 2020 that it will transform its Rodeo, CA refinery into World's Largest Renewable Diesel Plant

[2] **Air Liquide**: https://cen.acs.org/business/investment/Air-Liquide-plans-first-hydrogenenergy/96/i48
[3] **Industry Week**: https://www.industryweek.com/leadership/article/22024653/toyota-plans-california-fuel-cell-plant-to-make-power-hydrogen
[4] **Hydrogenics**: https://www.hydrogenics.com/2016/11/01/hydrogenics-enters-into-strategic-collaboration-with-stratosfuel-for-2-5-mw-power-to-gas-project-in-california/
[5] **California Energy Commission**: https://cafcp.org/sites/default/files/OCT17-EB-4_H2Production-CEC-Baronas.pdf
[6] **Green Car Congress**: https://www.greencarcongress.com/2020/05/20200521-sgh2.html
[7] **NEL:** https://nelhydrogen.com/press-release/nel-asa-awarded-usd-8-3-million-hydrogen-electrolyser-fueling-station-contract/

In California there are a number of energy project developers that identify, evaluate and deploy proven technologies to produce hydrogen. Table 5 lists the existing project developers in California and their technologies.

Table 5: Identified Technology Providers in California

Company	Technology
NuFuels	Gasification
Charm Industrial	Power
Yosemite Clean Energy	Gasification
SGH2	Plasma Gasification
Proton Power	Cellulose to Hydrogen Power (CHyP)
Clean Energy Systems	Oxyfuel Combustion

A recent report by Energy and Environmental Economics (E3), a consultancy firm in California, examined the market outlook for hydrogen across sectors in Western United States. Three scenarios were developed that represented the potential role of hydrogen in a deeply decarbonized future, including mid-hydrogen scenario, high-hydrogen scenario and transformative scenario (E3, 2020).

The mid-hydrogen scenario is aligned with achieving economy wide 80% reductions relative to 1990 by 2050. Under the mid-hydrogen scenario, hydrogen plays a moderate role in transportation sector, and a minor role in the industrial sector. This means, while the industrial sector contributes less to overall economy-wide decarbonization, most decarbonization occurs due to electrification of transportation and building end uses.

The high-hydrogen scenario is also aligned with achieving economy wide 80% reductions relative to 1990 by 2050. Under the high-hydrogen scenario, hydrogen plays a significant role in all sectors with moderate requirements for supporting policy and infrastructure upgrades. In this scenario, hydrogen plays an important role in decarbonization of heavy-duty freight transportation, but is also used within some industrial processes, and in some residential and commercial buildings.

The transformative scenario is in line with existing policies in several states in Western United States to achieve a "net zero" carbon outcome. Under the transformative scenario, hydrogen has a substantial presence in transportation, buildings, and industry, with supporting policy drivers and enabling infrastructure. Figure 1 provides a summary of the assumptions made regarding the penetration of hydrogen in each scenario.

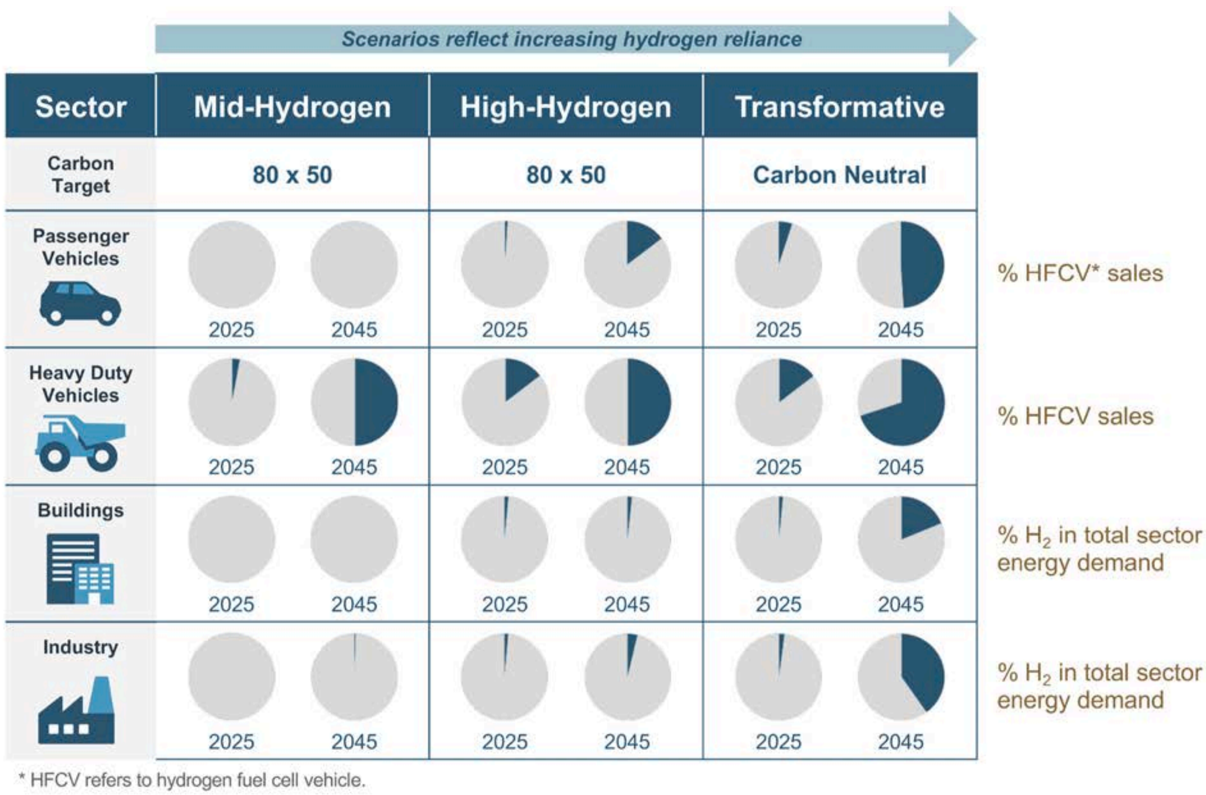

Figure 1: Hydrogen penetration in each scenario (Source: E3)

While the costs of the scenarios were not developed or compared, these scenarios aim to provide estimates of the potential market size for hydrogen in the future. Based on these three scenarios, Figure 2 provides the estimates of total final hydrogen demand in 2045.

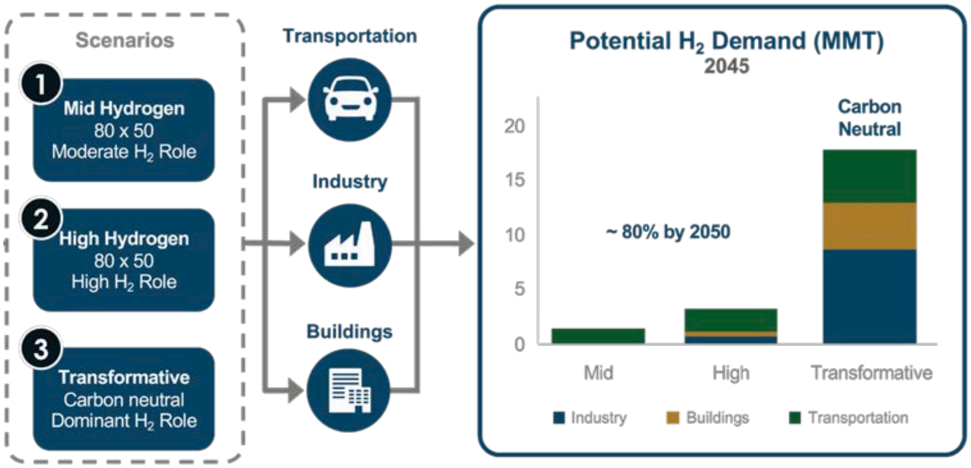

Figure 2: The potential role of hydrogen in buildings, industry and transportation in the West (Source: E3)

California Energy Commission (2020) assessed and forecasted costs and performance of all key elements of the renewable hydrogen production and delivery chain in California. The results showed that demand for hydrogen could exceed more than 4,000 million kilograms (4 million tons) per year by 2050. The facility buildout and siting analysis demonstrated that several hundred new renewable hydrogen production plants will be needed by 2050, and they will be located throughout the state in proximity with feedstock sources.

2 Assessment of Low-carbon and Carbon-negative Hydrogen Production from Woody Biomass

Previous research highlight some of the emerging questions and expectations surrounding the future of low-carbon and carbon-negative fuels in California. Several studies have examined biomass conversion to hydrogen. Here, we focus on three main hydrogen conversion platforms, namely gasification to hydrogen, gasification to hydrogen with CCS, and biomass pyrolysis to hydrogen in order to provide an insight into the mass and energy balances, costs, emissions, and scale from biomass to hydrogen.

2.1 Biomass Gasification

Biomass resources such as wood, agricultural residues, municipal solid waste can be used as feedstock to produce hydrogen. Biomass processing pathways to produce hydrogen include gasification, pyrolysis, supercritical extraction, liquefaction and hydrolysis. However, gasification has the highest hydrogen yield per unit feedstock (Larson et al. 2019). The two major biomass-to-hydrogen pathways are shown in Fig. 2. In both the pyrolysis and gasification processes, water gas shift is used to convert the reformed gas into hydrogen, and pressure swing adsorption is used to purify the product for small scale operations whereas Solexol or Rectisol are used at larger scale (Balat & Kirty, 2010). It is important to note that CO_2 and C for these processes can be captured and stored through geologic sequestration because the hydrogen produced does not contain carbon since the energy carrier is separated from the carbon (Baker et al. 2019). SGH2, a multinational company, is planning to build world's biggest green hydrogen production facility in Lancaster, California that will utilize the company's Solena Plasma Enhanced Gasification (SPEG) technology to produce hydrogen using mixed paper waste.

The production cost of hydrogen will have a significant impact on the viability of hydrogen as a zero-carbon resource. The production cost of biomass hydrogen varies widely in the published literature. The cost of hydrogen produced by biomass gasification is estimated between $1.82-2.11/kg for an expected hydrogen output of over 50,000 tons per year for the biomass cost of $47.4-82.5/bone dry ton (Bartels et al. 2010; Parkinson et al. 2019). Parkinson et al. (2019) reviewed the levelized cost of hydrogen (LCOH) from biomass sources reported in the literature and found it in the range of $1.48 to 3.00 /kg, with a mean of $2.24/kg for biomass feedstock prices of $48.37-115.2/ dry -ton biomass delivered. A number of studies conducted life cycle analysis in the field of hydrogen production via biomass gasification. The life cycle emissions (LCE) values reported in the past studies range from 0.31-8.63 kg CO_2e /kg H_2, with an average of 2.59 kg CO_2e /kg H_2. The wide range is due to variations in biomass feedstocks (e.g. solid waste, agricultural residues or woody biomass) as well as transportation requirements.

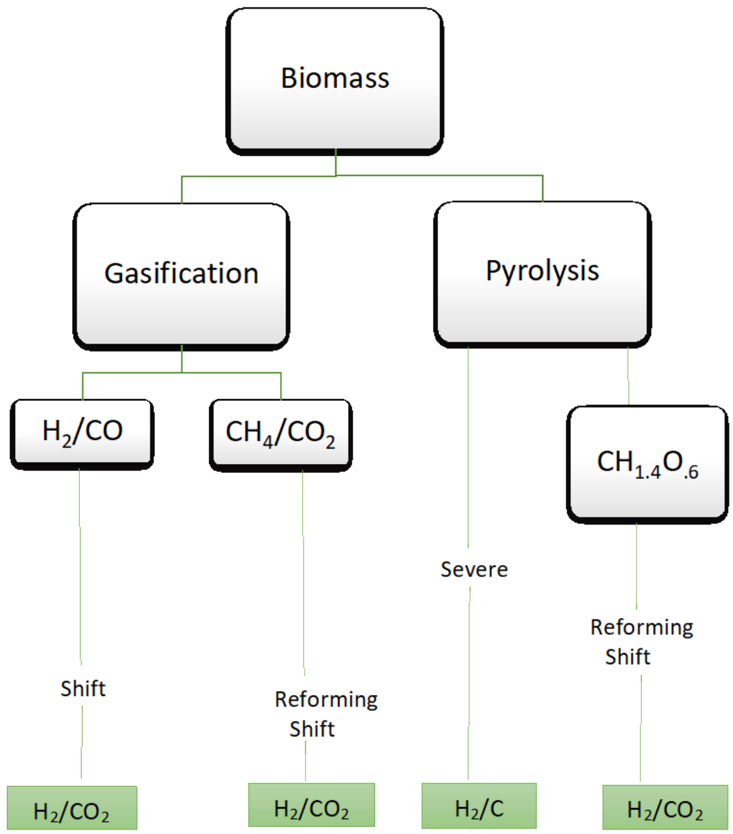

Figure 3: Two major pathways from Biomass to Hydrogen (Adapted from Milne et al. 2012)

Since gasification is conducted at a much temperature (700 to 1200 °C) than pyrolysis (500-700 °C), hydrogen yield increases from gasification is higher than that of pyrolysis. The reason of this is that higher temperature increases the efficiency of gasification reactions and promotes the destruction of tar thereby enhancing gas yield (Parthasarathy & Narayanan, 2014). Biomass gasification has the highest hydrogen yield per unit feedstock and is the focus here. Several past studies have investigated biomass conversion to hydrogen at scale via gasification with varying results. A BC Hydrogen Study (2019) found that a very large facility producing 36,500 tons/year of hydrogen would require 1,350 dry tons of biomass feedstock per day. Larson et al. (2009) studied large-scale gasification-based coproduction of fuels and electricity from switchgrass. This study used a basis of approximately 4,500 metric tons of dry switchgrass per day producing approximately 375,000 kg of hydrogen per day (~150,000 tons per year). In another study, Melaina et al. (2012) reported production efficiency as requiring 13.0 kg bone dry biomass to produce 1 kg of hydrogen. Table 6 summarizes the biomass to hydrogen yields as reported in various studies.

Table 6: Biomass to Hydrogen Yield

Input materials	Biomass input per day	H_2 yields tons per year	H_2 yields per kg bone dry biomass	Source
Biomass	1,350 BDT	36,500	1KG H_2/13.5	BC Hydrogen Study
Biomass - Dry switchgrass	4,500 BDT	150,000	1KG H_2/10.95	Larson et al.
Biomass	Unspecified	Unspecified	1KG H_2/13	Melaina et al.

2.2 Biomass Gasification with Carbon Capture and Storage

There are relatively few studies on biomass gasification with CCS, including costs and emissions. LCOH from biomass gasification coupled with CCS has been reported as \$2.27/kg H_2. (National Research Council, 2004). This total LCOH for biomass gasification with CCS value was re-estimated by Parkinston et al. (2019) based on key parameters that influence the LCOH for biomass gasification with CCS, this is equivalent to \$3.37/kg H_2 for the mean case, with a range of \$3.15–3.6/ kg H_2. Susmozas et al. (2013) reported the gasification of poplar biomass with capture and sequestration of 70% of the produced CO_2 resulting in an overall LCE of -14.58 kg CO_2/kg H_2 (-121.5 gm CO_2e/MJ). Table 7 provides a summary of cost and emissions inventories for biomass gasification, biomass gasification with CCS, SMR and SMR with CCS technologies.

Table 7: Summary of the Costs and Emissions for Hydrogen Production

Technology name	Input material	TRL	Hydrogen production costs ($ /kg H2)			Hydrogen emissions kg CO_2e/ kg H2 (g CO_2e/MJ)		
			Low	Central	High	Low	Central	High
Biomass gasification	Biomass	5-6	1.48	2.24	3.00	0.31 (3)	2.6 (22)	8.63 (72)
Biomass gasification with CCS*	Biomass	3-5	3.15	3.37	3.6	-11.66 (-97)	-14.58 (-122)	-17.50 (-146)
Steam methane reforming	Natural gas	9	1.03	1.26	2.16	10.09 (84)	13.24 (110)	17.21 (143)
Steam methane reforming with CCS	Natural gas	7-8	1.93	2.09	2.26	2.97 (25)	5.61 (47)	9.16 (76)
Electrolysis wind	Water	9	4.61	7.86	10.01	0.52 (4)	0.88 (7)	1.14 (10)
Electrolysis solar	Water	9	7.1	12.0	14.87	1.32 (11)	2.21 (18)	2.5 (21)

Source: Adapted from Parkinson et al. (2019)
* The study assumes Pressure Swing Adsorption (PSA) as CO_2 capture technology

2.3 Pyrolysis

Our review found that pyrolysis of biomass for hydrogen production is, similarly, not well-covered in the academic literature. While there are relatively fewer examples of pyrolysis of biomass for hydrogen production at a commercial scale, there are commercial vendors. For instance, Proton Power, a Tennessee company, has developed a pyrolysis-based system to produce small scale hydrogen. It can also be used to provide heat, electricity and synthetic fuels (Jones et al. 2016). Another example of small-scale operation to convert biomass to hydrogen through pyrolysis is provided by Charm Industrial[9], a company based in San Francisco, CA. The process is carried out in two steps. In the first step biomass is converted to bio-oil using fast pyrolysis and in the second step bio-oil produced through fast pyrolysis is then converted into hydrogen through partial oxidation.

[9] Charm Industrial: https://charmindustrial.com

2.4 The Scale of Production

The scale of the production facility is an important factor affecting the unit cost of hydrogen production. Studies have shown that biomass gasification demonstrates significant economies of scale in both capital and operational costs, excluding the feedstock cost (Larson et al. 2009). Typically, gasification reactors are built on a large-scale in order to offset the higher capital costs of a complex solid fuels gasification facility (Holladay, 2009). In other words, the larger the gasification facility, the lower the capital and operating costs per kilogram of hydrogen. Parker et al. (2008) found that the highest cost estimate in the literature corresponds to the smallest production facility. However, their results also confirmed that biomass hydrogen can potentially compete with the near-term option of natural gas steam reforming at the refueling station in California, but the competitiveness of biomass hydrogen will depend on a full systems design approach to the supply chain.

3 Hydrogen Potential from Biomass in California

Waste biomass resources are promising in California, especially in the near term. The main sources of biogenic carbon feedstock in California are (Baker et al. 2019):

- Agriculture residue;
- Municipal solid waste;
- Gaseous waste from landfills and anaerobic digesters; and
- Waste forest biomass (calculated as the sum of sawmill residue, shrub & chaparral and residue from forest management)

The total biomass availability in California for the year 2025 and 2045 is estimated to be 54 million tons per year and 56 million tons per year, respectively (Table 8).

Table 8: Summary of California Biomass Availability in 2025 and 2045

Biomass Source	2025 Amount	2045 Amount
Agricultural Residues	10.4 M BDT/yr	12.7 M BDT/yr
Municipal Solid Waste	12.3 M BDT/yr	13 M BDT/yr
Landfill and Anaerobic Digester Gas (Gaseous Waste)	7.1 M tons/yr	6.1 M tons/yr
Forest Biomass	24 M BDT/yr	24 M BDT/yr
Total	**54 M tons/yr**	**56 M tons/yr**

Source: Baker et al. (2019)

Assuming all of the available and applicable biomass is utilized, Baker et al. (2019) estimated that 3.8 million tons of hydrogen could be produced annually via biomass gasification, supplying around 95% of the renewable hydrogen demand for the state by 2050. For forest resources alone, this is 85% of present demand, and 40% of future 2050 demand of 4 million tons hydrogen per year (California Energy Commission, 2020).

In a previous study, Parker et al. (2008) estimated that waste biomass resources in California could provide 335 petaJ (1 PJ = 10^{15} J = approximately 7,000 tons of hydrogen) of hydrogen energy for transportation fuel. This is equivalent to 2.34 million tons of hydrogen. Their analysis showed that the municipal solid waste represents the largest resource available for development, followed by mill residue, logging slash, and forestry thinnings.

4 Hydrogen Infrastructure

Hydrogen requires infrastructure for both its storage and transportation. Hydrogen can be stored in small-scale storage near the point of use, intermediate-scale “buffer” storage, and large-scale bulk storage (Ogden, 1999). Previous studies have shown that the costs for compression and pressure vessel storage could add $2.5–$4/GJ to the delivered cost of hydrogen, liquefaction and storage could add $5–$10/GJ to the cost of liquid hydrogen, and large-scale underground storage could add about $2-$6/GJ.

4.1.1 Stational Storage at Intermediate and Small Scales

Intermediate to small-scale liquid hydrogen and compressed hydrogen gas in cylinders are already in use by the industry. Capital costs for storage in pressure vessel is estimated to be between $3,000 to $5,000/GJ of storage capacity. Varying costs have been reported in the literature for compression and pressure vessel storage of hydrogen. Ogden et al. (1995) have estimated that costs for compression and pressure vessel storage of 0.025 million (59 kg) to 0.5 million scf (1,180 kg) of hydrogen at a hydrogen refueling station might add $2.5–$4/GJ to the delivered cost of hydrogen.

Hydrogen can be liquified at very low levels of temperature (-253 ^{O}C). Liquid hydrogen is stored in specialized vessels called cryogenic dewars that are designed to minimize heat loss. Storage capacity of these cryogenic dewars range from a few kilograms to hundreds of tons. Significant capital costs are associate with liquefaction and storage equipment (Table 9). Beyond the capital cost, there is a large energy cost; electricity equivalent to about one-third or more of the energy value of the hydrogen is needed to liquefy. Liquefaction and storage could add $5–$10/GJ to the cost of liquid hydrogen, depending on the scale of the liquefier, about as much as the cost of gaseous-hydrogen production (Ogden, 1999).

4.1.2 Large-scale Storage

Large quantities of gaseous hydrogen could be stored underground at several hundred to 1,000 pounds per square inch (psi) in depleted oil or gas fields, aquifers or salt or rock caverns. An example of underground hydrogen storage is provided by ICI at Teesside, England where 95% pure hydrogen is stored in salt caverns (Beutel & Black, 2005). Underground storage is suitable for large-scale storage needs since underground formations normally have very large capacities, ≤ 1 billion Nm^3 of gas for aquifers or gas fields and millions of NM^3 of gas for cavern[10]. The levelized cost of large-scale underground storage is estimated to add about $2-$6/GJ to the cost of hydrogen

[10] 1-Nm^3 =12.8MJ (HHV)

(Ogden, 1999). Large-scale seasonal underground storage is already in use for natural gas in California. Aliso Canyon Underground Storage Facility in Porter Ranch, California is the second-largest natural gas storage site in the western United States, with a capacity of over 86 billion cubic feet of natural gas. With the current moratorium on natural gas injection in Aliso Canyon field in the backdrop of the 2015 gas leak, Aliso Canyon gas field with its existing infrastructure could potentially be repurposed for underground storage of large quantities of gaseous hydrogen in California.

4.2 Distribution

Most of the hydrogen used in the United States is produced at or near where it is used — typically at large industrial sites. As a result, an efficient means of delivering large quantities of hydrogen fuel over long distances and at low cost does not yet exist (DOE, 2020). Varying costs associated with the delivery of hydrogen have been reported in the literature and the difference in these costs depends upon a number of factors, including the quantity of hydrogen transported, the transport distance, and for distribution systems, the density of demand.

4.2.1 Truck Delivery

A study conducted by Yang and Ogden (2008) analyzed the three modes of hydrogen delivery that are in commercial use today: trucks with hydrogen stored in compressed gas tanks (often referred to as tube trailers), trucks with hydrogen stored as a cryogenic liquid (below 20K), and pipelines that transport compressed hydrogen gas.

The main factors determining hydrogen delivery costs are the capital costs of the truck cabs and tube trailers, the driving distance, the driver labor cost, diesel fuel cost, and operations and maintenance costs. Table 9 provides a comparison between some of the direct costs of a compressed gas truck delivery system and Cryogenic Liquid H_2 Trucks.

Table 9: Direct costs of a compressed gas trucks and cryogenic liquid trucks

	Compressed Gas Trucks	Cryogenic Liquid H_2 Trucks
Total Truck Capacity	300 KG H_2	4000 KG H_2
Tube Trailer Cost	$150,000	-
Undercarriage Cost	$60,000	$60,000
Cab Cost	$90,000	$90,000
LH2 Tank Cost	-	$650,000

Source: Yang and Ogden (2008)

The break-even point between crogenic liquid hydrogen trucks and a compressed gas trucks will vary depending on the distance and quantity. Cryogenic liquid trucks can transport approximately 10 times more hydrogen than compressed gas trucks. As Table 9 shows, liquid hydrogen tank trailers cost significantly more than tube trailers. Nevertheless, the trucking cost per unit of hydrogen delivered is lower, which can lead to a lower overall hydrogen delivery cost. On the other hand, tube trailers have fairly low capital costs but also low hydrogen capacity. This makes them suitable for hydrogen markets that have small delivery requirements with less than 500 kg/d of hydrogen.

4.2.1 Pipeline Delivery

The least expensive way to deliver large amounts of hydrogen is transmission by pipelines and several lines have been built in the United States, specifically near large petroleum refineries with approximately 1,600 miles of hydrogen pipelines currently operating in the country (DOE, 2020). However, the current hydrogen pipeline infrastructure in the United States is very small compared to the more-than-one million miles of natural gas pipelines. Blending hydrogen into natural gas pipeline networks can be an optimum delivery method during the early market development phase as blending can defray the cost of building dedicated hydrogen pipelines.

The cost of hydrogen pipeline delivery depends on the installed capital cost of the pipeline, as well as costs for compression and storage at the central production plant. As can be seen in Table 10, the cost of the right-of-way (ROW) and installation would be significantly higher for hydrogen distribution in urban areas compared to the rural. The capital cost of the pipeline itself is dependent on pipeline diameter, which is based upon the amount of material used within the pipe.

Table 10: Pipeline costs

Installation and ROW cost - rural	$300,000/km
Installation and ROW cost - urban	$600,000/km
Pipeline Capital Costs ($/km) ($d_{pipe}$ is pipeline diameter in inches)	$1869 ($d_{pipe}$)^2
Fixed operating costs	5% of total capital
Compressor capital costs	$15,000
Compression energy requirements	0.7-1.0 kWh/kg

Source: Yang and Ogden (2008)

Yang and Ogden (2008) conclude that for short distances (10 -50 miles) and small amounts (500 kg/d or less), gas trucks are preferred. For medium amounts of hydrogen (500-1,500 kg/d) and long distances (100 miles), LH2 truck delivery is preferred. The largest cost factors are liquefaction equipment capital and electricity for liquefaction. For large amounts of hydrogen (1,800 kg/d), pipeline transmission is preferred.

4.2.2 Railroads Delivery

Hydrogen distribution through railroads in California has received scant attention in the literature. California has one of the world's most extensive freight railroad system that plays a crucial role in the state's handling of international trade with its 5,295-mile freight rail system (DOT, 2018). In the United States, railroads are commonly characterized in the context of revenues, with Class I being the largest, and Class III being the smallest. California is serviced by BNSF and the US Pacific Railroads (UPRR), two Class I railroads. There are no Class II railroads in California. Class III carriers, commonly or also known as "short lines," provide service to various communities across the state. California's railroad network evolved, in part, due to the logging industry. As a result, around 27 short lines provide access to remote sawmills (DOT 2018). Figure 4 shows Class I and Public Agency Owned Rail System and short lines in California.

Figure 4: California Freight Network (Source: US Department of Transport)

Railroads could provide the most efficient hydrogen distribution systems, however there are currently no hydrogen transport containers that are approved for train traffic. Future research should focus on comparing the economics of hydrogen transportation by road and rail, especially when sites are co-located with rail capacity.

5 Next Steps in California

While many researchers have focused on biomass logistics and supply chain in California and the potential to use this biomass in biofuels production, the potential for hydrogen production using forest biomass has received scant scholarly attention. California is particularly an interesting jurisdiction for hydrogen research because of a wide range of policy measures encouraging low-carbon fuels such as the low-carbon fuel standard (LCFS). Given the rapidly evolving hydrogen market in California coupled with the availability of large volumes of non-merchantable forest biomass, future research should focus on conducting techno-economic analysis and feasibility of a hydrogen facility at various scales in California that could leverage on the non-merchantable forest biomass in the state.

Unit Conversion Data of Hydrogen:

Table 11: Conversion Factors for Hydrogen[11]

	Weight	Gas	Liquid	Energy Content
	kilogram (kg)	cubic feet (scf)	gallons (gal)	Kwh/BTU
1 kilogram	1.0	423.3	3.377	HHV: 39.4/134,200 LHV: 33.3/113,400
1 scf gas	0.00236	1.0	0.00882	
1 gallon liquid	0.2679	113.4	1.0	
Scf (standard cubic foot) gas measured at 1 atmosphere and 70°F. Liquid measured at 1 atmosphere and boiling temperature.				

[11] Universal Industrial Gases: http://www.uigi.com/h2_conv.html

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