PATHWAYS TO CARBON NEUTRALITY IN CALIFORNIA

The Hydrogen Opportunity

February 2022

Stanford
Center for Carbon Storage
Carbon Removal Initiative

About

About the Stanford Center for Carbon Storage

Carbon Capture, Utilization, and Storage is a key technology for achieving net-zero greenhouse gas emissions. The Stanford Center for Carbon Storage (SCCS) uses a multidisciplinary approach to address critical questions related to flow physics, monitoring, geochemistry, geomechanics and simulation of the transport and fate of carbon dioxide stored in partially- to fully-depleted oil & gas fields and saline reservoirs. SCCS is an affiliates program associated with the Stanford University School of Earth, Energy and Environmental Sciences.

About the Stanford Carbon Removal Initiative

The Stanford Carbon Removal Initiative (SCRI) seeks to create science-based opportunities and solutions for gigaton-scale negative emissions and atmospheric carbon removal. The initiative helps to enable removal of atmospheric greenhouse gasses at scale by generating and integrating knowledge, creating scalable solutions, informing policies for technology deployment and governance, and demonstrating approaches and solutions with industry collaborators. All of this is done with a focus on social acceptance and equity, as well as environmental, economic, and social costs. SCRI is an affiliates program associated with the Precourt Institute for Energy and the Woods Institute for the Environment.

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Acknowledgements

Report Authors

Justin Bracci

Adam Brandt

Sally M. Benson

Gireesh Shrimali

Sarah D. Saltzer

Project Team[1]

Anela Arifi

Inês M.L. Azevedo

Ejeong Baik

Jocelyn Chen

In Jae Cho

Alexander Evers

Christopher B. Field

John Foye

Thomas Grossman
University of San Francisco

Eleanor M. Henessey

Michael L. Machala

Joshua Neutel

Franklin M. Orr Jr (Principal Investigator)

Madalsa Singh

Terry Surles
Consultant

Anna Tarplin

John Weyant

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California Chamber of Commerce

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California State Building and Construction Trades Council

International Brotherhood of Boilermakers

Western States Petroleum Association

[1] Stanford University unless indicated otherwise

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List of Acronyms

AEM	anion exchange membrane
API	American Petroleum Institute
ATR	auto thermal reforming
BEV	battery electric vehicle
CI	carbon intensity
CARB	California Air Resources Board
CCS	carbon capture and storage
EIA	Energy Information Administration
IEA	International Energy Agency
EPA	Environmental Protection Agency
FCEV	fuel cell electric vehicle
GHG	greenhouse gas
HRI	hydrogen refueling infrastructure
kg	kilogram
kWh	kilowatt-hour
LCFS	Low Carbon Fuel Standard
LCOH	levelized cost of produced hydrogen
LDV	light-duty vehicle
LHV	lower heating value
LLNL	Lawrence Livermore National Laboratory
LOHC	liquid organic hydrogen carriers
Mt	million metric tonnes
NETL	National Energy Technology Laboratory
NREL	National Renewable Energy Laboratory
PEM	proton exchange membrane
PSA	pressure swing adsorption
RNG	renewable natural gas
SMR	steam methane reforming
WGS	water-gas shift

Key Findings

- The hydrogen industry is well-established in California with over 1.8 Mt/yr of production capacity. This existing industry experience can be leveraged to spur continued infrastructure development and cost reductions.
- Hydrogen produced from SMR-CCS and electrolysis using renewables are cleaner than traditional SMR.
- It would be economically favorable to build SMR-CCS facilities in northern California and electrolysis facilities powered by solar electricity in southern California.
- Further production and/or end-use incentives are needed to make clean hydrogen competitive in the industrial, residential, commercial, and, to a lesser extent, transportation sectors in California.
- Hydrogen transport and storage remain major challenges to hydrogen market growth. Development of hydrogen carriers and/or subsurface storage for hydrogen would aid in eliminating these hurdles.
- Within the electricity sector, if large-scale low-cost underground hydrogen storage can be unlocked, hydrogen can be used for long-duration energy storage and can be used to produce on-demand and easily dispatchable electricity.
- Within the industrial sector, hydrogen is most likely to be used for high-temperature heating applications, such as in the cement subsector.
- Within the residential and commercial sub-sectors, electrification technologies are most likely to dominate, but hydrogen technologies may be preferable for some space heating, cooking, and drying applications.
- Within the transportation sector, hydrogen fuel cell technologies are preferrable for heavy-duty long-haul trucking applications. Consumer choice will play an important role in light-duty fuel cell electric vehicle adoption through 2045.
- Compared to the other economic sectors, transportation sector hydrogen end-use technologies are the most mature, and transportation sector hydrogen demand is expected to grow the most by 2045.
- Companies, government, academics, and policymakers each have a role to play in expanding the hydrogen economy in California.

Introduction

Hydrogen is the lightest, simplest, and most abundant element on the periodic table. In its purest form, it is diatomic (H_2) and is found in a gaseous state at standard temperature and pressure with a density of 0.09 kg/m^3. On a mass basis, pure hydrogen contains more energy than any fossil fuel alternative and has no greenhouse gas (GHG) emissions when the energy is consumed. Hydrogen can be used for a variety of applications including transportation, space and water heating, cooking, high-temperature combustion applications for heavy industries and electricity generation. Unfortunately, hydrogen is reactive and therefore rarely found in its high energy-dense diatomic form. Therefore, input energy is required to convert hydrogen from feedstocks into its pure form. In addition,

because of how light hydrogen is, on a volumetric basis, even pure hydrogen compressed to 700 bar or liquified hydrogen do not contain the same amount of energy as fossil fuel alternatives.

To overcome these challenges, large investments in production, transport, and storage infrastructure are required. This has hindered widespread adoption of hydrogen infrastructure around the world and in California. However, with increasing focus on mitigating climate change, clean hydrogen[2,3] technologies are maturing and coming closer to cost parity with fossil fuel alternatives. The opportunity for California to invest in hydrogen to reach net-zero is large, and with further investment in hydrogen infrastructure, the cost of hydrogen will likely continue to decline. This report details the opportunities for investment in hydrogen with the realization that other technologies solutions, such as electrification, will also be integral to reaching net-zero emissions in California by 2045.

Current State of the Hydrogen Economy in California

Hydrogen produced in the United States today is primarily used for making ammonia for chemical products and fertilizers and for refining of crude oils into finished products such as gasoline and diesel [1]. Roughly 95% of U.S. produced hydrogen is made through the process of steam methane reforming (SMR) [1]. In this process, high-temperature steam (H_2O) is reacted with methane (CH_4) in a reformer, followed by a water-gas shift reaction, to produce carbon dioxide (CO_2) and hydrogen (H_2). This process is fossil-based and emits carbon dioxide into the atmosphere without the addition of carbon capture equipment to the facilities [2].

In California, current production capacity is about 1.83 million metric tonnes of hydrogen per year (Mt/yr). All this capacity is SMR production plants. The Environmental Protection Agency (EPA) reports carbon dioxide emissions of about 10 Mt/yr from these production facilities [3]. Roughly 99% of this capacity is used for crude oil refining at the 14 refineries in-state [4] which are concentrated in the San Francisco Bay Area and Los Angeles [5]. Figure 1 shows the location of the 20 SMR facilities in California, and Table 1 lists the hydrogen capacity and owner of each production facility. Ten of these facilities are located within the gate of refineries and the other ten are merchant facilities, many located next to oil refineries and selling hydrogen directly to the California refineries.

Hydrogen is used for multiple purposes at petroleum refineries. These include lowering the sulfur content of petroleum products to meet fuel quality regulations and cracking heavier molecules into lighter, more valuable products. As sulfur content regulations have become more stringent for diesel products, hydrogen production at petroleum refineries has risen [6].

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[2] Clean hydrogen is defined as any hydrogen that has a carbon intensity less than 2 kg CO_2 per kg H_2 at the site of production as indicated in the Infrastructure Investment and Jobs Act signed into law on November 15th, 2021 (Source: Section 40315, Infrastructure Investment and Jobs Act, 2021).

[3] In this report, the term clean hydrogen is generally used to describe hydrogen produced from any of the following technologies: SMR-CCS, ATR-CCS, electrolysis from renewable electricity, biomass gasification, and methane pyrolysis.

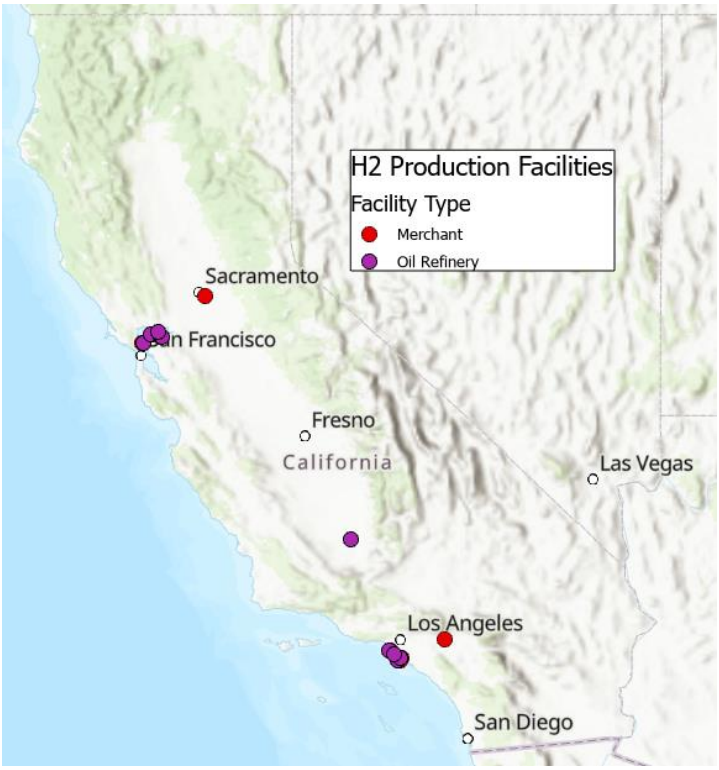

Figure 1: Merchant and Oil Refinery Hydrogen Production Plants in California in 2021. Purple indicates oil refinery plants and red indicates merchant hydrogen plant. (Data Source: Hydrogen Tools) [5].

Producer	City	Facility Type	Capacity (kg/day)
Air Liquide	El Segundo	Merchant	207,240
Air Liquide	Rodeo	Merchant	289,172
Air Products	Sacramento	Merchant	5,542
Air Products	Carson	Merchant	240,976
Air Products	Martinez	Merchant	212,059
Air Products	Martinez	Merchant	84,342
Air Products	Wilmington	Merchant	385,562
Praxair	Ontario	Merchant	20,483
Praxair	Ontario	Merchant	28,917
Praxair	Richmond	Merchant	626,539
Chevron USA Inc.	Richmond	Oil Refinery	795,222
Chevron USA Inc.	El Segundo	Oil Refinery	178,323
Marathon Petroleum Co	Martinez	Oil Refinery	209,649
Marathon Petroleum Co	Carson	Oil Refinery	289,172
PBF Energy Inc.	Martinez	Oil Refinery	465,084
Phillips 66 Company	Rodeo	Oil Refinery	53,015
Phillips 66 Company	Wilmington	Oil Refinery	253,025
San Joaquin Refining Co Inc	Bakersfield	Oil Refinery	9,639
Torrance Refining Co LLC	Torrance	Oil Refinery	351,826
Valero Refining Co California	Benicia	Oil Refinery	325,318

Table 1: Hydrogen Production Plants in California in 2021 including producer company, capacity, location, and facility type (Data Source: Hydrogen Tools) [5].

The Marathon petroleum refinery in Martinez, California is in the process of converting into a renewable diesel plant that converts waste oils, greases, and fats into a useable and clean diesel product. This refinery will continue to use the hydrogen production capacity in-place to upgrade the organic feedstocks into diesel for heavy-duty vehicles. Marathon estimates the facility conversion will lead to 60% reductions in greenhouse gas emissions, 70% reductions in total criteria air pollutant emissions, and will reduce water usage by 1 billion gallons every year [7].

Hydrogen produced in-state that is not used for oil refining, including hydrogen from the Sacramento production facility, has multiple end-use applications including refueling for light-duty vehicles and other chemical processes [8]. These end-use activities are not always co-located with current production facilities which means hydrogen transport is required. With the majority of hydrogen pipeline in the U.S. in the Gulf Coast region [9], and no hydrogen pipelines in California today, the primary mode of hydrogen transport in the state is by truck.

Prior to transport, hydrogen has traditionally been compressed to 200 bar and transported via steel cylinders (Figure 2). These tube trailer trucks can carry 100-200 kg H_2 per trip. Compressed hydrogen is also transported at pressures between 450-700 bar using composite material cylinders. These transport and storage methods, along with liquid hydrogen transport and storage, will be discussed in **Transmission, Distribution and Storage Pathways** on Page 24 of this report [2], [10].

Figure 2: Tube Trailer Transport Vehicle: 200 bar steel cylinder transport (Replicated from: Edwards, 2021) [10].

After the industrial sector, the next largest user of hydrogen in California is the transportation sector, most notably for light-duty vehicle (LDV) transport applications. As of September 2021, there are about 11,000 fuel cell electric vehicles (FCEVs) that have been bought or leased in California [11] with an accompanying 47 hydrogen refueling stations currently in operation to support those FCEVs. As shown in Figure 3 from the California Air Resources Board (CARB), most of the FCEVs and hydrogen refueling stations in the state are concentrated in the San Francisco Bay Area and Los Angeles, where fuel demand is greatest [12]. In total, refueling station capacity in California for FCEVs is about 14.3 metric tonnes

per day (t/d) with over 5 t/d capacity in both the San Francisco Bay Area and the Los Angeles regions [12].

The hydrogen for California FCEVs comes from multiple sources including the liquid H_2 plant in Sacramento [8]. There is also an Air Liquide liquid hydrogen plant under construction in Las Vegas that will produce hydrogen to support California FCEV growth [13]. To encourage low-carbon sourced hydrogen, California enacted Senate Bill 1505 in 2006, which requires all state-funded refueling stations in California to dispense hydrogen that is at least 33.3% renewable. In addition, for stations to become eligible for the Low Carbon Fuel Standard Hydrogen Refueling Infrastructure program (LCFS HRI) they must dispense at least 40% renewable hydrogen [12]. These renewable hydrogen percentages are met by reforming renewable natural gas (RNG), primarily from landfills [14].

At refueling stations in California today, dispensed hydrogen is sold at around $13-$16 per kg. This is equivalent to about $6.50-$8 per gallon of gasoline on a miles traveled basis. New stations being built with higher capacities typically have lower hydrogen prices than smaller capacity stations. Automakers such as Hyundai and Toyota, which both have FCEVs on the market, alleviate fuel costs to owners of their fuel cell vehicles by providing free fuel for 3 years [15].

Aiming for a future that is less dependent on fossil fuel for transport, Governor Gavin Newsom issued Executive Order N-79-20 in January, 2021 requiring CARB to develop vehicle regulations targeting 100% in-state zero-emission vehicle sales by 2035 for passenger vehicles, by 2045 for all buses and trucks where feasible, and by 2035 for all drayage and off-road vehicles and equipment [16]. The primary technology options being considered are battery-electric and fuel cell electric vehicles. In the near term, FCEVs are expected to grow to about 61,000 by 2026 with an expected 176 refueling stations in operation by that same time [12].

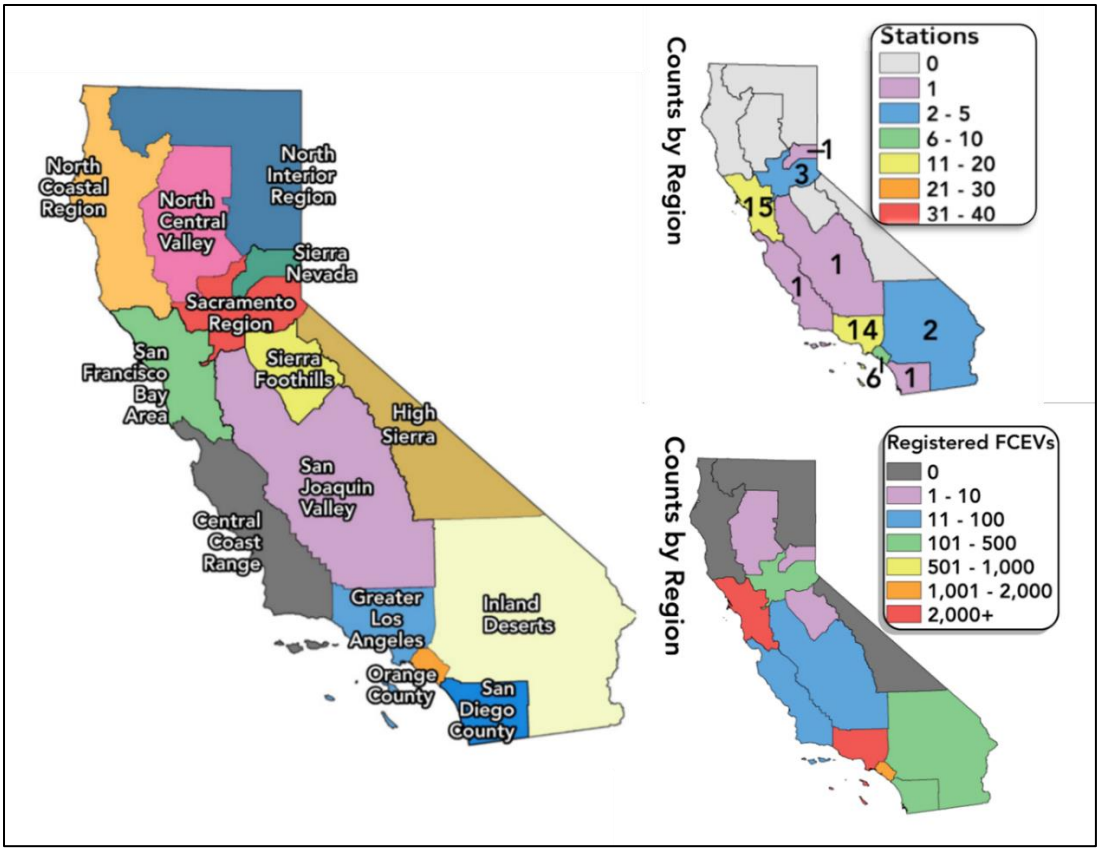

Figure 3: FCEV and Refueling Stations in California by Region: (Top) Operating refueling stations as of May 12th, 2020, (Bottom) FCEVs registered as of April 1st, 2020 (Adapted from: CARB 2021) [12].

Clean Hydrogen Production Pathways

To reach net-zero emissions by 2045 in California, clean hydrogen can play a major role and can make a significant emissions reduction impact in each of the energy sectors. For hydrogen end-use technologies to scale to help mitigate emissions, California must first increase the scale of deployment of clean hydrogen production technologies. This section will cover clean hydrogen production pathways, the economics of each pathway, and any policies and regulation in place to spur production infrastructure build-out.

Steam Methane Reforming (with Carbon Capture and Storage)

Process Flow

All hydrogen production occurring in California today is through the process of SMR. On average, this process emits about 9 kg CO_2 per kg H_2 produced [17] but could still be used to produce clean hydrogen if carbon capture equipment is installed at the facilities. Figure 4 shows the process flow diagram for a typical SMR facility before the addition of carbon capture technology.

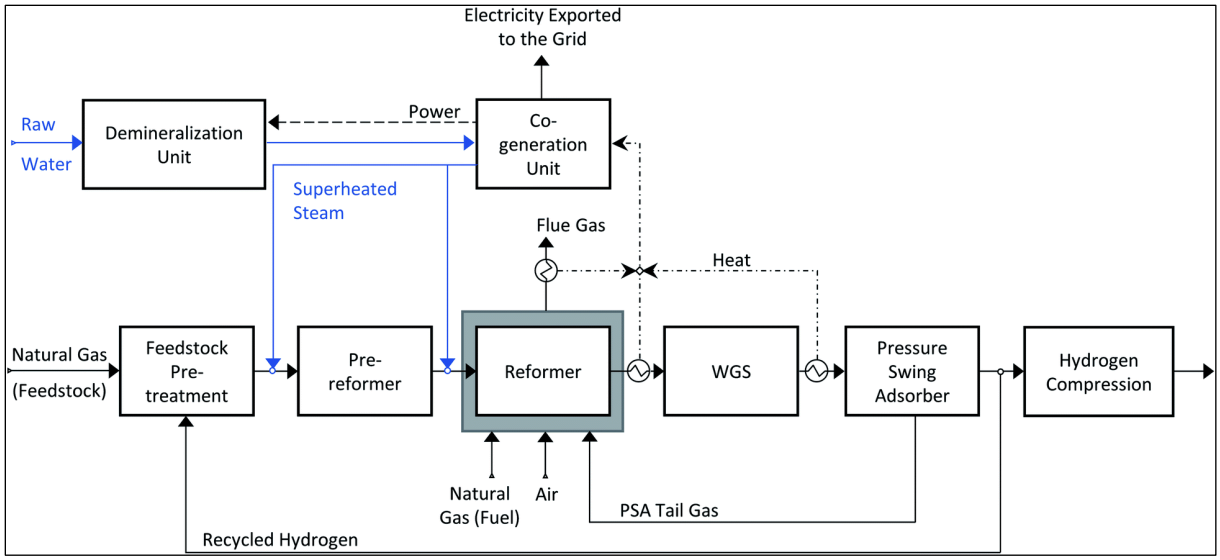

Figure 4: SMR process flow diagram including a co-generation unit to produce electricity. No carbon capture included (Replicated from: Antonini et al. 2020) [18].

The primary reactions in this process occur at the reformer and the water-gas shift (WGS) unit. The reformer operates between 800 and 1000°C with natural gas feedstock reacting with high-temperature steam to produce carbon monoxide (CO) and hydrogen (Eq. 1). The reaction is endothermic, and methane is the primary fuel used to heat the reformer [2].

$$CH_4 + H_2O\ (+\ 206\ kJ/mol) \longrightarrow 3H_2 + CO \qquad \text{(Eq. 1)}$$

Following the reforming process, carbon monoxide further reacts with high-temperature steam in the WGS unit to produce more hydrogen and carbon dioxide (Eq. 2), along with a smaller amount of heat (exothermic) [2].

$$CO + H_2O \longrightarrow H_2 + CO_2\ (+\ 41\ kJ/mol) \qquad \text{(Eq. 2)}$$

The net reaction is (Eq. 3):

$$CH_4 + 2H_2O\ (+165\ kJ/mol) \longrightarrow 4H_2 + CO_2 \qquad \text{(Eq. 3)}$$

Roughly 3.3 kg CH_4 is required for every kg H_2 produced with about 60% of this methane fed into the reformer and the remaining 40% used as fuel to heat the reactor [19], [20]. This results in two separate carbon dioxide streams. One stream from the combustion of methane and one stream from process reactions. In total, about 5.4 kg CO_2 per kg H_2 is generated from the process stream and 3.6 kg CO_2 per kg H_2 is generated from methane combustion for heat.

After the water-gas shift reaction, the resulting gas mixture contains about 75-80 mol% H_2, 15-20 mol% CO_2, and small amounts of carbon monoxide, methane, and nitrogen. It is then sent through a pressure swing adsorption (PSA) unit that captures roughly 86% H_2 at over 99.99% purity. The flue gas, still containing about 30 mol% H_2 and containing the process

generated carbon dioxide, is then fed to the reformer and combusted to provide additional reaction heat [2], [21]. It is at the flue gas stack of the reformer where process and combustion related carbon dioxide emissions are combined and can be captured as one stream [19].

Box 1

Auto-thermal Reforming in Comparison to SMR

A similar commercialized hydrogen production method to SMR is auto-thermal reforming (ATR). This production method has yet to emerge in California but could play an important role in decarbonizing if CCS is successfully implemented in the state. Unlike SMR, ATR reaction heat is provided within the reformer vessel and no additional fuel is needed to heat up the reactor. In the reaction vessel, methane is partially combusted with oxygen in an exothermic reaction which drives the reforming reaction. An air separation unit is installed at the reformer to provide the oxygen for partial combustion. Pure oxygen is used to avoid nitrogen contamination in the reforming process. The temperature in the reformer is higher for ATR (up to 1150°C) in comparison to SMR, resulting in a higher conversion efficiency. The reformer reaction in shown in Eq. 4 [18], [22], [23].

$$4CH_4 + O_2 + 2H_2O \rightarrow 10H_2 + 4CO \qquad \text{(Eq. 4)}$$

Similar to SMR, the reformer reaction is followed by a WGS reaction to convert carbon monoxide into carbon dioxide, and then a PSA unit, which separates out hydrogen from other process gases [19]. Figure 5 shows the entire process flow diagram of an ATR facility.

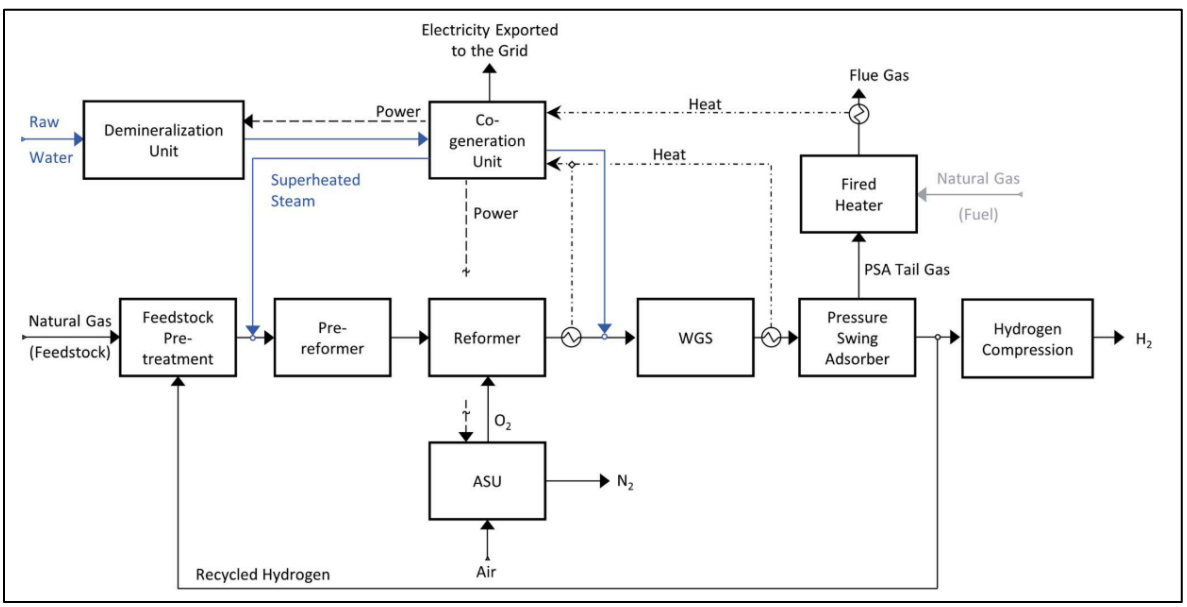

Figure 5: ATR process flow including a co-generation unit to produce electricity. No carbon capture included (Replicated from: Antonini et al. 2020) [18].

ATR is typically a more expensive production method in comparison to SMR because of the additional oxygen separation unit. However, ATR only has process carbon dioxide emissions which can be captured at high pressure after the WGS or PSA. Therefore, ATR carbon dioxide capture would have lower relative energy input and cost in comparison to SMR flue gas capture [18], [22], [23]. Further techno-economic studies should be performed to assess whether SMR-CCS or ATR-CCS is a lower cost clean hydrogen production solution for California to pursue for the future.

For SMR to become a suitable hydrogen production method on a path net-zero emissions in California, the existing 20 SMR facilities in California, as well as new build facilities, will need to increase the use of RNG feedstocks and add carbon capture technology to mitigate carbon dioxide emissions associated with the production process. As mentioned in the introduction, the California state government, and CARB have both taken steps to ensure increased use of RNG feedstocks and fuel for SMR produced hydrogen for transportation applications. The expectation is that vehicle refueling stations will continue to enroll in CARB's LCFS HRI program resulting in at least 40% renewable hydrogen produced for state utilization as a vehicle fuel [12]. Similar regulation for other end-use applications of hydrogen have yet to be developed in California [2].

With the addition of a carbon capture system at the flue gas stack of the reformer capable of capturing 90% CO_2 emissions, methane input increases to about 3.7 kg per kg H_2 produced due to the carbon dioxide capture system input energy requirement [19], [24]. Taking carbon dioxide capture at the flue gas stack into consideration, a typical SMR will only emit about 1 kg CO_2 per kg H_2 in comparison to SMR facilities without capture emitting about 9 kg CO_2 per kg H_2 [19]. Fugitive methane emissions must also be considered when comparing the net emissions reductions of SMR-CCS to other clean hydrogen production technologies. There are few studies that quantify fugitive methane emissions from SMR, and it is still unclear as to how significant they are.

One notable consequence of increased deployment of SMR technologies is the water input requirement. SMR hydrogen production requires a minimum of 4.5 kg H_2O (1.2 gallons) per kg H_2 produced and is even higher with added carbon capture equipment. Studies have indicated life cycle water consumption (on an energy content basis) at SMR hydrogen production facilities are on the same order of magnitude as fossil-fuel derived fuels and significantly less than any bio-derived fuel [25]–[27]. This indicates a switch from fossil-derived energy sources to hydrogen would likely not have a large impact on California's water consumption. However, it remains important to choose a production plant location with easy access to water.

Technoeconomics

To minimize hydrogen production and distribution costs from SMR with carbon capture and storage (CCS), the following facility location criteria should be met [2]:

- Locate facility a short distance from existing natural gas pipeline to limit or eliminate pipeline infrastructure development
- Co-locate or locate a short distance from potential carbon dioxide storage to limit or eliminate carbon dioxide transport cost
- Locate a short distance from high-travelled roadways to limit hydrogen transport costs
- Locate where natural gas prices are low to limit energy costs
- Locate where there is a low local population density to reduce likelihood of public concerns
- Locate nearby areas where there is likely to be high hydrogen demand to limit hydrogen transport costs

Using the geospatial tool ArcGIS, the areas that meet these criteria can be visualized to determine where in California SMR-CCS production infrastructure deployment is optimal and most likely to occur in the future (Figure 6). Table 2 contains the specific acceptance criteria chosen to develop this visualization.

	Criteria	Data Sources
1	Facility must be located within 2 miles from existing natural gas pipeline rights-of-way	EIA 2020 [28]
2	Facility must be located within 5 miles of a major roadway	Caltrans 2020 [29]
3	Facility must be co-located with viable carbon dioxide storage locations	EFI/Stanford 2020 [30]
4	Facility must be in a location with less than 75 people per km^2	ORNL 2019 [31]
5	Facility must not be in a sensitive habitat or protected lands	ANL 2016, USGS 2019 [32], [33]

Table 2: SMR-CCS Geospatial Criteria Selection (Derived from: Bracci 2021) [2].

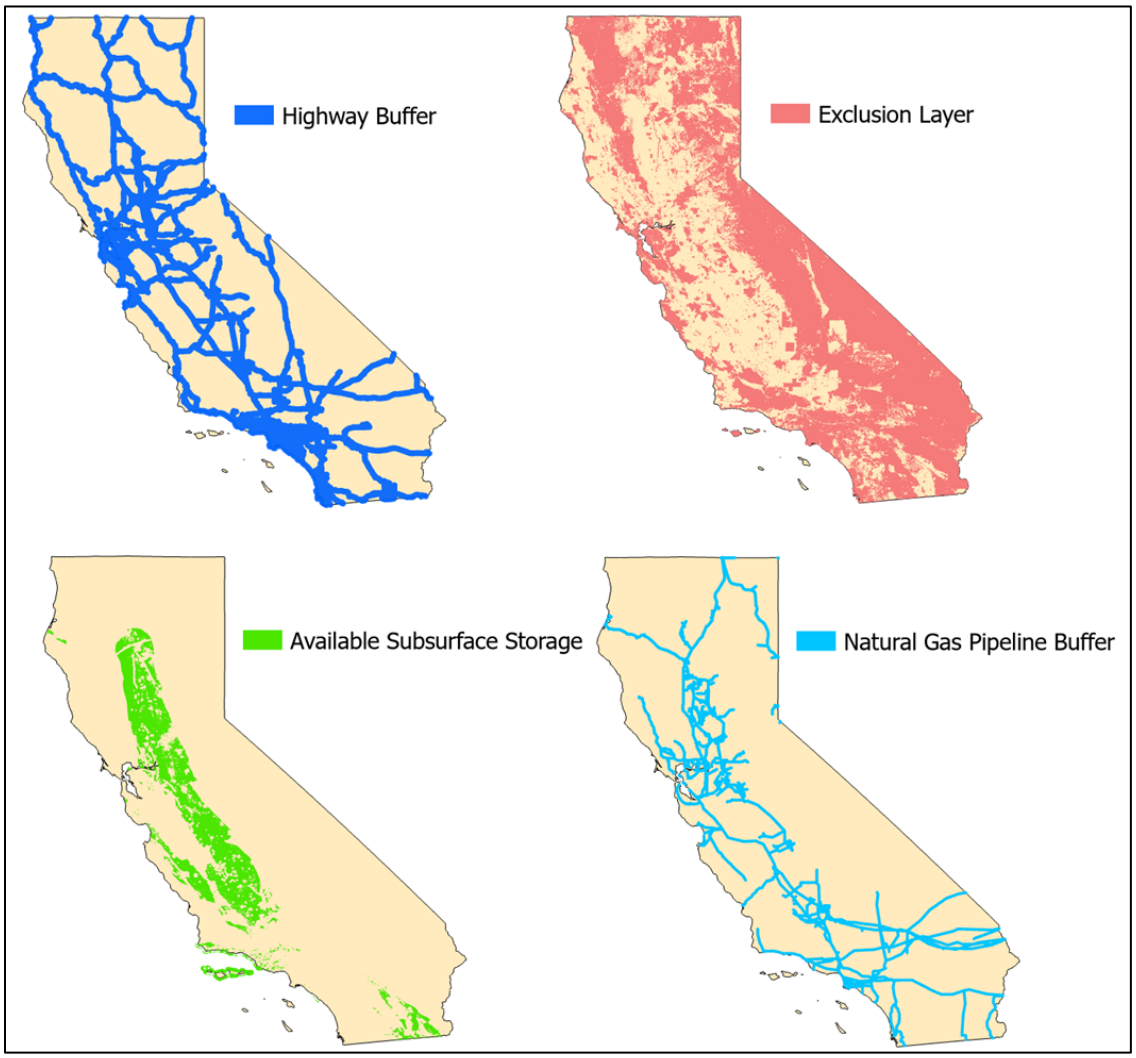

Figure 6: SMR-CCS Geospatial Criteria Selection Layers (Replicated from: Bracci 2021) [2], [28]–[33].

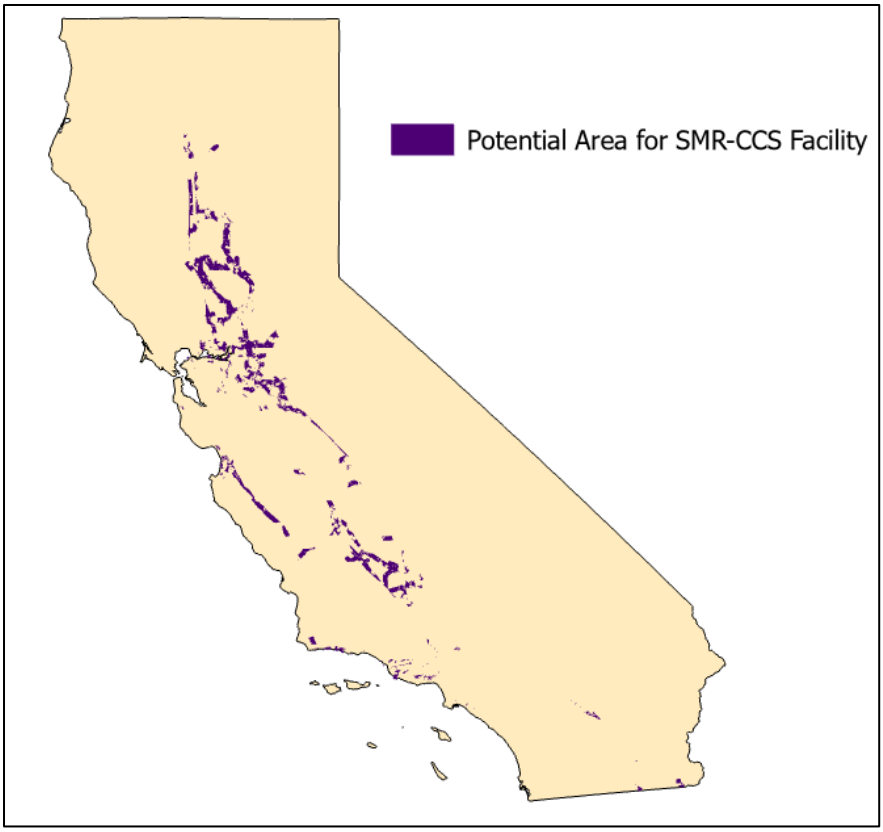

Figure 7: Optimal Locations for SMR-CCS Facility in California (Replicated from: Bracci 2021) [2].

Overlaying the images shown in Figure 6, Figure 7 illustrates that the optimal locations for SMR-CCS production facilities in the state are primarily located in Northern California, where there are optimal carbon dioxide storage locations. Note, Figure 7 does not account for variability in natural gas prices across the state or consider location specific hydrogen demand potential. These two factors would impact the relative cost of hydrogen production from this method [2]. Results shown in Figure 7 should be taken in a general sense. Only one set of acceptance criteria were explored and performing sensitivity analyses on these criteria would result in changes to the size of the optimal SMR-CCS production layer. Many other factors might influence the choice of locations within these zones as well.

A California-specific technoeconomic model was developed to determine the levelized cost of hydrogen produced (LCOH) from SMR pathways. Figure 8 displays the LCOH from several SMR production schemes seen today and likely to come online in the future in California. These include SMR production, SMR with RNG blending, and SMR with carbon capture and storage. The results in Figure 8 do not incorporate costs for any hydrogen compression, storage, transport, or cooling that may be required before end-use (i.e. as a transportation fuel dispensed at a refueling station). Argonne National Laboratory provides detailed estimates of these cost components in their HDSAM model [34]. The results in Figure 8 should be considered as approximate and are generated using input parameter values shown in Table 3. The levelized cost of produced hydrogen is calculated using the simplified Eq. 5.

$$LCOH = \frac{Annualized\ SMR\ Facility\ CapEx + Yearly\ OpEx + Yearly\ Fuel\ Cost}{Yearly\ H_2\ Production\ Rate} \quad \text{(Eq. 5)}$$

Where:

- CapEx - capital expenditure
- OpEx – operational expenditure

As shown in Figure 8A, without considering any incentives, SMR production pathways range from $1.65 to $2.42 per kg. These costs align closely with other studies that investigated the levelized cost of SMR hydrogen production [1], [35]–[38]. As expected, SMR using fossil fuels or fossil fuels with mixed RNG yields lower hydrogen costs than SMR with CCS. However, SMR pathways without 100% RNG input or without CCS are not decarbonization solutions and typically only provide limited emissions reductions in comparison to fossil fuels [39].

Figure 8B illustrates the LCOH of the different SMR production schemes including possible incentives available in California. These incentives include the 45Q tax credit for carbon dioxide capture and storage in the SMR-CCS production pathway and LCFS credits if the hydrogen is used as a transportation fuel. LCFS revenue generated by each type of SMR production method is based on the carbon intensity (CI) of production and the value of the LCFS credits (Eq. 6). The CI scores for each of the SMR production methods highlighted and the LCFS credit values ($/tonne CO_{2e} avoided) used are shown in Table 3.

$$LCFS\ Revenue\ \left(\frac{\$}{kg\ H_2}\right) = \frac{(CI_{BL} - CI_{H2})}{1*10^6} * LHV_{H2} * LCFS\ Credit\ Value \quad \text{(Eq. 6)}$$

Where:

- CI_{BL} = carbon intensity of baseline fossil fuel (g CO_{2e} / MJ)
- CI_{H2} = carbon intensity of produced hydrogen (g CO_{2e} / MJ)
- LHV_{H2} = lower heating value of hydrogen (MJ/kg)

For SMR production, LCFS credits reduce the LCOH by $0.57 per kg, but for more decarbonized solutions such as using dairy gas or SMR with CCS, LCFS credits reach $1.64 and $1.16 per kg H_2, respectively. SMR-CCS producers are also eligible to receive a 45Q tax credit totaling $0.27 per kg H_2 if the carbon dioxide is stored permanently in the subsurface (Figure 8B).

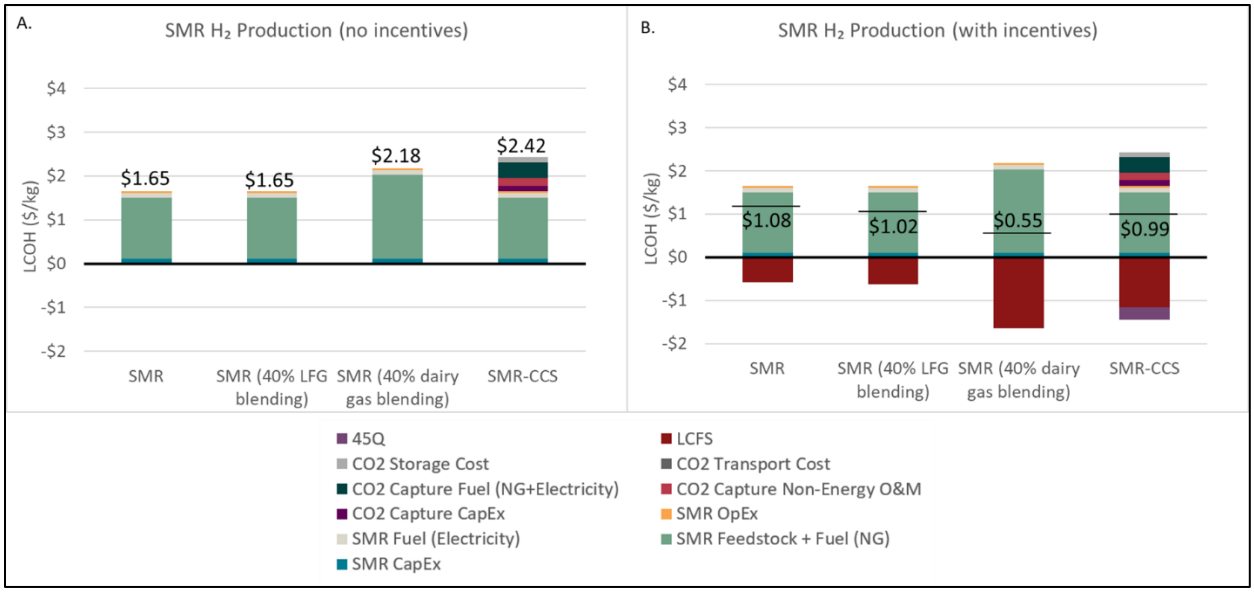

Figure 8: SMR Hydrogen Production Pathways LCOH (Technoeconomic Model Modified and Adapted from: Bracci 2021) [2].

Input Parameters	Values	Units	Source
Discount Rate	5%	%	NETL 2019 [40]
Inflation Rate	2%	%	Assumption
Project Life	30	Years	NETL 2019 [40]
Fossil/Landfill Natural Gas Price	7.28	$/MMBTU	EIA 2020 [41]
Dairy Natural Gas Price	14.19	$/MMBTU	IEA 2020 [42]
Electricity Rate	0.1442	$/kWh	EIA 2020 [43]
H_2 Production	250	t/day	Assumption
LCFS Credit Value	100	$/t CO_2e	Conservative Assumption [44]
Baseline CI Score	100.8	g CO_2e / MJ	CARB 2018, 2020 [39], [45]
SMR CI Score	62	g CO_2e / MJ	
SMR (40% LFG blend) CI Score	58	g CO_2e / MJ	
SMR (40% dairy gas blend) CI Score	-10	g CO_2e / MJ	
SMR-CCS CI Score	22	g CO_2e / MJ	

Table 3: SMR Levelized Cost Model Assumptions (Modified and Adjusted from: Bracci 2021) [2].

It is unclear how SMR production pathways will be utilized to help reach net-zero emissions in California. Scaling up SMR without adding CCS will not help the state reach its decarbonization goals. Using 100% RNG as input fuel and feedstock for the process is a potential solution, but the availability of dairy, landfill, and municipal waste natural gas for future hydrogen production is uncertain. Including CCS with SMR facilities is also a promising low-carbon production scheme, but there still exists challenges and uncertainties (i.e. injection well permitting, upstream methane leakage, etc.) [30].

Hydrogen Production through Electrolysis

Process Flow and Energy Inputs

Water splitting through electrolysis for hydrogen production is a commercially available technology that is gaining traction in places such as New York [46], the United Arab Emirates [47], and Saudi Arabia [48], but is yet to be deployed at large-scales in California. This

process uses electricity to split water into hydrogen and oxygen using an electrolyzer (Eq. 7). Electrolyzers currently require about 50 kWh of electricity per kg H_2 produced [49], [50].

$$H_2O\ (+\ 235\ kJ/mol) \rightarrow H_2 + \tfrac{1}{2}O_2 \qquad \text{(Eq. 7)}$$

Sources of electricity in California for electrolysis include grid electricity and dedicated renewable electricity. California has a renewables-heavy grid with capability of meeting demand requirements with close to 100% renewable electricity during peak sun hours [51]. However, hydrogen produced outside of these hours or on cloudy days would not be considered carbon neutral as it would be produced from carbon-based electricity sources such as natural gas power plants [52]. In addition to not being fully decarbonized, the price for California grid electricity for industrial applications is on average over $0.16/kWh, very high compared to most other areas of the country [53]. Dedicated large-scale renewable electricity facilities, mainly wind and solar, are becoming less expensive with generation costs as low as $0.03/kWh, and have the potential to reduce California electricity prices if they can be cost-effectively integrated into the grid [38], [54]. California also has a favorable solar resource in relation to most other parts of the United States, making hydrogen production with electrolysis from solar photovoltaics in California a viable option for the future [55]. Recent work at Stanford has also looked to identify optimal locations for wind turbine build-out in California which can also be utilized to produce hydrogen from electrolysis [2], [56].

Like with SMR, it is important to note that scaling hydrogen production from electrolysis will require water consumption. At a minimum, 9 kg of high-purity water (2.4 gallons) is required per kg H_2 produced from electrolysis. This is twice the water requirement at an SMR facility, however, this does not consider water usage to produce natural gas for the reforming process. Studies indicate that well-to-wheels life cycle water consumption for hydrogen production is less if the hydrogen is generated from electrolysis using renewable electricity than if it is generated using SMR [25]. In addition, full life cycle water consumption for electrolysis produced hydrogen from renewables is of the same order of magnitude as fossil fuel production water use on an energy content basis [25]–[27]. As with SMR technologies, using electrolysis coupled with renewable energy to produce hydrogen would likely not result in higher water consumption in California as it tries to achieve net-zero greenhouse gas emissions by 2045.

Electrolyzer Technologies

Electrolyzer technologies commercially available today include alkaline and proton exchange membrane (PEM) systems. Figure 9 shows how each of these electrolyzers operate.

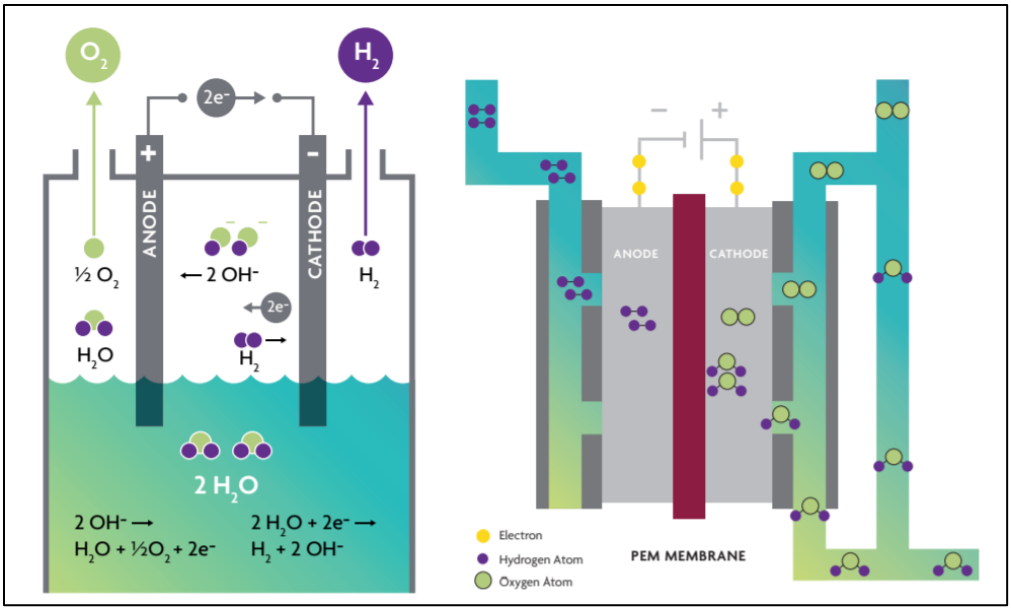

Figure 9: Commercialized Electrolyzer Operations: Alkaline Electrolyzer (left), PEM Electrolyzer (right) (Replicated from: Cockerill 2020) [57].

Alkaline electrolyzers are more mature and typically less expensive than PEM systems, but use a liquid potassium hydroxide electrolyte, which is much more corrosive than the solid polymer electrolytes used in PEM electrolyzers [57], [58]. In addition, alkaline electrolyzers do not have the capability to ramp-up and down as can PEM electrolyzers [57], making PEM electrolyzers more ideal for the future as hydrogen production input energy will likely be sourced from cheap, but variable renewable energy loads. A challenge with PEM electrolyzers is that they require expensive rare earth metal catalysts, platinum and iridium, to operate [59]. About 80% of these metals are sourced from South Africa [60]. This could lead to supply concerns into the future. A few catalyst materials that have shown promise to replace platinum and iridium in PEM electrolyzers are cobalt phosphide [61] and molybdenum disulfides [62]. Cobalt phosphide catalysts have been shown to withstand harsh operating conditions over extended periods of time but yield lower production efficiency than platinum and iridium catalysts [2], [61].

While commercially available, PEM electrolyzers also have yet to scale in size. The largest PEM electrolyzers on the market today have a hydrogen production capability of around 2.4 t/d while current SMRs used for industrial applications can have capacities as high as 400 t/d [5]. This issue will need to be addressed with further research and development and will need to happen quickly if large industrial hydrogen users intend to decarbonize using electrolysis hydrogen production.

Other development phase electrolyzer technologies that are emerging include solid-oxide and anion exchange membrane (AEM) electrolyzers. Solid oxide electrolyzers operate over 600°C and have the capability of achieving conversion efficiencies over 80%, higher than both PEM and alkaline systems. Challenges with solid oxide electrolyzers include high production costs with the introduction of ceramics into the system and material degradation with electrolyzer ramping [63]. AEM electrolyzers are a hybrid between an alkaline and PEM

electrolyzer that use lower cost material than a PEM electrolyzer. These electrolyzers are still in nascent stages of development and only operate at small-scale and for a short life-time [2], [64], [65].

Technoeconomics

To minimize the production and distribution costs of hydrogen generated through electrolysis using solar and grid electricity, the following facility location criteria should be met [2]:

- Locate facility a short distance from existing electricity transmission lines to limit or eliminate transmission infrastructure development
- Co-locate with high solar irradiance regions in California to limit solar electricity charges
- Locate a short distance from high-travelled roadways to limit hydrogen transport costs
- Locate where grid electricity prices are low to limit energy input charges
- Locate where there is a low local population density to reduce likelihood of public grievances
- Locate nearby areas where there is likely to be high hydrogen demand to limit hydrogen transport costs

Using the geospatial tool ArcGIS, the areas that meet these criteria are shown in Figure 10. Table 4 contains the specific acceptance criteria chosen.

	Criteria	Data Sources
1	Facility must be located within 2 miles from existing electricity transmission lines	CEC 2020 [66]
2	Facility must be located within 5 miles of a major roadway	Caltrans 2020 [29]
3	Facility must be co-located with high solar irradiance regions in the state (> 66th percentile in-state)	NREL 2019 [67]
4	Facility must be in a location with less than 75 people per km^2	ORNL 2019 [31]
5	Facility must not be in a sensitive habitat or protected lands	ANL 2016, USGS 2019 [32], [33]

Table 4: Solar and Grid Electrolysis Geospatial Criteria Selection (Derived from: Bracci 2021) [2].

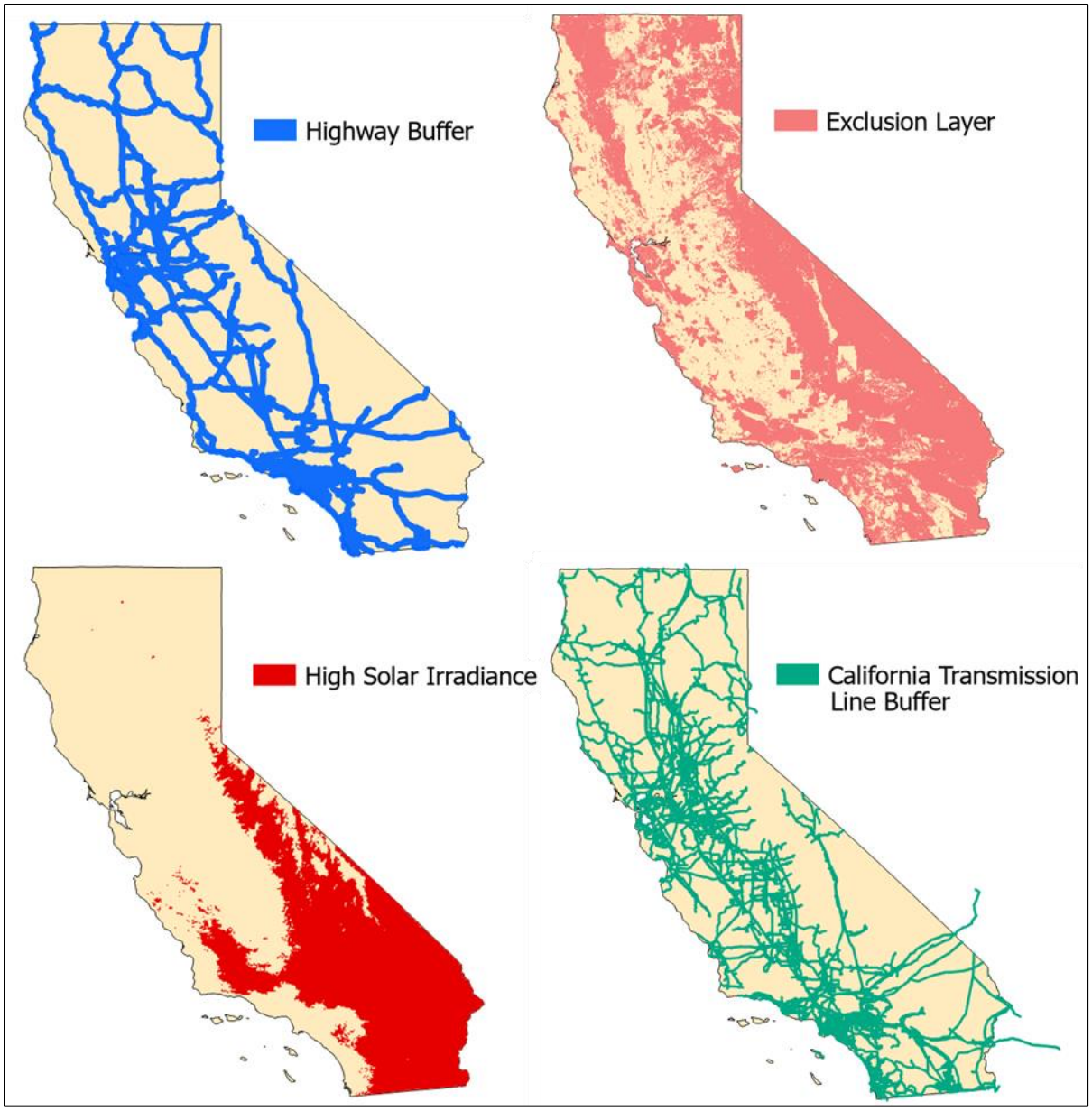

Figure 10: Electrolysis Geospatial Criteria Selection (Modified from: Bracci 2021) [2], [29], [30], [32], [33], [66], [67].

Figure 11 is generated by overlaying the layers shown in Figure 10. Figure 11 illustrate that the optimal locations for electrolysis production facilities in the state are primarily located in Southern California, where there is a high-quality solar resource. Note that Figure 11 does not account for variability in electricity prices across the state or consider location specific hydrogen demand potential which would both impact the relative cost of hydrogen production from this method. Similar to the results in Figure 7 for SMR-CCS, results shown in Figure 11 should be taken in a general sense as only one set of acceptance criteria was explored. Performing sensitivity analyses on these criteria would result in changes to the size of the optimal electrolysis production layer shown in Figure 11.

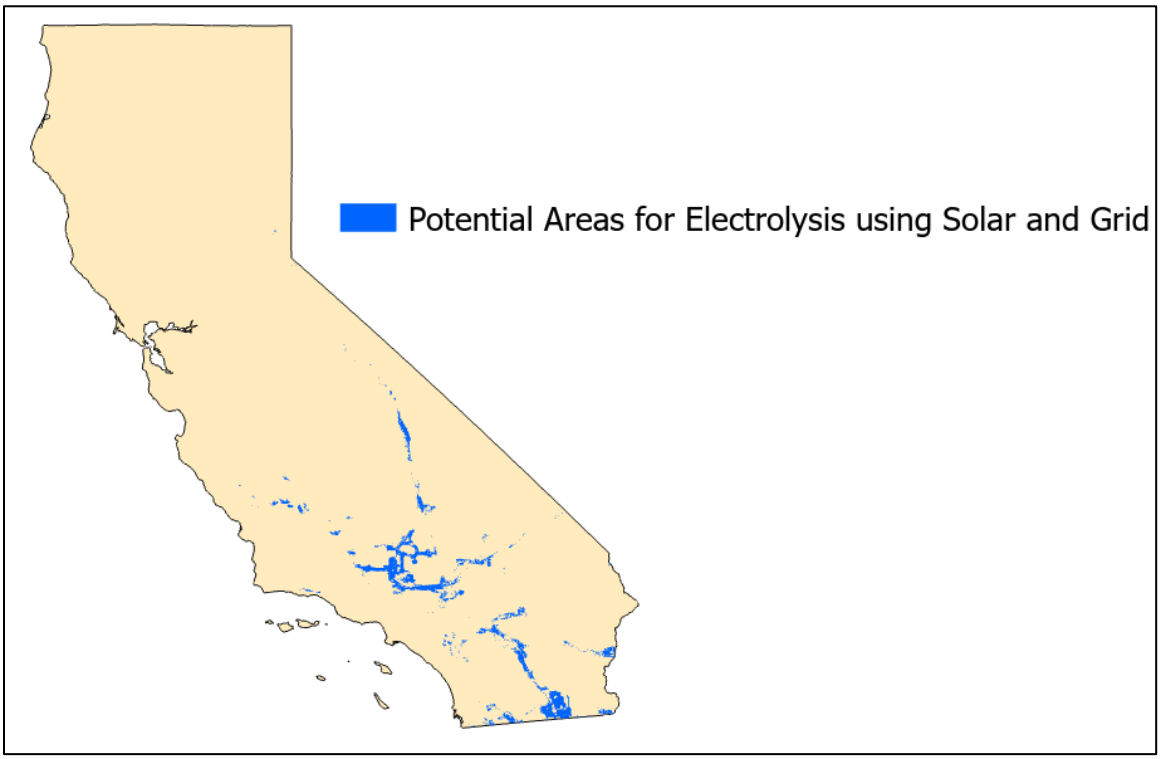

Figure 11: Optimal Locations for Solar and Grid Electrolysis in California (Replicated from: Bracci 2021) [2].

A California-specific technoeconomic model was also developed for electrolysis pathways to determine LCOH. Figure 12 displays the LCOH results from several possible electrolysis pathways including production using only grid electricity, only solar electricity, solar and wind electricity, and solar and battery electricity. Similar to Figure 8, costs shown in Figure 12 are on a production basis and do not include costs of hydrogen compression, storage, transport, or cooling that may be required if production and consumption are not co-located nor concurrent. The results shown in Figure 12 should be considered as approximate and are based on input parameter values shown in Table 5. The levelized cost of produced hydrogen is calculated using the simplified Eq. 8.

$$LCOH = \frac{Annualized\ Electrolyzer\ CapEx + Yearly\ OpEx + Yearly\ Electricity\ Cost}{Yearly\ H_2\ Production\ Rate} \quad \text{(Eq. 8)}$$

As shown in Figure 12A, without considering any hydrogen transport or incentives, the production cost of hydrogen from electrolysis ranges from $4.04 to $10.61 per kg. These values closely align with those found in literature for hydrogen production from electrolysis pathways [1], [35]–[38], [68]. Using grid electricity and operating the electrolyzer at full capacity every hour of the day is shown to have the highest levelized cost due to the high cost of grid electricity in California. This method is also not clean, as the grid in California is yet to be fully decarbonized. Using clean solar electricity exclusively to split water requires an overbuild of the electrolyzer to produce all the required hydrogen when the sun is shining. However, average solar electricity prices are low enough that this production method comes at a reduced cost in comparison to using grid electricity. Using a combination of solar and

wind to increase the capacity factor of the electrolyzer further means less of an overbuild of the electrolyzer and even lower production costs in relation to using solar electricity exclusively. For this scenario, this study assumed solar panels and wind turbines were both located in Sacramento and electricity produced is used to operate a nearby electrolyzer. Finally, this analysis considers an option to operate the electrolyzer using solar electricity coupled with a battery system to keep the electrolyzer running every hour of the day at a constant production rate. While reducing electrolyzer costs by not overbuilding, this production method has an overall higher cost because of the high capital expenditure for battery storage systems today.

Figure 12B shows the cost of produced hydrogen including LCFS credits that can be obtained by using hydrogen as transportation fuel. LCFS credit revenue can be calculated using Eq. 6 on Page 12. As is shown, LCFS credits can reduce the cost of hydrogen from electrolysis by about $1.28/kg if the production process is fully decarbonized. In the case of hydrogen produced using current grid electricity in California, the LCFS credits are only worth about $0.17/kg.

Comparing the results in Figure 12 to those of Figure 8, hydrogen from electrolysis is still more expensive than SMR production pathways. With advancements in electrolyzer technologies and continued reduction in wind and solar costs, hydrogen production from electrolysis may reach cost parity before 2045 and play an important role in decarbonizing California [68], [69].

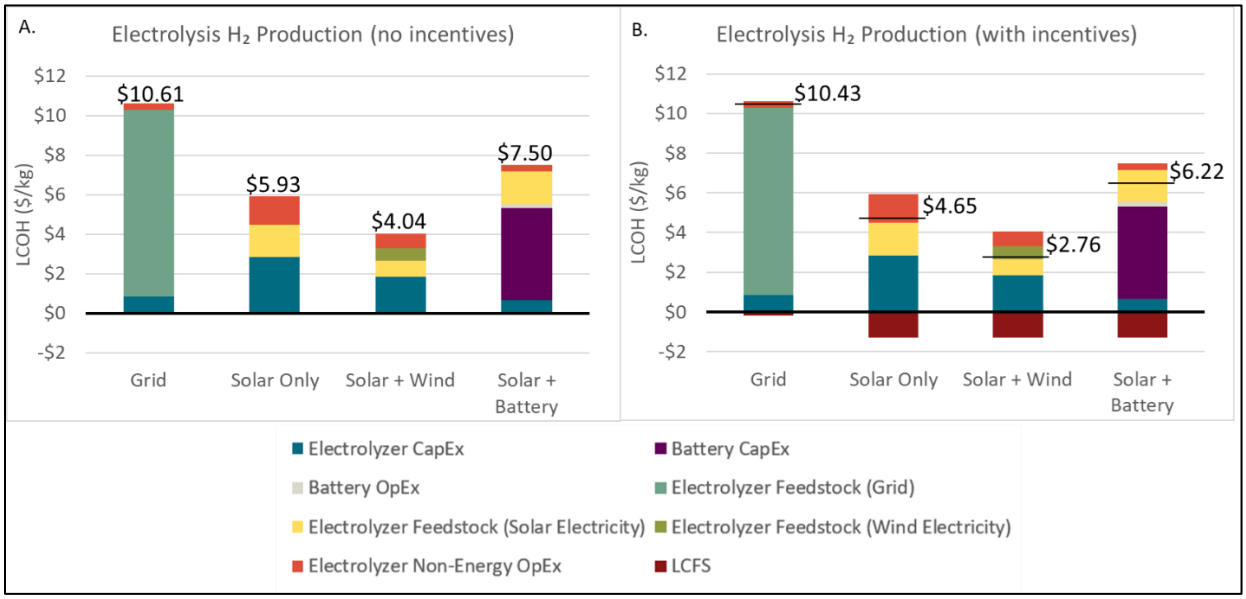

Figure 12: Electrolysis Hydrogen Production Pathways LCOH (Technoeconomic Model Modified and Adapted from: Bracci 2021) [2].

Input Parameters	Values	Units	Source
Discount Rate	10%	%	NREL 2019 [70]
Inflation Rate	2%	%	Assumption
Project Life	20	Years	Assumption
Electrolyzer Capital Cost	1100	$/kW	McKinsey [68]
Solar Electricity Rate	0.036	$/kWh	NREL ATB 2021 [71]
Wind Electricity Rate	0.027	$/kWh	NREL ATB 2021 [72]
Grid Electricity Rate	0.1772	$/kWh	EIA 2020 [43]
Distributed H_2 Production Capacity	1.2	Mt/day	Assumption
Solar Capacity Factor (Sacramento)	23.2	%	Renewables.ninja 2019 [73]
Wind Capacity Factor (Sacramento)	22.6	%	Renewables.ninja 2019 [73]
Combined Solar + Wind Capacity Factor (Sacramento)	45.1	%	Renewables.ninja 2019 [73]
LCFS Credit Value	100	$/t CO_{2e}	Conservative Assumption [44]
Baseline CI Score	100.8	g CO_{2e} / MJ	CARB 2018, 2020 [39], [45]
CI Score Electrolysis from Renewables	0	g CO_{2e} / MJ	
CI Score Electrolysis from Grid	86.6	g CO_{2e} / MJ	

Table 5: Electrolysis Levelized Cost Model Assumptions (Modified and Adjusted from: Bracci 2021) [2].

Other Emerging Hydrogen Production Methods

Other emerging clean hydrogen production technologies that California could implement to facilitate a hydrogen economy in-state include biomass gasification and methane pyrolysis.

Biomass Gasification

This process involves converting biomass into a mixture of gases, called syngas (mainly carbon dioxide, carbon monoxide, and hydrogen), by applying high temperatures (over 700°C) and pressures in the presence of steam and a controlled amount of oxygen [74]. A simplified version of the gasification reaction is shown in Eq. 9 [2].

$$C_6H_{12}O_6 + O_2 + H_2O \rightarrow H_2 + CO_2 + CO + \text{other species} \qquad \text{(Eq. 9)}$$

The mixture is then sent to a water-gas shift reactor (Eq. 2) where carbon monoxide and water are converted into carbon dioxide and hydrogen. This technology can provide net-negative emissions if a carbon dioxide capture unit is installed to capture any process and fuel combustion carbon dioxide emissions [2], [75].

Gasification is a relatively mature technology today. There are about 120 active commercial gasification plants around the world at a variety of scales [75]. Of these facilities, about 36% of them generate fuels such as hydrogen or liquid biofuels [76]. This indicates that no technological breakthrough is required to deploy biomass gasification in California, only a breakthrough in deploying the technology at scale and at a competitive price [2], [75].

As for the possible scale biomass gasification for clean hydrogen production in California, Lawrence Livermore National Laboratory's (LLNL) Getting to Neutral report [75] indicates there will be about 56 Mt of bone-dry biomass available for consumption from various waste streams each year (Figure 13). As shown in Figure 13, most of the biomass resources are available from forest management, municipal solid waste, and agriculture residue. At full deployment of waste biomass gasification systems, LLNL reports about 75 Mt CO_2 per year

of negative emissions are achievable with the addition of carbon capture to the gasification systems [75]. Studies indicate that the potential hydrogen production from gasification of switchgrasses, bagasse, and other crop residues is in the range of 78-88 kg H_2 metric ton of bone dry biomass [75], [77]. Using 80 kg H_2 per metric tonne of dry biomass and considering agricultural residue availability presented by LLNL (13 Mt dry biomass), agricultural residue alone would have the potential to produce about 1 Mt H_2 per year in California, which is about half of the current SMR capacity in the state today. Further scientific investigation is still required to determine the hydrogen production potential for biomass resources available in California [2].

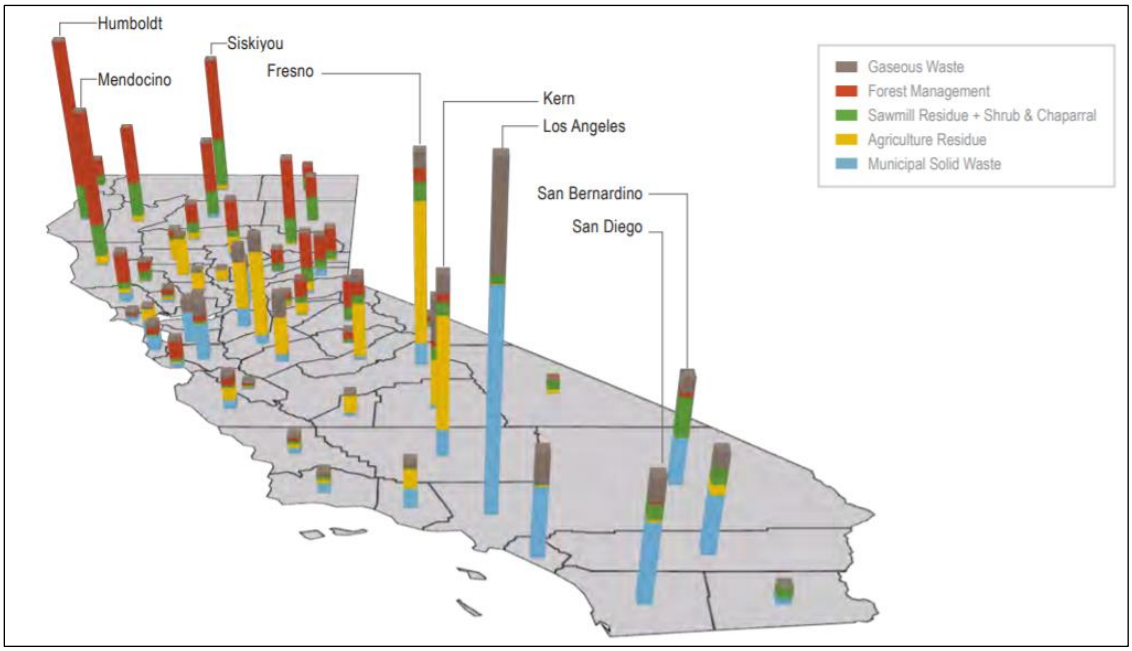

Figure 13: California Biomass Resource Availability Map (Replicated from: LLNL 2020) [75].

In addition to gasification, biomass can also be converted into hydrogen through fast pyrolysis with bio-oil reforming. Fast pyrolysis is a conversion process that breaks down biomass at a lower temperature (500°C) and pressure than gasification that results in a high oil content product stream. The bio-oil is then catalytically reformed into a mixture of gases and sent through a WGS reactor to increase hydrogen yield (see Eq. 2). There exists challenges with coke formation on the catalyst during bio-oil refining that would need to be addressed before this technology can be considered for deployment at large-scale in California [2], [75].

Methane Pyrolysis

To produce hydrogen from methane pyrolysis, methane is split into solid carbon (currently carbon black) and hydrogen through catalytic thermal decomposition (Eq. 10). The input heat required to facilitate this reaction can come from electricity, more specifically, renewable electricity to eliminate carbon emission from the fuel. In addition, unlike SMR and

ATR, there are no process carbon dioxide emissions from methane pyrolysis making the overall production pathway carbon neutral.

$$CH_4 \text{ (+ 75 kJ/mol)} \rightarrow 2H_2 + C \qquad \text{(Eq. 10)}$$

Another benefit of methane pyrolysis over both SMR and electrolysis is a lower energy input requirement to generate hydrogen. Methane pyrolysis only requires 37.5 kJ/mol H_2 energy input while SMR requires 165 kJ/mol CH_4, or 41 kJ/mol H_2, and electrolysis requires 235 kJ/mol H_2 produced. Additionally, this production method requires no water input and therefore would allow the state to use limited water resources for other applications.

Instead of producing carbon dioxide, methane pyrolysis generates carbon black which has a variety of industrial applications such as in the production of car tires, plastics, and batteries [78]. One of the primary challenges of this hydrogen production method is that carbon black deposits onto the solid catalyst surface and deactivates it over time. The catalyst is typically regenerated by oxidizing the carbon, which in turns results in carbon dioxide emissions. One technology that may solve this problem is using liquid metal or salts that act as both the heat source and catalyst for reaction [79].

Methane pyrolysis is not a new concept as there are a few commercial-scale plants in North America [80]. Countries including Australia, Russia, and the European Union are also working to scale the technology. In the United States, the start-up company Monolith Materials operates a methane pyrolysis facility in Nebraska that generates about 14,000 metric tons of carbon black each year using a plasma decomposition technology to avoid fouling of catalyst [78]. This technology is starting to gain momentum [81] and has a chance to play a significant role as California strives for net-zero emissions.

Clean Hydrogen Production Summary

Table 6 contains each of the clean hydrogen production methods discussed and the associated characteristics of each of these production methods. As shown, SMR-CCS, ATR-CCS, and biomass gasification each have carbon dioxide as a byproduct, but the addition of carbon capture and storage can make these close to zero-emission technologies. In the case of biomass gasification, adding carbon capture and storage makes it a negative emission technology because of the biogenic nature of the feedstock. The build-out of SMR-CCS, ATR-CCS, or methane pyrolysis hydrogen production facilities would mean the continued consumption of fossil fuels in California with methane pyrolysis requiring the largest methane inputs per mass of hydrogen produced. Finally, each of the hydrogen production methods requires water input except for methane pyrolysis. As mentioned this may not be a significant concern for the state as water consumption for clean hydrogen production is similar to that of fossil fuel production [25]–[27].

	SMR-CCS	ATR-CCS	Electrolysis with Renewable Electricity	Biomass Auto-Thermal Gasification	Methane Pyrolysis
Primary Reaction	$CH_4 + H_2O \rightarrow 3H_2 + CO$	$4CH_4 + 2H_2O + O_2 \rightarrow 3H_2 + CO$	$H_2O \rightarrow H_2 + ½O_2$	$C_6H_{12}O_6 + O_2 + H_2O \rightarrow H_2 + CO_2 + CO$ + other (not balanced)	$CH_4 \rightarrow 2H_2 + C$
Additional Reactions	CH_4 combustion for process heat, water-gas shift reaction	Water-gas shift reaction	None	Water-gas shift reaction	Process heat production (electricity, plasma, etc.)
Byproducts	CO_2	CO_2	O_2	CO_2	C
Methane Input	~2 kg per kg H_2 process ~1.3 kg per kg H_2 combustion ~0.4 kg/kg H_2 for CO_2 capture) [24]	~2.3 kg per kg H_2 process ~0.2 kg per kg H_2 for CO_2 capture [24]	None	None	~4 kg per kg H_2
Electricity Input	~1-2 kWh/kg H_2 [20], [24]	Did not explore. Likely similar input as SMR with added input for air separation until	50-55 kWh/kg H_2 [49], [50]	Did not explore, likely similar input as SMR	6-10 kWh/kg or 6-7x less than electrolysis input [79], [80]
Greenhouse Gas Impact	Some (~9 kg CO_2 per kg H_2 w/o capture but capable of 90% capture)	Some (~6.3 kg CO_2 per kg H_2 w/o capture but capable of over 95% capture)	None	None (negative impact with CCS)	None
Process Water Use [4]	> 4.5 kg H_2O/kg H_2	> 3.85 kg H_2O/kg H_2	> 9 kg H_2O/kg	Variable	None

Table 6: Clean Hydrogen Production Method Summary

[4] Values based on reaction stoichiometry. Does not include any water consumption requirements for CO_2 capture systems.

Transmission, Distribution, and Storage Pathways

After production, hydrogen that is not directly sent to an end-use system must be stored and possibly transported before use. Transport and storage costs for hydrogen tend to be more expensive than other fuel alternatives because of the energy input and materials required to carry hydrogen in a more energy dense state. As mentioned previously, hydrogen has traditionally been stored and transported using gas cylinders capable of carrying hydrogen up to 200 bar. This section will cover other commercial or research and development phase transportation and storage technologies. These technologies may become increasingly advantageous to utilize as California hydrogen demand increases into the future.

Gaseous and Liquid Hydrogen Trucking

In addition to 200 bar gaseous tube trailer transport and storage, hydrogen is also transported and stored at pressures between 450 and 700 bar via composite cylinders. These tube trailers are capable of carrying up to 700 kg H_2 per truck depending on the type of composite material and the cylinder pressure [10], [82]. Figure 14 shows typical 450 bar and 700 bar tube trailer trucks. Typical energy requirements to compress hydrogen from 20 bar to pressures between 350 and 700 bar are between 2-4 kWh/kg H_2 [2], [83].

Hydrogen is increasingly being transported and stored in a liquified state as well. Hydrogen is liquified using liquid nitrogen pre-cooling and a Joule-Thomson expansion liquefaction process [84]. In contrast to gaseous transport, hydrogen that is transported in a liquid state via tanker trucks is close to atmospheric pressure, and below -253°C. Typical energy input for liquifying hydrogen after production ranges from about 10 kWh/kg to 13 kg/kWh H_2 [83]. These trucks have the capability of carrying up to 3,500 kg H_2 per trip [10] and are typically used for larger volume, longer distance transport of hydrogen in comparison to tube trailers [1]. A typical liquid hydrogen tanker truck is shown in Figure 15 [2].

Figure 14: Compressed Hydrogen Transport Vessels: 450 bar composite cylinder hydrogen tube trailer (left), 700 bar composite cylinder hydrogen tube trailer (right) (Replicated from: Edwards 2021) [10].

Figure 15: Liquid Hydrogen Tanker Truck capable of carrying 3,500 kg H_2 per trip (Replicated from: Edwards 2021) [10].

Pipeline Transport

Hydrogen pipeline transport becomes an attractive option as demand increases in California and long-haul, large-volume hydrogen transmission is needed [1]. There currently exists about 1,600 miles of compressed hydrogen pipeline in the United States [85] with about 1,300 miles of pipeline in the Gulf Coast region and no dedicated hydrogen pipeline in California [10]. Capital costs for new build hydrogen transmission pipelines are expensive and can cost about $2.2-4.5 million per km [68]. These hydrogen pipelines are typically manufactured from fiber reinforced polymer [85]. An onshore retrofit, to address hydrogen embrittlement, of existing natural gas pipelines would be a cheaper option but would likely still cost between $0.6 and $1.2 million per km [2], [68].

A thorough examination of pipeline agreements as well as existing natural gas pipeline material and age in California would be crucial to determine if they are viable for reuse as hydrogen pipelines. A study of this kind has been performed for European oil and natural gas pipelines. Results showed that about 70% of onshore oil and natural gas pipelines in Europe could directly be reused as hydrogen pipeline with the remaining 30% also promising for reuse [86]. These results were based on criteria which included pipeline material (steel grades up to API 5L X52 are reusable), internal pipeline conditions, pipeline age, and pipeline transport capacity. If studies reveal much of the natural gas pipeline in California is viable for reuse as hydrogen pipeline, significant transportation infrastructure savings will be made as the statewide hydrogen economy grows.

A cheaper, yet challenging, interim option to transport hydrogen by pipeline is to blend it into existing natural gas pipeline infrastructure. The hydrogen could then be separated from the natural gas at the point-of-use at an additional cost, or the mixed fuel could be used directly [87]. With today's knowledge of natural gas pipelines in California and the U.S., the accepted upper limit of hydrogen blended into natural gas pipelines is about 20-30% due to pipeline embrittlement issues as hydrogen is introduced into the system [68], [88], [89]. However, hydrogen blend percentages of 5-15% by volume are more viable without increasing risk [89]. In addition to embrittlement challenges, since hydrogen has a lower volumetric energy density than natural gas, a higher pipeline flow rate is required to deliver

the same amount of energy to demand locations. For example, with a 20% volumetric hydrogen blend, the flow rate of a distribution pipeline would need to increase by 15% to deliver the same amount of energy for an end-use application [88]. Another challenge is that natural gas compressors, gas turbines, and natural gas storage tanks can handle even less volume percent hydrogen than natural gas pipelines, so each of these would also need modification [89]. Finally, this hydrogen transport solution can only be an interim solution. It requires a continued reliance on natural gas which would make it difficult to reach net-zero emissions by 2045 if it is still being used by then [2].

Box 2

Hydrogen Safety and Handling

Hydrogen is odorless, tasteless, and colorless which makes it undetectable by humans. There are also no known odorants that have as high of a dispersion rate as hydrogen, so hydrogen technologies, such as FCEVs, hydrogen pipelines, and hydrogen carrying trucks, require special leak detection and ventilation equipment. Hydrogen also burns very quickly and requires lower energy input to initiate combustion than fossil fuels such as natural gas and gasoline. However, in comparison to fossil fuel combustion, hydrogen combustion produces a flame with lower radiant heat which decreases the risk of secondary fires. It is also highly buoyant and so will not pool or collect like some heavier hydrocarbon vapors. With proper understanding of the hydrogen behaviors described, hydrogen can be safely used much like any other fuel [90].

Hydrogen is also considered an indirect greenhouse gas because it reacts with tropospheric hydroxyl radicals in the atmosphere that would otherwise react with methane or ozone greenhouse gases. With increasing hydrogen concentrations in the atmosphere, less hydroxyl radicals will be available to react with methane and ozone resulting in a higher global warming potential for those gases. As a result, hydrogen is considered to have a 100-year global warming potential of around 5.8 [91].

Therefore, when scaling hydrogen transport and storage infrastructure, operators need to be especially careful not to lose any product due to leakage. Truck operators, especially liquid hydrogen handlers, need to be careful not to lose a significant amount of product when transferring hydrogen from the truck to a stationary storage tank. Some amount of hydrogen boil-off occurs naturally through heat transfer from the outside of the tank but this can be largely avoided by using liquid hydrogen storage tanks that have a low surface area to volume ratio and by keeping each of the tanks as cool as possible [10], [84].

It has been estimated that if a hydrogen economy completely replaced the global fossil fuel industry, a hydrogen leakage rate of 1% would have 0.6% of the impact as the current global fossil industry [91].

Hydrogen Carriers

Hydrogen carriers are another potential hydrogen storage and transport method still in the development phase. Hydrogen carriers are hydrogen-rich molecules that are found in a liquid or solid state at or near ambient conditions. These are advantageous for hydrogen transport and storage because they contain a high weight percent of hydrogen and require minimal to no energy input for compression or liquification. Common hydrogen carriers considered include ammonia, methanol, and liquid organic hydrogen carriers (LOHCs). While beneficial for transporting hydrogen, hydrogen carriers require energy input both for production and for dehydrogenation at the end-use location. Methanol and ammonia hydrogen carriers have the potential to be used in fuel cells directly, which eliminates the

dehydrogenation step, but this comes at a reduced energy output in comparison to operating the fuel cell on pure hydrogen [92], [93]. Methanol also has the disadvantage of generating process carbon dioxide emissions whether it is used in a fuel cell or dehydrogenated [93]. Another shortcoming of methanol and ammonia as hydrogen carriers is that they are both significant health hazards to humans and significant build-out of methanol or ammonia infrastructure would come with major public health and safety risks. Further research and developments are needed in this area before any hydrogen carrier is utilized in California.

Underground Hydrogen Storage

Underground hydrogen storage is a promising high-volume, long duration energy storage solution that can play a key role as California strives to reach net-zero by 2045. It comes at a reduced relative cost in comparison to above ground hydrogen storage [10] and can help to balance the intermittency and seasonal variation in power generation from a renewable energy dominated grid in California [94].

Currently, underground hydrogen storage in salt caverns is the only proven long-duration hydrogen storage method [10], [94]. Unfortunately, salt cavern storage locations in California are non-existent (Figure 16). In addition, even if there were prime salt cavern locations in California, the process of leaching the salt cavern to make room for hydrogen storage is a water intensive process and leaves behind a brine that must be disposed of properly [95]. Instead of utilizing the limited salt cavern storage in California, what seems more likely is that salt cavern storage in other western states is developed and hydrogen is trucked or pipelined from these storage caverns into California.

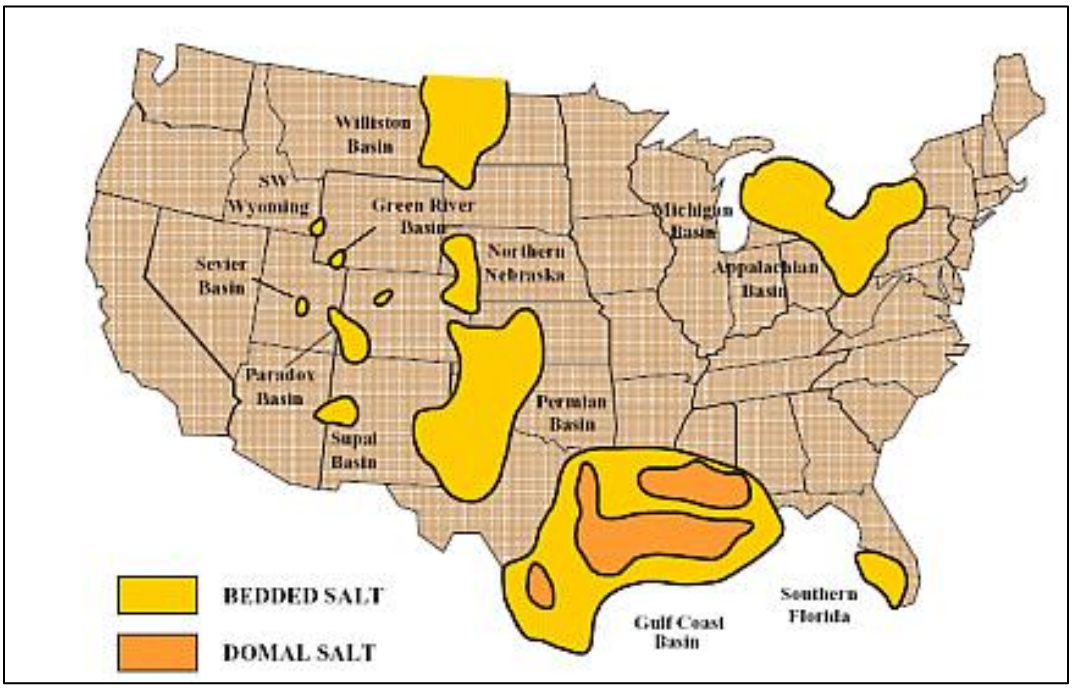

Figure 16: U.S. Salt Cavern Storage (Replicated from: NETL 2005) [96].

Depleted oil and gas reservoirs may also be suitable for long-term hydrogen storage. There are several depleted oil and gas reservoirs to choose from in California (Figure 17) and the geology is well identified and characterized. In addition, existing well infrastructure could be leveraged for hydrogen injection and withdrawal from the reservoir. However, it is still unclear whether there is a way to store and withdraw pure hydrogen from these reservoirs. Residual oils in these reservoirs also can react with hydrogen to form methane and would result in loss of product. Further studies and experimentation are required before hydrogen storage in depleted oil and gas reservoirs can be scaled in California [95].

Saline storage reservoirs are another potential underground storage location for hydrogen under examination. There exists vast saline storage space underneath the Central Valley of California in which hydrogen could be injected and stored (Figure 17). Gas storage in saline aquifers is also not a new concept and so there is a guide on how to do it safely and effectively. However, saline reservoirs are not as well characterized in California as depleted oil and gas reservoirs, and it is still yet to be determined if hydrogen can be withdrawn from saline reservoirs without contamination [95].

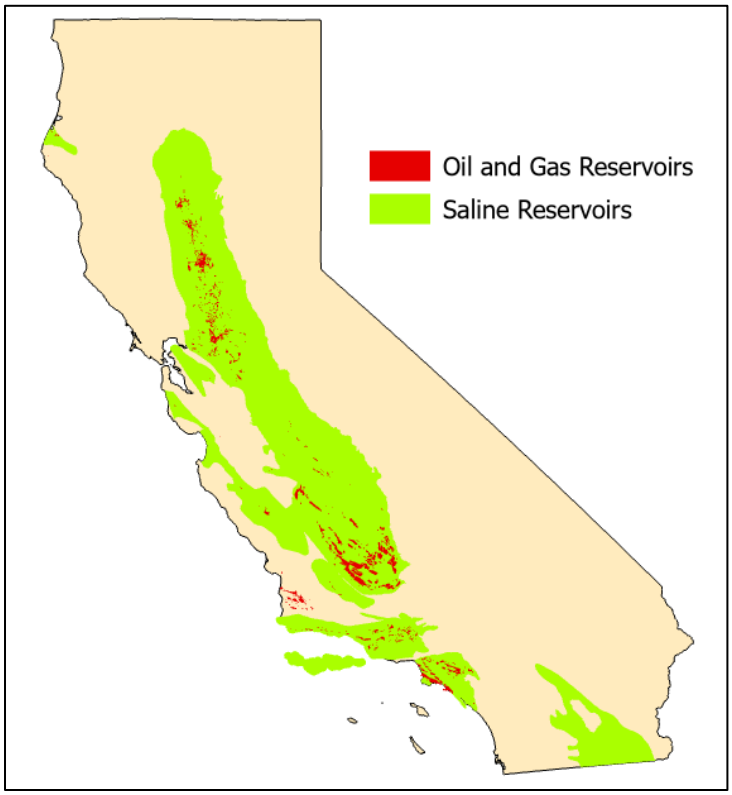

Figure 17: California Oil and Gas Reservoirs and Saline Reservoirs (Data Source: NETL 2015) [97].

Hydrogen Fuel Switching Opportunities

While build-out of hydrogen production and distribution infrastructure is necessary to enable a hydrogen economy in California, finding hydrogen off-takers and build-out of hydrogen end-use equipment is just as important. The primary end-uses of clean hydrogen include heating, power generation, hydrocracking, and chemical production and processing. This section will

explore each energy sector and the role hydrogen can play in decarbonizing the sector. Figure 18 displays what the hydrogen landscape could look like in 2045 if California seizes the opportunity to develop a hydrogen economy.

Electricity Sector

The primary role hydrogen can play in the electricity sector is to act as an easily dispatchable long-term energy storage solution. This will become increasingly important as the grid is decarbonized using variable and intermittent renewable energy. If effective subsurface hydrogen storage in saline reservoirs or depleted oil and gas fields is achieved in California, it would unlock low-cost long-term energy storage that could replace fossil-based power generation facilities the state relies on today.

This energy storage system could work by producing hydrogen from electrolysis using renewable electricity during the summer months when solar electricity generation is high. The hydrogen could then be stored at a low-cost underground until the winter months when renewable power generation is low. Hydrogen from SMR-CCS production, which is not constrained by weather, could also be stored in and withdrawn from subsurface formations as needed. This is comparable to the way natural gas is currently utilized in California's electric grid to meet seasonal electricity demands, and hydrogen would be a cleaner alternative. Once withdrawn, the hydrogen can be utilized in a fuel cell or hydrogen turbine to generate the electricity needed to meet demand. The overall efficiency of such a storage system would be lower than (for example) battery round-trip efficiency, but the large storage volumes and ability for seasonal shifts in energy could make this a viable technology in a decarbonized grid.

The potential hydrogen demand for the electricity sector by 2045 is going to be determined by the change in cost of hydrogen storage as well as future grid size and composition. If low-cost long-duration hydrogen storage can be achieved, it is possible hydrogen will play a significant role in power generation. Without low-cost production and storage, it remains unclear as to the extent clean hydrogen will be used for electricity generation into the future.

Industrial Sector

As mentioned previously, most of the hydrogen produced in California today is being used by the industrial sector for crude oil refining. There is also a small portion of the hydrogen that is being used for industrial-scale chemical production and processing. Looking toward 2045, hydrogen can play a role in multiple industrial sub-sectors. While continuing to be used for chemical processing and production, hydrogen utilized for crude oil refining may start to diminish with the adoption of zero-emission vehicles. One strategy oil and gas companies are pursuing in the near-term to mitigate carbon emissions while continuing to use existing infrastructure is converting crude oil refineries to renewable feedstock refineries that generate renewable diesel [7]. In addition to keeping the facility online, this switch will also allow the refineries to take advantage of LCFS for making a low-carbon transportation fuel. These bio-refineries would take in waste oils, greases, and fats and convert it into a clean, renewable diesel that could power heavy-duty locomotives. Converted bio-refineries would still require the existing hydrogen production infrastructure for hydrocracking the renewable feedstocks. There are challenges with hydrogen production capacity reuse for bio-oil refining

that must be considered. These are addressed in Box 3. In addition, it is still unclear as to how many refineries in California will be able to switch to bio-refining because of renewable feedstock constraints. An alternative strategy refinery owners may take as crude oil inputs decline is to start selling excess hydrogen to the transportation markets. This would generate an additional value stream for the refineries as they start selling less refined product.

It is also important for refineries in California to add CCS to on-site SMR units. This will allow the refineries to gain more lucrative LCFS benefits and would help the state reach net-zero emissions targets by 2045. In total, about 1.83 Mt/yr of existing hydrogen production infrastructure is available to be used for hydrocracking of renewable feedstocks or as a transportation fuel. The fraction of the existing hydrogen production capacity devoted to each of these end-use applications will be determined based on how refinery owners handle reduced crude oil inputs into the future.

Box 3

Hydrogen Implications with a Switch to Renewable Feedstocks at Refineries

One shortcoming of converting crude oil refineries in California to renewable feedstocks is that renewable feedstocks require increased hydrogen input for processing in comparison to crude oils. On average, renewable feedstocks such as waste oils and greases require about 4 to 5 kg H_2 per barrel of renewable feedstock [98]. Existing California refineries have a total crude oil input capacity of 2 million barrels per day [4], with a supplied hydrogen capacity of about 5 million kg H_2 per day [5]. This corresponds to about 2.5 kg H_2 per barrel of crude oil input, or about half the hydrogen input requirement of renewable feedstock refining.

This hydrogen imbalance will make it challenging for every refinery in California to switch to renewable feedstocks without installing additional hydrogen production capacity. Refinery owners may choose to fill the hydrogen production capacity gap by building out electrolytic hydrogen production facilities or buying hydrogen from existing merchant facilities. They could also choose to operate the refinery below its crude oil input capacity given the hydrogen constraint. However, this will only make sense if the facility remains economical operating at a lower capacity factor.

A conversion of all crude oil refineries in California to bio-refineries would require a surplus of renewable oil feedstock and a continued growth in demand for renewable diesel. Neither of these are certainties. This may cause refinery owners to look elsewhere for a solution or be forced to shut down the facility.

For industrial sub-sectors in California, such as chemical and cement production, which require high-temperature process heat, hydrogen can also play a role. The primary advantage of using hydrogen combustion for high-temperature heating is that it is reliable and can provide flexible heating temperatures [99].

Residential and Commercial Sectors

Within the commercial and residential sector in California, space heating, water heating, and cooking contribute significant GHG emissions [100], most of which could in principle be mitigated by using clean hydrogen. However, electrification solutions such as electric appliances and heat pumps are already commercially available in California and are expected to be the primary solutions utilized in California to decarbonize both the residential

and commercial sectors due to their established nature and lower costs [101], [102]. However, this does not rule out hydrogen for the residential and commercial sector entirely. In large urban buildings, it could make more sense to retrofit or replace existing boilers to burn hydrogen rather than installing heat pumps for each separate unit [103]. This could become especially attractive if some natural gas pipelines in California are deemed to be reusable as hydrogen pipelines without significant upgrading, as was found in Europe [86]. Finally, niche commercial buildings such as restaurants may desire to continue using gas appliances, instead of electric ones because of clientele preference, and could look to the viability of using hydrogen appliances as an alternative. Realistically, hydrogen will likely play a minimal role in residential and commercial sector decarbonization. Hydrogen end-use technologies applicable for these sectors remain well behind electrification solutions in terms of maturity, development, and implementation.

Transportation Sector

The primary decarbonization options available for the transportation sector are battery electric vehicles (BEVs) or hydrogen fuel cell electric vehicles (FCEVs). In the light-duty vehicle space, both battery electric and fuel cell electric options have penetrated the market in California with battery electric holding a significant edge in total car sales [104]. Battery electric options have the advantage in that they can be charged at home or at work and thus eliminate the need to go to a refueling station. Shortcomings with battery electric passenger vehicles is that they can require multiple hours to fully recharge, unless high speed chargers are available, and the battery degrades with each charge and discharge cycle. FCEVs are more like internal combustion engine vehicles on the road today in that they require the passenger to go to a refueling station to fill up the tank for a few minutes. The issue FCEVs face today is that there is little refueling station infrastructure developed to support them. With continued build-out of refueling station infrastructure and development of stable hydrogen supply chains, concerns about where to obtain hydrogen for a FCEV can be eliminated. This would enable further market development of fuel cell electric passenger vehicles in California. If fuel cell electric vehicles become the zero-emission vehicle of choice through 2045, the possible hydrogen demand required to reach net-zero in the light-duty vehicle space is about 4.0 Mt/yr. If trends continue the way they are today and battery electric passenger vehicles continue to hold much of the market, potential hydrogen demand for light-duty vehicles could be around 1.5 Mt/yr by 2045. These estimates are derived from a companion study “Pathways to Carbon Neutrality in California: Decarbonizing the Transportation Sector” [104].

In the heavy-duty vehicle space, hydrogen FCEVs seem more favorable for long-haul transport with shorter refueling time and less vehicle weight devoted to the energy storage system in comparison to battery electric options. Battery electric heavy-duty vehicles will be more likely to suffice for other heavy-duty vehicle fleets, but the choice between the two vehicle options will be business decision fleet operators will have to weigh. Fleet operators may like that hydrogen fuel cell trucks have similar refueling times to their current truck fleet. It would be less of a business model and logistics change to make the switch to fuel cell electric in comparison to a battery electric. In addition, heavy-duty fuel cell trucks currently have a longer range than comparable battery electric alternatives. Any heavy-duty fleets that require high travel distance between refills would be more inclined to choose fuel

cell electric over battery options [105], [106]. A shortcoming of heavy-duty FCEVs that could impact uptake is how expensive they are in relation to both BEV and internal combustion engine alternatives. If fuel cell electric vehicles dominate the heavy-duty vehicle space in 2045, potential demand for these vehicles could reach almost 4.0 Mt/yr. A more conservative estimate of hydrogen demand for heavy-duty vehicles where the market is split between battery and fuel cell electric options is about 1.5 Mt/yr by 2045. These estimates are also derived from the companion study "Pathways to Carbon Neutrality in California: Decarbonizing the Transportation Sector" [104].

Box 4

Hydrogen Hub Model

Hydrogen can provide multiple end-use services as California strives to decarbonize. These services are often localized and can even be co-located with hydrogen production. This provides a significant opportunity to developed shared hydrogen infrastructure which can help to decarbonize multiple sectors and enable hydrogen economy of scale. Figure 18 depicts a hypothetical hydrogen hub in which electrolysis from renewables and SMR-CCS hydrogen production methods are co-located and provide hydrogen for nearby bus and truck fleet mobility, for dispatchable electricity generation, for methanol production, and for commercial and residential building heating [107].

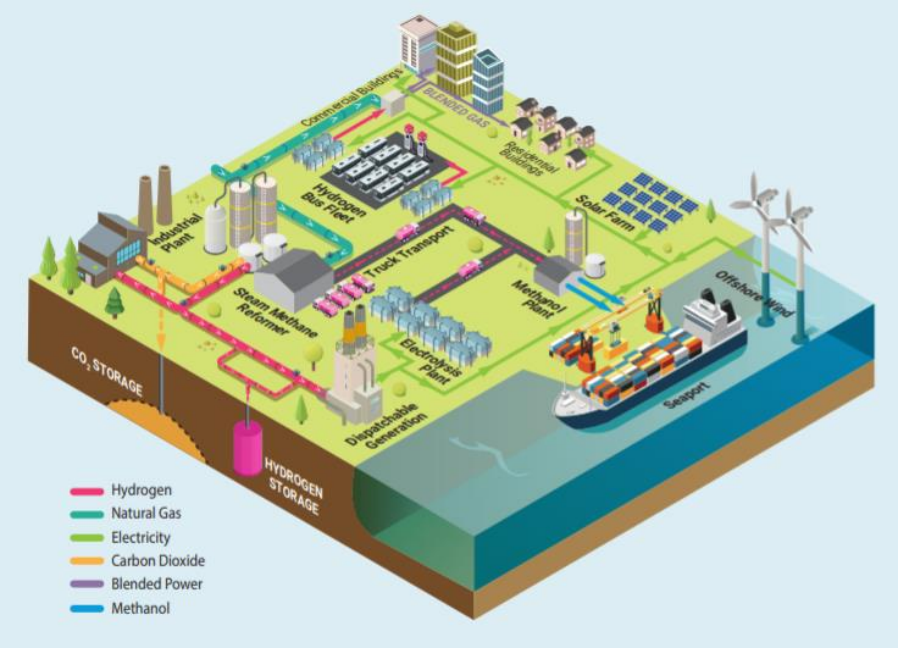

Figure 18: Example Hydrogen Hub Configuration (Replicated from: EFI 2021) [107]

In California, hydrogen hub opportunities exist in San Francisco and Los Angeles port areas where hydrogen can be both produced and used for applications such as industrial, residential, and commercial heating and as well as truck and bus fleet mobility. Another potential hydrogen hub location is in the San Joaquin Valley where there is ample geologic carbon dioxide storage and potential hydrogen geologic storage. Hydrogen production in the San Joaquin Valley could be utilized to make ammonia for fertilizer to be used in the Central Valley, industrial heating, or could be sent to nearby hydrogen refueling stations off the I-5 interstate connecting Los Angeles to the San Francisco Bay Area. One shortcoming of a hydrogen hub in the San Joaquin Valley is that hydrogen transport to larger demand centers in Los Angeles and San Francisco would come at a noticeable cost.

Hydrogen Market Growth Limitations and Enablers

There are several variables to consider when forecasting the growth in hydrogen production infrastructure and hydrogen demand in California by 2045. Each clean hydrogen production technology has its shortcomings and overcoming these flaws will be integral in scaling production. The primary shortcoming with SMR and ATR with CCS is that it is not a net-zero emission production technology. Some carbon dioxide emissions cannot be captured and there are also fugitive upstream methane emissions to consider. California is also yet to deploy CCS at scale and there remain questions as to whether it will gain public acceptance. Hydrogen produced from electrolysis using renewable electricity is promising but high electrolyzer capital and operating costs continue to make this hydrogen more costly than fossil-based hydrogen or fossil fuel alternatives. Finally, hydrogen could simply lose out to electrification options in each of the energy sectors thus limiting build-out of hydrogen infrastructure in-state.

If California does choose to build a hydrogen economy to reach net-zero, there are several ways the local, state, and federal government can get involved to scale infrastructure in a timely manner. With the cost of hydrogen infrastructure still not at cost parity with fossil fuel alternatives, the government can get involved by providing funding or subsidies to companies looking to produce hydrogen or manufacture hydrogen equipment. They can also provide incentives to those that purchase more expensive hydrogen-operated equipment, such as a hydrogen FCEV, when they could be buying fossil-operated alternatives. This will enable hydrogen technology build-out and maturation which can bring infrastructure costs closer to, or on par with, fossil alternatives without the need for continued incentives [68], [108]. To further increase the rate of adoption of hydrogen infrastructure, the government can also get involved with streamlining the permitting process for new infrastructure. Quicker and simpler permitting of refueling stations, carbon dioxide storage wells, hydrogen storage tanks, and other equipment can help to scale-up the technology in time to meet 2045 decarbonization targets. Overall, government support in the short term can catalyze long-term sustainability of a hydrogen economy in California [105].

Universities and trade schools also have a role to play in growing the hydrogen market in California. Research universities can educate policymakers, engineers, and other researchers in the hydrogen space and can work to reduce the cost of clean hydrogen technologies further. Trade schools can also get involved by developing programs for students to learn how to operate, maintain, and repair hydrogen or other clean energy technology infrastructure. Having properly trained hydrogen technicians will become increasingly important with a growing hydrogen market [105].

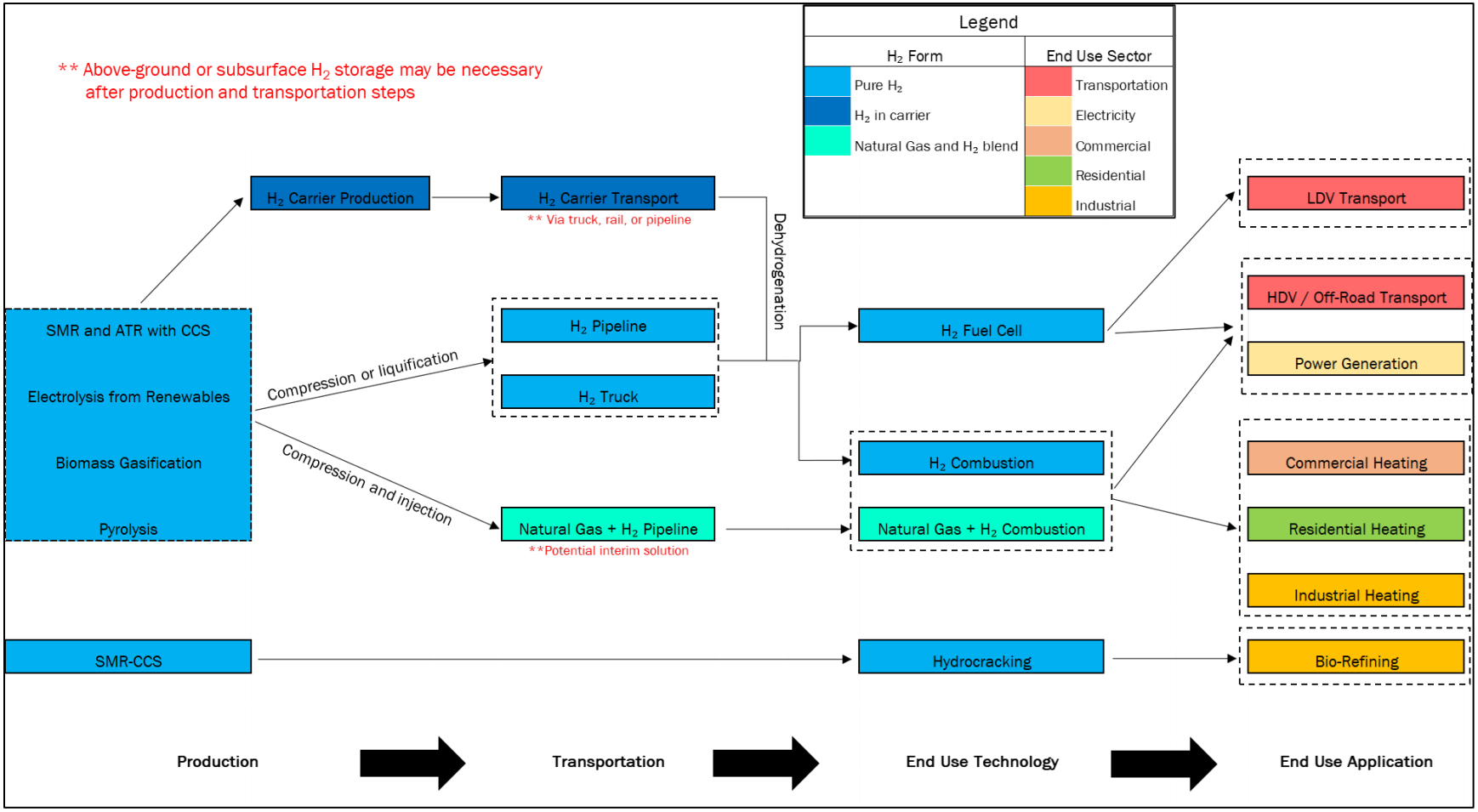

Figure 19: 2045 Potential Hydrogen Flow Diagram

Conclusions

While hydrogen has the potential to play a significant role as California strives to decarbonize, a decision must be made whether it is worth large-scale investment. The costs of hydrogen infrastructure on the production side are potentially reduced with the 45Q tax credit and California's LCFS program, but this is not enough. Without additional financial support or incentive, project developers and equipment manufacturers will continue to hesitate on a clean energy transition with hydrogen. With financial support, there will be lower risk in hydrogen investment. This investment could spur hydrogen infrastructure build-out and maturation that would bring about a hydrogen economy-of-scale no longer dependent on financial aid to prosper. Continued research and development of nascent hydrogen technologies can also aid in reducing investment costs as 2045 approaches. While not a perfect solution, building a hydrogen economy in California would yield significant emissions reductions and contribute to putting the state on a path to reach net-zero by 2045.

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