California's Hydrogen Hub: Meeting 2030 Demand

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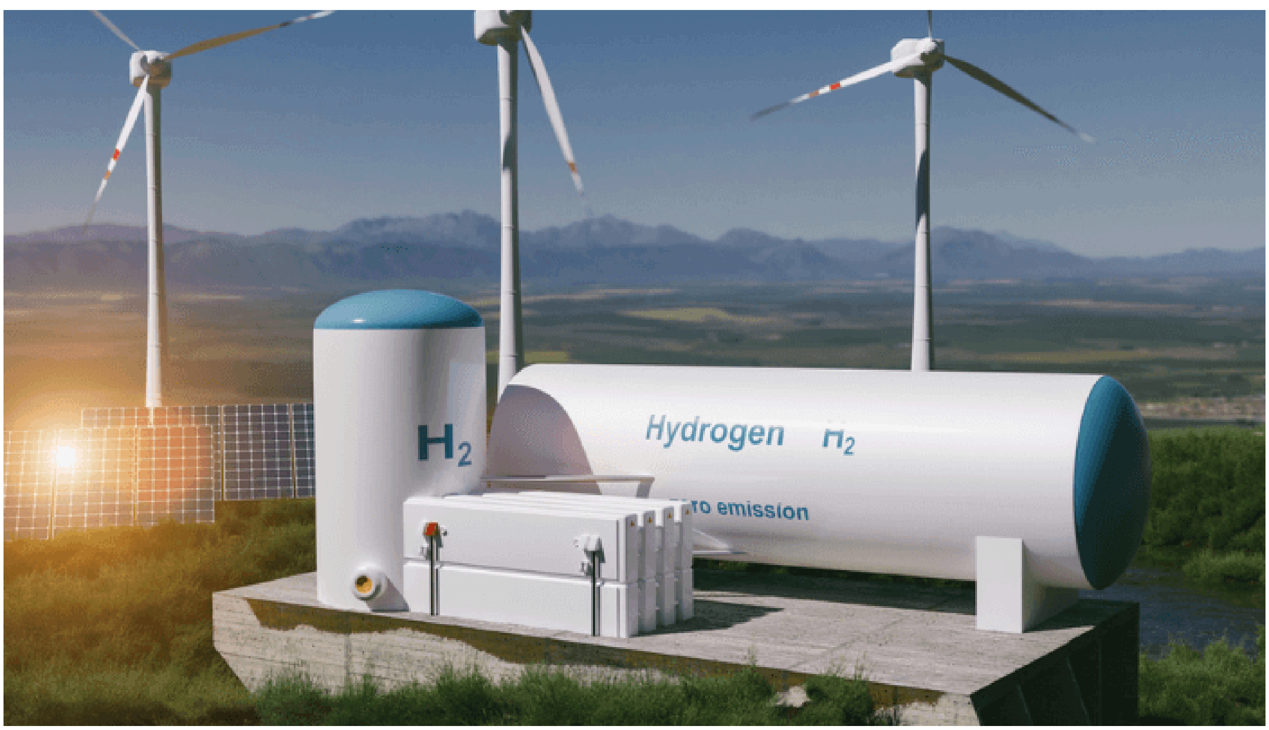

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California's Hydrogen Hub: Meeting 2030 Demand

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Research Objectives

1. Estimate optimal siting locations, production quantities, and supply prices of electrolytic hydrogen in 2030.
2. Evaluate statewide cost differences between centralized and distributed hydrogen production networks.
3. Assess barriers that limit the competitiveness and speed of adoption of hydrogen as an alternative fuel.

Part 1: Background, Policies and Literature Review

1.1 California's Hydrogen Goals and Efforts

Under the Biden administration, the United States has put a renewed focus on combating climate change, as shown through the passage of the Inflation Reduction Act and the Infrastructure and Jobs Act. California has been a leader in these efforts with a goal to reach carbon neutrality by 2045 (California Governor's Office, 2023). The most commonly touted route to decarbonization is electrification using renewable energy. However, it may not be feasible to rely only on electrification for achieving net zero as the California grid has insufficient renewable power supply to make this a reality (California Governor's Office, 2023). It also is currently financially or practically infeasible for approximately 15% of the economy to electrify (Reed et al, 2020). These economic sectors such as heavy industry and freight rely on energy-dense fuels such as natural gas or diesel, and electrification alone currently is not an adequate substitute. Green hydrogen, an energy carrier made with water and electricity, can provide that alternative decarbonization pathway (Reed et al, 2020).

Since decarbonization solely through electrification is not entirely possible, a combination of electrification and hydrogen adoption is necessary to achieve California's goal of carbon neutrality by 2045 (California Governor's Office, 2023). The state's climate plan has targets for hydrogen fueling infrastructure and zero-emission vehicle adoption, however, as policymakers desire to be technology-neutral there is no specific target for how large of a role hydrogen will play in decarbonization (Lazo, 2023). According to the California Air Resources Board's (CARB) 2022 Scoping Plan, "the scale of transition includes adding about 1,700 times the amount of current hydrogen supply" (*2022 Scoping Plan*, 2022). The levelized cost of hydrogen (LCOH), or the amount it costs to produce one kilogram of hydrogen including all supply components, also must be lowered to $4 per kilogram for hydrogen to compete with gasoline, diesel, and other fuels (Reed et al, 2020). To scale this alternative fuel and lower the price, California needs to create systems to manufacture and move renewable hydrogen to power industrial, commercial, residential, and especially transportation consumers across the state. This paper aims to pinpoint the locations, production methods, and distribution systems where hydrogen can be produced at the cheapest possible cost, at levels that satisfy projected demand. It also aims to identify barriers to market penetration and to suggest solutions to those barriers.

1.1.1 Demand Side Considerations

On-road transportation is anticipated to be the largest source of demand for green hydrogen in California. This is because state agencies such as CARB developed monetary incentives and regulatory measures to decarbonize the transportation industry. In regards to monetary incentives, CARB is working to reduce the high upfront costs of adopting fuel cell electric trucks (FCETs) through its Hybrid and Zero-Emission Truck and Bus Incentive Project (*Incentive for Clean Trucks and Buses*, n.d.) and the California Energy Commission (CEC) is offering incentives for hydrogen fueling infrastructure through its Energy Infrastructure Incentives for Zero-Emission Commercial Vehicles (EnergIIZE) Program (*Incentives for Commercial Zero-Emission*, n.d.). In regards to regulatory measures, CARB has introduced three new regulations to lower emissions from traditional internal combustion engine (ICE) vehicles. Firstly, transit agencies are mandated to have 100% zero-emission bus purchases by January 1, 2029, through CARB's Innovative Clean Transit Regulations (*Innovation Clean Transit Regulation*, 2019). By 2021, California had already deployed 127 fuel cell buses (Hamilton, et al, 2021). This number is expected to go up as transit agencies continue to decarbonize their fleets to meet regulatory mandates. Secondly, The Advanced Clean Trucks (ACT) rule will increase demand for zero-emission trucks (ZETs) by mandating that original equipment manufacturers (OEMs) sell between 40-75% ZETs by 2035 (*Advanced Clean Trucks*, 2021). Finally, CARB developed the Advanced Clean Fleets (ACF) rule, which requires fleets to purchase and deploy zero-emission vehicles to incrementally achieve 100% ZEVs (*Advanced Clean Fleets*, 2023). The fleets included in the ACF rule include trucks used for drainage operations, high-priority and federal fleets, as well as state and local fleets (*Advanced Clean Fleets,* 2023).

While none of these regulations mandate a percentage of the ZEVs adopted to be fuel-cell electric vehicles, it is understood that these regulatory goals cannot be met solely with battery electric vehicles. This is because hydrogen provides vehicles, especially those associated with freight, benefits that electric batteries cannot (Albatayneh et al, 2023). For instance, hydrogen fuel cell vehicles can quickly be refueled at hydrogen fueling stations, as opposed to battery electric vehicles which must be charged. Whereas a long charging time may be fine for the average driver, with both more time and a small battery, it can be burdensome for those in the heavy transport industry, who have tight deadlines and large vehicles which require larger batteries (Albatayneh et al, 2023). Hydrogen fuel cells also weigh significantly less than batteries, which is significant as trucks require more energy and thus large, and oftentimes expensive batteries. A lighter fueling system allows the trucks to take on more weight in freight, increasing efficiency (Albatayneh et al, 2023).

As hydrogen will be increasingly demanded by the California transportation sector due to incentives, regulations, and overall practicality, more hydrogen will need to be produced to meet this demand. In 2022, about 61,500 kg of hydrogen was available to the transportation sector in California. However, projections show that by 2027, the demand for hydrogen by FCETs will outpace hydrogen production capacity (Lee et al., 2023). Without additional hydrogen production sites and infrastructure, there will be a major shortage of hydrogen in the transportation sector. However, even if additional supply is generated, high costs could prevent market penetration. Currently hydrogen can be produced at a price between $2.50 to $6.80 (Vickers, 2020). However, levelized costs of hydrogen must drop to $4 per kg, making hydrogen costs at fuel stations approximately $6 to $8.50 per kg in order for hydrogen to outcompete diesel on the fuel market (Reed et al., 2020). In conclusion, the demand for hydrogen as a clean fuel is increasing in California and the state must build more production infrastructure to meet this demand.

1.2 Components of Hydrogen Production

The following is an overview of the supply-side components of hydrogen production. Together the availability of renewable electricity supply or biomass, water, and electrolyzers are vital to hydrogen production (Reed et al, 2020). They also make up the majority of the LCOH, meaning that it is vital to obtain these resources at a low cost to make hydrogen affordable (Reed et al., 2020).

1.2.1 Electricity

One of the greenest hydrogen production methods is hydrogen production via electrolysis. In electrolysis, electricity is used to separate hydrogen from water through a piece of equipment known as an electrolyzer. The most common type of electrolyzer is a polymer electrolyte membrane (PEM) fuel cell. In a PEM fuel cell, water reacts at a positively charged anode and separates into positively charged hydrogen and negatively charged oxygen. The electrons from the oxygen then move through an external circuit while the hydrogen permeates through the polymer to the negatively charged cathode. At the cathode, the hydrogen ions combine with the electrons and create hydrogen gas or H2 (US Department of Energy, n.d.). This hydrogen can then be used as an energy carrier and storage mechanism. Trucks or factories can combust hydrogen as a fuel, releasing energy, similarly to combusting natural gas or coal. However, instead of releasing CO_2 or particulate matter, water vapor is the only byproduct. Electricity is therefore one of the major resources required for hydrogen production. Roughly 50-55 kWh of electricity is needed to produce 1 kg of hydrogen (Vickers et al., 2020). Therefore, a region's wind and solar capacity and grid electricity costs are major factors to consider when determining if areas are suitable for hydrogen production (Vickers et al., 2020).

Electrolyzers can use electricity directly from the grid, or from dedicated renewables. Grid electricity tends to be more expensive, costing between 5 to 7 cents per kWh. Whereas standalone, non-grid-connected, renewable electricitycosts between 2.8 to 3.8 cents per kWh (Vickers et al., 2020). However, grid electricity has a higher capacity factor than wind or solar electricity. This allows hydrogen produced using grid energy to cost between $4.37 to $6.27 per kg, compared to hydrogen produced directly from renewable electricity, which is $5.54 to $6.09 per kg (Vickers et al., 2020). An exception to this is hydrogen produced using electricity from Class 1 winds, which have an average wind speed of 10 meters per second, and are substantially cheaper than other forms at $4.22 per kg (Vickers et al., 2020). Thus, the areas where hydrogen has the highest ability to penetrate the market are areas with Class 1 wind electricity production potential. Areas of wind or solar renewable energy potential with the lowest levelized cost of hydrogen (LCOH), the net present value of the total cost of construction and operation of a plant divided by the total production over the plant's lifetime, will be prioritized for siting hydrogen production hubs (Lazard, 2021). Hydrogen should be produced in areas with high solar and wind potential or low grid electricity costs to achieve the lowest production cost. However later sections will discuss other considerations that may outweigh electricity costs.

1.2.2 Biomass

A second method of producing hydrogen is through biomass gasification. In biomass gasification, biomass, or organic material, is converted into hydrogen through gasification, a process in which material is heated at high temperatures (greater than 700° C) along with steam and oxygen. This material isn't combusted, but instead the energy is transformed into gas, specifically hydrogen as well as carbon monoxide and carbon dioxide. The carbon monoxide can then be used to form more hydrogen by reacting it with carbon dioxide and water in a process known as a water gas shift reaction (US Department of Energy, n.d.). As carbon dioxide is released during biomass gasification, plants are paired with carbon capture and storage systems, to ensure that production results in net zero emissions.

In California, biomass gasification using woody biomass is projected to be a major hydrogen production method. It is projected that the state has 24 million tons of woody biomass available for hydrogen production every year (Gilani et al, 2020). Twenty-four million tons of biomass would produce 1.7 million tons of hydrogen. This is enough hydrogen to meet 85% of the current state hydrogen demand and 40% of the projected 2050 demand (Gilani et al, 2020). The LCOH from biomass production is estimated to be less than hydrogen produced from other sources, ranging from $1.48 to $3.15 per kg (Gilani et al, 2020).

Another way of producing hydrogen from biomass is through anaerobic digestion. In anaerobic digestion, waste products are broken down by bacteria in order to produce methane or carbon dioxide (Zappi et al, 2021). This process can be altered to produce hydrogen instead of methane. This can be done by stopping methanogenic bacteria from consuming hydrogen molecules, ensuring that hydrogen gas can be obtained from the biomass, instead of methane (Zappi et al, 2021).

1.2.3 Water

Water availability and costs are additional supply-side considerations for hydrogen hub siting. In general, 3.78 gallons of water is required to produce 1 kg of hydrogen through electrolysis (Beswick et al., 2021). This water needs to be potable, purified, and deionized to protect fuel cell equipment from damage (Farràs et al., 2021). Therefore, hydrogen production sites need to be located near both a water source and a treatment plant. Producers can also invest in water treatment infrastructure rather than relying on an existing treatment plant if there is no infrastructure in the area. Although some have expressed concern that the water demand of hydrogen production will substantially raise the price of hydrogen, water purification was found to have little impact on price, making up only 2% of total production costs (Blanco, 2021). Moreover, hydrogen production through electrolysis requires 33% less water than fossil fuel combustion (Beswick et a.l, 2021). However, 80% of California's water is used to fulfill some demand, making the state water stressed (WRI, 2021). Roughly 40% of the state's water is used on farms (PPIC, 2023). This means that hydrogen production will likely need to replace another source of water demand, instead of adding to this stress. Some areas in California are particularly vulnerable to stress. For example, parts of Calaveras, Fresno, Kern, Kings, Madera, Mariposa, Merced, Monterey, Sacramento, San Benito, San Diego, San Joaquin, San Luis Obispo, Santa Barbara, Santa Clara, Santa Cruz, Stanislaus, Tulare, and Ventura counties are situated in critically overdrafted basins, and have some sort of agricultural activity (California Department of Water Resources, 2023). This means that the groundwater in these areas is already being used at high rates for other purposes and that the aquifers there have not had the chance to recharge. This indicates that hydrogen should be produced using surface water, instead of over demanded groundwater. However, there is a large geographic imbalance in regards to California's surface water distribution. About 75% of surface water is located in the northern third of the state, while 80% of surface water demand is in the southern two thirds of the state (Water Education Foundation, 2023). This means that much of California's surface water is transported in order to meet demand. Therefore in Southern California, hydrogen production will likely need to replace another source of water demand, instead of increasing demand, as the availability of surface water is limited.

1.2.4 Capital Costs

Another major component of the LCOH is the capital cost of the electrolyzers themselves. Typically, electrolyzers that produce larger quantities of hydrogen cost more initially. For example, the projected 2030 cost of an electrolyzer that produces 50,000 kg of hydrogen a day being approximately $52,901,738 whereas an electrolyzer that produces 5,000 kg a day costs approximately $6,271,674 (H2A-Lite, 2023). However, since the larger electrolyzers produce more hydrogen, they benefit from an economy of scale, meaning that the capital cost is less per kg of hydrogen, when compared to electrolyzers with lower production capacity. For example, on average the projected 2030 capital costs of a 50,000 kg electrolyzer cost $1,058 per kg of hydrogen, whereas the capital costs of a 5,000 kg electrolyzer would cost $1,254 per kg of hydrogen (H2A-Lite, 2023). Ultimately the producer would need to decide whether it is more important to have a lower LCOH, or lower startup costs when deciding between a larger and smaller electrolyzer system.

1.3 Policy Incentives

1.3.1 California

In 2022, the California Governor's Office of Business and Economic Development (GO-Biz) created a statewide alliance, ARCHES, to partner with public and private-sector stakeholders to submit a single state-wide application to the Department of Energy (DOE) for a federal co-funded hydrogen hub in California (*California Formally Announces*, 2022). On October 13, 2023, the Biden-Harris Administration announced the seven regional hydrogen hubs selected to receive federal funding, one of which was the California Hydrogen Hub which could receive up to $1.2 billion of DOE funding (The White House, 2023). California's hub application targets producing renewable or green hydrogen, which is a nascent industry as 95% of the United State's hydrogen produced today is nonrenewable and produced from natural gas (California Energy Commission, 2020). Ramping up in-state production and distribution channels for hydrogen will help lower costs and reduce multi-sector emissions (*Hydrogen Refueling Stations*, n.d.). This will help California to meet its state-wide decarbonization target of net zero by 2045 by facilitating hydrogen adoption in power and heat generation, and manufacturing processes (*2022 Scoping Plan,* 2022). Additionally, this will make progress towards intermediate targets like California's goal of having 5 million zero-emission vehicles on the road by 2030 and 100% zero-emission vehicles by 2035 for drayage trucks and off-road vehicles (EO N-79-20, 2020). Once deployment begins for the creation of the clean hydrogen hub, California will have the task of allocating resources in a way that produces a quick, environmentally just rollout of hydrogen hub capacity.

The state's hydrogen leadership began in 2004, when Executive Order (EO) S-07-04 announced the California Hydrogen Highway Network (CaH2Net), which aimed to ensure adequate hydrogen fueling infrastructure to meet the demand for hydrogen fuel cell electric vehicles (*Hydrogen Fueling Infrastructure*, n.d.). This EO came to serve as a blueprint for California's more recent investments in hydrogen infrastructure. Since, EO N-79-20 set numerous zero-emission vehicle goals for California such as a 100 percent zero-emission vehicle sales goal for light-duty vehicles by 2035, 100 percent medium- and heavy-duty vehicles by 2045, and 2035 for drayage trucks (Executive Order No. N-79-20, 2020). Most of the state's hydrogen leadership and investments have been targeted at the transportation sector.

Assembly Bill 8 (AB 8; Perea, Chapter 401, Statutes of 2013) provided the California Energy Commission (CEC) with up to $20 million annually to help fund hydrogen fueling infrastructure developments. Fuel cell electric trucks (FCETs) can serve longer routes and require less refueling time than BETs. However, fleets are more hesitant to adopt FCETs until there is adequate refueling infrastructure (Lee, et al., 2023). The CEC has spent over $240 million on hydrogen projects between 2008 and 2021 (*Hydrogen Fact Sheet*, 2021). The agency's Clean Transportation Program, in particular, has invested $224 million in hydrogen, with $169.4 million for refueling infrastructure and $30.1 million for medium- and heavy-duty infrastructure deployment (*Hydrogen Fact Sheet*, 2021). According to the AB 8 report, the 100th open-retail hydrogen station is expected to open in 2024 (*2022 Annual Evaluation,* 2022). However, hydrogen is still expensive to make and transport (*Hydrogen Refueling Stations,* n.d.). The lack of infrastructure and low cost-effectiveness of hydrogen within California are bottlenecks to large-scale hydrogen adoption. In-state production of hydrogen fuel needs to expand to overcome these bottlenecks.

1.3.2 Federal

Two federal laws have incentivized all levels of government and industry groups to invest in green hydrogen infrastructure and production planning. The federal Infrastructure Investment and Jobs Act (IIJA), which was passed into law in 2021, gave the U.S. Department of Energy (DOE) responsibility for administering $8 billion in funding for the H2Hubs program (*Regional Clean Hydrogen Hubs*, n.d.). Hydrogen hubs are defined as "a network of clean hydrogen producers, potential clean hydrogen consumers, and connective infrastructure located in close proximity" (*Regional Clean Hydrogen Hubs*, n.d.). To demonstrate the viability of clean hydrogen, H2Hubs will need to develop a full value chain for clean hydrogen. Since the passing of the IIJA, California applied for and won federal funding for the buildout of infrastructure necessary to enable an early market for hydrogen.

The Inflation Reduction Act (IRA), signed into law in 2022, includes $370 billion in investments in clean energy and climate change (*Inflation Reduction Act Guidebook*, n.d.). Most importantly for hydrogen producers, there is a clean hydrogen production tax credit (PTC), which falls under Section 45V of the tax code. This PTC can pay up to $3 per kilogram of clean hydrogen produced over ten years. The maximum tax credit, which is attainable through green hydrogen production, can accelerate the deployment of electrolyzers. This tax credit can be awarded to projects developed as early as January 1, 2023. Other provisions of the IRA benefit hydrogen such as the elective payment for energy property, energy credit, and energy storage credit (*Financial Incentives for Hydrogen*, n.d.). The hydrogen provisions of the IRA will contribute to the DOE's overall strategy for market penetration. The hydrogen PTC will be critical for determining the financial viability of green hydrogen.

As the agency tasked with administering hydrogen funding, the DOE has published a National Clean Hydrogen Strategy and Roadmap which lays out the myriad initiatives and funding programs it offers and will offer, to scale up hydrogen production and usage (DOE, 2023). As part of this comprehensive strategy, in January of 2023, the DOE announced up to $47 million to accelerate research, development, and demonstration (RD&D). This RD&D funding is aimed at accelerating affordable clean hydrogen technologies focused on delivery and storage as well as fuel cells. The DOE's first Energy Earthshot, which accelerates breakthroughs in clean energy solutions, is the Hydrogen Shot. The Hydrogen Shot was launched in 2021 to reduce the cost of clean hydrogen by 80% to $1 per kilogram in 1 decade (*Hydrogen Shot, n.d.*). The current cost of clean hydrogen production is about $5 per kilogram. If the Hydrogen Shot is met, there could be a fivefold increase in clean hydrogen usage and a potential 16% reduction in carbon emissions by 2050 (*Hydrogen Shot, n.d.*). These federal actions have assisted states such as California in taking simultaneous action. California has been a prominent leader in decarbonizing energy services and adopting low-carbon technologies. With the help of federal initiatives and funding, California can help establish and accelerate the market for green hydrogen in various industries.

1.4 Environmental Justice Considerations

Green hydrogen production has the potential to provide many benefits to marginalized communities. For example, the adoption of FCETs would reduce transportation pollution, such as PM2.5 and NOx, which disproportionately impacts marginalized communities. In California, African Americans and Latinos are 40% more likely to be exposed to pollution from cars and trucks than Caucasians and have higher mortality rates from diesel particulate matter pollution as well (AltaSea, 2022). Most of the state's disadvantaged communities are in Clean Air Act nonattainment areas for both ozone and PM2.5 (CalEnviroScreen). Marginalized communities are also more likely to be adjacent to industrial facilities that emit large amounts of air pollution. Green hydrogen could also bring jobs to underserved communities. California plans to incorporate environmental justice initiatives into employment practices and workforce development at the hydrogen production facilities, to ensure that people from communities surrounding production facilities economically benefit from production (AltaSea, 2022).

Green hydrogen production can also harm marginalized communities depending on the context. For example, environmental justice groups, such as the California Environmental Justice Alliance, do not consider hydrogen production methods, such as biomass gasification, that involve carbon capture and storage to be green hydrogen (Fitzpatrick, 2023). This is because carbon capture does not necessarily prevent other pollutants, such as PM 2.5 or NOx from entering the air; it only captures carbon (Fitzpatrick, 2023). Environmental justice groups also oppose anaerobic digestion as one potential fuel source is agricultural waste from confined feeding operations (Fitzpatrick, 2023). These groups already experience harm, such as air and water pollution, from confined feeding operations, and therefore oppose any actions that would support them. Moreover, the development of green hydrogen production will not necessarily lead to higher rates of employment for local marginalized communities. Since jobs in the hydrogen field are typically skill-specific, the industry can favor external communities if local communities lack those particular skills. (Cremonese, et al., 2023). These potential outcomes should be considered when deciding whether to pursue hydrogen blending to meet industry demand.

1.5 Barriers to Lowering the Levelized Cost of Hydrogen

1.5.1 Permitting and Zoning

1.5.1.1 Hydrogen Production

In addition to resource-based requirements, regulatory barriers must be assessed to determine where the development of hydrogen production facilities is feasible. One major group of regulations that influence hydrogen hub siting are zoning codes and permits (Vacin and Eckerle, 2020). Zoning codes dictate where certain buildings, or even industries, are allowed to be located. Any industrially zoned area with a large enough footprint and grid access could be used for electrolyzer siting. In California, any area coded M1 for limited industrial uses, M2 for light industrial uses, or M3 for heavy industrial uses can be used for electrolysis (Basic Zoning Codes, 2021). Hydrogen produced specifically for transportation can be zoned in commercial zones, such as C2, C4, C5, and CM zones, which allow for light manufacturing of auto supplies or fuels (Basic Zoning Codes, 2021). There also must be space for the electrolyzer. Smaller electrolyzers, such as those that run on 1 MW of electricity only require 40 by 80 ft of space, however, larger electrolyzers, such as those that run on 30 MW require .25 acres (Reed et al, 2020). Since electrolyzers create minimal pollution, they can be placed in nonattainment areas as defined by the Clean Air Act (Reed et al, 2020). They also fit into existing California Environmental Quality Act (CEQA) approvals in industrial parks and the building permits of existing projects (Reed et al, 2020).

Biomass gasifier permitting has different requirements. Gasifiers can be placed in an area zoned for agriculture, and require a footprint of at least 10 acres for a 100 MW facility (Reed et al, 2020). They should be located near a woody biomass source, to reduce transportation costs and need to be connected to sources of natural gas, water, and electricity. Biomass Gasifiers do require CEQA permits, construction permits, and occasionally Clean Air Act permits if it is a large-scale combustor, and therefore could worsen air quality (Reed et al, 2020). Biomass gasifiers should not be located near residential areas as they are noisy and produce large quantities of hydrogen, meaning they cause frequent truck traffic that could disturb neighborhoods (Reed et al, 2020).

One of the more difficult methods of hydrogen production to permit is production through anaerobic digestion. Anaerobic digesters must be sited in areas zoned for industrial use (Reed et al, 2020). They require five acres for 100,000 MMBtu/year and connections to natural gas, electricity, and water (Reed et al, 2020). CEQA, Clean Air Act, and construction permits are required (Reed et al, 2020). Solid waste permits are required as well, however, these are difficult to obtain, so digesters should be located on sites that already have solid waste permits (Reed et al, 2020). Anaerobic digesters also should not be located near residential areas as they produce noise, odor, and frequent traffic (Reed et al, 2020).

1.5.1.2 Utility Solar and Wind Permitting

Permitting for utility-scale solar and wind energy has been difficult, with developers often needing to conduct an Environmental Impact Review under CEQA, and with wind developers needing incidental take permits, for any federally endangered birds or wildlife killed by the turbines. Wind farms often get opposition from environmental groups, such as the Sierra Club, for the harm they can cause to birds, as well as local communities, as they can be seen as an eyesore (Arnold and Beck, 2023). In total, applying for permits could take applicants up to 4 years (Arnold and Beck, 2023). To speed up the permitting process the California legislature passed AB 205 in 2022. This bill allows the California Energy Commission to have permitting control over all solar and wind farms with a generating capacity of over 50 megawatts, as well as any transmission lines running to and from the facility (Eisenson, 2022). It also requires that environmental impact reviews be conducted in 270 days so that developers can plan to have approval within a set timeline. AB 205 also mandates that the CEC create a community benefits plan, to ensure that communities are not harmed by the utility scale renewable development, and to reduce concerns and opposition (Eisenson, 2022). Although the bill has not been in place long enough to see if it has had a significant impact on utility-scale wind and solar permitting speeds, there is hope that utility-scale renewable permitting in California will be simpler, and therefore more wind and solar farms can be built for hydrogen production (Arnold and Beck, 2023).

1.5.2 Distribution Costs

Distribution methods affect the feasibility of transporting hydrogen from production facilities to consumers, as cost trade-offs exist based on distance and volume (BloombergNEF, 2020). The energy density of hydrogen is higher when hydrogen is a liquid, meaning there's more energy per kilogram in a liquid state than in a gaseous state. This makes it advantageous to transport hydrogen in a liquid state. However, hydrogen has an extremely low boiling point at 20°K or -253°C (Lanz, 2001). Therefore, it needs to be stored at low temperatures to be transported in a liquid state. Transporting hydrogen at low temperatures is expensive, so this form is typically used when large quantities are transported long distances. The cost of transporting 75 tons of liquid hydrogen 100 km by truck is estimated to be between $3 per kg to $2.50 per kg (Fulton et al 2023). This cost decreases with shorter transport distances and higher transport quantities, as the system benefits from economies of scale (Fulton et al, 2023).

A second way to transport hydrogen is as pressurized gas. In this transportation method, the hydrogen is not stored in its optimal state, but transportation costs are cheaper per kilogram since there is no need to refrigerate it (Lanz 2001). Typically this method is advantageous over the previous one when transporting smaller amounts of hydrogen. The cost of transporting gaseous hydrogen by truck is estimated to be between $16.11 per kg to $1.50 per kg, depending on the distance and the amount of hydrogen being transported (Fulton et al, 2023). In general, the cost of trucking gaseous hydrogen increases with larger transport distances and greater transport quantities. When large transport quantities and distances are required it becomes more cost-effective to truck hydrogen in the more energy-dense liquid state (Fulton et al, 2023).

In general, pipelines are the most cost-effective means of transporting hydrogen, and that efficiency increases with greater transport quantities; however, liquid transport can also be competitive with pipelines in some long-distance applications (Fulton et al., 2023). The cost of transporting hydrogen by pipelines is estimated to be between $.08 per kg to $11 per kg, depending on the distance traveled and the amount of hydrogen being transported (Fulton et al, 2023). However, transporting hydrogen through pipelines is difficult because of its chemical properties. Since hydrogen is a small molecule, it can leak through any minuscule crack. Hydrogen is also corrosive, so pure hydrogen cannot travel through existing pipeline infrastructure without causing embrittlement (Lanz, 2001). Therefore, hydrogen can only be transported through pipelines if existing gas pipelines are retrofitted or new pipelines are built specifically for hydrogen. Overall, distribution costs need to be considered when siting electrolyzers because they can significantly increase the LCOH.

1.5.3 Electrolyzer Placement

The two different types of hydrogen supply networks are centralized and distributed. For electrolyzers, it is common to evaluate siting with two electricity supply options, standalone renewable systems that are not grid-connected and grid-supplied electricity (Squadrito et al., 2023; Reed et al, 2020). Centralized systems are more widely studied and concern fewer large-scale production facilities which require higher transportation costs (Squadrito et al., 2023). For centralized green electrolytic hydrogen, there must be large-scale clean water and renewable energy close to the production site. However, the high transportation needs reduce the system's efficiency and increase hydrogen costs (Squadrito et al., 2023). Distributed hydrogen systems, also called forecourt, similarly require solar photovoltaics or wind power and potable water but at a smaller scale. Since hydrogen is produced close to or at the demand site, transportation requirements are little to none (Squadrito et al., 2023). The key tradeoff when placing electrolyzers is whether to collocate based on higher renewable energy resource quality or proximity to demand (Reed et al, 2020).

In 2009, National Renewable Energy Laboratory (NREL) released a Technical Report that compares central grid electrolysis, distributed grid electrolysis, and more (2009). It found central electrolysis cases to be more expensive than distributed electrolysis cases since installation is less expensive for smaller and fewer electrolyzers. Squadrito et al. (2023) shared the centralized system's advantage for heavy industrial end-uses and the distributed network's power to maximize efficiency and social utility. There are strengths and weaknesses to each supply network type and it is largely tied to the end-uses, demand, and available capital.

In conclusion, Part 1 established California's hydrogen efforts, the components of hydrogen production, hydrogen policies at the state and federal level, environmental justice considerations, and some barriers that could inhibit hydrogen deployment. There is an alignment of political will, monetary incentives, and technology readiness for the deployment of green hydrogen. However, additional modeling of California's hydrogen supply potential and demand end uses can further clarify and inform us on which factors are barriers to hydrogen diffusion in the transportation sector.

Part 2: Analysis

The overall goal of our analysis was to estimate and compare potential hydrogen production from renewable resources to future demand for hydrogen fuel from the transportation sector. To do so, we determined the locations and quantities of each and identified areas with parity between hydrogen production and demand. We then identified general barriers that prevent other areas from producing enough renewable hydrogen to supply local demand. We also estimated the LCOH delivered from production sites to demand centers to evaluate the cost-effectiveness of supply chain components (production and distribution) and production networks (centralized and distributed).

To achieve the overall goal, we completed the following objectives, which are detailed in sections 2.1.1 to 2.1.4 :

1. Estimate hydrogen production locations and quantities.
    a. Electrolytic hydrogen from land-based wind and solar resources
    b. Biogenic hydrogen from planned thermochemical facilities
2. Identify projected locations and quantities for hydrogen demand from the transportation sector in 2030.
3. Determine theoretical locations for production facilities based on production and demand locations and quantities.
    a. Centralized production network through an optimization model
    b. Distributed production network through co-location with demand
4. Estimate the LCOH delivered to demand locations based on production and distribution costs.

The results are described in section 2.2 and discussed further in section 3.

2.1 Methods

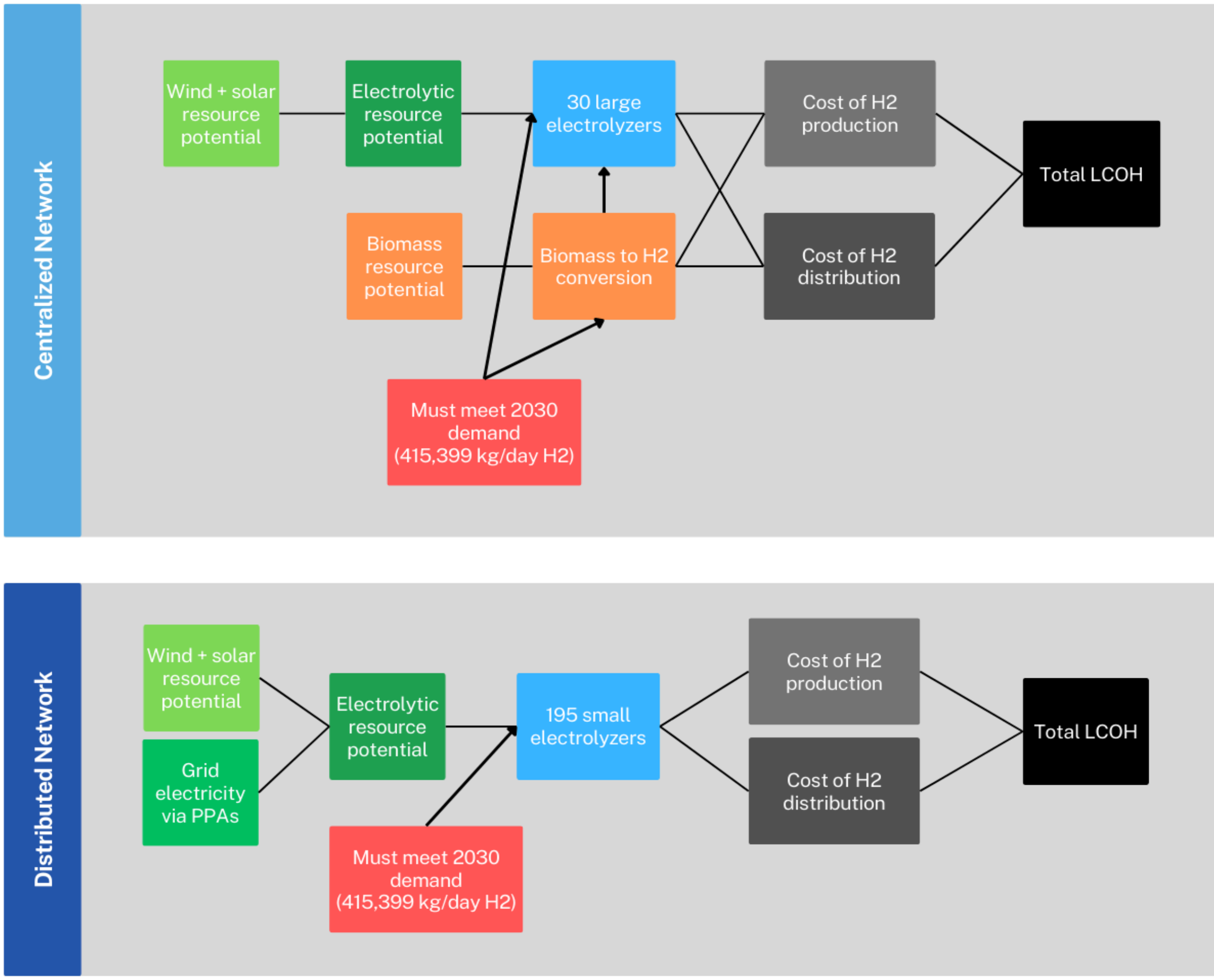

Figure 1. Flow chart of top-level methods used to calculate supply, production, and LCOH.

2.1.1 Production

We modeled electrolytic hydrogen production potential throughout California from land-based wind and solar PV resources.

2.1.1.1 Wind and Solar Resource Potential

We began with spatial wind and solar PV resource potential layers that were developed by NREL's Renewable Energy Potential Model (reV; Maclaurin et al., 2021). reV is a spatiotemporal modeling tool used to calculate renewable energy capacity, generation, and cost. ReV utilizes raw resource potential, land-use characteristics, grid infrastructure, transmission access, financial data, technology characteristics, and other customizable parameters to make its calculations(reV; Maclaurin et al., 2021). The base layers for calculating renewable potential are 90 m x 90 m rasters of annual average global horizontal irradiance (GHI) from the National Solar Radiation Database (NSRDB) and annual average wind speeds from the Wind Integration National Dataset (WIND) Toolkit (Sengupta et al., 2018; Draxl et al., 2015). For more information, see Appendix A.

We used two datasets that NREL produced through reV: one for land-based wind capacity and one for solar PV capacity. These data were available as centroids of 11 km x 11 km grid cells. Both datasets were developed by applying the most limiting level of exclusions possible in reV; the limited access supply curve data includes potential increased setback requirements and areas that may be difficult to deploy renewable resources such as federally managed lands and areas with existing restrictions. We chose to use the strictest exclusions to reflect California's relatively stringent permitting landscape (Schwartz and Brueske, 2020). These exclusions fall into three broad categories: physical barriers, regulatory restrictions, and stakeholder constraints. The physical barriers category excludes areas where wind turbines and solar panels cannot be built due to features like steep terrain or existing water bodies. The regulatory restrictions category excludes areas where renewables cannot be placed due to regulatory concerns like protected land, densely populated areas, or regions with restrictive permitting policies. The stakeholder constraints category excludes areas like private conservation lands, Department of Defense lands, and US Forest Service lands.

2.1.1.2 Electrolytic Hydrogen Potential

We converted the spatial wind and solar resource capacity values to potential electrolytic hydrogen by applying conversion factors for wind and solar electrolysis from NREL's Proton Exchange Membrane Electrolysis H2A Production Case Study. The study estimated that both wind and solar low-temperature electrolysis (LTE) pathways require 51.3 kWh of capacity to produce 1 kilogram of hydrogen at a 64.8% efficiency (Milbrandt and Mann 2007). By applying these conversion factors, we determined the theoretical maximum amount of hydrogen that could be produced in each 11 km x 11 km grid cell with renewable resource potential. We did this separately for wind- and solar-electrolysis.

2.1.2 Demand

We used estimates of potential future demand for hydrogen fuel from the transportation sector in California sourced from the UC Davis Institute of Transportation Studies (ITS) California Hydrogen Analysis Project. In particular, we used point locations and daily demand quantities of hydrogen fueling stations in 2030 (Fulton et al., 2023). Data on the threshold prices, or prices required for hydrogen to be cost-competitive with diesel, were also included for each station.

The California Hydrogen Analysis Project projected the amount of hydrogen demanded by light-, medium- and heavy-duty fuel stations between 2020 to 2050 by utilizing three comprehensive models: the Spatial Transportation Infrastructure, Energy, Vehicle and Emissions model (STIEVE model), Grid Optimized Operation and

Dispatch Model (GOOD model), and the Scenario Evaluation and Regionalization Analysis model (SERA model). The STIEVE model is a transportation demand model for California road networks that is used to estimate potential fuel cell vehicles, hydrogen demand, and the need for hydrogen fueling stations. The GOOD model is an economic dispatch model used to estimate the future electricity system with increased renewables, electrolytic hydrogen production, and energy storage systems. The SERA model is a hydrogen supply chain model developed by NREL that is used to site optimal locations for hydrogen production based on hydrogen demand, transportation, and storage. The study assumed that future hydrogen fueling stations would be co-located with existing gasoline and diesel stations, as it is easier to convert stations rather than develop greenfields (Fulton et al., 2023).

2.1.3 Electrolyzers

We then utilized the locations and quantities of hydrogen production and demand to site electrolyzers in two hydrogen production networks: a centralized production network and a distributed production network.

2.1.3.1 Centralized Network

For the centralized production network, we built an optimization model to site the optimal locations for large-scale electrolyzer systems. We limited the daily production capacity of large-scale electrolyzers to 50,000 kg/day (H2A-Lite, 2023). We used a capacitated multi-facility Weber problem to locate electrolyzers to best service transportation fueling stations. This is a locational optimization problem that minimizes the sum weighted distances from a set of points to facilities being placed on a plane (Akyuz, 2017). This type of problem is commonly used in supply chain optimization because it accounts for both limited supply capacity on the supplier's end as well as service requirements to points of demand. The optimization model minimizes the distance between hydrogen production sites and demand points, which is directly related to the costs of distributing hydrogen after it's been produced. It also balances the amounts of hydrogen demanded and produced to ensure that all demand can be met. We also excluded areas that are unsuitable for development based on the exclusion criteria used in NREL reV. The equation we used for the model is described below:

$$min\, Z = \sum_{j\in J} f_j x_j + \sum_{j\in J}\sum_{i\in I} \omega_i c_{ij} y_{ij}$$

Subject to:

(1) $\sum_{j=1} y_{ij} = 1, \forall i\in I$ demand must be completely fulfilled

(2) $\sum_{i\in I} \omega_i y_{ij} \le \kappa_j x_j \forall j\in J$ electrolyzer supply service cannot exceed capacity

(3) $y_{ij} \le x_j \forall i\in I, \forall j\in J$ only selected electrolyzers can supply demand

Where:

$x_j \in \{0, 1\}$: the decision variable for whether a facility is built at location *j*

$0 \leq y_{ij} \leq 1$: the continuous decision variable for the fraction of supply received by demand *i* from facility *j*

$i \in I$: the index for demand points

$j \in J$: the index for potential facility locations

$f_j \in R^+$: fixed costs of constructing facility *j*

$\omega_i \in R^+$: quantity of demand for point *i*

$\kappa_j \in R^+$: the capacity of facility *j*, currently equal across all potential facilities

$c_{ij} \in R^+$: cost per unit of demand to ship between facility *j* and demand *i*; a function of the Euclidean distance between facility j and demand i, distance d_{ij}, and cost per mile of distribution α, s.t. $c_{ij} = \alpha \cdot d_{ij}$

2.1.3.2 Distributed Network

For the distributed production network, we sited small-scale electrolyzers at hydrogen demand locations. We limited the daily production capacity of small-scale electrolyzers to 4,500 kg/day, which is on par with NREL's ongoing hydrogen production study's system boundary (H2A-Lite, 2023). In cases where the total station demand at a site exceeded 4,500 kg/day, we sited additional electrolyzers on the same site. The maximum number of electrolyzers sited at one fueling station was five. Here, we assumed that it will be possible to build small-scale electrolyzers at demand locations because it avoids the high storage costs of centralized standalone electricity generation to account for the intermittency of renewables (Squadrito et al., 2023). However, we do not account for variations in permitting, population density, and other relevant parameters.

For any electrolyzer sited on land where renewable resource capacity also exists, we assumed that the electricity would be provided by on-site renewables. For any electrolyzer sited on land where renewable resource capacity does not exist, we assumed that the electricity would be provided by connecting to the local electricity grid.

2.1.4 Levelized Cost of Hydrogen

2.1.4.1 Cost of Hydrogen Production

Next, we calculated the LCOH at each production site by using NREL's Hydrogen Analysis Lite Production Model (H2A-Lite) Tool. The LCOH is the cost of purchasing 1 kilogram of hydrogen after incorporating resource capacity, CapEx costs, OpEx costs, and other considerations. (Lazard, 2021). The H2A-Lite tool allows users to conduct a techno-economic analysis of hydrogen production across various technologies, spaces, and time horizons. The tool uses the Energy Information Administration's (EIA) Annual Energy Outlook 2022 and AEO2022 Reference case to calculate capital expenditure, water, and energy feedstock costs, annual operation and maintenance, and electrolyzer utilization rate to project the LCOH (H2A-Lite, 2023). For more information, see Appendix B.

We used the H2A-Lite tool to model the LCOH under four hydrogen production scenarios: wind-based electrolysis, solar-based electrolysis, grid electricity-based electrolysis, and biomass gasification. We based all modeled scenarios on the Pacific region (Washington, Oregon, California) and a start-up year of 2030 since this is when California aims to have a developed hydrogen economy (Fulton et al, 2023). For each scenario, we calculated the LCOH for production quantities between 2,000 and 100,000 kg/day to determine the relationship between LCOH and production quantity. We chose this range to include the widest range of data possible, as these values represent the minimum and maximum production capacities that can be input in H2A-Lite. We recorded the LCOH and feedstock costs from each production quantity in an Excel spreadsheet. Then, we determined the relationship between LCOH and production quantity for each production pathway, which are shown in Table 1.

Table 1. The relationship between the LCOH production and the daily quantity of hydrogen being produced through three production pathways: wind-based electrolysis, solar-based electrolysis, and grid electricity-based electrolysis. All production pathways were modeled in the Pacific Region with a start-up year of 2030 in H2A-Lite and LCOH values are reported in 2023 USD below.

Production Pathway	Relationship between LCOH and quantity of H2 production
Wind PEM	$LCOH\ (\$/kg\ H2)\ =\ 3.84\ -\ 0.082\ ln(daily\ kg\ H2)$
Solar PEM	$LCOH\ (\$/kg\ H2)\ =\ 4.47\ -\ 0.081\ ln(daily\ kg\ H2)$
Grid PEM	$LCOH\ (\$/kg\ H2)\ =\ 7.24\ -\ 0.050\ ln(daily\ kg\ H2)$
Biomass gasification	$LCOH\ (\$/kg\ H2)\ =\ 5.51\ -\ 0.316\ ln(daily\ kg\ H2)$

Next, we calculated the LCOH at each electrolyzer by using the hydrogen production quantities as an input to the production pathway-specific relationships determined above. We did this for electrolyzers in our centralized and distributed production networks. Electrolyzers in the centralized network were assumed to operate by wind-or solar-electrolysis since they are located near areas viable for renewable development; the renewable pathway with the lowest LCOH was chosen as the production pathway for a given location in the centralized network. We limited the daily production quantity to 50,000 kg/day for the LCOH calculation of centralized electrolyzers, as this is the expected size of electrolyzers in 2030 (H2A-Lite, 2023). Electrolyzers in the distributed system were powered by wind- or solar-electrolysis in areas that allow for renewable development and grid-electrolysis in areas where renewable development is not viable. We limited the daily production quantity to 4,500 kg/day for the LCOH calculation of small-scale distributed electrolyzers (H2A-Lite, 2023).

2.1.4.2 Cost of Hydrogen Distribution

Next, we calculated the cost of delivering hydrogen from electrolyzers to demand points in the centralized network by using cost data from the UC Davis Institute of Transportation Studies (ITS) California Hydrogen Analysis Project (Fulton et al., 2023). We included distribution by trucking hydrogen in gaseous and liquid forms, which are expected to be the primary distribution methods in 2030 (Fulton et al., 2023). We defined small stations as those that demand between 500-5,000 kg/day and large stations as those that demand more than 5,000 kg/day (Fulton et al., 2023). We then varied the distribution costs and mode of transport based on the station size, the distance being traveled, and the amount of hydrogen being transported. For more information, see Appendix C.

2.1.4.3 Total LCOH

Finally, we calculated the total LCOH at the demand stations for the centralized network by adding the production and distribution costs. The final LCOH at the demand stations for the distributed network was equivalent to the production costs alone since the electrolyzers were co-located with demand points and no distribution was included.

2.1.4.4 Biomass Resource Potential

To provide an indication of the role that biogenic hydrogen could play alongside electrolytic production, we estimated hydrogen potential for a subset of forest biomass facilities in California and compared the total LCOH to that of electrolysis. We leveraged data from the California Department of Conservation on facilities receiving state grant funding to produce hydrogen and/or liquid biofuels from forest biomass through the Forest Biomass to Carbon-Negative Biofuels Pilot Program (Forest Biomass to Carbon-Negative Biofuels Pilot Program, 2023). Hydrogen production capacity was calculated for the program's eight Phase 1 awardees using a rate of 1 kg hydrogen per 0.015 bone-dry ton of biomass (H2A-Lite, 2023). The LCOH without delivery was estimated using the NREL H2A-Lite model. We calculated the cost of delivery between each facility and each transportation demand point based on distance and quantity, and used this information to estimate total LCOH with delivery. Demand was then allocated to each facility based on lowest total LCOH, such that the total demand being served by each facility does not exceed its hydrogen production capacity. Finally, the total LCOH of biogenic hydrogen was compared to the LCOH of electrolytic hydrogen.

2.2 Results

2.2.1 Hydrogen Production Potential

The daily theoretical maximum amount of hydrogen that can be produced using electrolysis in a given location varies widely across California (Figure 2). Counties in the Central Valley have the highest production potential based on renewable resource availability and land use restrictions, although most unexcluded areas are able to produce at least 10,000 kg/day. Biomass facilities varied in their hydrogen production potential based on the amount of biomass they convert annually, with facilities ranging from about 3,200 kg/day of hydrogen production potential to as high as 46,575 kg/day for the largest facility. Many areas in the state have no theoretical potential to produce hydrogen due to technical features, like the slope of land in the Sierra Nevada Mountains. Other areas have no potential to produce hydrogen due to regulatory reasons; for instance, San Bernardino County has very little viable area for hydrogen production because the county bans utility-scale wind and solar power plants (Schwartz and Brueske, 2020).

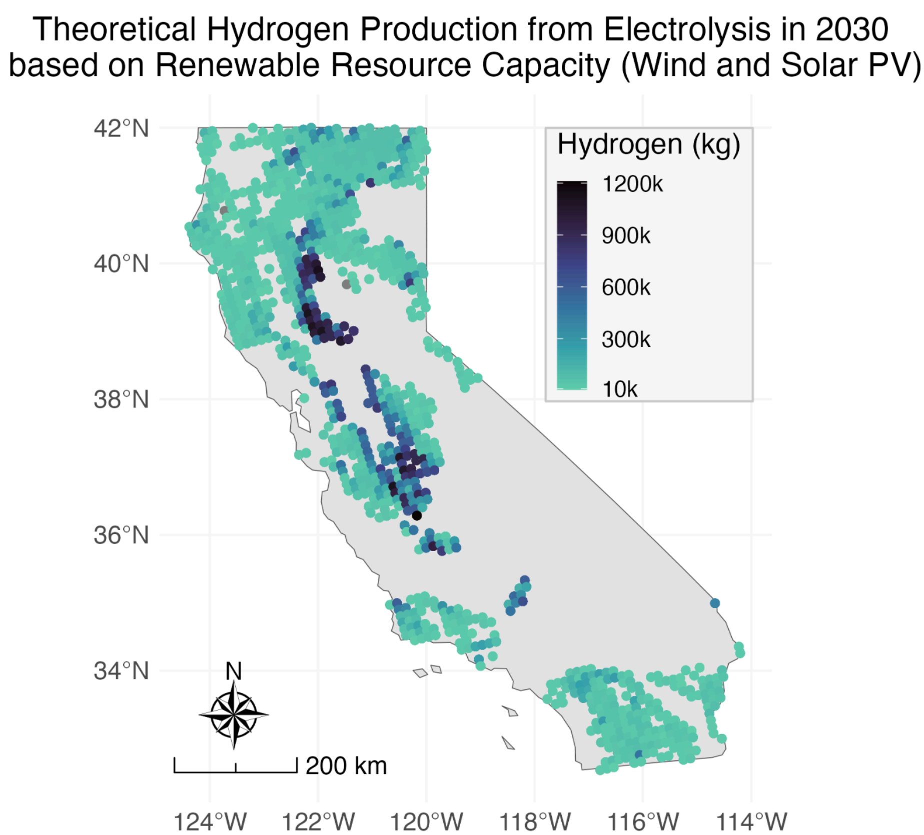

Figure 2. Maximum theoretical amount of hydrogen production through wind- and solar-based electrolysis. Daily quantities of hydrogen production at each 11 km x 11 km centroid are indicated by color. Values range from 10,000 kg/day (turquoise) to 1,200,000 kg/day (black) with highest values located in the Central Valley. The gray area represents land that has no potential to produce renewable hydrogen due to land use constraints.

2.2.2 Transportation Sector Demand

In 2030, projected demand for hydrogen fuel from the transportation sector is concentrated along major transportation corridors and areas with high current demand for fossil fuels (Figure 3). San Bernardino, Riverside, and Los Angeles counties have the highest county-wide demand for hydrogen in 2030. The large populations and key trucking corridors within these counties will likely lead to high amounts of medium- and heavy-duty fuel cell electric vehicles (FCEVs) in the near future. The statewide total amount of projected hydrogen demand in 2030 is 415,399 kg/day in 2030 (Fulton et al, 2023).

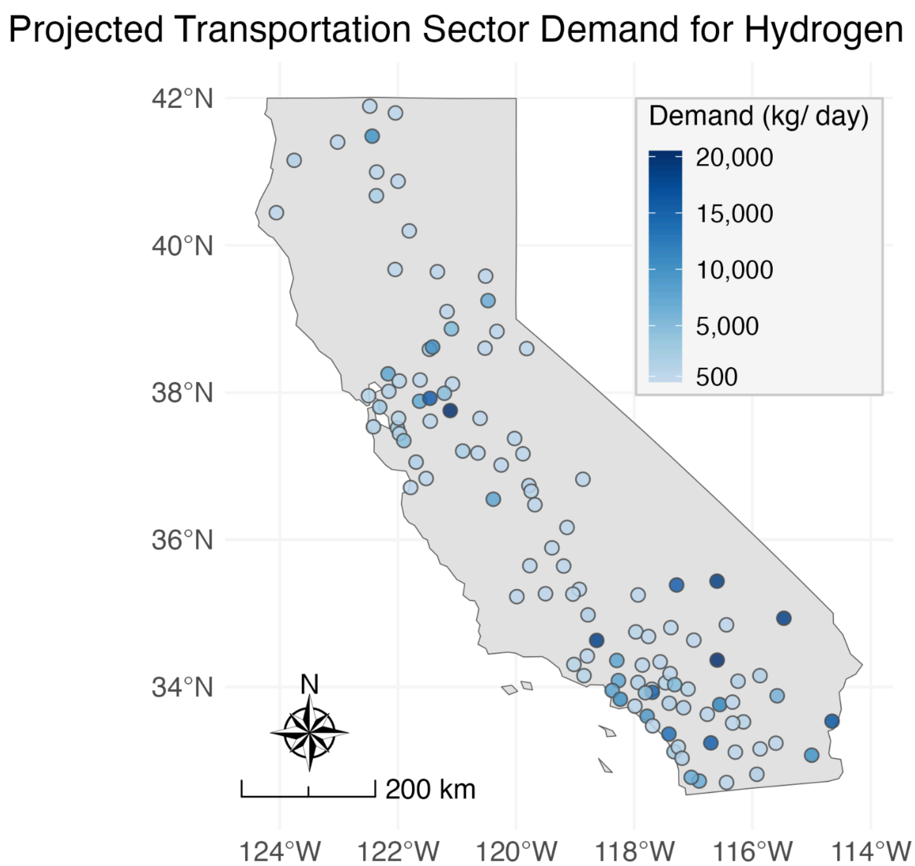

Figure 3. Estimated daily demand for hydrogen fuel from the transportation sector in 2030. Projected demand locations are shown across California where color represents the total daily demand at each location in 2030. Values range from 500 kg/day to 20,000 kg/day. Southern California counties have the highest aggregate demand.

2.2.3 Centralized Production Network

Under the centralized production network, 30 large-scale electrolyzers with the capacity to produce 50,000 kg/day would be required to meet 2030 transportation sector demand (Figure 4). Hydrogen produced at these 30 centralized locations would then need to be transported to individual demand centers. According to the H2A-Lite model, the estimated CapEx for a 50,000 kg/day electrolyzer is around $53 million. For 30 electrolyzers statewide, the total CapEx would be $1.59 billion. Though the CapEx per individual large-scale electrolyzer is high, the centralized electrolysis scenario benefits from an economy of scale. The cost per kilogram (CapEx/daily production capacity) is $1,060. Moreover, a centralized production network would include favorable organization and oversight that would allow hydrogen production and distribution to be easily adapted with changing demand. As hydrogen demand grows beyond 2030, this network would be compatible with future scaling of hydrogen storage.

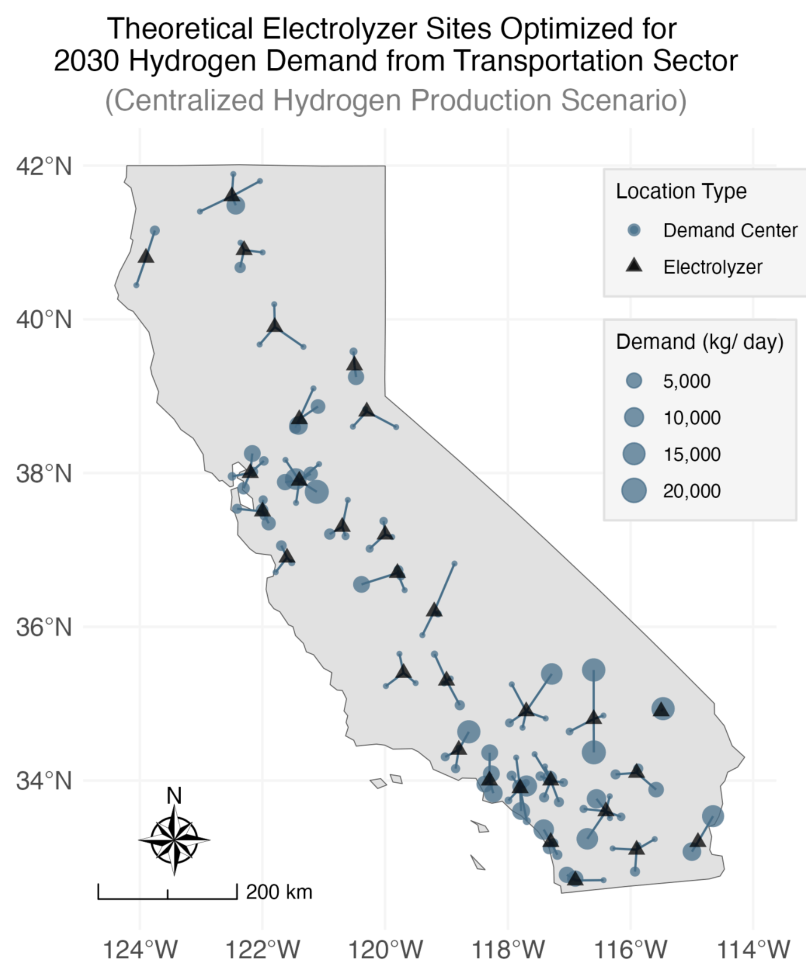

Figure 4. Optimized locations for centralized electrolyzers based on 2030 transportation sector demand. The location of centralized electrolyzers sited through an optimization model are shown as black triangles across California. The locations of transportation sector

demand are shown as blue circles where the size corresponds to the amount of daily hydrogen demanded. Demand amounts vary between 500 kg/day to 20,000 kg/day.

2.2.3.1 Supply and Demand by County

Under the centralized production network, 20 out of California's 58 counties would be able to produce electrolytic hydrogen based on resource availability and land use constraints (Table 2). The six counties with the highest production potential could theoretically each produce enough electrolytic hydrogen to serve the entire statewide 2030 transportation sector demand of 415,399 kg/day (Table 2). Moreover, California as a whole could produce 1,700 times more electrolytic hydrogen than will be demanded by the transportation sector in 2030 (Table 2). This high production potential indicates that the state could supply electrolytic hydrogen to meet additional demand from other end uses and in time horizons beyond 2030.

A total of 37 counties in California are expected to demand hydrogen fuel for transportation in 2030. Out of these 37 counties, 54% would be able to produce enough electrolytic hydrogen to meet their own demand and have excess available for storage or distribution. Kern county is estimated to have the largest daily excess, at 1.4 million kg/day (Table 2). Tehama and Placer counties are estimated to have large daily excesses as well, at 1.1 million and 0.9 million kg/day, respectively (Table 2).

On the other hand, 46% of the 37 counties will be unable to produce enough electrolytic hydrogen to meet their own transportation demand in 2030 (Table 2). Los Angeles, San Joaquin, and Sacramento counties have the largest demand deficits (Table 2); these counties will either need to import electrolytic hydrogen from surrounding areas or produce local hydrogen through means other than electrolysis. Hydrogen produced through non-renewable production pathways have higher environmental and health impacts, however; since distribution of hydrogen is expensive, production through less green pathways may continue to be used to meet statewide reliability in California until more net-zero hydrogen can be phased in (Reed et al. 2020).

Table 2. Difference between total production of electrolytic hydrogen and transportation sector demand by county. Total daily values for electrolytic hydrogen production, transportation sector demand, and the difference between supply and demand for each county. Counties with a positive difference have higher production than demand while counties with a negative difference have higher demand than production. Table is organized from largest difference (excess supply) to lowest difference (demand deficit).

County*	Difference (kg/day)	Supply (kg/day)	Demand (kg/day)
Kern	1,409,706	1,433,611	23,905
Tehama	1,118,619	1,119,119	500
Placer	903,681	915,935	12,254
Fresno	730,415	740,807	10,392
Contra Costa	571,290	579,708	8,417

Merced	442,551	445,486	2,935
Santa Clara	306,921	313,351	6,431
San Bernardino	293,529	392,151	98,622
Siskiyou	289,659	301,659	12,000
Tulare	258,886	259,987	1,101
Ventura	223,306	225,452	2,146
Riverside	104,743	144,667	39,924
Madera	53,903	54,653	750
Humboldt	47,216	49,187	1,971
Shasta	44,678	47,366	2,688
Alameda	36,379	44,636	8,258
San Diego	34,099	82,663	48,564
El Dorado	33,369	33,869	500
Imperial	23,935	36,435	12,500
Orange	15,152	25,505	10,353
Alpine	-500	0	500
Butte	-500	0	500
Calaveras	-500	0	500
Glenn	-500	0	500
Inyo	-500	0	500
Monterey	-500	0	500
Nevada	-500	0	500
Tuolumne	-500	0	500
San Benito	-550	0	550
Plumas	-732	0	732
Marin	-919	0	919
Mariposa	-1,328	0	1,328
San Mateo	-1,500	0	1,500
Solano	-8,744	0	8,744
Sacramento	-12,888	0	12,888
San Joaquin	-40,156	0	40,156
Los Angeles	-40,373	0	40,373
Total	**6,830,846**	**7,246,245**	**415,399**

*The following 21 counties are excluded from the table because they are estimated to have 0 production potential and 0 transportation sector demand in 2030: Amador, Colusa, Del Norte, Kings, Lake, Lassen, Mendocino, Modoc, Mono, Napa, San Francisco, San Luis Obispo, Santa Barbara, Santa Cruz, Sierra, Sonoma, Stanislaus, Sutter, Trinity, Yolo, and Yuba.

The top five counties with the highest aggregate demand for hydrogen fuel in 2030 are all located in Southern California and have varying levels of electrolytic hydrogen production. San Bernardino, San Diego, and Riverside counties are expected to be net producers and can supply between 170-400% of their daily demand through electrolytic hydrogen (Table 2; Figure 5). The excess electrolytic hydrogen could be stored or distributed to surrounding areas. In contrast, Los Angeles and San Joaquin counties are unable to produce any utility-scale electrolytic hydrogen due to their dense urban centers and/or land use regulations. These counties will either need to import electrolytic hydrogen from the surrounding area or produce local hydrogen through alternative processes.

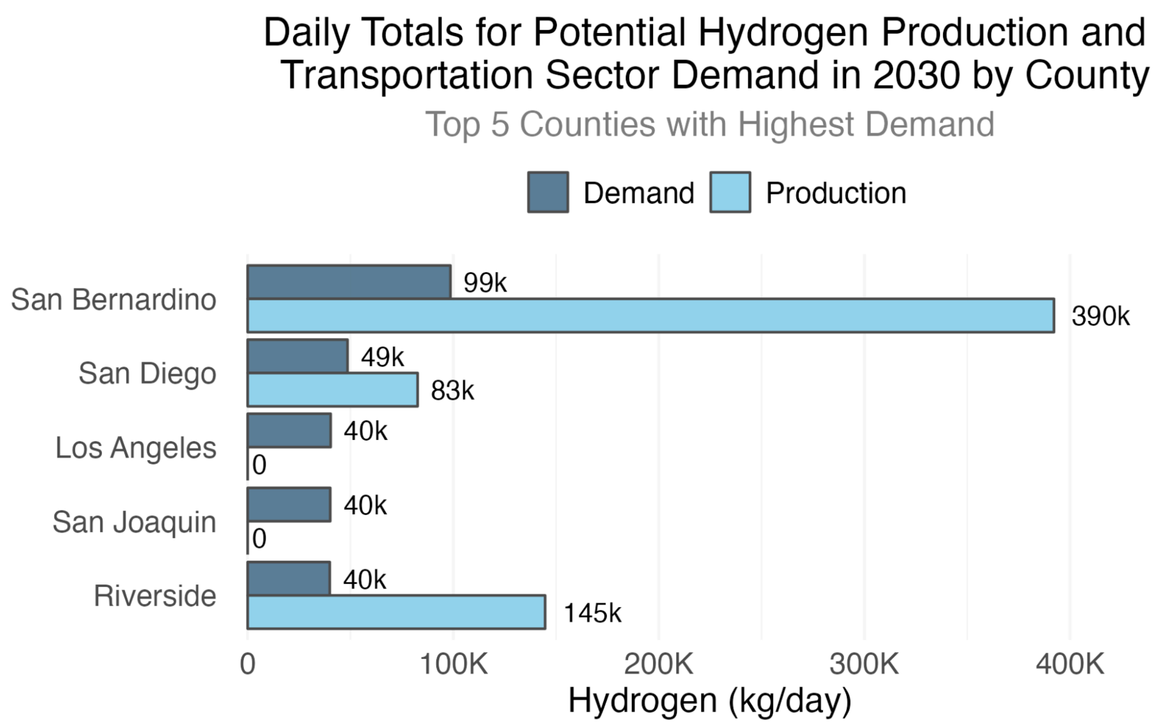

Figure 5. County totals for daily potential electrolytic hydrogen production and transportation sector demand in 2030 under the centralized production network. Total electrolytic hydrogen supply and transportation sector demand for the top 5 counties with the highest projected demand in 2030 is shown. Dark blue bars represent total daily demand for hydrogen fuel. Light blue bars represent total daily production of electrolytic hydrogen through wind- and solar-based electrolysis. The value of each total is shown on the right-hand side of each bar.

2.2.3.2 Levelized Cost of Hydrogen

Under the centralized production network, the LCOH production alone was relatively stable between $2.82/kg to $2.93/kg. However, the delivered LCOH varied between $1.88/kg to $12.20/kg (Figure 6). The main mode of distribution in the centralized model was trucking of gaseous hydrogen, as it is only favorable to transport hydrogen in temperature-controlled liquid form for long distances and large quantities which are not yet present with the expected 2030 demand.

The LCOH for delivered hydrogen was lowest in urban areas that have high transportation sector demand and close proximity to an electrolyzer (Figure 6). The LCOH was generally higher in rural demand centers, which tend to be located farther from an electrolyzer due to the lower overall demand quantity.

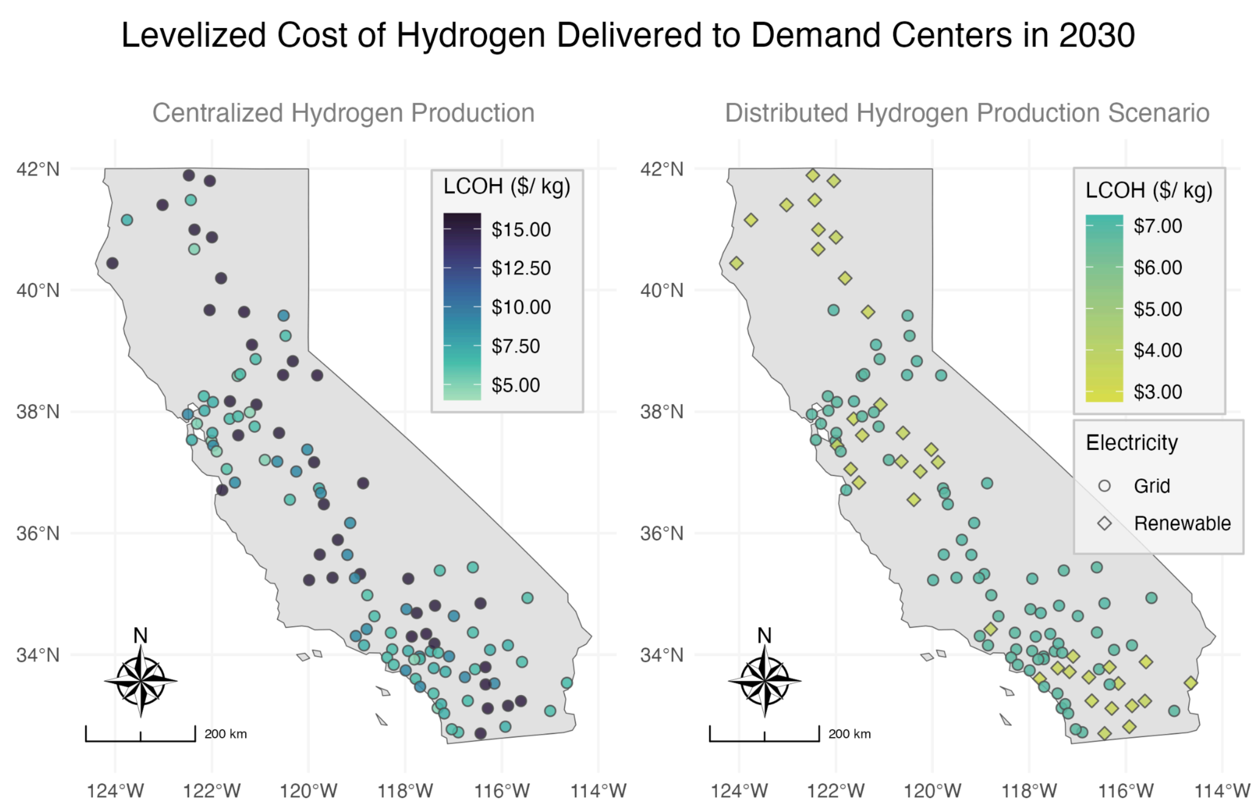

Figure 6. The levelized cost of hydrogen (LCOH) delivered to demand locations in 2030. The LCOH at each transportation sector demand location in 2030 are shown. (Left) The LCOH at each site under the centralized hydrogen production network varies between $4 - $16/kg. Most of the LCOH is attributed to the cost of distributing gaseous hydrogen by truck. (Right) The LCOH at each site under the distributed hydrogen production network varies between $3 - $7/kg. Circular markers indicate locations where hydrogen was produced from renewable electricity while diamond markers indicate locations where hydrogen was produced from connecting to the local electricity grid.

2.2.3.3 Biogenic Hydrogen

Total LCOH for biogenically produced hydrogen was compared to the total LCOH for each demand point in the centralized scenario. This helped identify locations where planned biomass-to-hydrogen facilities could deliver hydrogen at a lower cost than electrolytic sources (Figure 7). The LCOH production from biomass fell between $2.30/kg to $2.63/kg, while the LCOH of distributing this hydrogen ranged from $1.95/kg to $6.61/kg. In total, we found that six of the nine biomass conversion facility awardees were able to service 19 demand points at lower cost than the centralized electrolyzers. This ultimately fulfills 18.6% of statewide hydrogen demand.

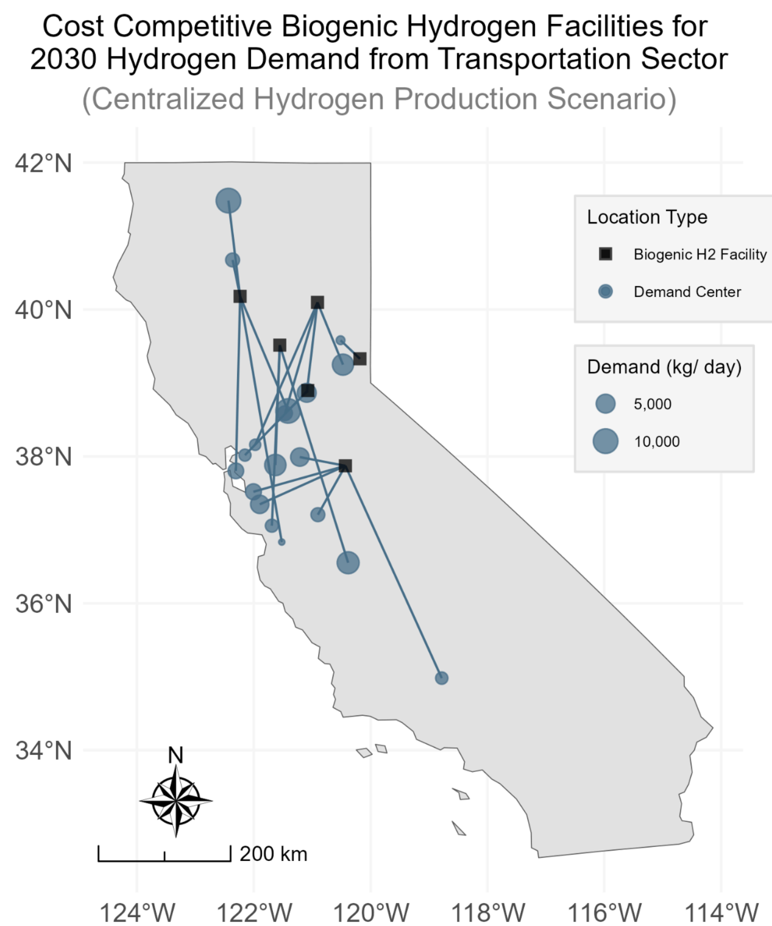

Figure 7. Biogenic hydrogen distribution for 2030, cost competitive to centralized electrolysis production. These 6 awardees from the California Department of Conservation's Forest Biomass to Carbon-Negative Biofuels pilot program were found to be able to supply hydrogen to 19 transportation demand points at lower cost than from the centralized electrolyzer network.

2.2.4 Distributed Production Network

Under the distributed production network, 195 small-scale electrolyzers with the capacity to produce up to 4,500 kg/day would be required to meet transportation sector demand in 2030. Each demand site would require between one to five small-scale electrolyzers to produce enough electrolytic hydrogen to meet its total demand (Table 3). The estimated CapEx for a 4,500 kg/day electrolyzer is around $5.67 million according to the H2A-Lite model. For 195 small-scale electrolyzers statewide, the total CapEx would be $1.11 billion. Although the statewide CapEx is lower for 195 distributed electrolyzers relative to 30 centralized ones, the cost per kilogram (CapEx/daily production capacity) is $1,262, which is roughly $200 more than the centralized model.

Table 3: The amount of electrolyzers needed to satisfy a single demand point (1-5), number of occurrences, and percent of total demand centers in 2030, where electrolyzers produce up to 4,500 kg/day. The number of small-scale electrolyzers, which have a maximum capacity of 4,500 kg/day, required to meet demand at individual locations in 2030 varies between 1-5. Only 1 electrolyzer is needed in 73% of demand locations.

Number of small-scale (4,500 kg/day) electrolyzers required (n)	Number of demand centers that will require n electrolyzers (2030)	% of total demand centers
1	85	73%
2	15	13%
3	6	5%
4	5	4.5%
5	5	4.5%

2.2.4.1 Levelized Cost of Hydrogen

Under the distributed production network, the LCOH varied between $3.15/kg to $6.93/kg (Figure 6). The variation in LCOH mainly stemmed from the price and source of electricity used. Electricity purchased from the grid is more expensive than renewable electricity purchased from power purchase agreements (PPAs) in part due to energy losses during DC to AC conversion (EIA, 2023). Note that the model utilizes an average grid price of electricity for the entire state, where the distributed electrolyzer is not co-located with a renewable electricity production site. However, these costs vary regionally in California and might be slightly lower or higher than the average in actuality. There is no cost to distribute hydrogen when small-scale electrolyzers are co-located with demand centers, so the entire LCOH at each demand point was solely based on production costs.

Part 3: DISCUSSION AND CONCLUSIONS

3.1 Significance of results

There are many factors that California must consider when developing a hydrogen supply network. In our analysis, we focused on three primary objectives: estimating the optimal siting locations, production quantities, and supply prices of electrolytic hydrogen in 2030; evaluating cost differences between centralized and distributed hydrogen production networks; and assessing barriers that limit the competitiveness and adaptation speed of hydrogen as an alternative fuel. Through this analysis, we examine two different hydrogen production methods: electrolytic and biogenic hydrogen. As our literature review demonstrates, these three objectives are key components in lowering the LCOH and helping hydrogen penetrate the market as an affordable fuel. However, there is still room for future research, especially into factors such as grid electricity, future demand, and pipelines.

3.1.1 Centralized and Distributed Systems

In our analysis, we focused on two hydrogen production systems: a centralized system and a distributed system. Both systems were modeled to produce enough hydrogen to meet the state's projected 2030 daily demand of 415,399 kg (Figure 3). In the centralized system hydrogen production occurs at 30 electrolyzers with a production capacity of 50,000 kg/day that are spread throughout the state (Figure 4). This hydrogen is then transported in a gaseous form to the nearest demand centers. In total this system has a maximum production potential of 1.5 million kg of hydrogen per day, significantly more than the state's daily demand of 415,399 kg. However, electrolyzers have a lower utilization rate than their production potential, so it is likely that this system would not actually produce 1.5 million kg of hydrogen per day (H2A-Lite, 2023). It is also beneficial for the state to have extra hydrogen stored, for periods when renewable energy generation is low (Lundbland et al, 2023). For the centralized system, the average LCOH of hydrogen ranges from approximately $5 per kg to $15 a day, with demand centers that are located near an electrolyzer having lower LCOHs, due to lower transportation costs (Figure 6), indicating the importance of transportation costs in the overall LCOH.

In the distributed system production occurs directly at the point of demand. To satisfy 2030 demand this requires 195 electrolyzers producing approximately 4,500 kg of hydrogen a day (Figure 5). With electrolyzers operating at maximum capacity, this system produces 877,500 kilograms a day. This is more than double California's daily demand of 415,399 but less than the 1.5 million kg per day produced by the centralized system. The distributed system has a smaller maximum capacity than our centralized system, because the smaller electrolyzers, as well electrolyzers drawing from the grid, have a higher utilization rate than larger electrolyzers or those drawing power from renewable resources (H2A-Lite, 2023). Therefore, they require less room for error and a lower overall capacity. The LCOH of these electrolyzers ranges in price from $3 to $7, and is generally dependent on where the electrolyzers source their electricity (Figure 6). Electrolyzers that source their electricity through

PPAs from renewable sources generally have lower energy costs than those that source energy from the CAISO grid (Figure 6).

Along with analyzing the LCOH of varying types of electrolyzer systems, we also examined the LCOH of biogenic hydrogen by including eight biogenic hydrogen production centers funded by the California Department of Conservation. We integrated these biogenic hydrogen production centers into the centralized production network. Ultimately, we found that six out of the eight biogenic hydrogen production facilities that were awarded funding had a lower LCOH than electrolytic hydrogen in the same region. For 18.6% of the state, the cheapest source of hydrogen was from a biogenic source. Since all biogenic production centers were located in Northern California, all but one of the 19 areas demanding biogenic hydrogen were located in Northern California (Figure 7). The LCOH of biogenic hydrogen ranged from $4.40 to $8.91, with prices largely depending on the distance between the facility and the demand center, and the amount of hydrogen produced at each facility, as larger facilities benefit from economies of scale. The LCOH without transportation varied from $2.30/kg to $2.63/kg while the levelized cost of transportation varied from $1.95/kg to $6.61/kg, meaning that for some facilities, transportation costs made up the bulk of the overall LCOH. Since biogenic hydrogen production facilities are all clustered near the Sierra Nevadas, there were instances of facilities out-competing other facilities. A larger biogenic hydrogen production facility, located slightly closer to a demand center, could easily outcompete smaller production facilities, located slightly further away. Ultimately this shows the importance of pipelines as a source of transportation. If pipelines were built out from biogenic facilities, it may be possible for biogenic hydrogen to also fulfill Southern California hydrogen demand and all eight facilities to be cost-effective.

One problem that our analysis indicates is that there is mismatched hydrogen supply and demand between counties. For example, some counties such as Kern, Tehama, and Placer can produce much more hydrogen than they are expected to demand. Whereas other counties such as Los Angeles, San Joaquin, and Sacramento are expected to demand much more hydrogen than they can produce (Table 2). Ultimately, the state has enough hydrogen production potential to meet state demand, so county-specific gaps could theoretically be closed. Counties that require more hydrogen to fulfill their demand should make deals with other counties to acquire their excess hydrogen. This would balance the mismatch between supply and demand.

3.1.2 Cost Differences Between Systems

The delivered LCOH is the main marker for assessing the economic viability of the two hydrogen supply networks. Three factors play into this delivered LCOH, CapEx for the infrastructure buildout, CapEx per kg of hydrogen produced, and distribution costs. Since trucking hydrogen is the most feasible distribution method in the study's 2030 timescale, distribution is costly. It also increases in price as hydrogen is transported further distances. This results in a tradeoff between achieving a centralized system with a low CapEx per kg of hydrogen and high distribution costs or a distributed system with high CapEx per kg and low distribution costs.

3.1.2.1 CapEx

A centralized network requires more capital to build than a distributed network. The estimated CapEx to build the 30 large-capacity electrolyzers for the centralized network is $1.59 billion while the CapEx of the 195 small-scale electrolyzers in the distributed network requires roughly $1.11 billion. The centralized network could produce up to 1.5 million kg/day while the distributed network would produce up to 877,500 kg/day. This means the centralized network could produce 1.7 times more hydrogen than the distributed network with a $490 million difference in CapEx. The CapEx per kilogram cost of hydrogen is lower for centralized and higher for distributed meaning that centralized benefits from economies of scale.

Since the DOE awarded California up to $1.2 billion in funding for its hydrogen hub (*Regional Clean Hydrogen Hubs*, n.d.), the distributed network CapEx could theoretically be covered with just federal funding. If California were to build out the centralized system, it would require additional funding from the state government or the private sector to supplement federal funding.

It is important to note that the 2030 hydrogen demand in California is projected to be 415,399 kg/day. Both supply networks' production potential overshoots the hydrogen demand. For the distributed network, this means the 195 electrolyzers need to be operating at about 47% capacity each day to meet the demand. The 30 electrolyzers in the centralized network would only need to operate at about 28% capacity to meet daily demand. This means that as hydrogen demand continues to grow, both networks are future-proofed. The distributed network is more right-sized for 2030 demand but the centralized network is more future-proofed than the distributed network as demand grows into 2050. Eventually, these factors will impact how much more CapEx is needed in the future beyond the 2030 timescale.

3.1.2.2 Distribution Costs

The two distribution options for hydrogen are trucking and pipelines. Trucking hydrogen is the most viable option today but it is expensive. Transporting hydrogen by pipelines is cheap but we assume they are not going to be operational by 2030. This is because there needs to be either dedicated pipelines or existing pipeline retrofits for this distribution method to be feasible. Hydrogen is typically trucked in gaseous form for short distances and liquid form for long distances. Liquid hydrogen is more energy-dense than gaseous hydrogen, however, since it has a low boiling point it can boil off during delivery. Thus trucking hydrogen long distances is not only expensive, it could also result in higher efficiency losses.

These distribution costs from trucking make the delivered LCOH higher in centralized systems than in the distributed system. Although centralized systems benefit from marginally lower production costs, the distribution costs far outweigh the benefits of the economies of scale that centralized production brings. This ultimately results in a lower delivered and total LCOH in the distributed system than in the centralized system by 2030, which is on par with the existing findings in a similar analysis for European countries (Lundblad et al., 2023).

3.1.3 Barriers to Competitiveness and Speed of Adoption

Two barriers that can limit the speed of green hydrogen production and deployment as a sustainable fuel include permitting and public perception. In a centralized network, there are larger permitting barriers, longer construction timelines, higher start-up costs, and higher distribution costs (Squadrito et al., 2023). These systems require proximity to utility-scale solar or wind projects and sufficient clean water resources (Lundbland et al, 2023). While a centralized system facilitates a more streamlined hydrogen hub buildout with fewer sites to permit, the start-up costs are higher due to the scale of each electrolyzer project (Lundbland et al, 2023). However, a distributed system buildout could be fragmented as there is a bigger number of projects across more jurisdictions with varying permitting requirements and timelines. There could also be varying levels of skepticism and excitement about hydrogen production and use across the state (Arnold and Beck, 2023). Appendix F discusses permitting and public perception in further detail.

3.2 Sources of Error

Several sources of error should be considered in our results. Firstly, we did not incorporate existing sources of hydrogen production into our analysis. According to the Department of Energy, all 2030 demand throughout the United States is already met by proposed projects (DOE, 2023) . As we lacked access to information about these projects, our analysis may not reflect where hydrogen production will actually occur in 2030. However, our results still provide a clear picture of what efficient hydrogen production could look like in the state.

A second source of error is that our project uses general electricity pricing. Electricity prices vary based on time, season, and region, and are not a single flat rate (CAISO, 2023). By not specifying this, our LCOH calculations of grid-produced hydrogen may not be entirely accurate. This could influence whether it is more affordable to use small grid-powered electrolyzers, or import hydrogen from larger renewable-powered electrolyzers in certain regions.

A final source of error is that our analysis did not consider high or low hydrogen demand scenarios. Therefore our projections could be inaccurate if demand shifts in the future, and more or less hydrogen is demanded than what is projected in the data we used. Adding high and low scenarios would make the analysis more robust.

3.3 Directions for Future Research

3.3.1 Supply

3.3.1.1 Land Cost

The NREL H2A-Lite model that we used to derive the LCOH used an average land cost for the entire Pacific region of the U.S. but land costs in California vary drastically by geographic region. For a more accurate analysis of the LCOH, future research should overlay high-resolution private land value data from the PLACES Lab (Nolte, 2020). A large portion of the state is publicly-owned land with more fragmented land cost data. Roughly 45% of the land in California is owned by the federal government. The agencies that own the most public land in the state are the U.S. Department of Agriculture Forest Service, Bureau of Land Management (BLM), and National Park Service. Most notably, the BLM is proposing the Renewable Energy Rule, which aims to reduce fees for renewable energy projects by 80% (Rights-of-Way, Leasing, and Operations for Renewable Energy, 2023). Once this rule is adopted, it has the potential to decrease the right-of-way fees and rent schedule fees for utility-scale renewable energy on public lands. Although the data is disparate for public lands in California, the private land cost and BLM land cost incentives would add a layer of robustness to the LCOH in the modeled scenarios.

3.3.1.2 Grid Electricity

As mentioned in previous sections, the grid electricity price used in our analysis for the distributed electrolyzers is an average per the NREL H2A-Lite model. Though grid electricity is still likely to be higher than renewable electricity purchased from an onsite generator through a PPA, real grid prices vary temporally and spatially across the state (CAISO, 2023). Therefore the actual levelized cost of energy (LCOE) of grid powered electrolyzers would vary across the state. Though using this average helps to generally compare financing the centralized electrolysis siting scenario with the distributed electrolysis scenario, it does not capture specific costs depending on electrolyzer location. A more in-depth future analysis should average the locational marginal price (LMP) of the closest California Independent System Operator (CAISO) pricing node (CAISO, 2023).

Additionally, a drawback of utilizing grid power rather than confirmed renewable electricity from PPAs is that the electricity is not necessarily renewable or “green” depending on the time of day, weather, and how the power is generated (CAISO, 2023). As a result, the carbon footprint of the hydrogen produced will be slightly higher from electrolyzers operating from grid power rather than from on-site renewables. Fortunately, as California continues to introduce cleaner fuel sources into its grid, this carbon footprint will continue to shrink. In future research, performing some carbon accounting to compare the output from the two sources of electricity would be beneficial, particularly if meeting the new renewable energy supply pillar is required for the 45V PTC.

3.3.1.3 Water Scarcity

A second direction for future research would be to incorporate water scarcity data into the model. As stated previously, 19 counties in the state are situated on critically overdrafted basins, and use at least some portion of their water for agriculture (California Department of Water, 2023). Therefore, the state needs to consider the availability and existing sources of demand when locating electrolyzers. One way to include water scarcity in the model would be to incorporate spatial data from the California Department of Water Resources. By incorporating this data, the model could show which electrolyzers would be located in areas with high water scarcity, and either find another way to fulfill hydrogen demand, or consider a sustainable way to obtain water supply. If incorporated into the model, this could help to address the environmental justice communities concerns about water use (cite). Appendix D reviews sustainable ways to obtain water in regions that suffer from water scarcity.

3.3.2 Future Demand

Our current model locates electrolyzers to fulfill the demand for the year 2030 but does not consider how demand could grow past this. As electrolyzers have an operating period of around 40 years, it would be beneficial to model out demand past 2030, to ensure that electrolyzers are optimally positioned for years to come (H2A-Lite, 2023). By running the same model with 2050 demand data, preferably for low, medium, and high demand scenarios, the state could compare the optimal locations of electrolyzers in 2030 and 2050 to see where there is overlap, and to see how demand changes. The state could then decide which areas should be prioritized for electrolyzer location by 2030, and where electrolyzers should be added as demand increases by 2050. The state could also see if there are regions where demand will fall off between 2030 and 2050, and determine if it would be worth locating electrolyzers in an area with only temporary demand. It would also be helpful to model the temporal buildout of specific facilities between 2030 and 2050.

Another aspect of future demand to consider qualitatively is the electrolyzer supply chain. PEM electrolyzers are at a technology readiness level of 9 so the technology is viable but has not reached commercialization. Some materials are not available domestically, such as iridium, yttrium, platinum, strontium, and graphite (Water Electrolyzers and Fuel Cell Supply Chain, 2022). This could create supply chain vulnerabilities, especially for large electrolyzers required in the centralized supply network.

3.3.3 Ancillary Distribution Components

3.3.3.1 Pipelines

Dedicated hydrogen pipelines are not expected to be a major source of transportation for hydrogen produced by 2030, despite pipeline projects planned for Los Angeles and other concentrated demand areas (Fulton, et al., 2023). However, in later demand years such as 2050, it is more likely that dedicated hydrogen pipelines can be a more prevalent source of hydrogen transportation in addition to liquid and gaseous trucking. Additionally, since higher hydrogen demand quantities are expected in 2050, pipelines can offer a more cost effective transportation route than either trucking method. Therefore, incorporating an analysis of potential or planned hydrogen pipelines by 2050 could alter the optimal location of electrolyzers so it reflects what will be more economical in later years. Future research should also consider the feasibility of pipelines that redistribute biogenic hydrogen produced in Northern California to other regions in the state. This could potentially result in lower distribution costs and thus a lower totall LCOH of biogenic hydrogen.

To support California’s climate initiatives, there are projects that aim to eventually blend hydrogen at 5% into natural gas pipelines. In 2022, California consumed

2,056,267 MMcf of natural gas (Topolski et al, 2022). For an equivalent energy density, 8537.6 kg of hydrogen would replace 1 MMcf of natural gas. Therefore, blending 5% hydrogen into natural gas pipelines would require over 800 million kg of hydrogen in one year, or almost four times the expected demand by transportation end users in 2030 (Topolski et al, 2022). However, as growing demand from hydrogen end-uses drives up the production capacity in future years, natural gas pipeline blending may be an additional opportunity for hydrogen to contribute to California's clean energy goals.

3.3.3.2 Hydrogen Storage

Another element that our model does not consider but would be helpful in future analyses is hydrogen storage. Hydrogen storage could help smooth out the seasonal production variation of both systems, especially the centralized system since it produces much larger quantities of hydrogen. Since standalone renewables produce more abundant and cheaper electricity in the summer months, this translates to higher quantities of green hydrogen production at a lower cost during that time (Reed et al., 2020).

The RESOLVE resource planning model from the California Public Utilities Commission shows that in the mid-2020s there will be an increased need for stored renewable energy to generate power during times of low solar and wind generation (Reed et al., 2020). Currently, the RESOLVE model does not consider hydrogen as a potential energy source during times of low renewable production potential, however as hydrogen is an energy carrier, it could be used to fill the gap between supply and demand during these times (Reed et al., 2020). This would be especially true if the cost ratio of electrolyzers to batteries decreases, making hydrogen a more affordable energy storage option. Therefore future studies should include the potential demand for hydrogen in energy storage solutions. This way hydrogen could help ensure energy stability and security throughout the state. Additionally, the CEC is currently soliciting grant proposals to research the feasibility of underground hydrogen storage in the state (*Feasibility of Underground,* n.d.). The findings from this forthcoming research could also factor into California's in-state storage potential and costs.

Other research found that even after factoring in storage, there are still lower production and storage costs in the centralized system than in the distributed system (Lundblad et al., 2023). Moreover, that same research found that in all comparisons of centralized versus distributed systems in different regions in Europe, the distributed system always resulted in a lower total LCOH (Lundblad et al., 2023). It would be beneficial to conduct a robust analysis of how storage costs impact the delivered LCOH in California.

3.3.4 Mixed Centralized and Distributed Network

As mentioned above, our analysis assessed the feasibility of the centralized and distributed supply network but not a combination of the two. While there are strengths and weaknesses to each supply network, the most cost-effective hub supply network is the distributed network. However, if the same analysis is conducted at a more granular level looking at sub-regions of the state, it is possible that the centralized scenario may be more cost-effective in some areas than the distributed system. Future research should consider which areas would benefit from smaller distributed electrolyzers, and which areas would benefit from larger electrolyzers. For areas that have lower demand quantities but high transportation costs, it may make sense to have a standalone distributed production site. If hydrogen pipelines and storage infrastructure are built, this could also have an impact on the economic feasibility and cost-effectiveness of California's hydrogen hub buildout, especially on a 2050 timescale.

3.4 Conclusion

Our analysis emphasized three primary objectives: estimating the optimal siting locations, production quantities, and supply prices of electrolytic hydrogen in 2030; evaluating cost differences between centralized and distributed hydrogen production networks; and assessing barriers that limit the competitiveness and adaptation speed of hydrogen as an alternative fuel. Ultimately this analysis provided us with several major takeaways. Firstly, it revealed the mismatch between potential supply and demand throughout the state. Some counties produce more hydrogen than their county demands, while others have unmet demands. Therefore counties should collaborate to balance their supply and demand needs. Secondly, biogenic hydrogen can meet 18.6% of the state's demand, but predominantly in Northern California, due to high transportation costs. This leads to the state's biomass conversion facilities competing against each other to supply demand centers and results in two facilities not being cost-competitive. Thirdly, our model compared the total LCOH in two supply network types, centralized and distributed, and found the distributed network to be the more cost-effective infrastructure buildout strategy to meet 2030 transportation sector demand. This is largely due to its significantly lower distribution cost. Despite the centralized network's ability to achieve economies of scale and lower hydrogen production costs, the low transportation costs of the distributed system far outweigh those benefits. Ultimately, all of these results emphasize the importance of incorporating pipelines into a hydrogen production network. Pipelines would resolve the county-level mismatch between production and demand, allow biogenic hydrogen to be transported throughout the state, and lower the LCOH of a centralized production network. Therefore, it is vital for future research on California's hydrogen hub to include the construction of hydrogen pipelines and pipeline retrofits.

Appendices

Appendix A: NREL reV Assumptions

Distributed Electrolyzer (4500 kg per day) The reV tool begins with base wind speed and solar global horizontal irradiance (GHI) data, excludes unusable areas, and then calculates output capacity based on technological assumptions for each technology (land-based wind and solar PV).

Base Resources & Technological Assumptions

Wind speed data come from NREL's Wind Integration National Dataset (WIND) toolkit, which includes output from a computer model of instantaneous meteorological conditions for over 100,000 sites in the U.S. from 2007-2013. The meteorological data are granular down to weather conditions in a 2-km x 2-km grid cell.

Below are the technological assumptions for land-based wind turbines to capture this wind speed resource as utilized by the reV model and published by NREL. There are 3 classes of turbines utilized for electrical power generation, determined by wind speed.

NREL reV tool parameters

Table A-1. Land-Based Wind Technology Parameters

Parameter	Unit	Class 1	Class 2	Class 3
Wind speed (v)	Meters/Second	v > 9	8 > v> 9	v <8
Power density	MW/km^2	3	3	3
Rated output	kW	1,500	1620	1620
Hub height	Meters	80	80	80
Rotor diameter	Meters	77	82.5	100
Total losses	Percentage	16.7	16.7	16.7

Solar resource data come from NREL's National Solar Radiation Database (NSRDB), which contains half-hourly to hourly meteorological data of global horizontal, direct normal, and diffuse horizontal irradiance covering the United States, granular to grid cells of 4 km x 4 km. The global horizontal irradiance is captured by solar PV cells with the following technological assumptions. Solar PV technology is ubiquitous across the study area in reV and does not vary by resource value, unlike with land-based wind.

Table A-2. Utility-Scale Photovoltaic Technology Parameters (Urban and Rural)

Parameter	Unit	Utility-Scale PV
Power density	MW/km2	32
System capacity	kW	20,000
DC-to-AC ratio	Unitless	1.3
Inverter efficiency	Percentage	96
Array type	Categorical	1-axis tracking
Tilt	Degree	0
Azimuth	Degree	180
Losses	Percentage	14.07566
Module type	Categorical	Standard
Standard Ground cover ratio	Unitless	o.4

Spatial Exclusions

Areas that are unusable for electrical capacity are excluded from output by reV. The base exclusions include protected areas, urbanized areas, natural features, and terrain features. This project utilized the most 'Limited Access' scenario with most restrictive exclusions, including regulatory barriers such as wind/solar bans.

Spatial Exclusions include:

- Slope greater than 5% (solar PV) and 20% (land-based wind)
- Urban areas including suburban
- Land use exclusions
  - Open Water
  - Woody Wetlands
  - Emergent Herbaceous Wetlands
  - Deciduous Forest
  - Evergreen Forest
  - Mixed Forest
- U.S. Bureau of Land Management Areas of Critical Environmental Concern (including historical sties, sites of scenic or cultural value, etc.)
- Forest Inventoried Roadless Area from the U.S. National Forest Service
- Federal Lands, National
  - Battlefields
  - Conservation Areas
  - Fish Hatcheries
  - Monuments
  - Parks
  - Recreation Areas

    - Scenic Areas
    - Wilderness Areas
    - Wildlife Refuges
    - Wild and Scenic Rivers
    - Management Areas
    - Forests
    - Grass Lands
    - Land for Air Force Guard, Air Force, Army, Army Guard, Coast Guard, Marine Corps, Navy
- Airports
- Protected Areas from the U.S. Geological Survey Gap Analysis Program
- National Conservation Easement areas managed for biodiversity
- Ridges

Appendix B: H2A-Lite Assumptions

Type of System	Solar	Wind	Grid
LCOH	$2.83	$2.69	$5.80
Start Up Year	2030	2030	2030
Region	Pacific	Pacific	Pacific
Feedstock Impact on Price per kg H2	$0.77	$1.32	$5.03
Feedstock Usage per kg H_2	55.500[kWh]	55.500[kWh]	55.5 kwh
Feedstock Startup year costs	0.020[$/kWh]	0.032 [$/kWh]	0.092 $/kwh
Water Costs per kg H2	$0.06	$0.06	$0.06
Water use per kg H2	3.780 gallons per kg	3.780 gallons per kg	3.78 gallons per kg
Water Price per Gallon	$0.0080 per gallon	$0.0080 per gallon	$0.008 per gallon
Total installed capital cost [2020$]	$5,688,635	$5,688,635	$5,688,635
Fixed OpEx w/o replacements [2020$/year]	$277,425	$277,425	$277,425
Variable OpEx [2020$/kg H_2]	$0.029	$0.029	$0.029
Normalized CapEx	1,264[$/kg-day]	1,264[$/kg-day]	1,264[$/kg-day]
System life [years]	40	40	40
Utilization [%]	27%	47%	86%
Production Rate	1,215[kg/d]	2,120[kg/d]	3,869[kg/d]
Annualized replacement costs [2020$/year]	83,935	83,935	83,935
Land Rent (2020$/year)	$20,000	$20,000	$20,000

Appendix C: Hydrogen Transportation Costs by Mode and Quantity

The following tables show the LCOH transportation by total distribution distance as well as system capacity, in a low-pipeline utilization scenario. Numbers are in US$.

The table below shows the levelized cost of transporting hydrogen through gaseous trucks, when the station capacity is 0.5 tons/day.

	Amount of H2 Being Transported Daily					
Distance (km)	**0.5 tonnes/day**	**1.0 tonnes/day**	**1.5 tonnes/day**	**2.0 tonnes/day**	**3.0 tonnes/day**	**5.0 tonnes/day**
10	12.1	6.14	4.15	3.15	X	X
20	12.12	6.15	4.16	3.16	2.2	1.9
30	12.14	6.16	4.17	3.18	2.21	1.91
40	12.15	6.18	4.18	3.19	2.22	1.92
50	12.17	6.19	4.19	3.2	2.23	1.93
60	12.19	6.2	4.21	3.21	2.24	1.94
80	12.22	6.23	4.23	3.23	2.26	1.96
100	12.26	6.25	4.25	3.25	2.28	1.99
120	12.29	6.28	4.27	3.27	2.3	2.01
140	12.32	6.3	4.3	3.29	2.32	2.03
160	12.36	6.33	4.32	3.32	2.34	2.05
180	12.39	6.36	4.34	3.34	2.36	2.07
200	12.43	6.38	4.37	3.36	2.38	2.09
250	12.51	6.45	4.42	3.41	2.43	2.15
300	12.6	6.51	4.48	3.47	2.48	2.2
350	12.68	6.57	4.54	3.52	2.53	2.25
400	12.77	6.64	4.6	3.57	2.58	2.31
450	12.85	6.7	4.65	3.63	2.63	2.36
500	12.94	6.77	4.71	3.68	2.69	2.41
600	13.1	6.89	4.82	3.79	2.79	2.52
700	13.27	7.02	4.94	3.9	2.89	2.63
800	13.44	7.15	5.05	4.01	2.99	2.73
1000	13.78	7.41	5.28	4.22	3.19	2.95
1200	14.12	7.67	5.51	4.44	3.39	3.16
1500	14.63	8.05	5.86	4.76	3.69	3.48

This table shows the levelized cost of transporting hydrogen through gaseous trucks, when station capacity is 5 tons/day.

	Amount of H2 Being Transported Daily					
Distance	**0.5 tonnes/day**	**1.0 tonnes/day**	**1.5 tonnes/day**	**2.0 tonnes/day**	**3.0 tonnes/day**	**5.0 tonnes/day**
10	13.58	7.62	5.63	5.63	3.67	3.37
20	13.6	7.63	5.64	4.64	3.68	3.38
30	13.62	7.64	5.65	4.65	3.69	3.39
40	13.63	7.65	5.66	4.66	3.7	3.4
50	13.65	7.67	5.67	4.68	3.71	3.41
60	13.67	7.68	5.68	4.69	3.72	3.42
80	13.7	7.71	5.71	4.71	3.74	3.44
100	13.73	7.73	5.73	4.73	3.76	3.46
120	13.77	7.76	5.75	4.75	3.78	3.49
140	13.8	7.78	5.78	4.77	3.8	3.51
160	13.84	7.81	5.8	4.79	3.82	3.53
180	13.87	7.83	5.82	4.82	3.84	3.55
200	13.9	7.86	5.84	4.84	3.86	3.57
250	13.99	7.92	5.9	4.89	3.91	3.62
300	14.07	7.99	5.96	4.94	3.96	3.68
350	14.16	8.05	6.02	5	4.01	3.73
400	14.24	8.12	6.07	5.05	4.06	3.78
450	14.33	8.18	6.13	5.11	4.11	3.84
500	14.41	8.24	6.19	5.16	4.16	3.89
600	14.58	8.37	6.3	5.27	4.26	4
700	14.75	8.5	6.42	5.38	4.37	4.1
800	14.92	8.63	6.53	5.48	4.47	4.21
1000	15.26	8.89	6.76	5.7	4.67	4.42
1200	15.6	9.14	6.99	5.92	4.87	4.64
1500	16.11	9.53	7.34	6.24	5.17	4.96

Appendix D: Policies to Decrease LCOH of Production

Even with strategic placement and distribution networks, there are still areas of the state where, according to our analysis, hydrogen will be above $4 per kg in 2030. This is where policies come into play. In order to make hydrogen cost-competitive with diesel throughout the state, both California and the federal government need to cooperate on existing policy or adopt new policies that lower the LCOH.

One example of an existing policy that can reduce the LCOH is the Clean Hydrogen Production Tax Credit or 45V PTC. This credit, as discussed in our literature review, pays producers up to $3 per kilogram of clean hydrogen produced over ten years. Therefore it could reduce the cost of hydrogen from a range of $5 to $13 to $2 to $10 for a centralized system For a distributed system, this could reduce the current $3 to $7to $0 to $4. However, the requirements needed to qualify for the 45V PTC are not yet decided. It is possible that in order to qualify for the credit, producers may need to meet conditions known as the three pillars: additionality, regionality, and time matching. The goal of the additionality is to ensure that hydrogen production comes from new clean energy sources so that states are not using clean energy to produce hydrogen, and then using energy from fossil fuels to replace the clean energy that was diverted to hydrogen production. The proposed guidelines currently state that in order to meet the additionality requirement energy must be from a new source explicitly created for hydrogen generation, that this new source must be built within three years of initial installation of the electrolyzer(s), and that capacity can be added to an existing project, to help it qualify (Great Plains Institute, 2024). The goal of the time matching is to align the time that hydrogen is using power to the time that power is being generated, this way hydrogen generation will not put additional strain on the grid. Currently, the proposed requirements state that the annual amount of energy demanded by hydrogen generation must match the annual amount of energy produced (Great Plains Institute, 2024). However, starting in 2028, there must be an hourly match between energy demand and energy generation. The goal of regionality is that the energy produced for the electrolyzer should be able to reach it. Proposed rules define this by stating that electricity must be generated within the same ISO region (Great Plains Institute, 2024).

The 45V PTC makes it appear that grid electricity is not an ideal source of energy, since the majority of electricity throughout the United States is generated from greenhouse gas and energy-intensive technologies (*Hydrogen Production: Electrolysis, n.d.*). However, in 2021, California reported that 37.2% of the state's electricity came from Renewables Portfolio Standard (RPS) sources (*New Data Shows*, 2023). When including hydroelectric and nuclear power, roughly 59% of the state's electricity came from carbon-free sources that same year (*New Data Shows*, 2023). The makeup of zero-carbon sources in the California grid will continue to increase since SB 100 (2018) shifted the RPS goal to 60% by 2030 (*New Data Shows*, 2023). When hydrogen developers use grid electricity they will likely need to sign a PPA to ensure that the electricity they use is generated using a proportional amount of zero-carbon sources like solar or wind. The PPA may also require time-matching and close regionality of the electricity generation to the electrolysis site. In certain areas with limited renewable energy potential, using grid electricity for small-scale projects may result in a lower LCOH than the centralized scenario which demands trucking costs. However, since this does not meet the additionality requirements, hydrogen sourced using green grid energy may not qualify for the tax credit.

If these regulations go through, it will be more difficult for California hydrogen producers to qualify for the tax credit. This is because California has many different demands of electricity, such as a large population, and industries, such as the tech industry, that demand a lot of energy (CAISO, 2023). This means it is difficult to guarantee that a power source will be used specifically for hydrogen. It is also difficult for utility-scale solar and wind companies to get permits, due to California's strict environmental regulations and due to the fact certain localities have banned utility-scale solar altogether. However, the regionality guideline does allow for some flexibility, as electricity can be generated for hydrogen production anywhere in the state. This means electricity can be produced for hydrogen production in one part of the state, while hydrogen itself is generated in San Bernardino, a county with a ban on utility-scale solar. Hopefully, the generality of the regionality pillar could make 45v PTC attainable to some producers.

A second way to lower the price of hydrogen and increase development speed is through a carbon contract for differences (CCfD). Studies have shown that CCfDs are one of the most effective ways to introduce hydrogen into the market. A CCfD would pay the developer of a hydrogen project the difference between a tendered strike price and the actual carbon price, for the abated amount of emissions. (Hoogsteyn et al, 2023). In California, the carbon market available would likely be credits generated by the state's Low Carbon Fuel Standard (LCFS) program (California Air Resources Board, 2024), while the tenderized strike price would be $4, or the LCOH needed to integrate hydrogen onto the markets. Since hydrogen producers would qualify for credits for their creation of a low carbon fuel, they could sell these credits to industries making fossil fuels. The credits could help hydrogen producers lower LCOH. Then the state could pay producers to fill in the gaps, under the CCfD. For example, if the sale of credits only lowered the price of hydrogen to $5 per kg, the state could pay producers the difference to lower the price to $4. However, if the producer were to make enough on credits to sell hydrogen for $3, they would have to pay the state back that difference. This keeps hydrogen at a stable price of $4 per kg, for the agreed-upon contract period.

Ultimately, CCfD has three main objectives. Firstly, they aim to reduce the risk of investing in renewable technologies, by financing through debt as opposed to equity. Secondly, they show that the government is actually committed to their climate goals, and will not back down from regulations while continuing to provide support to green initiatives. This gives businesses enough certainty to invest in green technologies. Thirdly, they bring down the costs of learning for developers investing in new technologies such as hydrogen. This would be especially beneficial if the state wishes to use hydrogen to decarbonize different industries, as the technology is more difficult and expensive to develop than it is for the transportation industry (Hoogsteyn et al, 2023).

A third policy that could lower the LCOH for biogenic hydrogen, is biomass subsidies. This can be executed by subsidizing the transportation of biomass to biogenic hydrogen production facilities. For example, the My Sierra Woods Biomass Transportation Incentive initially subsidized biomass by $4-$28 per BDT, depending on how far the biomass needed to travel to reach the facility (Calfire, 2023). However, this subsidy rate proved to be ineffective. The program then doubled the amount of the subsidy, which resulted in almost 100,000 BDTs of biomass being delivered to biofuel production facilities (Calfire, 2023). Matching the payments that landowners receive by providing facilities with biomass, can also increase biomass production. This program ended in 2023 but has been one of the more successful biomass subsidy programs to date (Calfire, 2023).

Appendix E: Water for Electrolytic Hydrogen

As California is water-stressed, it is vital that California's hydrogen production not add additional demand to the state's water supply (WRI, 2021). Therefore, water used for hydrogen production must either come from a new source, from reused water or be diverted from another use. Research shows that there are three main ways water could be obtained for hydrogen production: desalinization, purification from water treatment plants, or purchasing through water markets. Each of these solutions has benefits and drawbacks and should be considered thoroughly before investment.

Desalinization

One way to add new water to California's water supply would be to build desalination plants. Desalination plants remove salt from seawater using thermal technology or membrane technology (Krishna, 2004). Salt can be removed from seawater thermally by heating the water and then collecting the condensed vapor or distillate, and using this to form water that could be used in electrolysis (Krishna, 2004). An example of thermal desalination would be multi-stage flash distillation or vapor compression distillation (Krishna, 2004). There are two main forms of membrane technology: Electrodialysis and reverse osmosis. In electrodialysis an electric current pushes seawater through a membrane, leaving behind the salt, and producing freshwater (Krishna, 2004). In reverse osmosis pressure forces seawater through a membrane, producing a stream of fresh water, and a stream of salty brine (Krishna, 2004). Currently, both thermal and membrane technologies are equally used to desalinate seawater (Krishna, 2004).

Although the desalination capacity is seemingly unlimited, due to the large quantity of water in the ocean, both high capital costs and high energy requirements prevent desalination from being the best source of water for hydrogen production. For example, one Australian study found that an average desalination plant creates approximately 1000 L of water a day, or approximately 264 gallons, and that it costs approximately 200 million dollars to create 36 gigaliters (GL)gal of water, or approximately 9.5 billion gallons (Woods et al., 2022). In Australia, it was projected that 280 GL of water would be required to meet the nation's goal of producing 18 mt of hydrogen per year (Woods et al, 2022). This would require approximately 1.6 billion dollars in capital costs, to build additional desalination plants (Woods et al., 2022). Although California has different goals, one can assume that it would not be feasible for the state to take on such extreme costs and that desalination would cause the LCOH to rise until hydrogen was not cost-competitive with other fuels.

Desalination would also be infeasible due to the plant's high energy demands. It takes approximately 2,400 MWH to run a reverse osmosis plant producing 264 gallons of water a day (Woods et al., 2022). If California were to build enough plants to meet the state's demand for hydrogen, it would add a tremendous strain on the grid. Additionally, for the hydrogen to be truly "green" the plants would need to be powered by renewable energy, again increasing demand for solar and wind power. Since a significant amount of electricity is required to produce hydrogen without desalination, the state should acquire water from other sources.

Water Purification

A second way to acquire water for hydrogen production would be to reuse it. Water known as tertiary effluents, may be pure enough to be suitable for hydrogen production (Woods et al, 2022). Tertiary effluents derive from wastewater that passes through at least three stages of purification until it is pure enough to drink. It is heavily filtered, sometimes even undergoing reverse osmosis, to ensure all impurities are removed (*Water Treatment*, 2022). Los Angeles County alone produces 400 million gallons of treated sewage a day, so there is no shortage of available supply (Becker, 2023). The state of California is also already investing in the tertiary treatment of wastewater to support the state's drinking water supply. In July 2023, the state proposed Title 22 to the California Code of Regulations, which would allow tertiary effluents to be designated as potable water (Becker, 2023). To back up this proposal, the state allocated 80 million dollars to the Metropolitan Water District Of Southern California, to assist with the capital costs of building advanced water treatment plants. In total, construction of the new plant is expected to cost 3.4 billion dollars and will produce 115 million gallons of water per day (Becker, 2023).

As the state is already beginning to invest in these plants, it would make sense to co-locate electrolyzers along the facilities (Woods et al, 2022). This is especially true since the first plant will be located in Los Angeles County, which also has the highest hydrogen demand. Most following plants are likely to be located in urban areas as well, as urban areas produce the most wastewater, so updated water treatment plants have the lowest economies of scale in those areas (Becker, 2023). Since hydrogen is also demanded by the transportation sector in urban areas, by co-locating electrolyzers with water treatment plants the state could match supply with demand.

Water Markets

A final way to acquire water for hydrogen production would be to utilize the state's water markets. California's water market allows those who have rights to water to lease those rights for the short or long term or sell those rights permanently (Hanak et al., 2021). It is beneficial to have different types of leases on the market as short-term leases account for environmental concerns such as drought, as water can be bought by industries with the highest demand that are therefore willing to pay the highest cost, whereas long-term leases and permanent exchanges of rights can account for more permanent economic or demographic changes (Hanak et al., 2021). Most of the water that is traded is surface water, as groundwater is traded through specifically managed basins (Hanak et al., 2021).

Approximately 4% of all water used by cities or farms, or 1.5 million acre-feet (488,776,410,000 gallons) is traded annually (Hanak et al., 2021). Between 2012 and 2019, most water on the market was acquired by cities or San Joaquin Valley farmers specifically, with cities acquiring about 600 acre-feet (195,500,000 gallons) per year and San Joaquin Valley farmers acquiring 500 acre-feet (162,900,000 gallons) per year (Hanak et al., 2021). Despite this, farms currently own four times as many water rights as cities, giving them a large amount of power on the market (Hanak et al., 2021). Any group that is not a farm or city, has a lot less power on the water market. For example from 2012 to 2019 less than 100 acre-feet (32,590,000 gallons) were purchased for mix use (Hanak et al., 2021). Still, acquiring water on the state's water market would be cheaper than building desalination of water treatment plants, with water rights typically being sold at prices between $200 and $1,200 per acre-foot, depending on environmental conditions (such as drought) and total quantity available on the market (A Clear Solution for Water, 2024).

A final factor to consider concerning water markets is how purchasing water would affect electrolyzer locations. Approximately 72% of water in California is traded locally or regionally, meaning that rights generally stay within the same region (Hanak et al., 2021). This means that the area in which water rights were purchased would likely be the area in which hydrogen would be produced. Since such a large portion of rights are owned by farmers, this would likely mean that hydrogen production using purchased water would likely occur in the Central Valley, specifically the San Joaquin Valley. This hydrogen could potentially be used to fulfill hydrogen demand along Interstate5, while hydrogen produced to fulfill demand in urban areas could utilize water from wastewater treatment facilities.

Appendix F: Barriers to Rapid Hydrogen Adoption

Several factors that were not considered in our model can impact the speed of hydrogen hub adoption in California. This includes permitting speed and the public perception of hydrogen as a fuel source. The public perception of hydrogen is addressed in two ways, through environmental justice considerations and the Socio-Political Evaluation of Energy Deployment (SPEED) framework for analyzing energy technology deployment (Stephens et al., 2008).

Permitting Speed

The European Union began its deployment of hydrogen as an alternative fuel before the United States. An assessment done by Hylaw, a group of lawyers in the European Union trying to make hydrogen policy more efficient found four recommendations to streamline it (Floristean, 2019). Firstly, permitting standards should be standardized at the largest scale possible. In the European Union, this means each country should streamline its own standards, however, given the size of the U.S., it might make sense to do this on a state-by-state basis or to develop a national code that can be adopted and tweaked by the states according to their own needs. Countries that have streamlined permitting standards have found that the process no longer hinders development. The second recommendation provided by the organization was to streamline safety requirements. This could mean that all countries have similar safety requirements for hydrogen production so that electrolyzers and other equipment could be traded across borders, and so that production could be more efficient. Thirdly, Hydrogen refueling stations should be allowed in the same places where gas stations are allowed. This way operators of heavy-duty vehicles could have easy access to refueling stations, increasing demand. The fourth recommendation was for governments to pass policies that directly reduce the price of hydrogen, and that promote the development of appropriate infrastructure.

Failing to Address Environmental Justice Concerns

Environmental justice (EJ) is a priority for California and the federal government. Since there is top-down interest in ensuring a just energy transition, it is important to adequately engage with and take the EJ community's priorities into account. The California Environmental Justice Alliance (CEJA) and eight other community groups established a set of "Environmental Justice Equity Principles for Green Hydrogen in California"(Floristean, 2019). These principles are divided into three categories: production, storage & delivery, and end uses. Since the principles oppose biogenic hydrogen, this could result in additional opposition to the permitting of new biomass conversion facilities in the state. For storage & delivery, the EJ community places a strong emphasis on ensuring adequate safety measures and transparency for surrounding communities. Procedural justice and distributive justice are key when determining where pipelines are built and what safety mechanisms they utilize. The end uses principles focus on using hydrogen only where electrification is not feasible. ARCHES, the public-private partnership leading California's Hydrogen Hub buildout, established a Community Benefits Plan to engage with NGOs, tribes, labor groups, and more to ensure their input is taken into account when deploying hydrogen technologies (Community Benefits, n.d.).

Using the SPEED Framework for Energy Technology Deployment

The SPEED framework was developed by Stephens et al. (2008) to assess how myriad socio-political factors influence energy technology deployment. This framework is meant to be applied to specific emerging technologies in specific states (Stephens et al., 2008), which makes this a strong fit for studying which factors are facilitating or inhibiting the deployment of green hydrogen in California.

This framework could be integrated into the three levels of energy technology transition management: strategic, tactical, and operational. The strategic level is the highest level which examines overarching and long-term goals and objectives through researching the opinions of actors and broad policy goals. In the tactical level, the research focus is on the partnerships and negotiations between institutions and coalitions involved in planning and deploying the technology. The operational level looks at the institutions implementing relevant policies and what type of adaptations need to take place to realize the technology deployment. The SPEED framework is meant to be applied to three research methods, (1) policy review and analysis, (2) media analysis, and (3) focus groups and structured interviews with key stakeholders.

Policy Review and Analysis

This method can break down the legal, regulatory, and institutional factors that are enabling and hindering green hydrogen. California's Assembly Bill 8 (AB 8; Perea, Chapter 401, Statutes of 2013) provides annual reports on hydrogen fuel cell electric vehicles and refueling station development. Though the SPEED framework could supplement CARB's annual reporting. One way is to examine how broader stakeholder groups such as energy managers, developers, nonprofits, and others experience the implementation of hydrogen policies. Another method could be to assess the documentation of new procedural, rule, and structural changes that organizations need to make to facilitate greater hydrogen deployment.

Media Analysis

A media analysis can help assess the representation of policies and goals, understand local coverage of relevant policies and stakeholder groups, and uncover themes in local coverage of implementation and deployment. This framework was used to study the social context that led to successful deployment of a carbon capture and storage project in Saskatchewan (Hulbert and Osazuwa-Peters, 2023). It found two frames were pivotal to the success of the project's deployment, framing the province as a 'World Energy Leader' and having 'Managed Risks' (Hulbert and Osazuwa-Peters, 2023). A similar media analysis of a successful launch of a hydrogen production facility in California could be critical to understanding how socio-political and economic factors impact hydrogen hub deployment and diffusion. The findings from such an analysis could be applied by local leaders and stakeholders to address institutional and public perception-related roadblocks in the hydrogen hub buildout.

Focus Groups and Structured Interviews with Key Stakeholders

Focus groups could facilitate a deeper understanding of the perceptions of policy and coalition formation along with where hydrogen policy solutions tend to fail in the legislative process and why. It could also gather different perceptions of how institutions need to change or have changed to enable smoother implementation of new policies and technology deployments.

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