

## Article

# Low Carbon Scenario Analysis of a Hydrogen-Based Energy Transition for On-Road Transportation in California

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**Abstract:** Fuel cell electric vehicles (FCEV) are emerging as one of the prominent zero emission vehicle technologies. This study follows a deterministic modeling approach to project two scenarios of FCEV adoption and the resulting hydrogen demand (low and high) up to 2050 in California, using a transportation transition model. The study then estimates the number of hydrogen production and refueling facilities required to meet demand. The impact of system scale-up and learning rates on hydrogen price is evaluated using standalone supply chain models: H2A, HDSAM, HRSAM and HDRSAM. A sensitivity analysis explores key factors that affect hydrogen prices. In the high scenario, light and heavy-duty fuel cell vehicle stocks reach 12.5 million and 1 million by 2050, respectively. The resulting annual hydrogen demand is 3.9 billion kg, making hydrogen the dominant transportation fuel. Satisfying such high future demands will require rapid increases in infrastructure investments starting now, but especially after 2030 when there is an exponential increase in the number of production plants and refueling stations. In the long term, electrolytic hydrogen delivered using dedicated hydrogen pipelines to larger stations offers substantial cost savings. Feedstock prices, size of the hydrogen market and station utilization are the prominent parameters that affect hydrogen price.

**Keywords:** fuel cell vehicle; hydrogen demand modeling; hydrogen supply chain



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## 1. Introduction

California's latest greenhouse gas data show that the state was able to achieve its targets for 2020 as set out in the Global Warming Solutions Act of 2006 [1,2], but California, being true to its reputation as a global leader in the fight against climate change, has set itself even more ambitious targets for the future. In September 2018, Governor Brown signed into effect the SB 100 and the EO B-55-18, to put California on track to achieve carbon neutrality by 2045. In October 2020 this was reiterated, when California's Governor called for achieving statewide carbon neutrality by 2045. The transportation sector accounts for the largest share of GHG emissions in the state (close to 40%) and hence any decarbonization strategy will need to prioritize the transportation sector [3]. As assessed in the recent California university study the state will need to prioritize rapid increases in the sales of zero emission cars and trucks with a full transition by 2035 or 2040 at the latest [4].

Transport electrification is considered one of the most effective decarbonization strategies since it can be coupled with decarbonization of grid electricity to get close to zero net emissions. There are two prominent zero-emission vehicle (ZEV) technologies: battery electric vehicle (BEV) and hydrogen fueled cell electric vehicles (FCEV). FCEVs offer a driving experience closer to that of conventional vehicles owing to their shorter refueling time and longer range, making them look more attractive in comparison to a BEV especially in some vehicle segments like long haul trucks. California has enacted several policies to decarbonize the transportation sector such as the Zero Emissions Vehicle (ZEV) mandate, Low Carbon Fuel Standard (LCFS), Advanced Clean Truck program (ACT) and the Clean

Vehicle Rebate program (CVRP). These policies are technology agnostic, and it is difficult to predict how these and other policies will affect the market adoption of BEVs versus FCEVs in the state. Nevertheless, it is safe to assume that these policies have played an important role for FCEV sales already, as by June 2021, California accounts for the largest fleet of fuel cell vehicles globally, with 10,665 fuel cell cars and 48 fuel cell buses [5].

California's hydrogen refueling station network is also growing rapidly and is one of the first in the world to demonstrate the feasibility of hydrogen fuel sales in a retail environment [6]. Assembly Bill 8 dedicates up to \$20 million per year to support construction of the first 100 hydrogen refueling stations in the state. The 100-station milestone of AB 8 was extended to 200 hydrogen stations by 2025 through EO B-48-18 [7]. The State's funding programs, in parallel with private funding, contribute to achieving this goal. Additionally, hydrogen stations are eligible for LCFS infrastructure credits, based on the capacity of the station minus the quantity of dispensed fuel. Despite favorable policies and investments valued at over \$300 million in the past 10 years, California's dream of establishing a "hydrogen highway" with 100 refueling stations as envisaged in the 2005 California Hydrogen Blueprint Plan has not yet been achieved [8]. There are many challenges, but perhaps the most important one is the availability of infrastructure for hydrogen production, distribution, and refueling. It is increasingly clear that the government needs to extend a greater level of support in terms of incentivizing market via pricing or direct capital investments to establish a large-scale, sustainable hydrogen ecosystem. In the wake of the current pandemic, global economies have pledged additional investments worth billions of dollars (as part of the economic recovery plan) for a hydrogen-centered green and sustainable future [9,10]. Therefore, it is critical to analyze the type and capacity of infrastructure that will be required to cater to an increasing stock of fuel cell vehicles and resulting additional demand for hydrogen.

Hydrogen demand in the state is expected to be propelled by the transportation sector [11]. Previous studies have analyzed hydrogen demand in California at various levels of granularity and suggested different pathways for satisfying this demand. Schoenung et al., projected the total hydrogen demand from fuel cell electric vehicles to reach 70 million kg per year by 2030. The study concluded that this hydrogen demand can be fulfilled through commercial electrolysis using excess renewable energy. The study did not consider heavy duty vehicles and did not analyze the economics of various hydrogen delivery and refueling pathways [12]. Yang et al., employed a quasi-spatial model, CA-TIMES, to analyze the infrastructure requirements to meet hydrogen demand for eight different California regions. Hydrogen demand was an exogenously specified input and was derived only based on light duty vehicles. Further, the study did not give a perspective on the variation of hydrogen costs based on the capacity of production and refueling facilities [13]. Brown et al., developed a detailed economic model, to analyze the cost of dispensed hydrogen in California for existing and future stations. The study concluded that for low FCEV penetration (10%) scenarios, high-pressure gaseous and liquid delivery stations can be profitable. The study observed that current station configurations and technologies can be financially self-sustaining, and even profitable, with a very slow FCEV deployment rate and without additional capital investment, if adequately loaded [14]. However, onsite hydrogen generation and prospects of employing pipeline delivery were not considered for new stations in this study.

Romero et al., employed the Spatially and Temporally Resolved Energy and Environment Tool (STREET), to demonstrate how systematic planning can optimize early investments in hydrogen infrastructure for the City of Irvine, California. The results show that substantially fewer Hydrogen refueling stations (HRSs) are required to provide comparable levels of service as existing gasoline stations. The study further identified locations where early FCEV customers are likely to be located, which enables planning for rollout of hydrogen fueling stations to meet the greatest number of users in the earliest stages. The study was focused on a city level and did not include costs of hydrogen production or distribution in the analysis [15]. The STREET model was also employed for a statewide

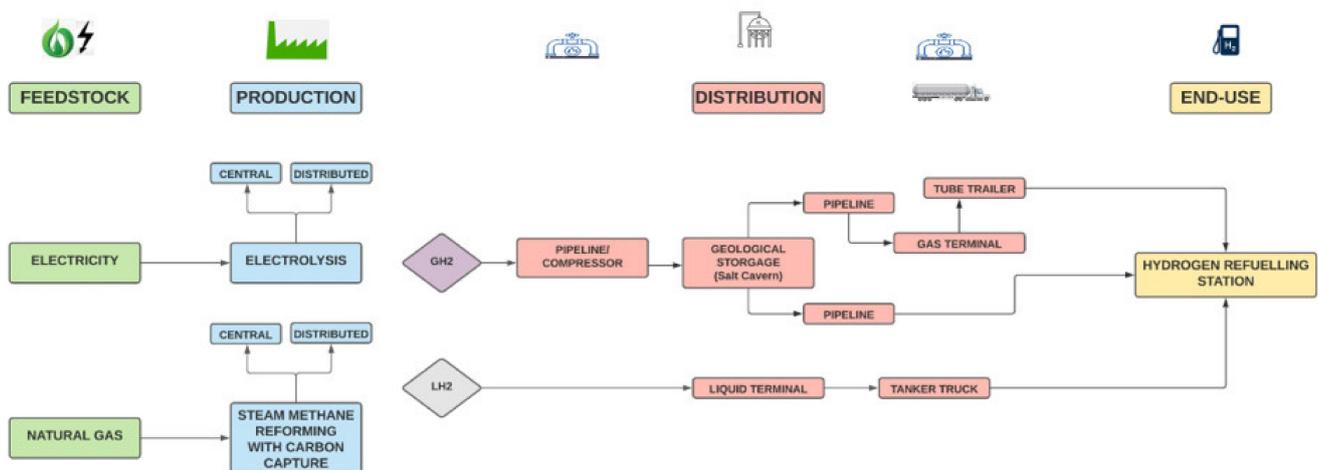
analysis by CEC, to optimally locate hydrogen stations that minimizes upfront capital investments and ensuring that these investments are effectively utilized [16]. The authors recommended building fifty new stations in California by 2015, to enable (i) commercial production volumes of fuel cell electric vehicles and (ii) provide enough spatial disaggregation to fuel these vehicles. Here again the study focused on light duty vehicles and the analysis did not touch upon any upstream infrastructure requirements that would ensure the supply of hydrogen to these stations.

Hydrogen supply chain network design (HSCND), also referred to as strategic supply chain planning, is one of the most crucial aspects for the deployment of hydrogen infrastructure [17]. The complexity of hydrogen supply chain network design depends on modeling of the interactions that exist between the different echelons of the HSCN, that begins at the feedstock level and ends at the selling of hydrogen for different end uses in the transportation sector, building heating and other industrial applications. The different echelons in a HSCN are hydrogen production, distribution and end use. There are multiple choices available in each echelon. A typical analysis of a HSCN for the transportation sector would involve water (with electricity), natural gas, biomass and coal as feedstock for hydrogen production processes, such as electrolysis, steam methane reforming or gasification. Hydrogen in different physical forms (gaseous, liquid, liquid organic hydrogen carriers) could be stored in terminals or geological storages (salt caverns, aquifers, depleted gas fields) before being transported (via trucks, trains, or pipelines) to the refueling stations. Refueling stations could also have onsite hydrogen production. Therefore, with so many choices available at each level of the network, the selection process is a complex optimization problem. The complexity is further accentuated by temporal and spatial variations of these choices.

Most of the previous studies for California were focused on analyzing hydrogen demand only from light-duty vehicles. Given the different challenges (like refueling times, payload penalty) of using a BEV in many heavy-duty applications (like long haul trucks), hydrogen demand for heavy-duty vehicles is expected to grow substantially in the future. This study will project hydrogen demand from both light duty and heavy-duty vehicles up until 2050, using a vehicle stock turnover model. The analysis will employ simplified assumptions to ascertain the infrastructure requirements (production plants and refueling stations) to satisfy this demand without employing a full-scale optimization model. Subsequent to this, a suite of existing standalone models (developed by the US Department of Energy) is employed to evaluate every echelon of the hydrogen supply chain, to calculate the life cycle costs of hydrogen, considering the effects of economies of scale and learning as the hydrogen market expands into 2050. Additionally, a sensitivity analysis is also performed to capture the most important parameters that will affect the hydrogen prices along different hydrogen pathways. Overall, this analysis will provide a holistic idea of what the future demand for hydrogen from on-road transportation in California could be, what infrastructure needs to be built and how the cost of hydrogen will vary based on its pathway to the refueling station. The subsequent sections will describe the modelling approach, assumptions and also a detailed description of the various input parameters employed across the different models.

## 2. Modeling Methods

This section describes how hydrogen demand is projected along with the infrastructure (production plants and refueling stations) that needs to be built to satisfy the demand. Further, a plausible hydrogen supply chain network for California is designed as depicted in Figure 1. Then the life cycle costs for each echelon of the hydrogen supply chain (production, distribution and refueling) is analyzed using standalone supply chain models developed by US Department of Energy (DOE). Different scenarios for hydrogen demand as well as hydrogen pathways are analyzed to understand the cost implications of learning rates and scale up of the hydrogen supply chain.



**Figure 1.** Supply chain network for analyzing cost of dispensed hydrogen at the station based on the pathway.

### 2.1. Hydrogen Demand Projection

We project hydrogen demand for the transportation sector using the Transportation Transition Model (TTM). TTM is a stock turnover model developed by researchers at the University of California, Davis. TTM is largely based on the VISION model developed by Argonne National Laboratory (Lemont, IL, USA), but with additional modifications to simulate low carbon scenarios for California [18]. The model allows for investigation of various scenarios of market penetration of new vehicle technologies that employ a wide range of transport fuels (gasoline, diesel, biofuel, Natural gas, electricity and hydrogen). Ten different vehicle categories, based on vocation and gross weight, are defined in TTM. For the current study, a low and high scenario of market penetration of ZEVs is assumed for each vehicle category starting 2025 and extending up until 2050. Assumptions of ZEV sales shares in future are based on existing California policies [19–21]. These policy targets are assumed to be achieved in the respective vehicle category. Further, each scenario is linked with a certain market penetration of fuel cell vehicles within the overall ZEV sales share in the state. The relative sales share of FCEVs in comparison to BEVs in the two scenarios are derived based on extensive deliberations and discussions with industry (automotive and energy companies) and government agencies. The ZEV and the FCEV sales shares in California considered in this study for the low and high scenarios are tabulated in Tables 1 and 2. The yearly hydrogen demand is then calculated for each vehicle category based on the vehicle stock, fuel economy and vehicle miles travelled (VMT). Fuel economy is assumed to increase for all categories of fuel cell vehicles between 2025 to 2050. The fuel economy improvements are attributable to advances in hydrogen storage capabilities, improved efficiency of fuel cell stacks, plus advances in light-weighting and aerodynamics of the vehicle [22,23]. Annual VMT of each vehicle category is assumed to be increasing during the initial period of vehicle purchase, but then as the vehicles age, the VMT eventually stabilizes. This is a trend observed from the historical data of VMT for each of these vehicle categories. It may be noted that we are not considering the Total Cost of Ownership (TCO) for the sales projections of fuel cell vehicles, but rather employing a more heuristic approach that considers present policies in California and also feedback from automotive companies on what they expect the future market for FCEVs in California would look like. However, we do acknowledge that TCO based demand projections are very relevant and many of the existing literatures provide a deep insight on how TCO varies across different vehicle technologies [24–26].

**Table 1.** 100% ZEV sales share with target years for high and low scenarios.

Year in Which ZEVs Reach 100% of Total Vehicle Sales	Scenarios	
	Low	High
Transit buses	2030	2030
LDVs	2040	2035
Class 2b/3 heavy duty pickup trucks	2040	2035
Class 4–7 Delivery trucks	2040	2035
Class 7–8-day trucks (including drayage)	2040	2035
Class 8 tractor (long haul) trucks	2045	2040

**Table 2.** FCEV share of ZEV sales in 2030 and beyond 2040 for high and low scenarios.

	FCEV Share of ZEV Sales, Low Scenario		FCEV Share of ZEV Sales, High Scenario	
	2030	2040 and beyond	2030	2040 and beyond
LDVs	5%	10%	18%	50%
Transit buses	20%	20%	25%	50%
Class 2b/3 heavy duty pickup trucks	15%	25%	20%	50%
Class 4–7 Delivery trucks	15%	20%	20%	50%
Class 7–8-day trucks (including drayage)	33%	33%	40%	66%
Class 8 tractor (long haul) trucks	60%	60%	66%	97%

A simple spreadsheet model is developed to estimate the roll out of hydrogen infrastructure (production plants and refueling stations) in California, commensurate with the demand scenarios. This approach is less granular (especially on spatial characterization) and therefore computationally less intense but provides a high-level understanding of the future infrastructure requirements in the state. This information can help answer critical policy questions like how many, when and at what cost can we build out these infrastructures? This study does not project the delivery infrastructure requirements like construction of hydrogen pipelines or building of delivery terminals, which requires dedicated modelling efforts to characterize these systems spatially and temporally.

## 2.2. Estimation of Hydrogen Production Facilities

To project the number of production plants, a set of production technologies, plant capacities and technology adoption rates are assumed. Two prominent low carbon hydrogen production technologies, namely steam methane reforming (SMR) of natural gas with carbon capture and proton exchange membrane (PEM) electrolysis, are considered here [11,27]. The other low carbon hydrogen production technique that is relevant in the Californian context is reformation of renewable natural gas (RNG). Previous studies show that RNG production potential from dairy manure, municipal solid waste, wastewater treatment plants, and landfill in California will amount to only four percent of the state's total gas demand [28]. Hence, RNG is not considered as a possible feedstock for hydrogen production in this study, owing to its scalability challenges. However, with a more predictable/reliable supply chain and with technology advancements that can help boost the yield of RNG, this can be a significant low carbon hydrogen production route in the future.

Looking into the future, the relative preference of SMR (with carbon capture) over electrolysis is highly uncertain. California has taken a technology agnostic standpoint and have passed legislations that support both technologies [29,30]. In this study, two different scenarios of technology adoption are created to understand the potential impacts

of one technology gaining market dominance over the other. In a slow electrolysis adoption scenario (Slow EL), all new plants built in 2050 are electrolysis based. For the fast electrolysis adoption scenario (Fast EL) this happens as early as 2040. The adoption rates for other years are linearly interpolated as detailed in Table 3. These scenarios work within the overall scenarios for hydrogen demand (high and low) across the different time periods.

**Table 3.** Scenarios considered for hydrogen production plant buildout.

Year →	2025		2030		2035		2040		2045		2050	
Scenario →	Slow EL	Fast EL										
Percentage of new plants employing SMR technology	95%	95%	76%	63%	57%	32%	38%	0%	19%	0%	0%	0%
Percentage of new plants employing electrolysis technology	5%	5%	24%	37%	43%	68%	62%	100%	81%	100%	100%	100%

Two types of production, central, and distributed/forecourt production with capacities of 30 tons per day (tpd) and 5 tpd, respectively, are considered. These capacities are representative of plants currently under construction or in planning phase in the US [31–33]. For simplicity of analysis, all plants are considered to operate at their full capacities with no down time throughout the year. The capital cost of building a plant is estimated using the H2A model, details of which are explained in the subsequent section.

### 2.3. Estimation of Hydrogen Refueling Stations

The average daily amount of hydrogen dispensed by retail refueling stations in California has registered a multifold increase, growing from 340 kg in 2016 to more than 2800 kg in 2020 [34]. Most stations currently in operation use gaseous hydrogen delivered from a SMR plant. In this study, two station capacities (1.5 tpd and 5 tpd) are considered, each catering to the light and heavy-duty vehicle fleets, respectively. The current focus of public funding through agencies like the California energy commission (CEC) and the California Air Resources Board (CARB) is on establishing a network of refueling stations for the light duty vehicle fleet, mostly in urban areas. The maximum dispensing capacity for these stations needs to be around 1.5 tpd to qualify for LCFS hydrogen refueling infrastructure credits [35]. There are not many big refueling stations (greater than 2 tpd) currently in operation, but a 5 tpd station can be representative of a refueling station catering to heavy duty vehicle fleets [33]. These stations are expected to be built along highways or as a base refueling station for transit buses or truck fleets. Given the suburban nature of these stations, there could be sufficient land available to have onsite hydrogen production alongside the refueling station. Thus, onsite hydrogen production is accounted as a possibility for the bigger stations in this study.

Station utilization rates vary based on location, local demand, and station up time [36]. Analyzing these factors in detail is beyond the scope of this study. A simplistic assumption is made by considering a utilization rate of 75%. This is an upper limit to the utilization rate at stations, above which one would likely encounter long customer lines according to current hydrogen fuel retailers in the state. The analysis does not consider cross refueling between the stations i.e., a vehicle classified under the light duty segment does not refuel at a heavy-duty refueling station and vice versa. This may not be consistent with actual refueling behavior, but this assumption allows for drawing a clearer distinction of the refueling station requirements for the two vehicle segments.

Additional simplifying assumptions are made to synchronize hydrogen demand at the refueling station and hydrogen production. It is assumed that all hydrogen demand from the light duty vehicle fleet (cars, light trucks, medium duty vocational and medium duty urban vehicles) is satisfied from a central production facility. Currently less than ten percent of the stations have provisions for onsite hydrogen production. However, this could change drastically with a greater number of high-capacity stations coming up equipped with options for low cost modular electrolyzer units [33]. In this study we take a very optimistic stand on onsite hydrogen production and assume that a quarter of the total

hydrogen demand from the heavy-duty vehicle fleet (heavy duty short haul, heavy-duty long-haul trucks, heavy duty vocational trucks and buses) is sufficed through onsite or forecourt production plants, that are built alongside the refueling stations. The balance demand for hydrogen from the heavy-duty vehicle fleet is satisfied from central production facilities. The capital cost of building a refueling station is estimated using HRSAM and HDRSAM, details of which are explained in the next section.

#### 2.4. Hydrogen Pathways and Supply Chain Costs

The current retail price of hydrogen at a refueling station in California is around \$16 per kg [37]. This price can vary substantially depending on the pathway through which hydrogen reaches the end user. Hydrogen pathways differ based on the type of production, mode of delivery and type of refueling station. It is important to understand the cost implications of choosing a particular option at an echelon of the HSCN. To understand this, a scenario analysis of fourteen different hydrogen pathways based on the HSCN illustrated in Figure 1 is carried out. A detailed breakdown of the individual pathways is provided in Table 4. The pathways are evaluated for three different time periods: Near Term (2025–2030), mid-term (2030–2040), and long-term (2040–2050). Each echelon of the HSCN is analyzed separately using standalone models that allow the computation of hydrogen prices (\$ per kg), infrastructure costs, and a series of additional metrics, like environmental emissions.

**Table 4.** Hydrogen pathways identified for the analysis.

S. No	Pathway Name	Production Technology	Delivery Mode	Refueling Type
<b>1.5 tpd refueling station</b>				
1	STG	SMR (CC), central production	Tube trailer	Gaseous
2	SLG	SMR (CC), central production	Liq.H <sub>2</sub> truck	Gaseous
3	SPG	SMR (CC), central production	Pipeline	Gaseous
4	ETG	Electrolysis (PEM), central production	Tube trailer	Gaseous
5	ELG	Electrolysis (PEM), central production	Liq.H <sub>2</sub> truck	Gaseous
6	EPG	Electrolysis (PEM), central production	Pipeline	Gaseous
<b>5 tpd refueling station</b>				
7	SLL	SMR (CC), central production	Liq.H <sub>2</sub> truck	Liquid
8	SPG	SMR (CC), central production	Pipeline	Gaseous
9	ELL	Electrolysis (PEM), central production	Liq.H <sub>2</sub> truck	Liquid
10	EPG	Electrolysis (PEM), central production	Pipeline	Gaseous
11	SG	SMR, onsite production	-	Gaseous
12	SL	SMR, onsite production	-	Liquid
13	EG	Electrolysis (PEM), onsite production	-	Gaseous
14	EL	Electrolysis (PEM), onsite production	-	Liquid

Some of the widely used standalone models were developed by the national labs in the US. Established in 2003, the H2A (which stands for hydrogen analysis) program under the US Department of Energy (DOE), have developed a standardized approach and set of assumptions for estimating the lifecycle costs of hydrogen production and delivery pathways. These modeling tools are open source and users can assess the cost of producing

and delivering hydrogen for different scenarios pertinent to a geographical location. These models assume hydrogen as a transport fuel for the simulations. Hydrogen production, delivery and refueling costs can be determined separately using the H2A model, hydrogen delivery scenario analysis model (HDSAM) and Hydrogen Refueling Station Analysis Model (HRSAM), respectively [38–40]. Additionally, the Heavy-duty Hydrogen Refueling Station Analysis Model (HDRSAM) is available to analyze the refueling station costs for heavy duty vehicles. These models are very effective in analyzing the different factors that affect the hydrogen cost, when every echelon of the HSCN (production, delivery, refueling) are considered in isolation. The lifecycle costs are calculated based on an IRR (internal rate of return) based cash flow analysis. An IRR of 8% is assumed in this study which is in line with the reference assumptions of these models.

The H2A model developed by National Renewable Energy Laboratory (NREL, Golden, CO, USA) is employed to calculate the hydrogen production costs. The model uses a standard discounted cash flow rate of return methodology to determine the hydrogen production costs (levelized) for the desired internal rate of return. The model users have the option of accepting default technology input values such as capital costs, operating costs, and capacity factor from established H2A base cases or enter custom values. Two variants exist for this model: central and distributed/forecourt production. The central production model is suited to analyze larger production facilities (range of 30–300 tpd) and can incorporate carbon capture calculations, whereas the distributed model is suited for smaller production plants (range of 0.5–5 tpd) that are typically situated alongside a hydrogen refueling station. H2A can model a suite of production technologies like steam methane reforming of natural gas, electrolysis, coal gasification, biomass gasification and hydrogen production from photochemical and solar thermo-chemical reactions. Model users can choose the relevant technologies in their respective regions and modify the input parameters suitably to obtain the production costs. H2A model inputs employed for this study are detailed in Appendix A.

Hydrogen delivery is an essential component of any future hydrogen supply chain network. The scope of hydrogen delivery (for the transportation sector) includes everything between the production plant to the fueling station. HDSAM developed by Argonne National Laboratory (ANL, Lemont, IL, USA) estimates the cost of delivering hydrogen from a centralized production facility to hydrogen refueling stations. HDSAM employs optimization algorithms to identify least cost delivery configurations, as a function of hydrogen throughput and manufacturing volumes of system components. For a given scenario, a set of components (e.g., compressors, storage vessels, tube-trailers) are specified, sized and linked into a simulated delivery system or pathway. Financial and technological assumptions are then used to compute the cost of those components and their overall contribution to the delivered cost of hydrogen. Two distinct hydrogen delivery pathways (gaseous and liquid) can be analyzed using HDSAM. The choice of the least-cost delivery mode will depend upon specific geographic and market characteristics such as population density, size, and number of refueling stations [41]. The present study considers three delivery options namely hydrogen pipeline, tube trailer and liquid tanker. One other very relevant method of hydrogen distribution (not considered in this study) could be to blend hydrogen into existing natural gas pipelines and then extract the hydrogen at the point of end use. California currently does not allow hydrogen blending into natural gas pipelines and hence there is not much data available on its cost implications. However, many countries (especially in Europe) allow hydrogen blending and is considered an important piece towards development of a fully dedicated hydrogen pipelines system [42,43]. The detailed breakdown of the delivery pathways and the inputs to HDSAM considered for this study are provided in Appendix B.

The refueling cost component for dispensed hydrogen is calculated using HRSAM and HDRSAM, for the smaller and bigger stations, respectively [44]. In these models, refueling station costs are calculated as a function of station utilization, the number of dispensers a station has, the number of consecutive fills a station can complete, and the modes of

hydrogen delivery the station accepts. The model employs optimization algorithms to identify least cost refueling station configurations. Users can specify economic and technical inputs, such as station utilization rates, daily demand profile, cost of equipment, rate of return, and debt-to-equity ratio. The model outputs include the annual and cumulative cash flows, cost of refueling per kg of hydrogen, years required to break even on investment, total capital investment and the station footprint. Reddi et al. [45] analyzed different station configurations and market parameters that influence the refueling cost of hydrogen stations. The authors conclude station utilization rates, equipment cost, and economies of scale strongly influence the cost of refueling. Elgowainy et al. [46] describes a strategy for employing high-pressure (250-bar) tube-trailers for hydrogen delivery to the station whereby the compression cost at the station can be reduced by about 60% and the station's initial capital investment by about 40%. This study draws upon these literatures for preparing the inputs to HRSAM and HDRSAM (refer Appendix C) in addition to feedback from industry.

### 2.5. Sensitivity Analysis of Hydrogen Supply Chain Costs

The cost estimates by H2A, HDSAM, HRSAM and HDRSAM could vary substantially depending on the assumed input parameters. The input assumptions could change substantially during actual construction and operation of hydrogen infrastructures. Sensitivity analysis is a common tool to address uncertainty, and here we perform a one-way sensitivity analysis using tornado charts to ascertain the relative importance of different underlying factors that determine the cost of hydrogen production, delivery and refueling. A total of ten sensitivity cases is presented (refer Table 5). Sensitivity analysis of hydrogen production costs is majorly focused on parameters like capacity factor of production, feedstock, capital and operating costs. For hydrogen delivery, the impacts of delivery distances, market size and technical parameters associated with each delivery mode (pipeline, liquid truck and gaseous trailer) is analyzed. For hydrogen refueling, the effect of station utilization rates, refueling time and learning rates of station components that impact capital investments are considered. The ranges of different parameters selected for the sensitivity analysis are based on existing knowledge and feedback from industry collaborators.

**Table 5.** Sensitivity analysis matrix.

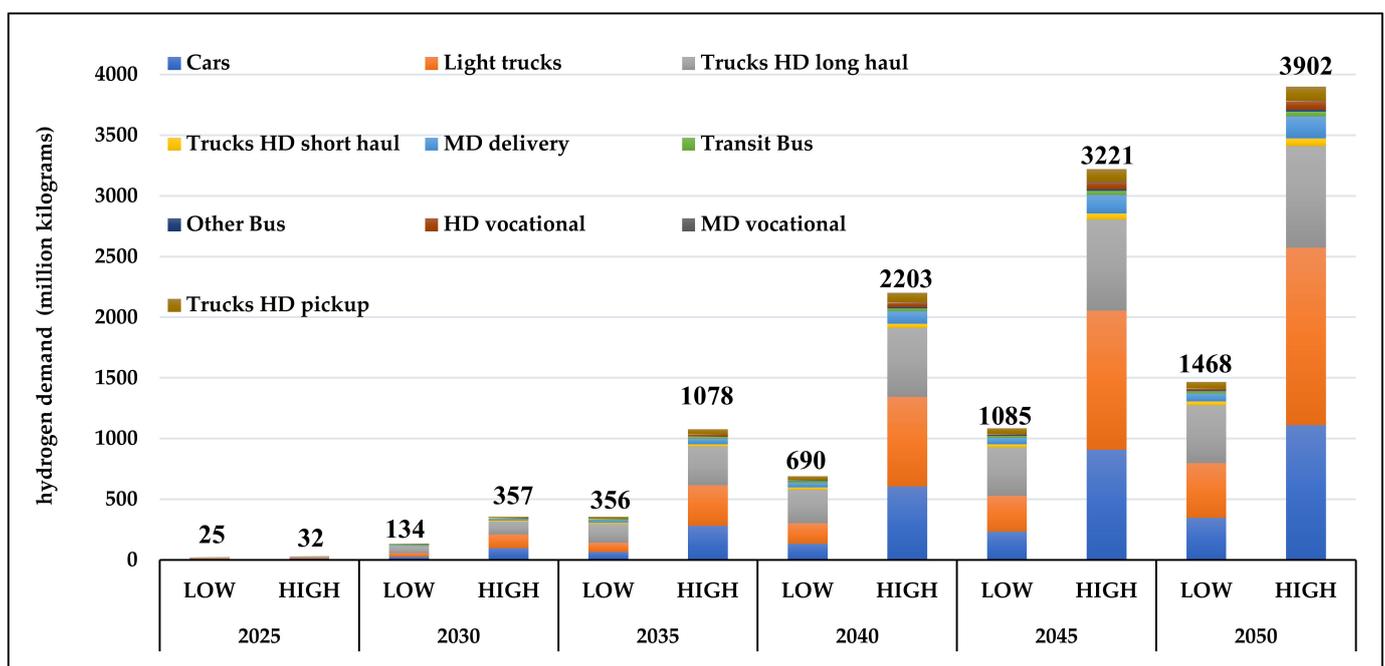
S. No	Type of Hydrogen Cost	Sensitivity Case	Factors Considered
1	Production	Central Electrolysis	<ul style="list-style-type: none"> <li>Plant Capacity Factor, %</li> <li>Feed stock costs, \$/MMBtu</li> <li>Capital Costs, \$ million</li> <li>Fixed Operating costs, \$ million/year</li> </ul>
2		Central SMR	
3		Distributed electrolysis	
4		Distributed SMR	
5	Delivery	Gaseous pipeline	<ul style="list-style-type: none"> <li>Electricity rates, \$/kWh</li> <li>Market penetration of FCEVs, %</li> <li>Production volume of components (low, mid, high)</li> <li>Hydrogen delivery distance from production plant, km</li> <li>Factors specific to each delivery type like tube maximum operating pressure (atm), pipeline pressure, boil off</li> </ul>
6		Gaseous tube trailer	
7		Liquid tanker	
8	Refueling	Station with pipeline delivery of hydrogen	<ul style="list-style-type: none"> <li>Electricity rates, \$/kWh</li> <li>Vehicle fill time (min)</li> <li>Dispensed amount per vehicle (kg)</li> <li>Design (average) Hose Occupied Fraction (HOF) During Peak Hour, %</li> <li>Production volume of components (low, mid, high)</li> <li>Station utilization factor, %</li> </ul>
9		Station with liquid tanker delivery of hydrogen	
10		Station with tube trailer delivery of hydrogen	

### 3. Results and Discussion

#### 3.1. Hydrogen Demand and Infrastructure Buildout

Results presented in this section are based on hydrogen demand forecasting and infrastructure projections explained in Section 2.1–2.3.

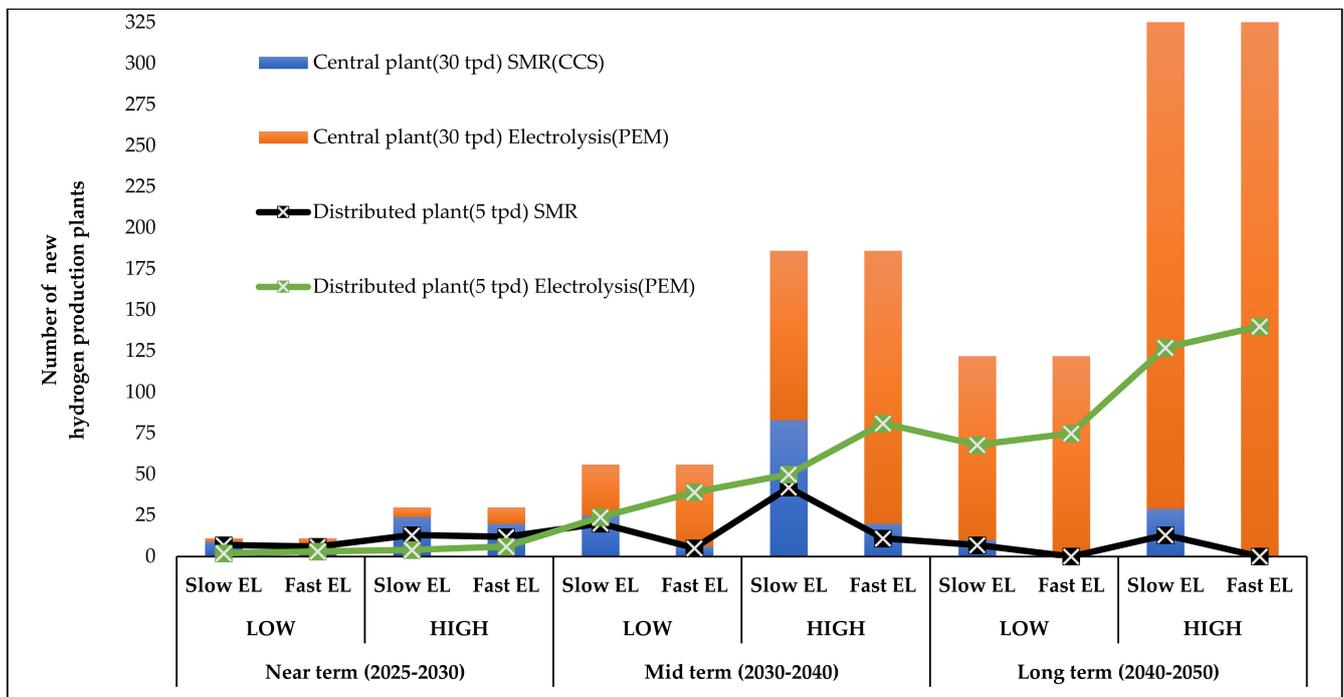
Annual hydrogen demand from on road transportation steadily grows in both scenarios, but more exponential growth is observed for the high scenario (refer Figure 2). By 2050, hydrogen becomes the dominant transport fuel in the high scenario, constituting roughly 54% of the total transport fuel demand in the state. In the low case, hydrogen's share reaches a maximum of 32% by 2050. For both scenarios, hydrogen's share remains under 10% until 2035 but ramps up substantially thereafter, which indicates that much of the zero-emission vehicle targets up until 2035 is expected to be achieved largely using battery electric vehicles. We notice that hydrogen demand is almost always driven by three vehicle categories for all scenarios: cars, light duty trucks and long-haul trucks.



**Figure 2.** Annual hydrogen demand projection scenarios from on road transport in California.

California currently consumes close to two million metric tons of hydrogen per year, predominantly for refining [11]. This is mostly captive hydrogen (hydrogen produced by the consumer for internal use), but other hydrogen consumers (like hydrogen refueling stations) may buy hydrogen from an industrial gas company or a byproduct producer or install a hydrogen plant on-site. California currently has a few tens of hydrogen production locations, that employ either SMR or electrolysis technologies [47]. The vast majority of these are located within refineries and a few are owned by industrial gas companies and this number also includes some planned facilities (mostly electrolysis plants) which are expected to come online very soon. The decade starting from 2030 looks very critical for both the low and high demand scenarios (refer Figure 3). A five-fold increase is observed in the number of plants that needs to be built during this period as compared to the near term (2025–2030). While most of the plants will be central facilities, distributed/forecourt production plants are substantial in number, especially in the near term. This seems reasonable because as the market for hydrogen grows, so will the distribution infrastructure to deliver hydrogen to the end user. This provides an opportunity to tap into the benefits of economies of scale of larger production plants. It is observed that irrespective of the technology adoption scenarios (Fast EL and Slow EL) and demand scenarios (Low and high), SMR remains the

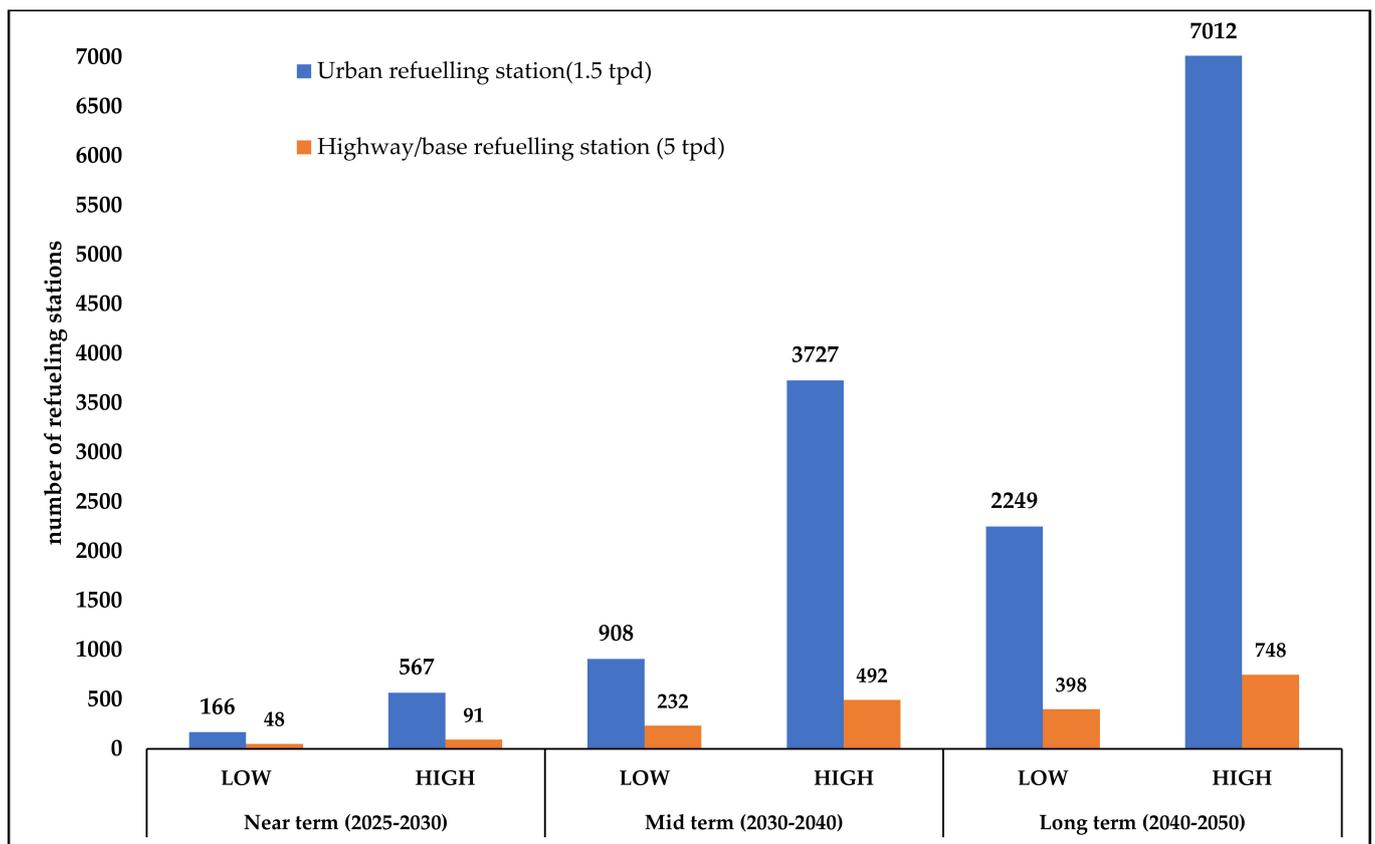
technology of choice until 2030. This observation fits well with decarbonization scenarios analyzed in other regions where, natural gas-based systems remain relevant during the full transition toward a low-carbon economy [48]. Beyond 2030, electrolysis is found to be dominant across all scenarios as seen in Figure 3. This is valid for both central and distributed production.



**Figure 3.** Projections of hydrogen production facilities in California for different demand and technology adoption scenarios.

California currently has forty-eight operational retail hydrogen stations, and another 134 stations are at various stages of approval. This will take the total tally to a 181 by 2025, which is still short of the two hundred station target of the state [49]. Hydrogen refueling station (HRS) location optimization studies (that estimate the number of HRS required for early consumer adoption of FCEVs) suggest building a network that is at least 5% of the existing gas stations (minimum threshold) would be optimal [6]. California currently has around 9000 gas stations [50] and going by the minimum threshold requirement of hydrogen stations, that would mean 450 stations will need to be built. This number is far higher than the state's current plan for station buildout, but a lot depends on the actual market penetration of FCEVs. A strategy that complements station buildout with market penetration of FCEVs is critical, to avoid either over building or underbuilding of refueling infrastructure.

It is evident from Figure 4 that the State's current station roll out plan of establishing 200 stations by 2025 (AB 8) is sufficient for the near term, if the hydrogen demand remains low. But for a high demand scenario, the number of stations required nearly triples, which will require additional funding either from public or private sources. CARB's recent report (draft) [51] estimates that for the HRS network to attain self-sufficiency, an additional \$300 million dollars of state funding will be needed to construct 250 more stations, over and beyond the EO B-48-18 goal of 200 stations by 2025. This amount will be roughly 10% of the total investment required and the agency expects the balance to be contributed by the industry so that the state can achieve self-sufficiency anywhere between 2027 and 2030.

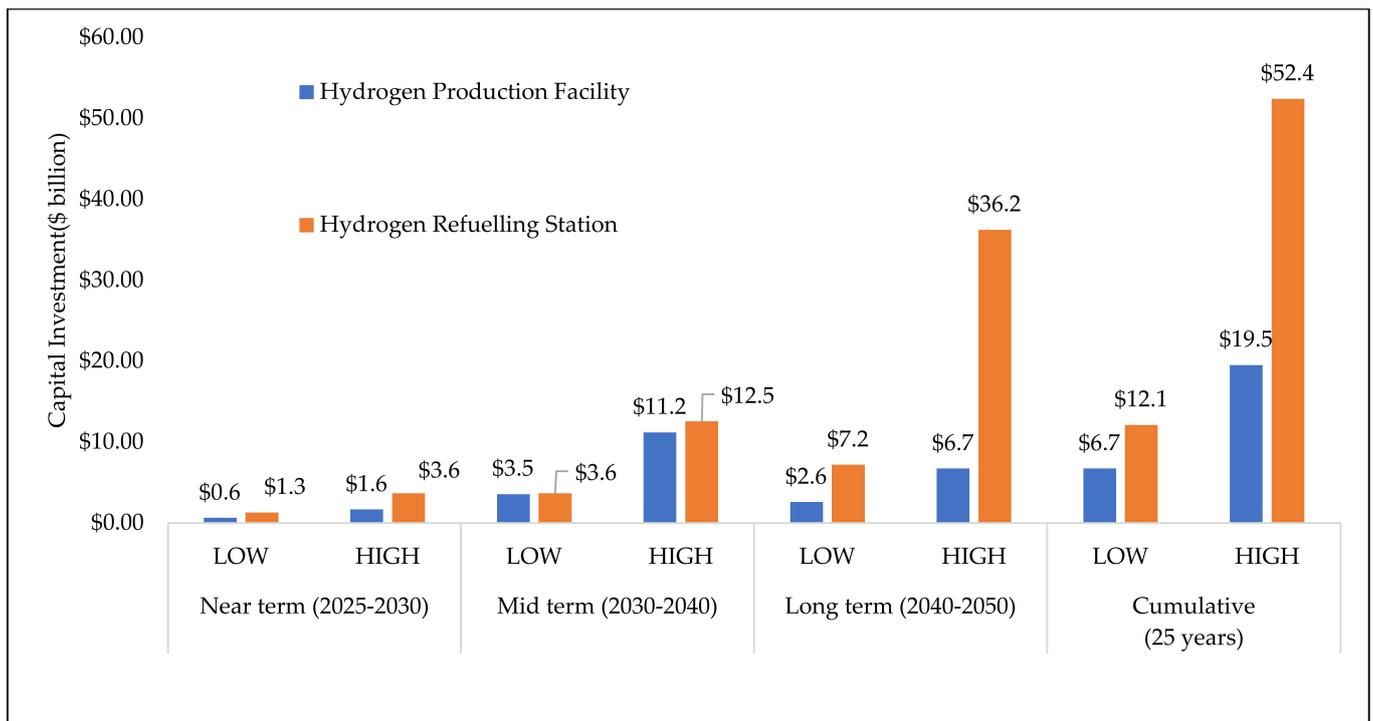


**Figure 4.** Projections for hydrogen refueling stations in California for different demand scenarios.

At present there is no clear policy roadmap for station buildout beyond 2025. It can be observed from Figure 4 that there is an exponential increase in the number of stations that need to be built between 2030 and 2040 (for both scenarios) and hence drawing some sort of a road map beyond 2030 will be critical. The rate (in percentage) at which new stations are built declines after 2040 (as compared to preceding year/time frame). A similar trend is observed for the build out of production plants as well, which is a direct consequence of the hydrogen demand profile. Overall, a total of 3000 stations will need to be built by 2050 for the low scenario, which is less than one-third of the total stations that will be needed for a high hydrogen demand scenario.

Clearly the number of smaller stations (1.5 tpd) outnumber the larger ones, which is commensurate with the higher hydrogen demand from the light duty vehicle sector for all scenarios and time frames. Though the number of larger stations is lower, the challenges of building these will be altogether different from their smaller counterparts. Smaller stations with lower footprints have the flexibility of being built alongside existing gasoline stations, and that is true for many stations currently operating or is planned. This provides an opportunity for reducing the uptime of a station, especially on account of time saved for some station approvals and land acquisition. Larger stations with larger footprints will mostly be green field expansion projects which need to follow the complete cycle of station development starting with pre-application outreach and ending with station commissioning. In general, station development time have decreased from more than four years to complete to just over two years now, as station developers have incorporated lessons learned and local authorities have become more familiar with hydrogen [52].

Figure 5 depicts the total capital investments required over a period of thirty years for establishing the projected number of production plants and refueling stations, without considering any discounting or effects of inflation.



**Figure 5.** Overnight capital costs for build out of refueling stations and production facilities.

While station building is directly supported by policies like AB-8, there is no direct state funding to build production plants apart from some grant funding by CEC available through the clean transportation program (the latest grant available is GFO-20-609-Renewable Hydrogen Transportation Fuel Production). The major incentive for hydrogen producers is LCFS credits that are generated for renewable hydrogen production. Assuming a \$125 per LCFS credit and 100% renewable hydrogen production, a producer could earn up to \$3.48/kg of hydrogen [53]. This would mean for the near term with a hydrogen demand of 159 million kg (low scenario), the LCFS credits would amount to roughly \$0.6 billion, which balances the cost of building the required number of plants (see Figure 5, near term, low scenario). This trend holds true up until 2040, with the producers breaking even by offsetting the costs of building plants by LCFS credits. Beyond 2040, when cost of building plants (mostly electrolyzers) falls drastically, the producers would make substantial gains if the LCFS credit value remained the same.

Public spending to build stations in California over the last ten years is valued at more than \$300 million [8]. Even with existing funding available through AB-8 and additional funding proposed by CARB, it would still fall short even to satisfy the station build out in the low scenario which totals to \$1.3 billion. While the balance will need to come mostly from private industry, government support (such as loan guarantees) will no doubt be important in attracting that investment. Also, much of this investment would likely be in lieu of investing in conventional (gasoline, diesel) refueling equipment, so the incremental cost may not be anywhere near this level (though that estimation is outside the scope of this paper).

### 3.2. Hydrogen Supply Chain Costs

Results presented in this section are based on hydrogen supply chain modelling explained in Section 2.4.

Figures 6 and 7 show the price of dispensed hydrogen for different hydrogen pathways (as described in Table 4) at a refueling station with 1.5 tpd and 5 tpd capacities, respectively. The dispensed cost of hydrogen at the pump is calculated by adding up production, delivery and refueling station costs. The costs for each function (production, delivery,

refueling) is represented on a \$ per kg basis. The dispensed costs do not include the fuel credits that is accrued for production or at the station.

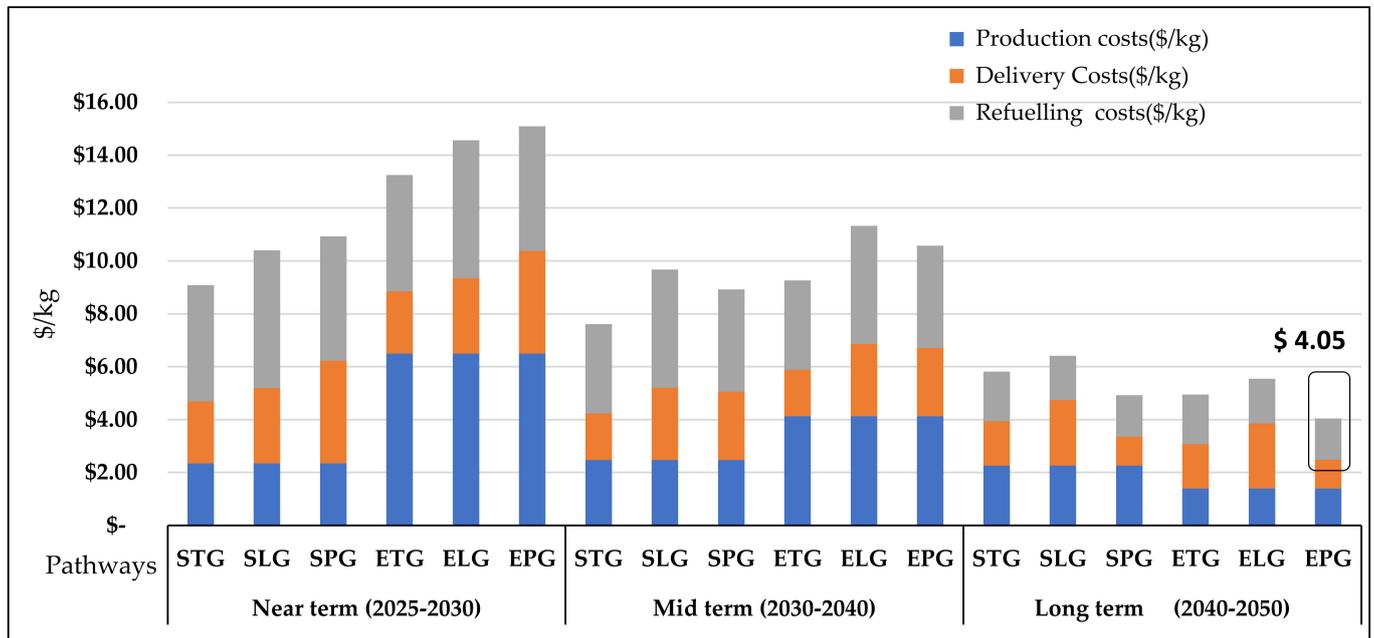


Figure 6. Hydrogen dispensed costs at a 1.5 tpd refueling station through different pathways.

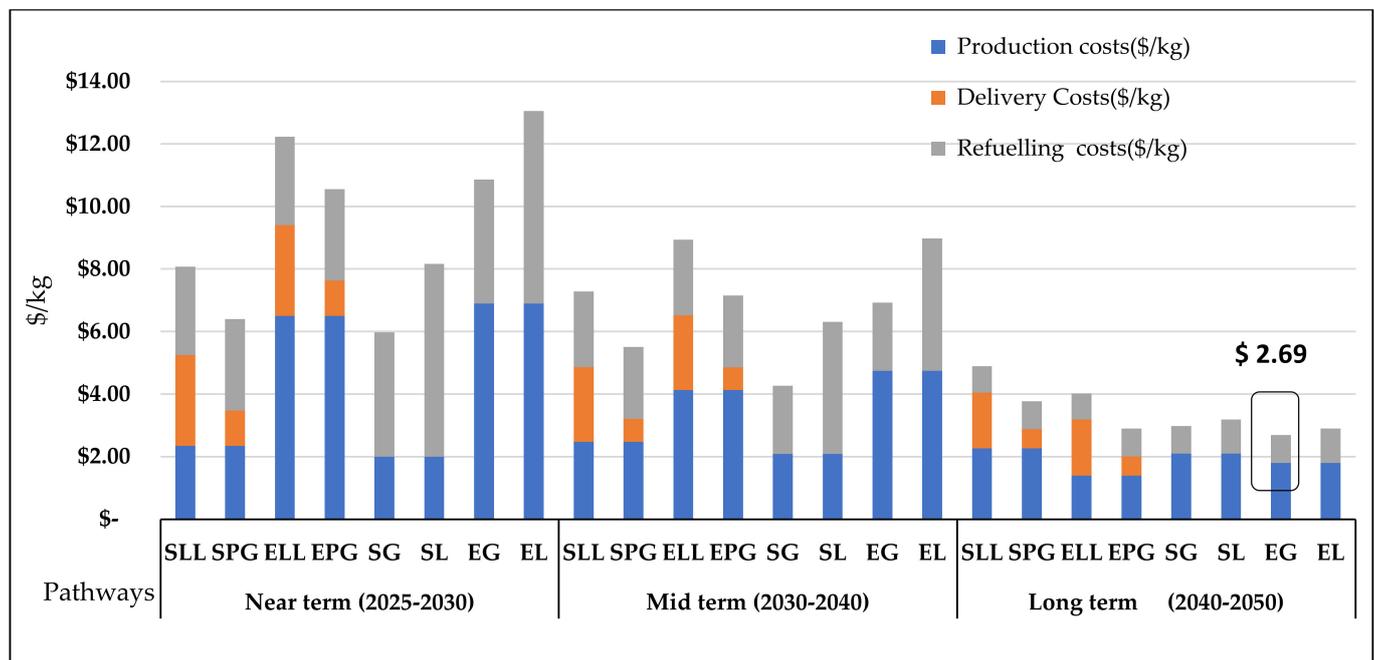


Figure 7. Hydrogen dispensed costs at a 5 tpd refueling station through different pathways.

For the smaller station, average dispensed cost of hydrogen (from all pathways) decreases from \$12.2 in the near-term to \$5.28 a kg in the long term. The lowest cost of hydrogen at the nozzle for the smaller station is \$4.05 (refer Figure 6). This is achieved after 2040 through the EPG (electrolytic hydrogen delivered via pipelines in a gaseous form) pathway. This is a very long-term, very low-cost end point when large scale hydrogen pipeline systems are built, and high utilization rates are achieved across the supply chain. Similarly, for the larger station, the average dispensed cost of hydrogen falls from \$9.60 in

the near term to \$3.42 in the long term. The lowest cost achievable at a bigger station (refer Figure 7) is \$2.69, which is much lower than for a smaller station. This is because of the fact that onsite hydrogen production is allowed at some larger stations which helps to bypass any delivery costs. Also, larger stations are able to leverage the cost benefits associated with economies of scale.

Moving from the near term towards the long term, pipeline delivery of gaseous hydrogen is cost effective especially when utilization rates at the refueling stations are high, which happens much after they are built. In the near term, hydrogen delivery using gaseous tube trailers are very cost effective.

Refueling costs are found to vary considerably depending on the state of hydrogen (gaseous or liquid) delivered to the station. For the smaller stations, lowest refueling costs are observed for a gaseous refueling station employing tube trailers for hydrogen delivery, owing to savings on compression at the station end. Production, delivery and refueling costs are found to decrease considerably in the long-term, owing to falling costs of system components (learning) and feedstock prices. The least cost pathway for the smaller stations for the near and midterm is STG (steam methane reformed hydrogen delivered via tube trailers). Similarly for the larger station the least cost pathway is SG (onsite SMR with gaseous refueling) for the near and midterm. For the long term, electrolytic hydrogen production (central/forecourt) pathway is the most cost-effective option for both station configurations.

### 3.3. Sensitivity Analysis Results for Hydrogen Supply Chain Costs

Results presented in this section are based on inputs and assumptions explained in Section 2.5.

Figures 8 and 9 depict sensitivity relationships for a central production plant using SMR and electrolysis, respectively. The production costs are generated using the H2A model. Feedstock prices (natural gas and electricity) have the highest sensitivity ranking for centralized hydrogen production. This is followed by plant capacity factor and the capital costs needed to build these plants. SMR technology is mature and therefore the capital costs for these plants are not expected to vary substantially as compared to electrolysis plants. Therefore, a wider swing of hydrogen production costs for electrolysis plants can be observed for the ranges of capital costs considered here. Operating costs are less influential for both plant types, but here again the swing of production costs for electrolysis plants is substantial.

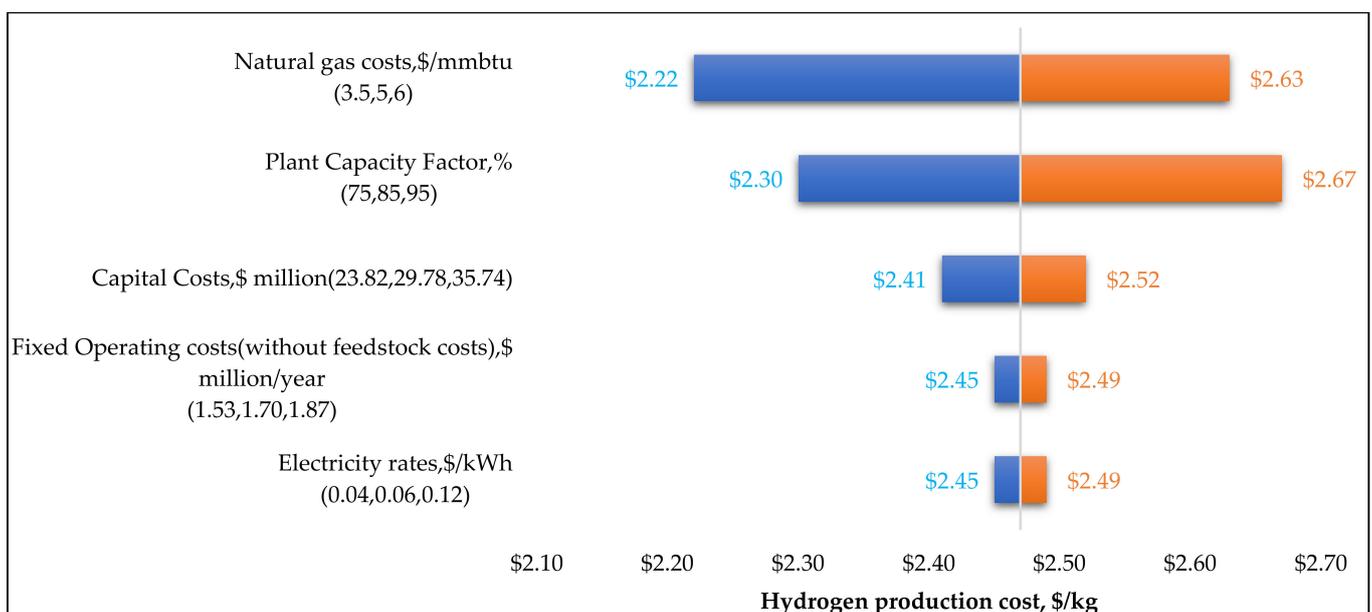


Figure 8. Range of hydrogen production costs for a 30 tpd central SMR plant.

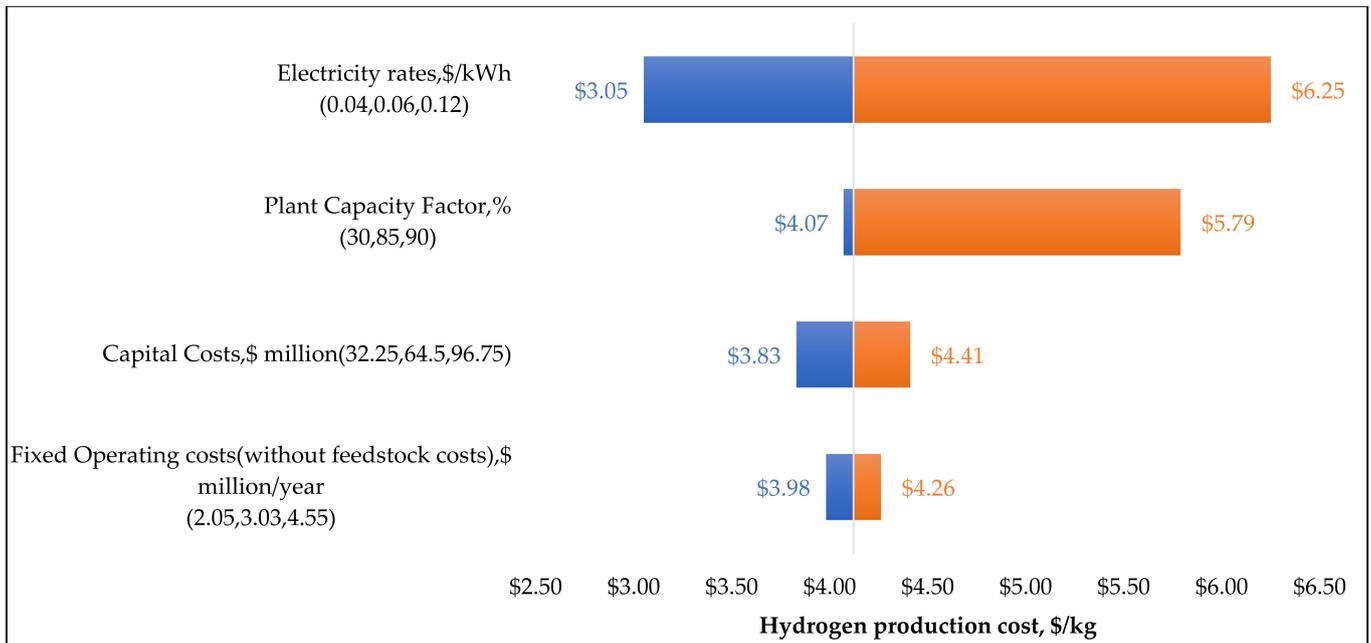


Figure 9. Range of hydrogen production costs for a 30 tpd central PEM electrolysis plant.

For a distributed/forecourt electrolysis plant (Figure 10), the trends are similar to the larger 30 tpd plant, with electricity rate and plant capacity factor being the most influential factor that determines the cost of hydrogen production. For a distributed SMR plant (Figure 11), feed stock price remains the most influential parameter, but the overall production costs are either similar or at times lower than their bigger counterparts. This is in stark contrast to electrolysis plants, where the bigger plant almost always has lower production costs than their smaller counterparts. One reason for this trend might be the fact that SMR plants do not scale as linearly as the electrolysis plants, which gives electrolysis plants the advantage of being flexible/modular to add additional capacity relatively easily when the need occurs, i.e., when demand increases.

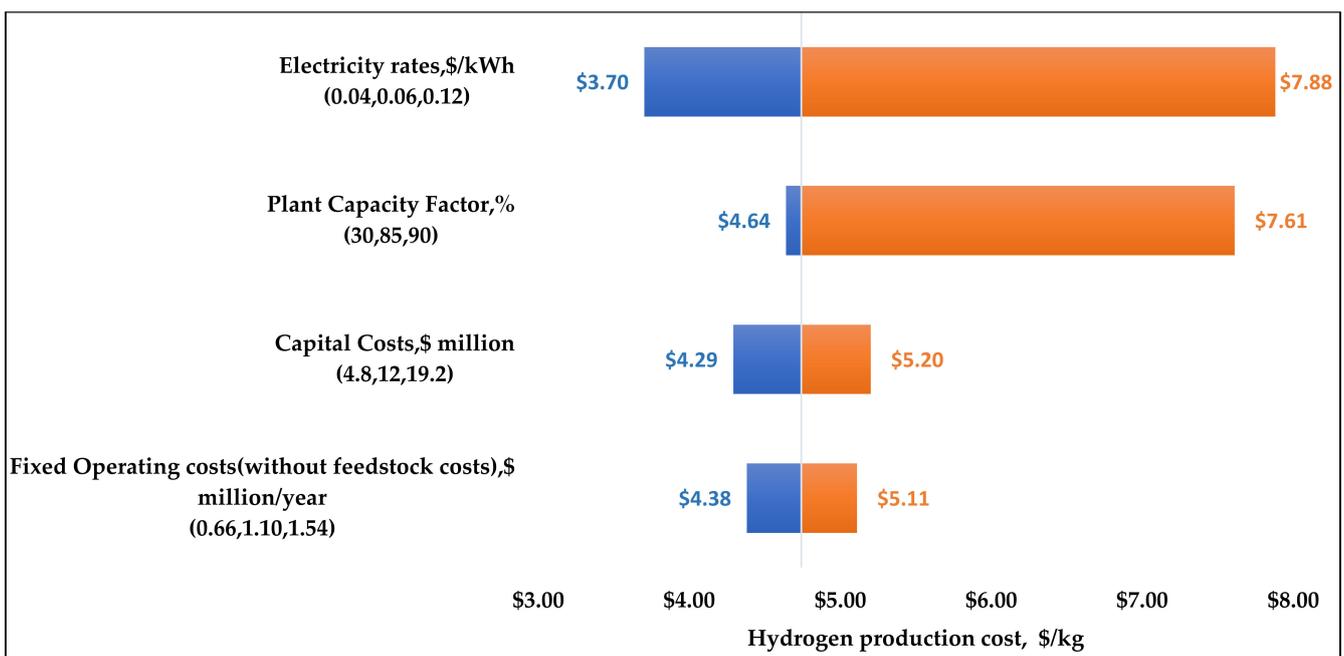


Figure 10. Range of hydrogen production costs for a 5 tpd forecourt electrolysis plant.

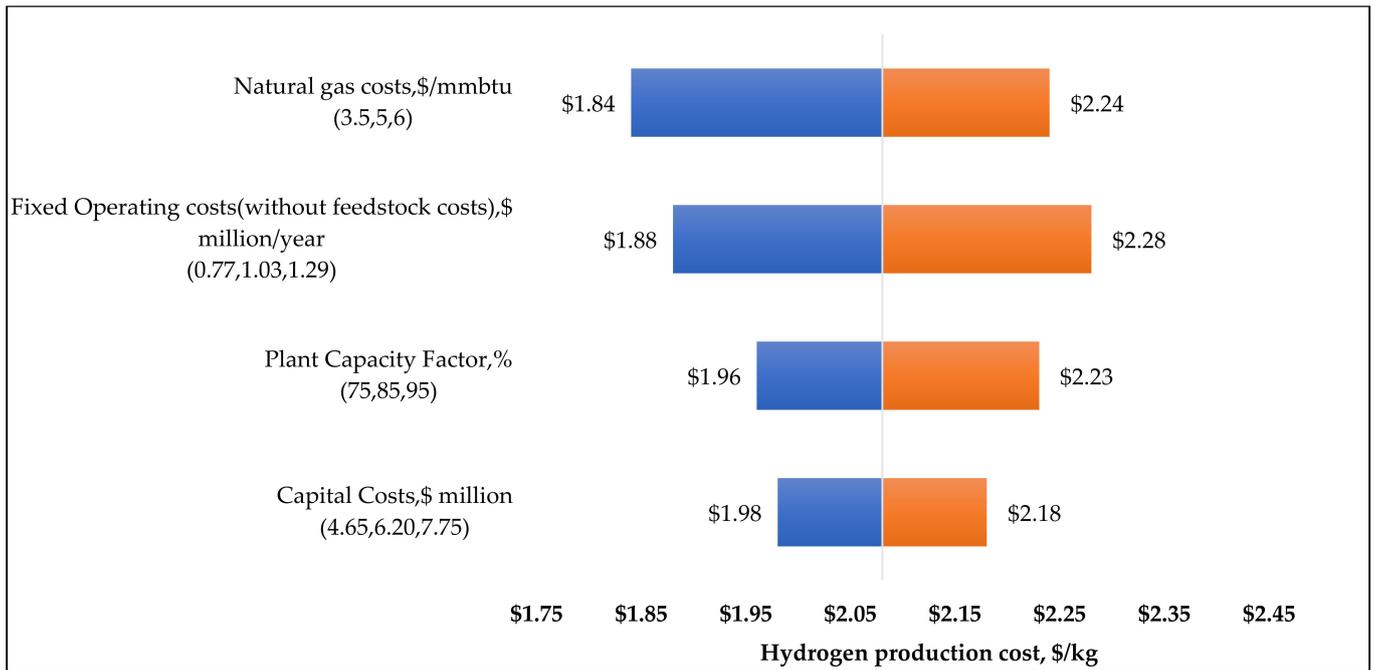


Figure 11. Range of hydrogen production costs for a 5 tpd forecourt SMR plant.

Figures 12–14 represent the sensitivity analysis for hydrogen delivery to a 1.5 tpd refueling station using three different modes: pipelines, gaseous tube trailer and liquid tanker. The costs are generated using the HDSAM model.

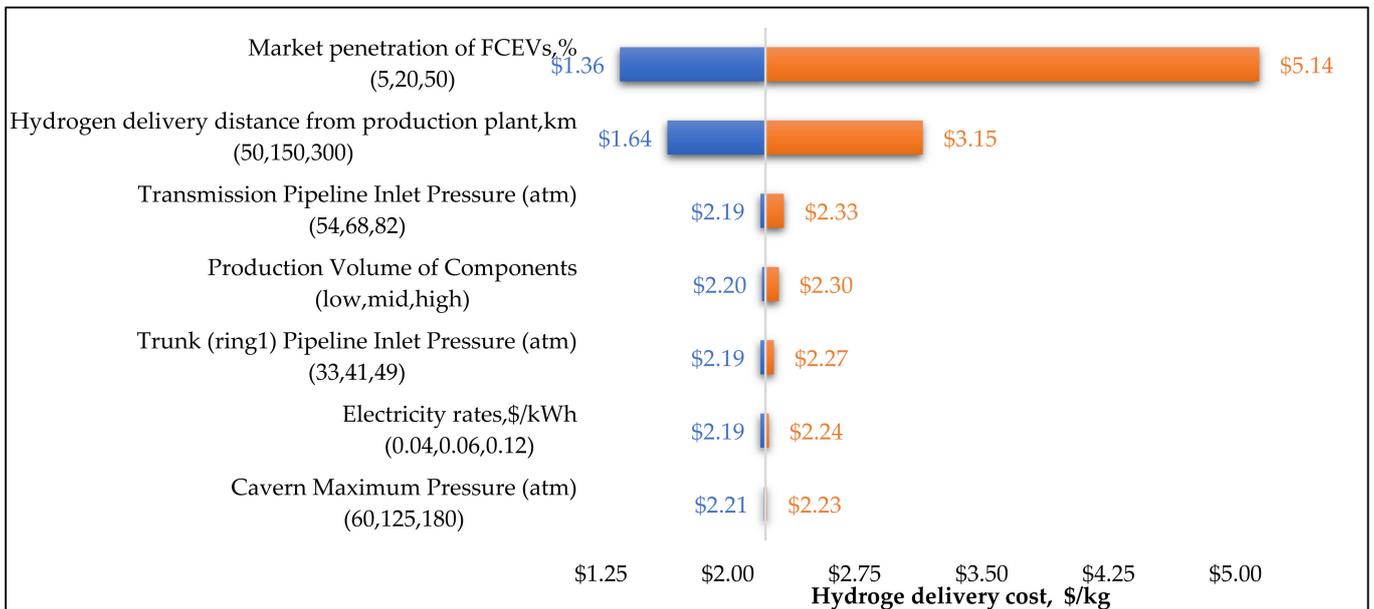


Figure 12. Range of pipeline delivery costs to a 1.5 tpd refueling station.

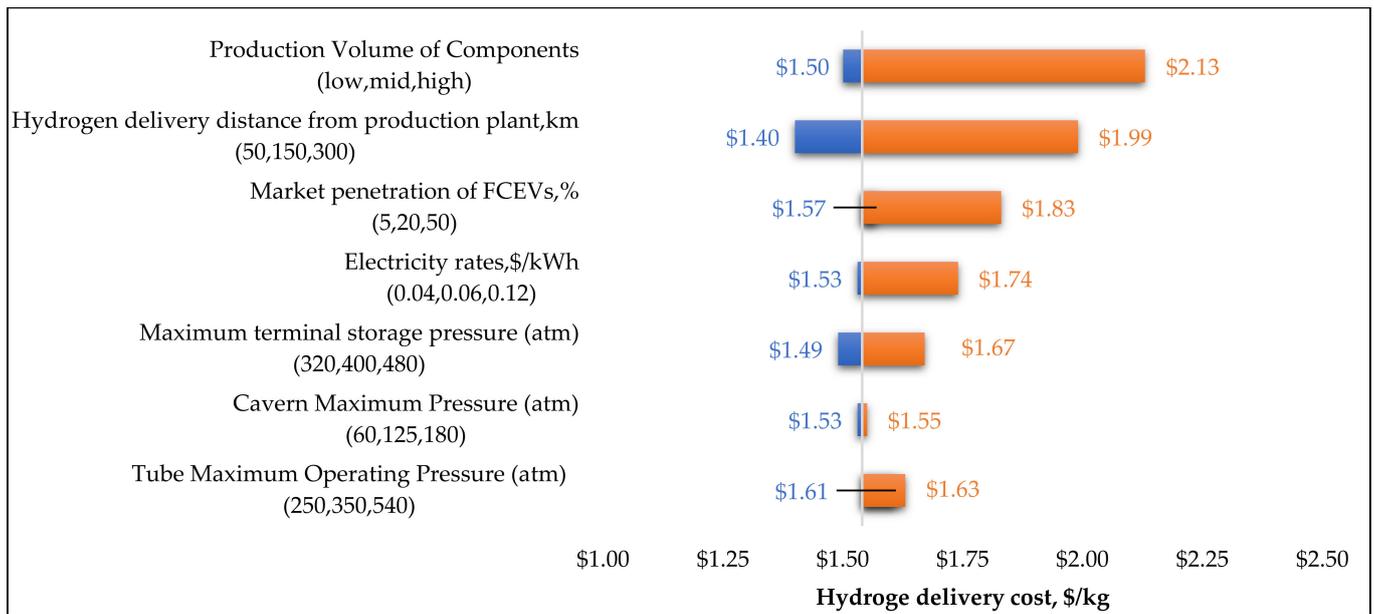


Figure 13. Range of gaseous tube trailer delivery costs to a 1.5 tpd refueling station.

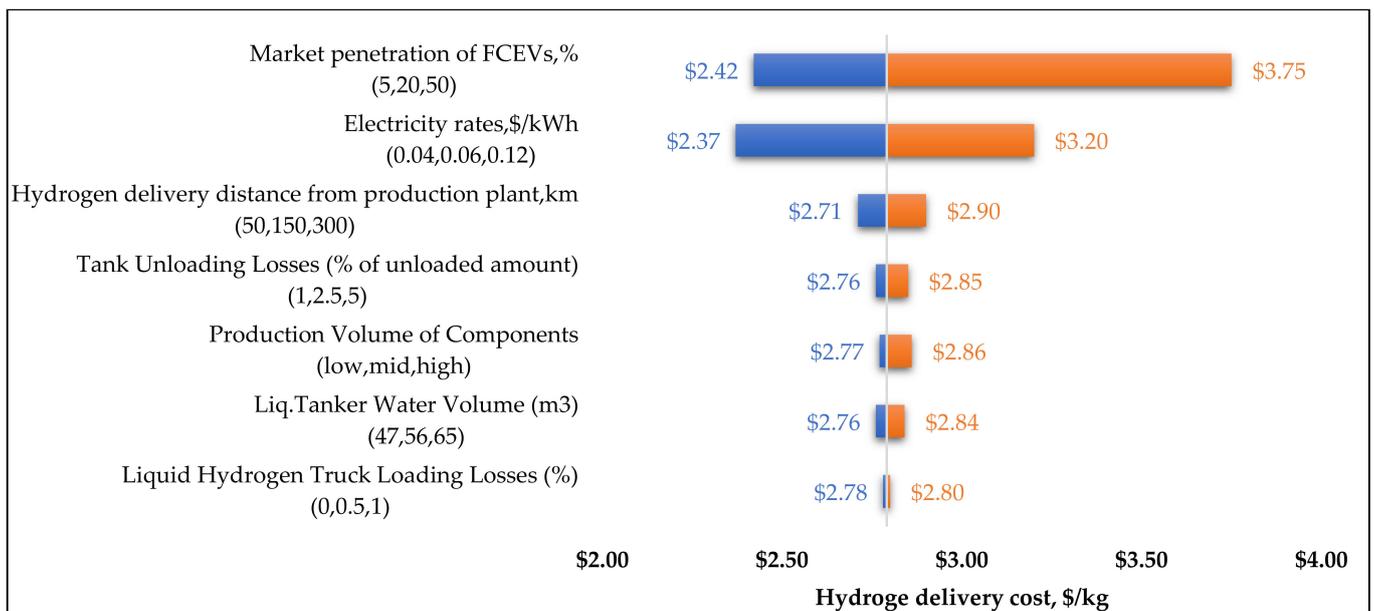


Figure 14. Range of liquid hydrogen tanker delivery costs to a 1.5 tpd refueling station.

For pipelines, the scale of the hydrogen system (here measured as the market penetration of vehicles) is the most influential factor. Market penetration is reflective of the hydrogen demand for the region given a certain vehicle mile travelled and fuel economy. In the current analysis, a 5% market penetration would result in nine refueling stations. Similarly, a 20% and 50% market penetration will result in 36 and 89 stations, respectively, for a region like Sacramento. The reduction in delivery costs with increasing market share of FCEVs is attributable to the larger utilization of pipeline infrastructure. Distance of the hydrogen production plant from the refueling station is the second most influential factor, owing to the larger capital costs involved in laying pipelines over longer distances. However, this analysis does not consider the market risks associated with sunken costs of laying pipelines, rather it is assumed that adequate pipeline infrastructure will always be laid to meet the demand. The delivery costs are influenced by the operating pressures in

the transmission, trunk, and supply pipelines. Variation in the pressure for transmission pipelines is the most influential followed by trunk and supply pipelines. The operating pressures of geological storage (salt cavern) does not seem to contribute significantly to the overall cost of delivered hydrogen.

For tube trailers, the cost reduction of equipment (compressors, tubes) due to economies of scale is the most influential parameter (refer Figure 13). This is followed by the delivery distance and market penetration of FCEVs. Interestingly for tube trailer, the delivery costs do not scale linearly with market penetration or with increasing number of HRS in the region. This might be because multiple tube trailer deliveries are required to serve a single refueling station (of 1.5 tpd capacity) as the maximum amount of delivered hydrogen per tube trailer is around 1000 kg. The underlying dynamics of the number of round trips made by the tube trailer from the gas terminal to the refueling station and the compression costs can vary substantially leading to such a nonlinear trend. The influence of electricity prices and maximum terminal storage are reflective of the compression and storage costs. For both pipeline and tube trailers the operating pressures of the geological storage (Salt cavern) does not seem to contribute significantly to the overall cost of delivered hydrogen.

For liquid tankers, the delivery costs are more sensitive to electricity rates than either pipelines or tube trailers. This is attributable to the energy intensive nature of the liquefaction process and the subsequent cryogenic storage requirements for liquid hydrogen. A typical liquid hydrogen tanker can carry close to 3500 kg of hydrogen, enabling to deliver more or more refueling stations on a single trip. There seems to be scale effects to the cost of hydrogen delivery as the market grows and there are more stations being built. But it should be noted that this mode remains expensive in comparison to gaseous tube trailer delivery in all scenarios. This is attributable to the high costs of liquefaction and high equipment costs that are compatible for handling cryogenic fuel. Also, in this analysis hydrogen is being dispensed into the vehicle as a gas at 700 bars. So, there are at least two instances of change in the physical form of hydrogen for this delivery pathway. Gaseous hydrogen at the terminal is converted to liquid cryogenic fuel, transported to the refueling station where is vaporized and then compressed to 700 bars before filling the vehicle. A concern associated with the liquid hydrogen delivery is hydrogen leakage/loss that can happen during the loading of the truck, hydrogen boil off during transit and loss during unloading at the station. From this analysis it is evident that the unloading losses (highest among the three losses) is not that significant and does not substantially affect the overall cost of delivered hydrogen.

Figures 15–17 depict sensitivity analysis results carried out for three different refueling station scenarios, based on the physical form of hydrogen delivery (liquid/gas) to the station. A 1.5 tpd refueling station is considered for all three scenarios. All station configurations considered in this study dispenses hydrogen in the gaseous form at 700 bars. It is evident from the figures that station utilization factor is unequivocally the most influential parameter when it comes to refueling station costs (on a \$/kg basis). Higher the utilization lower is the cost, but utilization rates beyond 75% might lead to queuing at the station which can hamper customer experience. It can also be observed that the electricity rates do not play a significant role in any of the station scenarios.

Another significant factor that contributes to the refueling costs is capital investment to build the station. HRSAM (model used to assess refueling station costs), captures the variation in capital costs via four parameters. Production volume of components, Hose Occupied Fraction (HOF) during peak hour, maximum dispensed amount of hydrogen per vehicle (kg) and vehicle filling time (min). Station components/equipment include storage tanks, compressors, evaporators, refrigeration units, heat exchangers and dispensers. A low, mid and high production volume for these components is considered commensurate with 200, 5000 and 10,000 refueling stations globally. These components are classified into different technology baskets based on industry experience with these components. With each doubling of station number, the costs of components are estimated to be reduced by 5% for basket 1, 10% for basket 2, and 15% for basket 3, reflecting learning elasticities of

0.074, 0.152 and 0.234, respectively. Maximum dispensed amount of hydrogen per vehicle impacts both the cascade storage requirements at the station and the number of dispensers. Higher HOF reduces the number of dispensers required in the station. Vehicle fill time considered in this study includes the time to fill the tank and the dispenser resetting time after successive refills. It is observed that increased vehicle fill times results in higher refueling costs per kg of hydrogen dispensed. This is because more dispensers are required to meet the demand profile (Chevron profile) for the day. Of all these factors that contribute to capital costs, achieving higher manufacturing scale for station components is the most influential in reducing the refueling station costs for most scenarios.

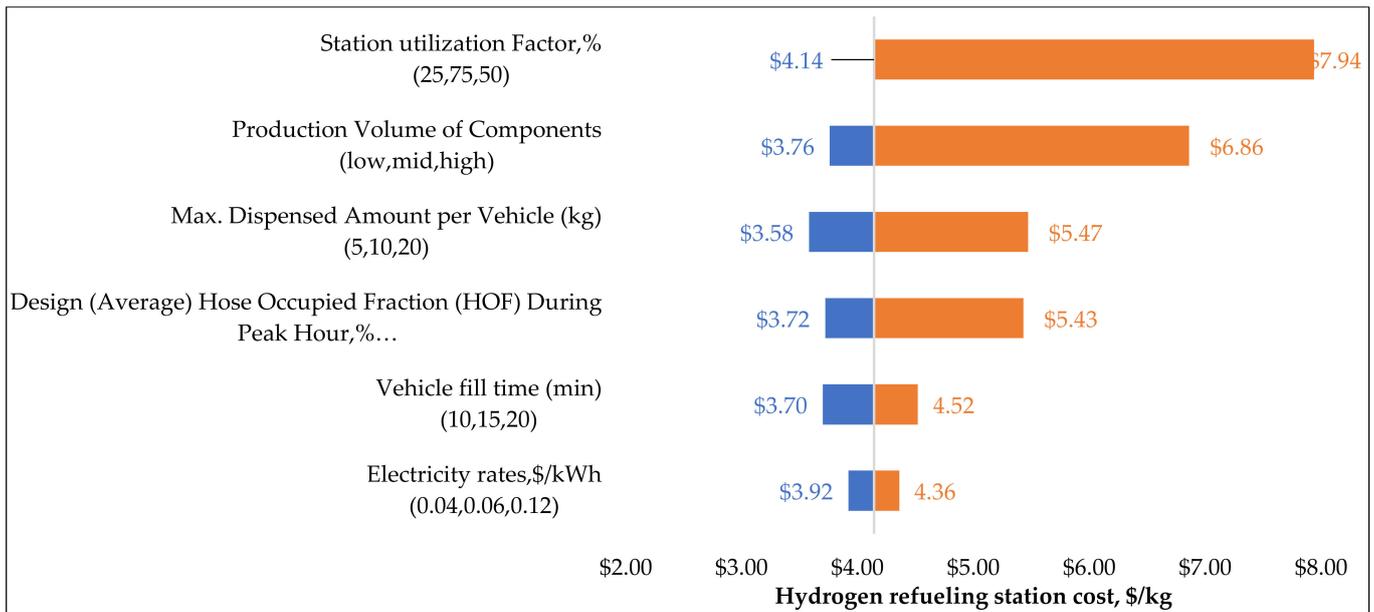


Figure 15. Range of refueling costs for a station receiving hydrogen through pipelines.

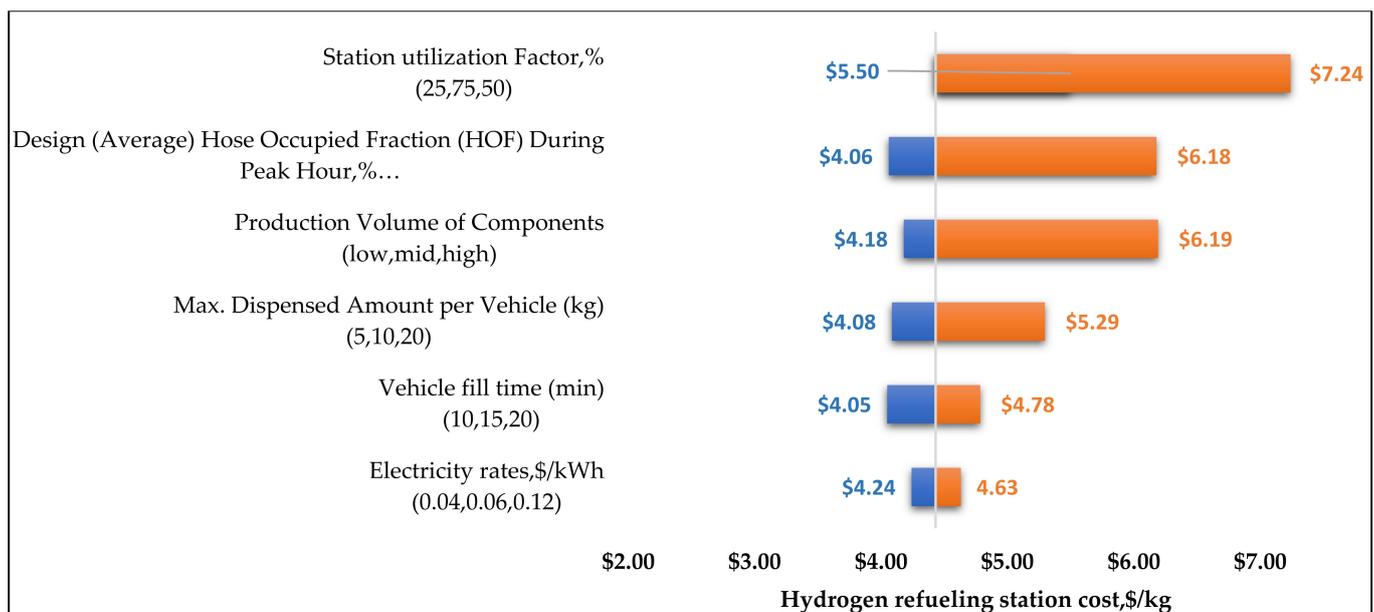
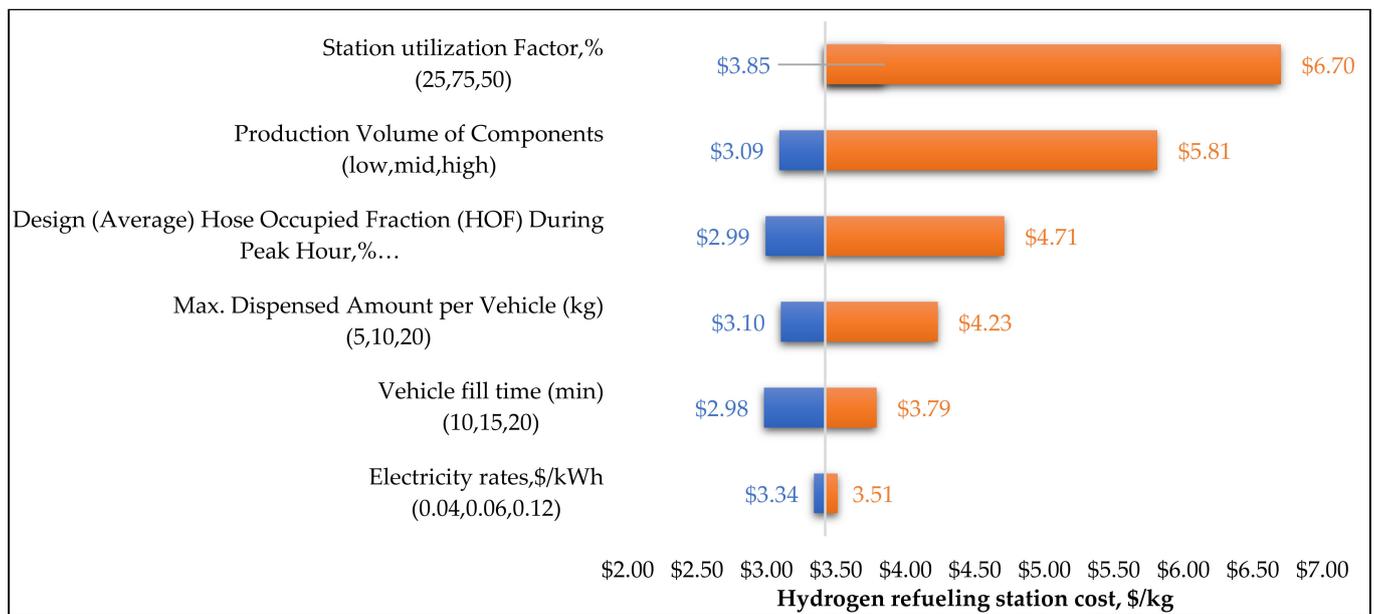


Figure 16. Range of refueling costs for a station receiving hydrogen in liquid tanker.



**Figure 17.** Range of refueling costs for a station receiving hydrogen through gaseous tube trailers.

#### 4. Conclusions

Despite a long-standing desire to establish a hydrogen ecosystem for transportation in California, the number of FCEVs and the infrastructure to support it has not achieved the envisioned success in the markets, especially compared to BEVs and PHEVs. However, there is renewed enthusiasm in FCEVs and hydrogen related technologies globally and in California. Therefore, it is important to undertake a holistic analysis of a possible rapid, large-scale roll out of hydrogen vehicles and deployment of the necessary infrastructure. This study has projected future demand scenarios for hydrogen (low and high) in California from the transportation sector, in line with achieving the carbon neutrality targets for 2045. The study describes the infrastructure requirements and also provide technology and cost insights along the entire hydrogen supply chain network, using standalone models for different hydrogen pathways. A one-way sensitivity analysis using tornado charts captures the relative importance of the underlying factors that contribute to hydrogen costs as it is delivered to the end use consumer.

Though hydrogen use grows rapidly it only satisfies less than 10% of transport demand until 2030 for both the low and high demand scenarios. From that point, in the high case, it expands to a very large scale and reaches market dominance over other transport fuels by 2050. Future hydrogen demand from the transportation sector in California is found to be largely from cars, light duty and long haul (Class-8) trucks. For cars and light duty trucks, the demand is spread across many vehicles travelling relatively fewer miles while for the long-haul trucks it is concentrated among fewer vehicles having very high annual mileage, mostly in fixed routes. This contrasting demand behavior needs to be acknowledged and there needs to be strong policy, backed up by a sound investment plan for development of different types of hydrogen infrastructure (like refueling stations) to cater to different vehicle categories.

The current and next decade (from 2030), both will be critical for the build out of hydrogen stations and associated infrastructure. Investment opportunities worth \$19 billion (for low scenario) and \$72 billion (for high scenario) may be required over the next 25 years to build the required number of refueling stations and production plants to satisfy demand. LCFS credits for hydrogen producers seem to be sufficient to incentivize the building of new production plants up until 2040. This is true only if LCFS is extended beyond 2030 and producers earn a very optimistic \$3.48 for every kg of renewable hydrogen produced. With no clear roadmap from the state agencies for station building beyond 2025,

much of the funding for building stations is expected to be fulfilled by private players. Expanding the current LCFS HRI credits to larger capacity stations (larger than 1.2 tpd) could incentivize building of larger stations, by which the HRS network could benefit from scale as well as network externalities.

Hydrogen production costs from an electrolysis plant fall drastically (from \$6.5 to \$1.5) between 2025 and 2050. SMR based plants remain the more cost-effective option until 2040. The cost of carbon capture (without sequestration) in the larger SMR plants amount to roughly \$0.10 per kg. There is not a substantial impact of economies of scale observed between the smaller (distributed) and larger central facilities for the plant sizes considered here (5 tpd versus 30 tpd). The benefits of scale kick in for much larger plant sizes like 200 tpd and above, and scale effects are more pronounced for electrolysis plants. Building such high-capacity electrolysis plants will make sense when electricity is generated from cheap renewable sources. Nevertheless, there needs to be a clear policy direction that sends out the right markets signals for investors to build large electrolysis plants. One policy lever that could be employed in this direction would be to require an increased renewable content in hydrogen dispensed at the refueling station, above and over the current specified limits as per SB 1505. Appending the renewable content to be above thirty three percent (current requirement in SB 1505) can incentivize building of larger electrolysis plants, provided we have steady demand as projected in the scenarios of this study. Sensitivity analysis on hydrogen production costs reveals that feed stock prices are the most dominant factor that contributes to the levelized cost of hydrogen production, followed by plant capacity factor. With policy mandates like the Renewable Portfolio Standards (RPS) and SB 100, California's electricity grid is expected to have an increasing share of renewables, which could drive down the electricity costs substantially in the future. This again is an incentive to build a greater number of electrolysis-based hydrogen production plants.

The cost of hydrogen delivery to the refueling station using pipelines falls to less than a dollar per kg of hydrogen in the long term, provided the pipelines are already laid and are operated close to its fullest capacities. The size of the hydrogen market is the most important factor that affect the delivery costs while using pipelines or liquid tankers. The size of the hydrogen market does not scale linearly with delivery costs for gaseous tube trailers, and hence the delivery costs do not decrease continuously with increasing size of the market. This is because tube trailers have limited hydrogen carrying capacity (as compared to a similar sized liquid tanker) and thereby limit the number of deliveries that can be made in a day to the refueling station. For delivery using liquid tankers, the costs are very sensitive to electricity rates. This is attributable to the energy intensive nature of the liquefaction process and the subsequent cryogenic storage requirements for liquid hydrogen. Overall, it is clear that as the market for hydrogen grows pipelines will be the most cost-effective option. However, laying of dedicated hydrogen pipelines is a very capital intensive and risky preposition, especially given the nascent stage of the hydrogen market. During the initial phase, it will be worthwhile to consider the option to utilize the vast existing natural gas pipelines to distribute hydrogen. Policies that allow blending of hydrogen into the existing gas pipeline network would incentivize repurposing of natural gas pipelines to carry hydrogen, thereby providing an additional route for hydrogen distribution in the early phase of market development.

On average, the cost of dispensed hydrogen falls by 15% due to economies of scale (i.e., dispensing at a bigger station) in the near term. In the long term, the cost drop is close to 23%. Gaseous dispensing of hydrogen is cheaper, especially when the station receives hydrogen in gaseous tube trailers, which is already compressed and thereby reduces the compression costs at the station level. Station utilization factor is the most influential parameter when it comes to cost reduction at the station level (on a \$/kg basis). Capital cost reductions driven largely by learning rates of station equipment is also critical for reducing the cost of dispensed hydrogen.

While this analysis using standalone models provides important insights on the techno-commercial aspects of the HSCN, it does not answer questions like where to build

refueling stations or production facilities, when and where to lay a pipeline and how to optimize capacity expansion over time. To analyze these questions a full scale HSCN needs to be designed and optimized both spatially and temporally. The data generated here (capital investments, supply chain costs) using standalone models will be used for the next phase of our analysis, focused on a full-scale spatial and temporal supply chain optimization for California.

**Author Contributions:** Conceptualization, V.V., A.J. and L.F.; Data curation, A.J.; Formal analysis, V.V.; Funding acquisition, L.F.; Methodology, V.V. and A.J.; Writing—original draft, V.V.; Writing—review & editing, A.J. and L.F. All authors have read and agreed to the published version of the manuscript.

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**Informed Consent Statement:** Not applicable.

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**Conflicts of Interest:** The authors declare that there is no conflict of interest.

## Appendix A.

**Table A1.** Base assumptions in H2A [38,54,55].

	Parameter	Value
1	Plant Capacity Factor (%)	85
2	Lifetime(years)	30
3	Carbon capture efficiency (%)	90
4	Inflation (%)	2
5	State tax (%)	6
6	Federal tax (%)	21
7	After-tax Real IRR (%)	8
8	Number of staff (central, distributed)	6, 4
9	Cost of land for plant (\$/acre)	50,000
10	Acres of land needed (central, distributed)	5, 1.5
11	NG usage (mmBtu/kg H <sub>2</sub> ) in SMR plants	0.1558
12	Electricity usage (kWh/kg H <sub>2</sub> ) for electrolysis	51

**Table A2.** Feed stock prices [56–58].

Time Frame	Electricity Rates (\$/kwh)	Natural Gas Price (\$/mmBtu)
Near-term (2020–2025)	0.12	3.5
Mid Term (2025–2030)	0.06	5
Long Term (2030–2035)	0.04	6

**Table 3.** Capital and operating cost assumptions.

Time Frame	Capital Cost \$ Millions				Fixed Operating Cost (\$/Year)			
	Central SMR Plant (30 tpd)	Distributed SMR (5 tpd)	Central PEM Plant (30 tpd)	Distributed PEM (5 tpd)	Central SMR Plant (30 tpd)	Distributed SMR (5 tpd)	Central PEM Plant (30 tpd)	Distributed PEM (5 tpd)
Near-term (2025–2030)	37.23	6.89	83.1	14.9	1.99	1.06	4.1	1.36
Mid Term (2030–2040)	29.78	6.20	64.5	12	1.7	1.03	3.3	1.1
Long Term (2040–2050)	23.83	5.58	17.8	4.6	1.46	1	1.9	0.77

**Appendix B.**

## Delivery Pathways

1. *Gaseous Hydrogen Delivery*

- ✓ Central production → compressor → geologic storage for plant outages → transmission pipeline → GH2 terminal → GH2 truck distribution → GH2 fueling station.
- ✓ Central production → compressor → geologic storage for plant outages → transmission & distribution pipeline → GH2 fueling station.

2. *Liquid Hydrogen Delivery*

- ✓ Central production → liquefier → LH2 terminal (including liquid storage for plant outages) → LH2 truck transmission & distribution → LH2 fueling station.

**Table A4.** Inputs to HDSAM.

S. No	Parameter	Value
1	Distance from central production plant to station (km)	100
2	Electricity rate for the three-time frames (\$/kwh)	0.1, 0.06 and 0.04
3	Market penetration of FCEV for the three-time frames (%)	5, 20, 50
4	Production Volume of Components for the three-time frames	Low, med, high
5	Tube trailer Maximum Operating Pressure (atm)	350
6	Maximum gas terminal storage pressure (atm)	400
7	Salt Cavern Maximum Pressure (atm)	125
8	Transmission Pipeline Inlet Pressure (atm)	68
9	Trunk (ring1) Pipeline Inlet Pressure (atm)	41
10	Service Pipeline Inlet Pressure (atm)	26
11	Liquid hydrogen Tanker Water Volume (m3)	56
12	Tank Unloading Losses (% of unloaded amount)	2.5
13	Discount rate (%)	8

**Appendix C.****Table A5.** Parameterization in HRSAM and HDRSAM models.

S. No	Parameter	Value
1	Station utilization rate (%)	75
2	Station Lifetime(years)	30
3	Location of station	Urban and Rural
4	Electricity rate for the three-time frames (\$/kwh)	0.1, 0.06 and 0.04
5	Hydrogen dispensing pressure(bar)	700
6	Number of dispensers for 1.5 and 5 tpd refueling stations	6 and 3
7	Hose Occupied Fraction (HOF) During Peak Hour (%)	50
8	Filling rate for 1.5 and 5 tpd refueling stations (kg/ min)	1 and 7.2
9	Vehicle fill time for 1.5 and 5 tpd refueling stations (min)	5 and 11

Table A5. Cont.

S. No	Parameter	Value
10	Vehicle Lingering time (min)	2
11	Discount Rate (%)	8
12	Total federal and state tax (%)	39
13	Max. Dispensed Amount per Vehicle for 1.5 and 5 tpd refueling stations (kg)	5 and 80
14	Production Volume of Components for the three-time frames	Low, mid, high

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