Understanding the evolution of hydrogen supply chains in the western United States: An optimization-based approach focusing on California as a future hydrogen hub.

By

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ABSTRACT

Interest in hydrogen as a clean source of energy has grown considerably over the past decade. With its ambitious climate goals and a vibrant economy, California looks poised to become one of the major hydrogen hubs in the country. However, insufficient infrastructure to support demand and lack of economies of scale, are critical factors that have impeded the uptake of hydrogen in California. Infrastructure requirements span across the supply chain including production, delivery, and distribution. Strong early investments are required, with a clear vision of where and when the future hydrogen system buildout will happen. The first chapter in my dissertation employs a suite of hydrogen supply chain (HSC) models developed by the US Department of Energy (DOE), to explore technology feasibilities (particularly for California) and identify factors that are most critical for achieving the lowest levelized costs of hydrogen across the supply chain. I find that feedstock prices, size of the hydrogen market and infrastructure utilization are the prominent parameters that affect the levelized costs of hydrogen.

These factors would evolve over time and space. Choosing a cost optimal technology in every section of the HSC after considering these factors is a complex optimization problem. I worked with researchers at the National Renewable Energy Laboratory (NREL) and Institute of Transportation studies (ITS, UC Davis) to upgrade NREL's Scenario Evaluation and Regionalization Analysis Model (SERA), a hydrogen infrastructure optimization model. I then employ SERA to understand how demand uncertainties, sector coupling (between the HSC and electricity grid) and renewable hydrogen policies could impact the buildout of hydrogen infrastructures in the

western United States, primarily to meet California's projected hydrogen demands from 2025-2050.

We find that falling electricity prices and electrolyzer capital expenditures encourage investments in renewable hydrogen production (grid connected electrolysis) across the Western states, more so outside California. Consequently, a complete reliance on the electricity grid for hydrogen supply can be expensive for California, as there needs to be a more elaborate build out of delivery infrastructure. If California's electricity grid rates continue to be higher (as compared to neighboring states), its regional hydrogen imports could range between 30-75% of its demand by 2050. With more favorable rate structures for grid-connected electrolyzers in California, some of those regional imports could be offset. Investments in blue hydrogen (fossil derived with carbon capture and sequestration) in California could continue well beyond 2030, but some of it could be disincentivized with additional renewable hydrogen mandates.

Evolution of the hydrogen delivery network is found to be driven by the rate of demand growth and its spatial distribution. For meeting road transportation demands, which is very distributed and growing only incrementally, hydrogen delivery using trucks seems to be cost-effective in most scenarios. Within trucking, liquid trucks present a better opportunity while demand scales up. But with large, concentrated demand (like in hubs), pipelines are the preferred option for hydrogen delivery. Generally, investments in building dedicated hydrogen pipelines require high degrees of demand certainty, which could be spurred by farsighted policy incentives. Line packing of hydrogen pipelines could be a valuable hydrogen storage proposition for California, which does not have access to some of the cheap underground bulk storage options (like salt caverns) within state. I demonstrate that long-term investment planning (like for 25 years) reduces system costs in all scenarios and is a critical piece in driving down the costs of hydrogen usage.

Given that the hydrogen ecosystem is still very nascent, much of the investment decisions will be policy driven, not only regional policy but global. In the last chapter of my dissertation, I review the status of hydrogen policies globally. I identify major economies like Japan, South Korea, Germany, and California as early adopters with specific policies that have encouraged hydrogen across different sectors, but with varying levels of adoption. Hydrogen is identified as a potent decarbonization vector by all these jurisdictions and there are substantial opportunities for collaborations that could help scale up a global hydrogen economy.

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Introduction

The 2021 UN Climate Change Conference (COP26) concluded with the signing of the Glasgow Pact, which agreed to keep a 1.5°C temperature increase due to climate change as a global mitigation target. This target translates into an energy transition that would have to achieve economy wide carbon neutrality by mid of the century [1]. Major economies have pledged to achieving this target, with many having identified hydrogen as one of the key tools to help in this transition [2–5]. Hydrogen's imminent role as a decarbonization vector stems from its innate versatility, both as an energy carrier and energy storage medium. In the United States, recent legislations such as the infrastructure bill [6], has earmarked close to $8 billion for scaling up of hydrogen technologies and establishment of at least four hydrogen hubs on a national level. Additionally, national level cost targets such as the" Hydrogen shot", seeks to reduce the cost of clean hydrogen production by 80% to $1 per kilogram in a decade. In California, policies such as the Zero Emissions Vehicle (ZEV) mandate, Low Carbon Fuel Standard (LCFS), Advanced Clean Truck regulation (ACT), and the Clean Vehicle Rebate program (CVRP) have encouraged the uptake of hydrogen, especially in the transportation sector. [7–10] Notable initiatives like the HyDeal LA, where the Los Angeles Department of Water and Power (LADWP) partners with the Green Hydrogen Coalition and SoCalGas's Angeles Link project to develop green hydrogen supply chains have catapulted California's prospects of becoming a future hydrogen hub [11,12]

An energy transition pivoted around hydrogen is inherently complex, requiring coordination among different stakeholders (automobile manufacturers, fuel suppliers, consumers, and policy makers) who have diverging interests and motivations. Market risks while navigating through the technological “valley of death” aggravates the complexities of a hydrogen-based energy transition. One way to address these barriers is to strategize the deployment of hydrogen infrastructure to support both current and future hydrogen demands. This can instill confidence for growth of the nascent hydrogen market and serve as an impetus to scale up hydrogen technologies like fuel cell vehicles and electrolyzers. Early hydrogen infrastructure development could be inherently regional and will often be accomplished through public–private partnerships [13]. A system level analysis capable of capturing the underlying interactions between the different echelons/sections of the hydrogen supply chain (HSC) such as production and distribution could guide some of the investment decisions. With so many choices available at each section of the HSC (production, delivery, and distribution), the selection process is a complex optimization problem. The complexity is further accentuated by temporal and spatial variations of these choices.

There are three broad categories of HSC modelling approaches. One is using energy system optimization models, second is using refueling station location models and the third is through geographically explicit optimization models [14]. Energy system models optimize hydrogen supply chains mostly at a regional scale, through the application of a bottom-up energy system approach. A key strength of these models is that they endogenously optimize hydrogen supply and demand, within an overall energy system boundary. An energy system-based optimization approach in general suffers from a weak representation of economies of scale, lack detailed spatial disaggregation and integer variables representing investments [14]. A large number of previous studies focus on optimizing the roll out of hydrogen refueling stations (HRS) as the transportation sector could be a major driver for hydrogen demand and the roll out of refueling infrastructure to support that demand is critical. [15–17] Obviously, this approach helps solve only half the problem as it only considers one section of the HSC (i.e., refueling stations) and does not provide information on other critical infrastructure requirements like for hydrogen production and delivery.

A more holistic approach, especially from an infrastructure point of view is considered in the geographically explicit optimization models [14]. These models consist of quantification of the hydrogen supply chain and are run at a national or a regional scale. These models could either be simple quantifications (standalone models) implemented as a spreadsheet model or by adopting a formal optimization methodology. The standalone models allow the computation of infrastructure costs, levelized hydrogen costs and a series of additional metrics, like environmental emissions. A formal optimization procedure (cross optimization) can incorporate all these indicators and additionally optimize the configuration of the entire hydrogen system rather than being assumed exogenously.

Cross-optimized models determine the optimal configuration of the HSC, subject to some specific criteria (economic, environmental, safety or social factors). These models may have either linear or nonlinear formulations. Typically, the inputs to these models include a set of options for hydrogen production, storage, and distribution. The outputs from these models include the type, number, location and capacity of the production, storage, and distribution facilities (refer Figure 1). [18] Several regions have been used as back-drops to these models, arriving at different conclusions about what the ideal hydrogen infrastructure buildout might look like. This is suggestive of the fact that it is yet unclear as to what the hydrogen system will look like, and it is plausible that hydrogen pathways will be tailored according to the needs of each region [19].

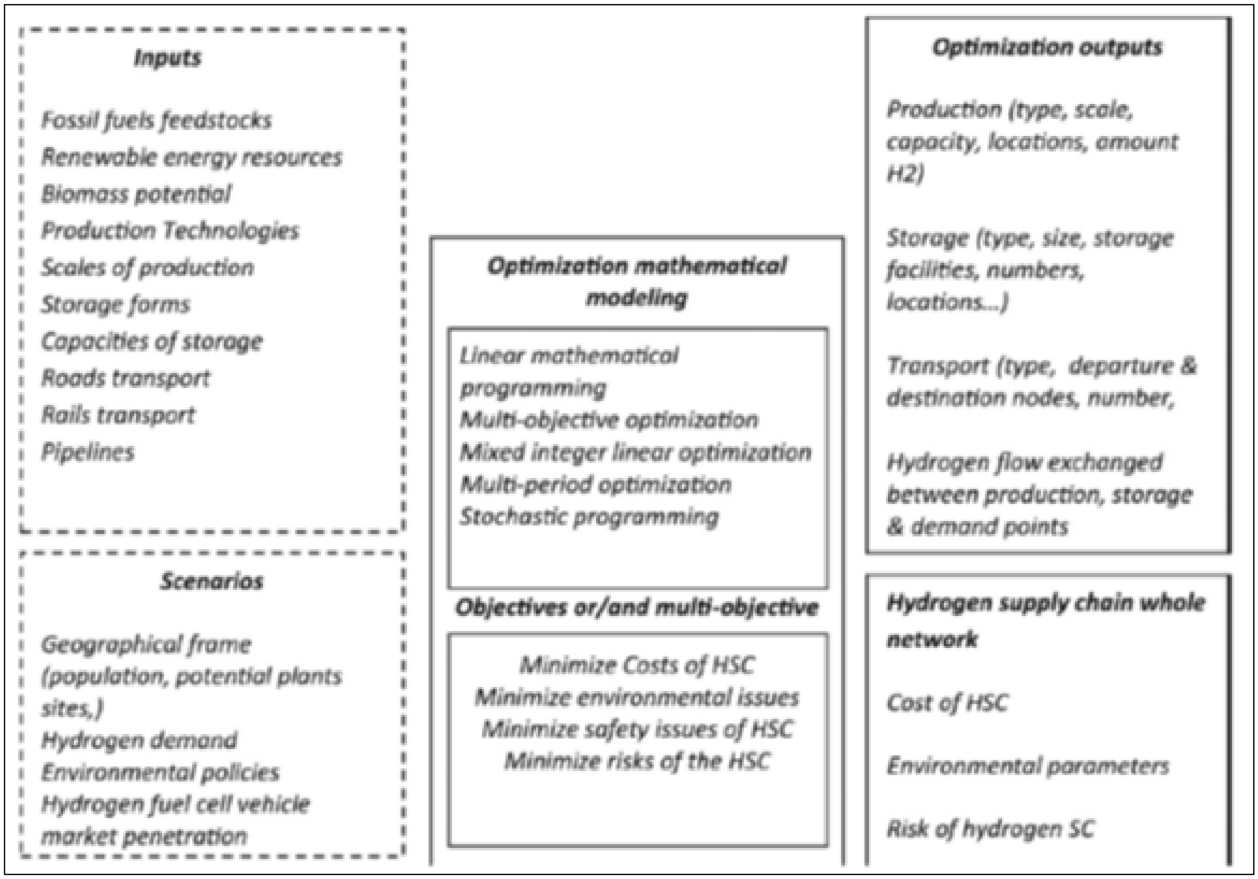

Figure 1: General layout of a cross-optimization model with inputs and outputs. [18]

Research Objectives

The motivation of this study is to understand the evolution of future hydrogen supply chain network (from hydrogen production to end use), given a certain projected demand for hydrogen in California starting 2025 and extending into 2050. Similar regional studies earlier have employed a cross-optimization modelling approach to characterize the hydrogen infrastructure evolution. [20–24] But before building such an optimization framework, it is important to gauge the different hydrogen infrastructure options (production, storage, and distribution) that are available in the western United States and particularly California. Knowledge of their techno commercial viability is paramount before incorporating them into the optimization framework. Therefore, I perform a standalone analysis using existing HSC models developed by the US DOE, which will provide me the necessary background information (technology costs and performance) and help inform the choices to be considered while building the optimization framework. I employ the H2A model, hydrogen delivery scenario analysis model (HDSAM), Hydrogen Refueling Station Analysis Model (HRSAM) and Heavy-duty Hydrogen Refueling Station Analysis Model (HDRSAM) [25–27] for the standalone analysis.

Further, existing literature [28] also identifies that a multi-zone, multi-period HSC optimization model (like the one I am interested in using) must be able to accommodate:

- A long-term future planning horizon like 2050.
- Multiple primary energy feedstocks and hydrogen production technologies.
- Large-scale centralized and small-scale distributed/onsite/forecourt production.
- Different forms of hydrogen like gaseous/liquid.
- Detailed techno economic data for the different technologies of the supply chain, accounting for economies of scale.
- Geographical site allocation of technologies.
- Multiple performance indicators (economic, environmental, social) that can drive the decision-making.
- Environmental policy drivers like carbon neutrality or clean hydrogen mandates

Hydrogen demand will be the key driver for any infrastructure planning and expansion model. However, there are many uncertainties associated with the scale of expected demand growth, infrastructure planning horizons (demand foresight) and on the types of demand (transport/non transport). In this work, I will delve into each of these aspects in detail and provide a system level perspective of how demand can influence investment decisions for future hydrogen infrastructures.

Very often, previous studies have analyzed the HSC in isolation, without proper integration with other supply chains, like the electricity grid [29] . Integrating these supply chains (often referred to as sector coupling), could lead to cost savings through increased asset utilization [30,31]. In this study, I propose a novel soft linking methodology of integrating a full-scale electricity dispatch model with the HSC, to accurately capture relevant parameters like electricity prices, electrolyzer capacity and hydrogen storage. With this integrated modelling framework, I can capture the impacts of critical supply chain drivers like policies, feedstock prices etc. on overall system costs and hydrogen prices.

Hydrogen storage is a critical piece to solving the puzzle of an optimized hydrogen supply chain. Large scale hydrogen storage options can offset the supply- demand imbalances in the network and help in sector coupling. Many studies have concluded that hydrogen is amongst the most cost-effective options for large-scale and long duration storage needs of the electricity grid. [32,33] In this study two such large-scale hydrogen storage options are considered: geological and line pack storage. Other storage options like cryogenic spherical vessels or pressurized cylinders will not be cost competitive, when we are considering grid level storage requirements [34,3536].

In this study, I employ a high-fidelity, multi-zone, multi-period, least-cost optimization framework: Scenario Evaluation and Regionalization Analysis Model (SERA 2.0), that was developed alongside researchers at the National Renewable Energy Laboratory (NREL). The model has undergone a major upgrade from its predecessor [37] both in terms of new capabilities and computational efficiency. In this study, SERA 2.0 is soft linked to a suite of other models including an electricity grid expansion model to accurately capture the relevant modelling parameters for this supply chain analysis. I follow a deterministic approach of modelling, using scenarios, to find the least cost technology mix across the hydrogen supply chain, while adhering to operational constraints along with spatial-temporal variations in demand, feed stock prices and infrastructure costs. I apply the SERA 2.0 model to western United States (with a focus on California) to understand the impacts of hydrogen demand variations, environmental policies and sector coupling, on the roll out of hydrogen infrastructure in the region. The analysis is spread over 25 years, starting in 2025 and looking into 2050.

Overall, this modeling effort will look to answer the following research questions:

1. Which are the cost-effective options for hydrogen production, storage, and distribution, for the Western United States, particularly California?
2. How, when, and where will the capacity expansion of hydrogen production and delivery infrastructures take place to meet on-road transportation demand in California? How would infrastructure evolution change under demand uncertainties?
3. How would sector coupling (hydrogen with the electricity grid) and renewable hydrogen policies impact the buildout of infrastructure to support hydrogen hubs in California? Will

California end up importing a vast majority of its future hydrogen demand from outside the state?

4. How is the global hydrogen economy shaping up? How different are the hydrogen policies/strategies in major economies like Japan, Germany, South Korea, and California?

The subsequent sections are divided into four chapters. Chapter one will look to answer research question one, using standalone HSC models (H2A, HDSAM, HRSAM and HDRSAM). Chapter two will delve into building a full-scale infrastructure optimization framework (SERA 2.0) and thereby address research question two. Chapter three will require modifying the initial optimization framework to include sector coupling and renewable hydrogen policies and analyzing its effects on the overall supply chain. Chapter four will be a policy review carried out across many countries, but then focusing on four specific jurisdictions that are considered front runners when it comes to establishing a hydrogen ecosystem.

Chapter 1. Deep dive into hydrogen infrastructure options, their technical feasibilities, and costs.

1.1 Background

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 [38,39], 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 Newsom 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 [40]. 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 [41].

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 [42].

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 [43]. 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 [44]. 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 [45]. Currently, California has 52 retail hydrogen fueling stations, and state agencies project a total of 179 stations by 2026. [42,46] There are many challenges to wider adoption of hydrogen, but perhaps the most important one is the availability of infrastructure for hydrogen production, storage, and distribution. 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 green and sustainable future [3,4], with hydrogen based technologies (like fuel cell vehicles) receiving substantial amounts of funding for demonstration and scaleup. 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.

Decarbonizing on-road transportation is critical for California, since this sector is the largest contributor to carbon emissions in the state.[46] Hydrogen fueled electric vehicles is one option to decarbonize the transportation sector and future demands could be substantial [47]. Previous studies have analyzed hydrogen demand in California at various levels of granularity and suggested different pathways for satisfying this demand. Schoenung et al.,[48] 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 [48]. 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. [49] Brown et al.[50], 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 utilized [50]. 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 (HRS) 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 [51]. 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 [52]. 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.

A typical analysis of an HSC for the transportation sector would involve water (with electricity), natural gas, biomass, and coal as feedstocks 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. 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. In this chapter, I 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. After 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 a detailed description of the various input parameters employed across the different models.

1.2 Modeling Methods

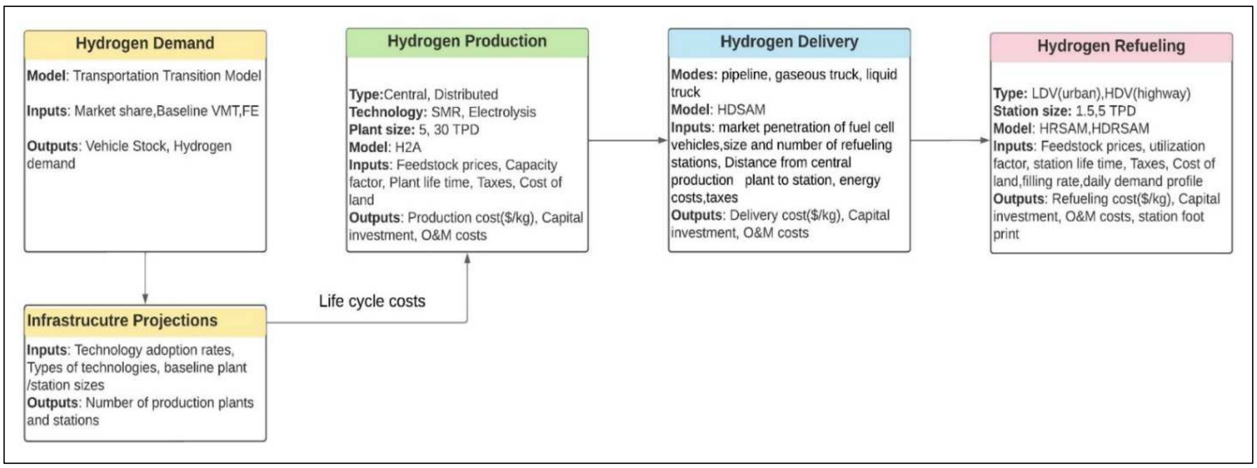

Figure 2: Modeling framework

A super structure of the modeling framework is depicted above. 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 3. Then the life cycle costs (including levelized 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.

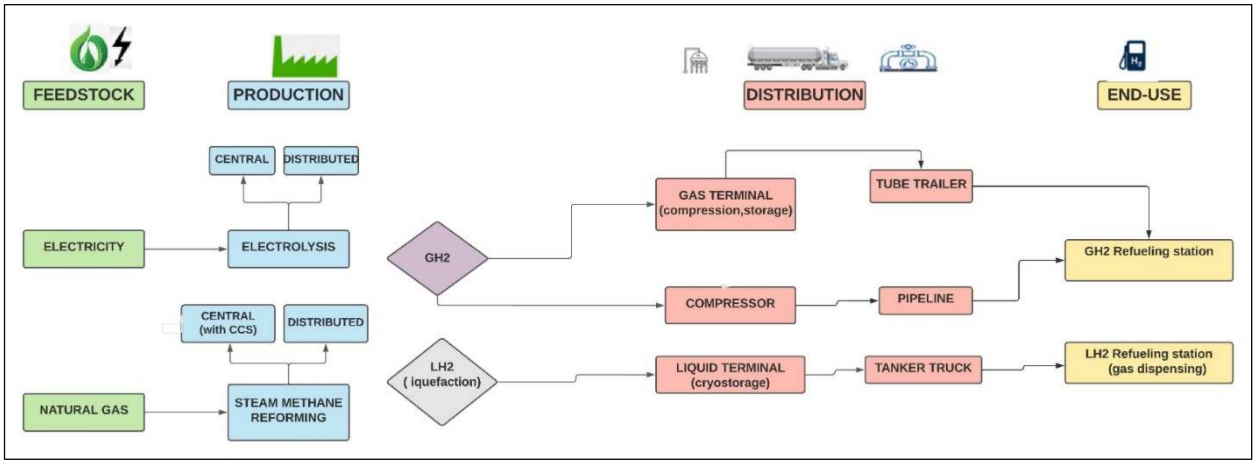

Figure 3: Supply chain network for analyzing cost of dispensed hydrogen at the station based on the pathway.

1.2.1 Hydrogen demand projection

I 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 [53]. 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 this analysis, 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 [9,54,55].

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 Table 1 and Table 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 [56,57]. 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 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 [58,59]

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 heady 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 heady 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%

Based on the assumptions in Table 1 and Table 2 we project the total FCEV stock to reach close to 13 million in 2050 for the high scenario. For the low scenario, the FCEV stock is about 3.2 million. Detailed breakdown of the vehicle stock for the two scenarios can be found in Figure 4 and Figure 5.

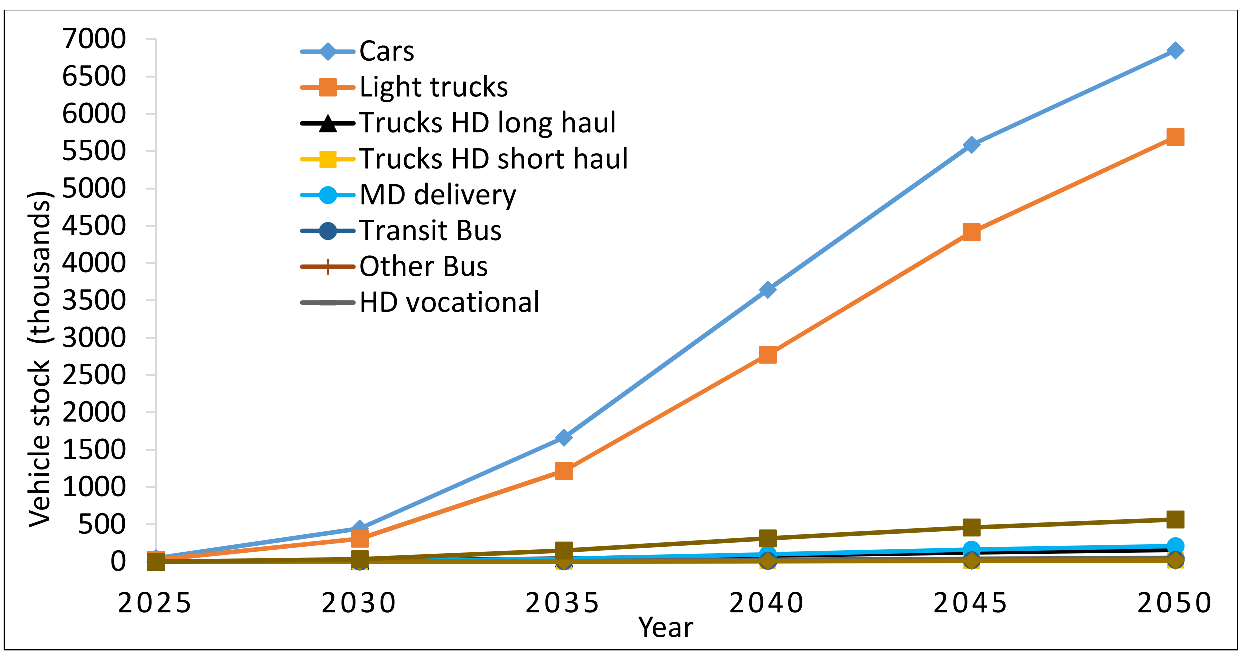

Figure 4: Projected stock of FCEVs in the high scenario

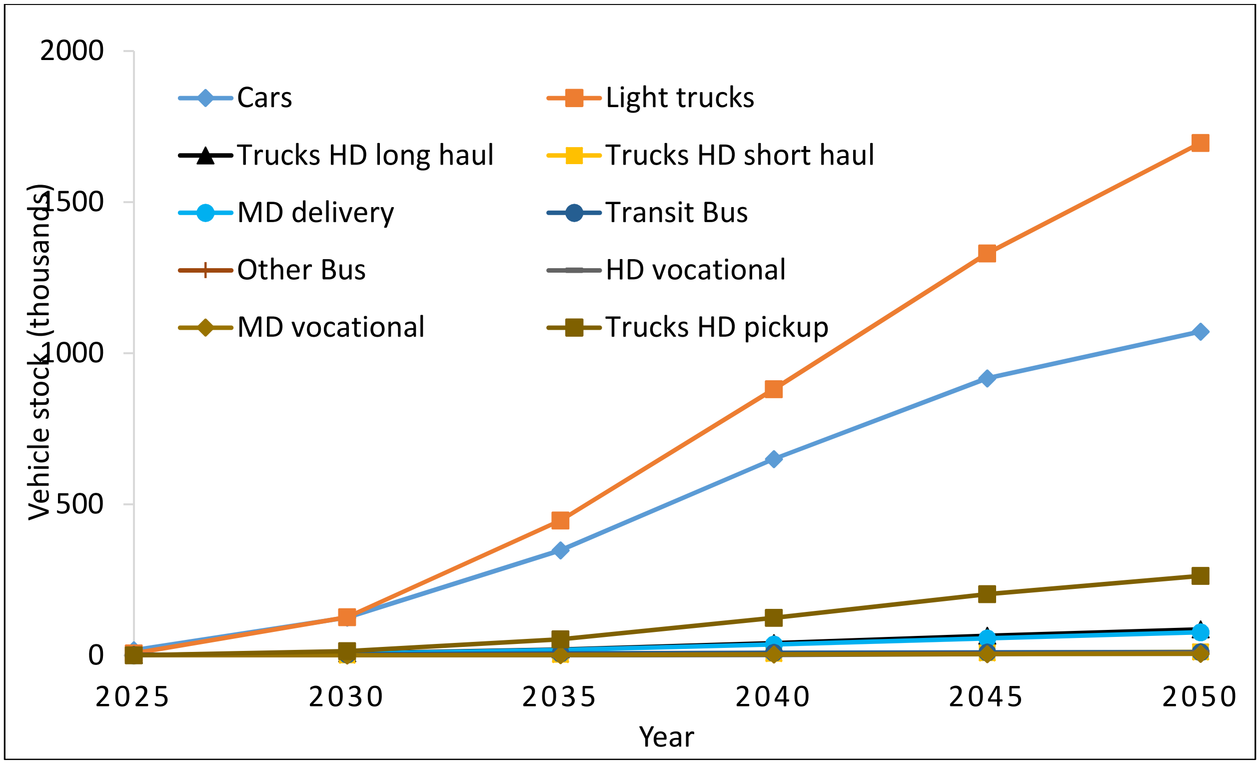

Figure 5: Projected stock of FCEVs in the low scenario

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 questions like how many, when and at what cost can we build out these infrastructures, without employing a complex optimization method. This section of the analysis 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.

1.2.2 Estimation of type and number 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 [47,60]. 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 [61]. 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 boast 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 [62,63]. 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	Slow EL	Fast EL	Slow EL	Fast EL	Slow EL	Fast EL	Slow EL	Fast EL	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 [64–66]. 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

1.2.3 Estimation of type and number 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 3500 kg in 2021. [46,67] Most stations currently in operation use gaseous hydrogen delivered from a SMR plant. Here, 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 [8]. 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 [66]. 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, I consider onsite hydrogen production as a possibility for the bigger stations here.

Station utilization rates vary based on location, local demand, and station up time [68]. 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 [66]. I 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 supplied through onsite or forecourt production plants, which 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.

1.2.4 Hydrogen pathways

The current retail price of hydrogen at a refueling station in California is around $16 per kg [69]. This price can vary substantially depending on the pathway through which hydrogen reaches the end user. Hydrogen pathways differ based on the type of production, mode of delivery and type of refueling station. It is important to understand the cost implications of choosing a particular option at an echelon of the HSC. To understand this, a scenario analysis of fourteen different hydrogen pathways based on the HSC illustrated in Figure 3 is carried out. A detailed breakdown of the individual pathways is provided in Table 4. The pathways are evaluated for three different time periods: Near Term (2025–2030), mid-term (2030–2040), and long-term (2040–2050). Each echelon/section of the HSC is analyzed separately using standalone models that allow the computation of hydrogen prices ($ per kg), and a series of cost metrics like capital costs.

Table 4: Hydrogen pathways identified for the analysis

S. No	Pathway Name	Production Technology	Delivery Mode	Refueling Type
		1.5 tpd refueling station		
1	STG	SMR (CC), central production	Tube trailer	Gaseous
2	SLG	SMR (CC), central production	Liq.H_2 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_2 truck	Gaseous
6	EPG	Electrolysis (PEM), central production	Pipeline	Gaseous
		5 tpd refueling station		
7	SLL	SMR (CC), central production	Liq.H_2 truck	Liquid
8	SPG	SMR (CC), central production	Pipeline	Gaseous
9	ELL	Electrolysis (PEM), central production	Liq.H_2 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 [25–27]. 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 supporting information(S1), Table 10.

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 [70]. 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 [71,72]. The detailed breakdown of the delivery pathways and the inputs to HDSAM considered for this study are provided in supporting information section 1.4 and Table 13.

The refueling cost component for dispensed hydrogen is calculated using HRSAM and HDRSAM, for the smaller and bigger stations, respectively [73]. 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. [74] 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. [75] 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 Table 14) in addition to feedback from industry.

1.2.5 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 (change one variable at a time) using tornedo 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	• Plant Capacity Factor, % • Feed stock costs, $/MMBtu • Capital Costs, $ million • Fixed Operating costs, $ million/year
2		Central SMR	
3		Distributed electrolysis	
4		Distributed SMR	
5	Delivery	Gaseous pipeline	• Electricity rates, $/kWh • Market penetration of FCEVs, % • Production volume of components (low, mid, high) • Hydrogen delivery distance from production plant, km • Factors specific to each delivery type like tube maximum operating pressure (atm), pipeline pressure, boil off
6		Gaseous tube trailer	
7		Liquid tanker	
8	Refueling	Station with pipeline delivery of hydrogen	• Electricity rates, $/kWh • Vehicle fill time (min) • Dispensed amount per vehicle (kg) • Design (average) Hose Occupied Fraction (HOF) During Peak Hour, % • Production volume of components (low, mid, high) • Station utilization factor, %
9		Station with liquid tanker delivery of hydrogen	
10		Station with tube trailer delivery of hydrogen	

1.3 Results and Discussion

1.3.1 Hydrogen demand in the transportation sector and infrastructure buildout

Results presented in this section are based on hydrogen demand forecasting and infrastructure projections explained in sections 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 6), which is driven by our assumptions of a larger market share for fuel cell vehicles within the ZEV vehicle stock. The FCEV vehicle stock in 2050 for the high case is 13 million (11 million light duty and 2 million heavy duty), versus 4 million for the low case. 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. Hydrogen demand is almost always driven by three vehicle categories for all scenarios: cars, light duty trucks and long-haul trucks.

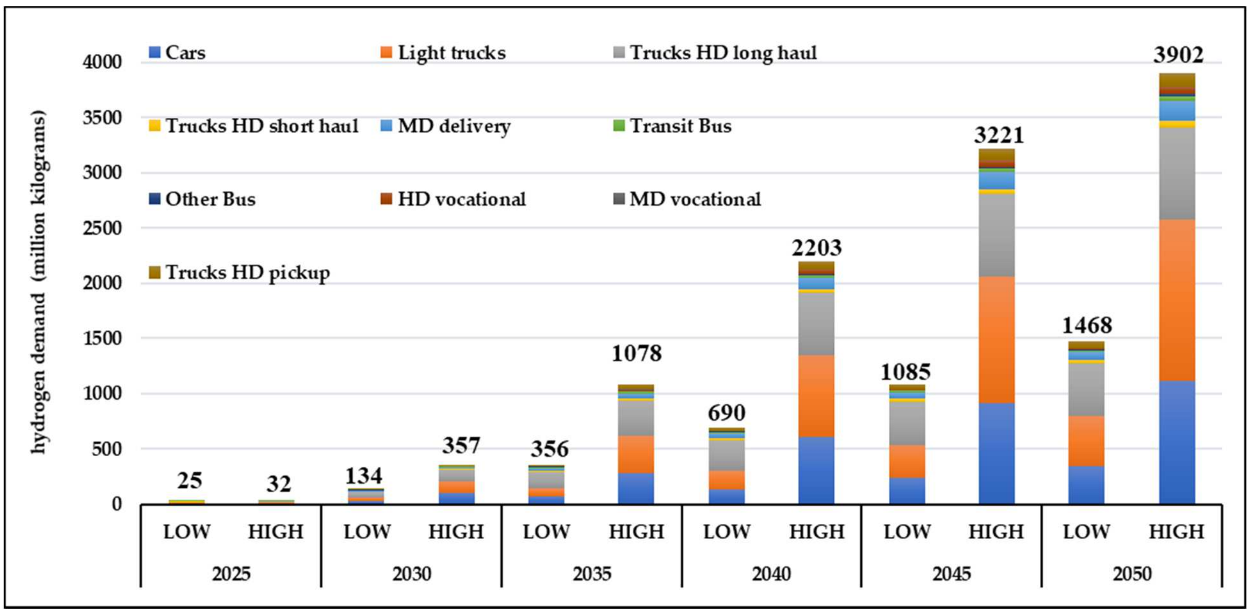

Figure 6: Annual hydrogen demand projection scenarios from on road transport in California

California currently consumes close to two million metric tons of hydrogen per year, predominantly for refining [47]. About 60% of this total is captive hydrogen (hydrogen produced by the consumer for internal use), but other hydrogen consumers (including industrial users, but also hydrogen refueling stations) may buy hydrogen from an industrial gas company or a byproduct producer or install a hydrogen plant on-site. [76] California currently has several dozens of hydrogen production locations, that employ either large SMRs (99% of the total) or electrolysis technologies. [77] About 60% of these are located within refineries and a 40% 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 7). 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 [78]. Beyond 2030, electrolysis is found to be dominant across all scenarios as seen in the figure below. This is valid for both central and distributed production.

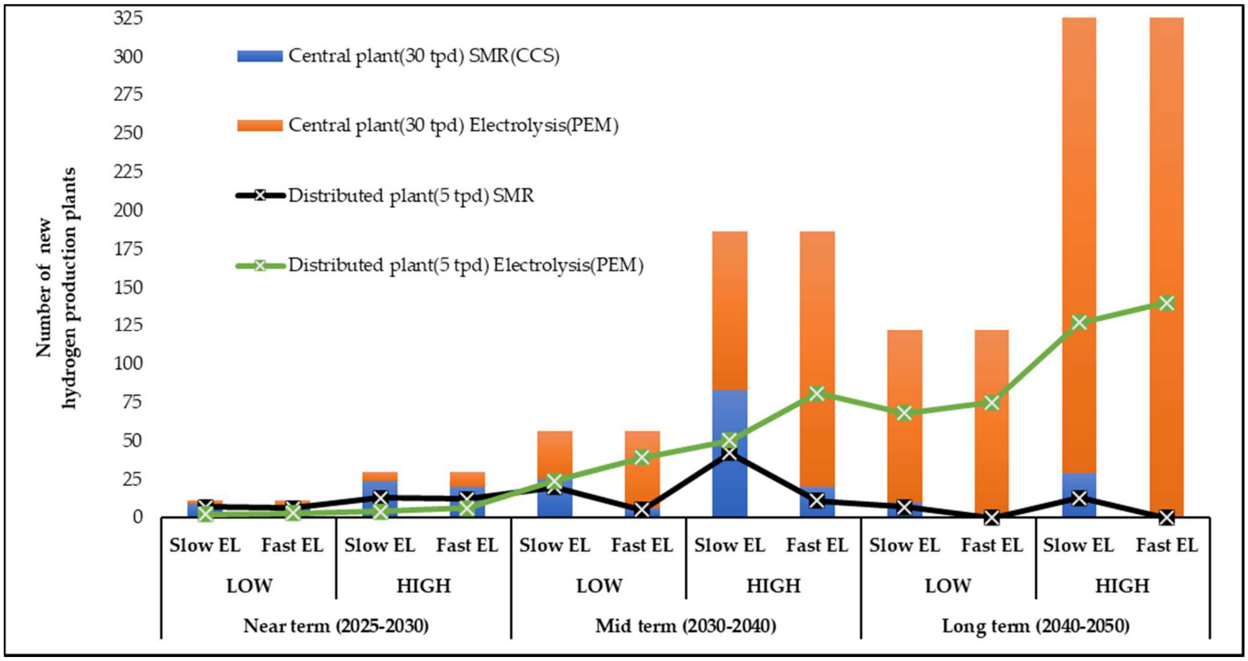

Figure 7: Projections of hydrogen production facilities in California for different demand and technology adoption scenarios.

Figure 8 depicts the annual hydrogen supply under different demand scenarios and under varying technology adoption rate. Under a slow electrolysis adoption scenario (Slow EL), we see that SMR based hydrogen production is significant until 2040 irrespective of the levels of hydrogen demand (low or high). But beyond 2040, we see that electrolysis gain prominence in all scenarios.

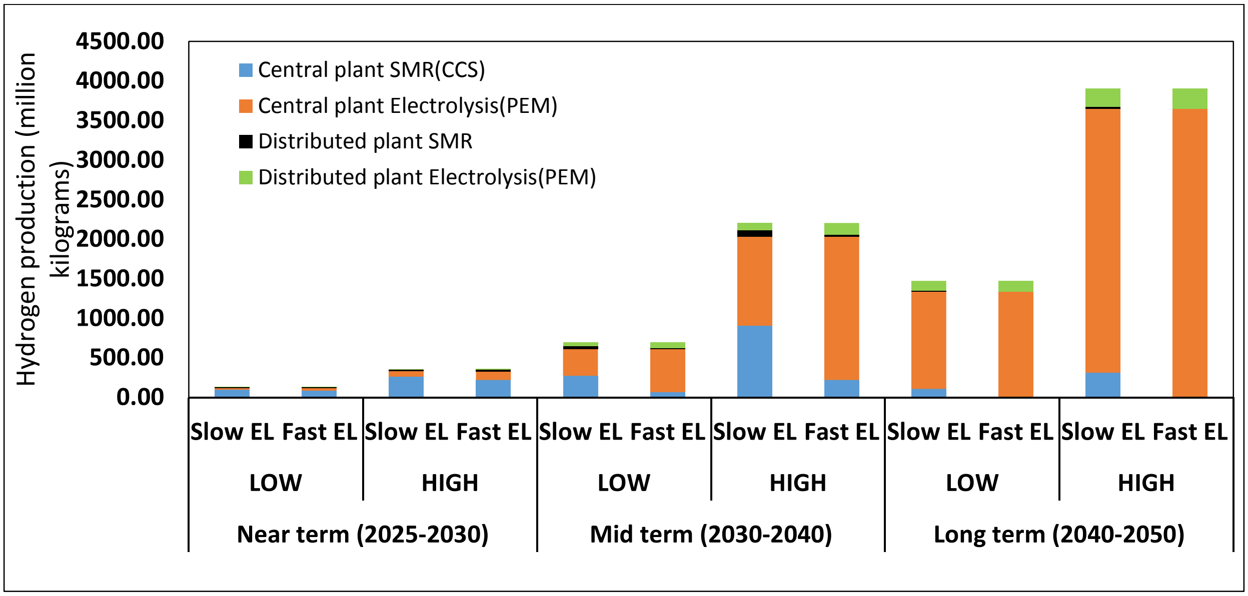

Figure 8: Annual hydrogen production/supply projections under different scenarios

California currently has 52 operational retail hydrogen stations, and another 134 stations are at various stages of approval. This will take the total tally to 181 by 2025, which is still short of the two hundred station target of the state [79]. 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 [43]. California currently has around 9000 gas stations [80] 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 9 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) [81] 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.

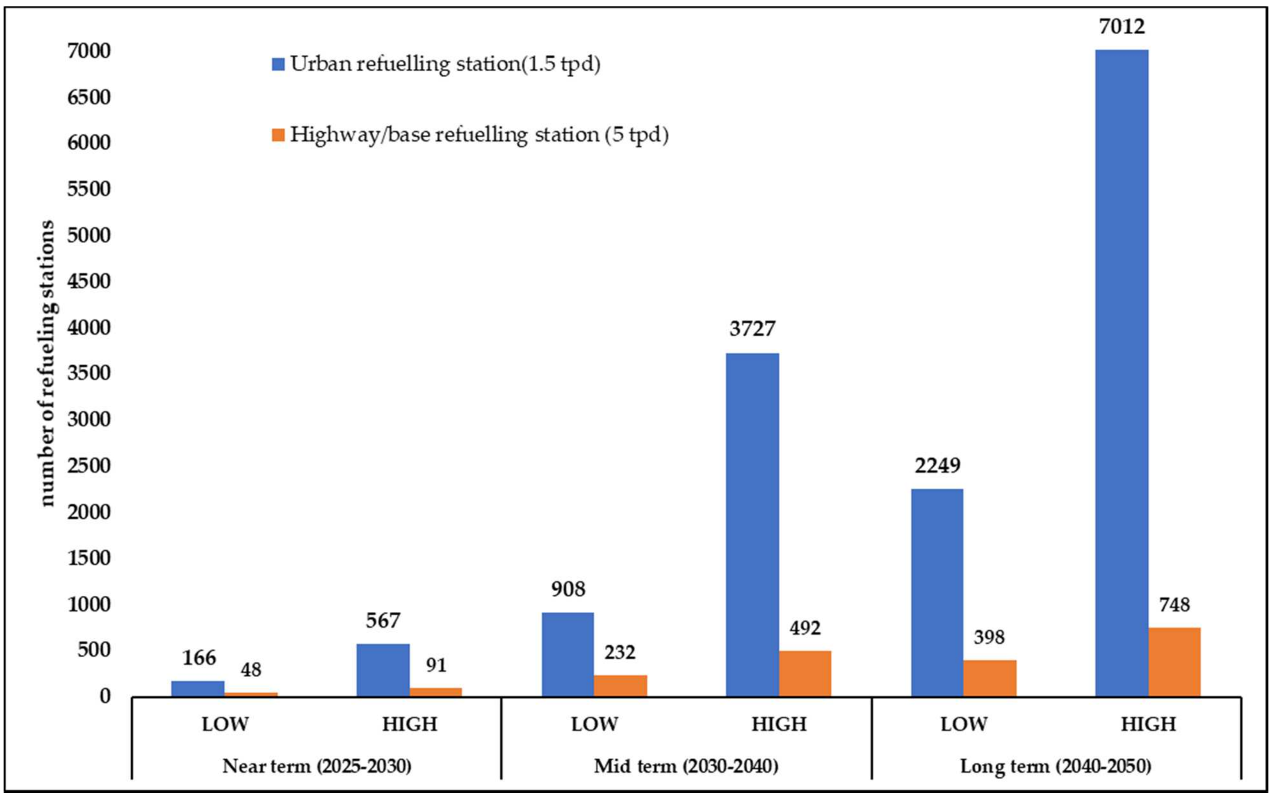

Figure 9: Projections for hydrogen refueling stations in California for different demand scenarios.

At present there is no clear policy roadmap for station buildout beyond 2025. It can be observed from the above figure 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 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 about 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 [82].

Figure 10 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.

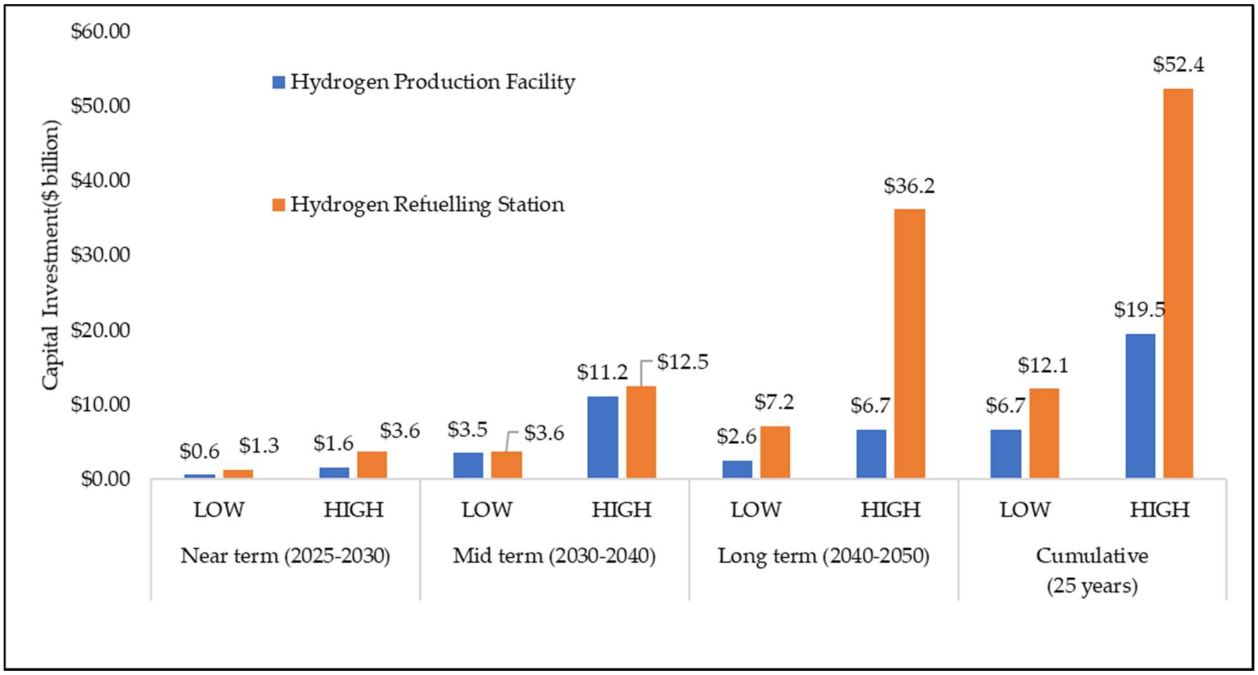

Figure 10: Overnight capital costs for build out of refueling stations and production facilities

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 [83]. This would mean for the near term, with an annual 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 above, 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 [45]. 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 the analysis done here).

1.3.2 Hydrogen supply chain costs

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

Figure 11 and Figure 12 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.

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 11). 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 12) is $2.69, which is much lower than for a smaller station. This is because onsite hydrogen production is allowed at some larger stations which helps to bypass any delivery costs. Also, larger stations can leverage the cost benefits associated with economies of scale.

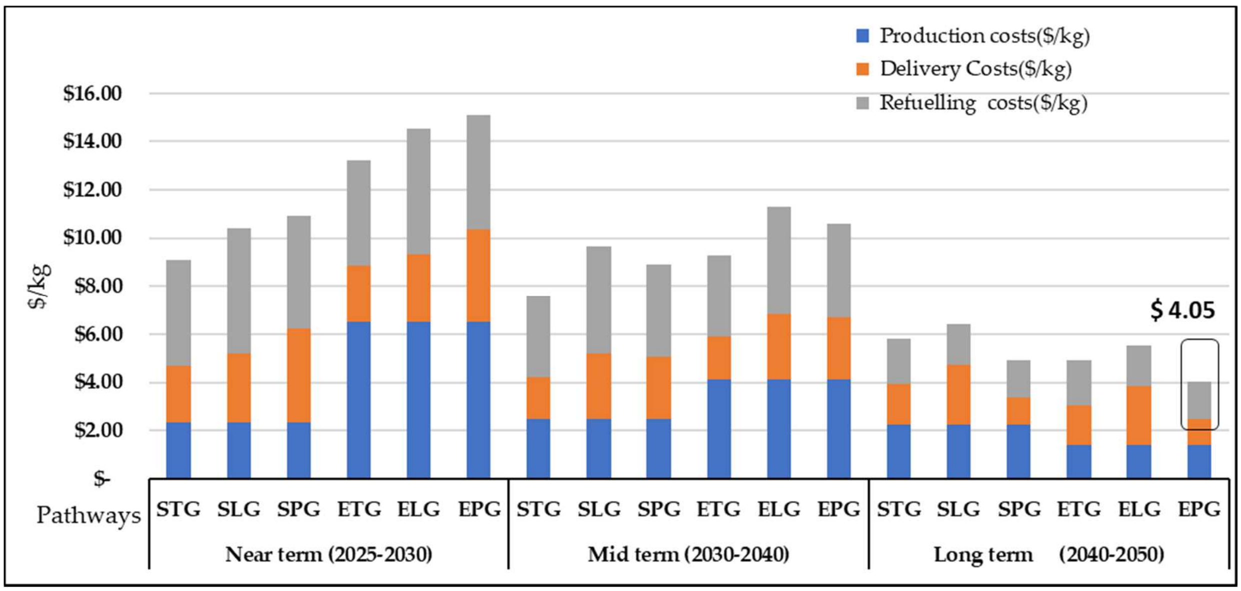

Figure 11: Hydrogen dispensed costs at a 1.5 tpd refueling station through different pathways

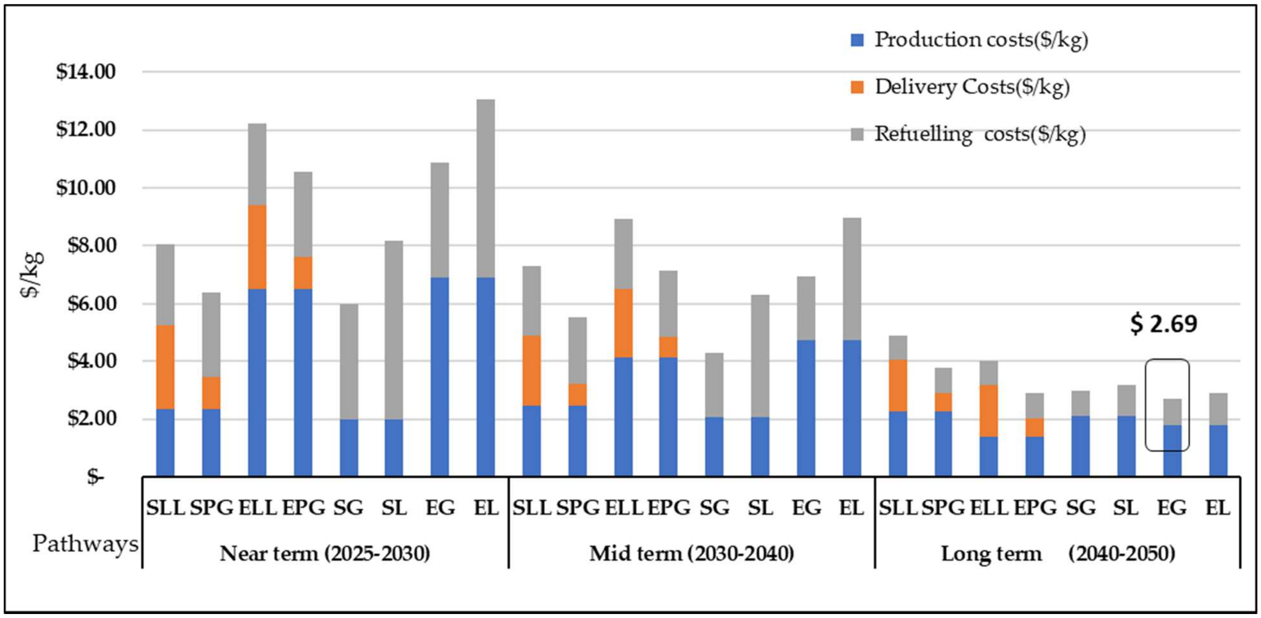

Figure 12: Hydrogen dispensed costs at a 5 tpd refueling station through different pathways

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 (1.5 tpd), 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.

1.3.3 Sensitivity analysis results for hydrogen supply chain costs

Results presented in this section are based on inputs and assumptions explained in section 1.2.5

Figure 13 and Figure 14 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.

Additionally, I explore the effects of building larger plant capacities (>30 tpd) on the levelized cost of production. I find that building larger plants (like 300 tpd) leads to a significant decrease in levelized costs (almost by 30%) owing to better economies of scale. This is more prominent for SMRs with CCS as the levelized costs for carbon capture and sequestration sees very significant drop in costs when we build large capacity plants (see S1, Figure 65). Alternatively, I find that for smaller plant sizes (like 10tpd) there is diseconomies of scale which lead to significantly higher levelized costs. Though we did not consider plant capacities >30tpd in this study, it is very much possible that with rapid increase in hydrogen demand we could see investments in lager plant capacities in future.

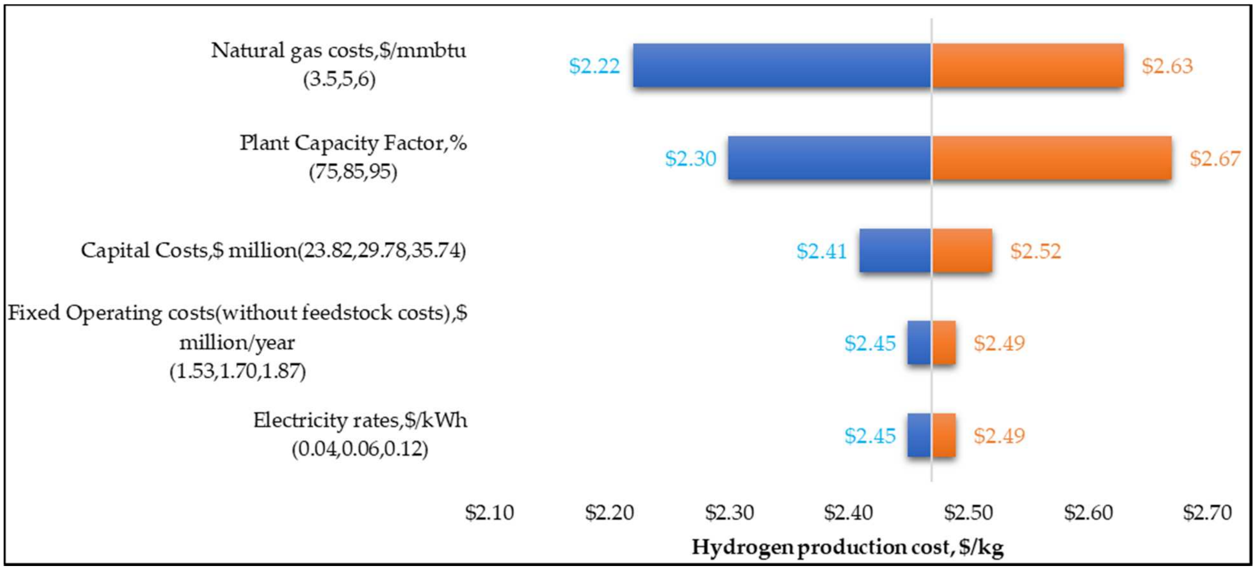

Figure 13: Range of hydrogen production costs for a 30 tpd central SMR plant.

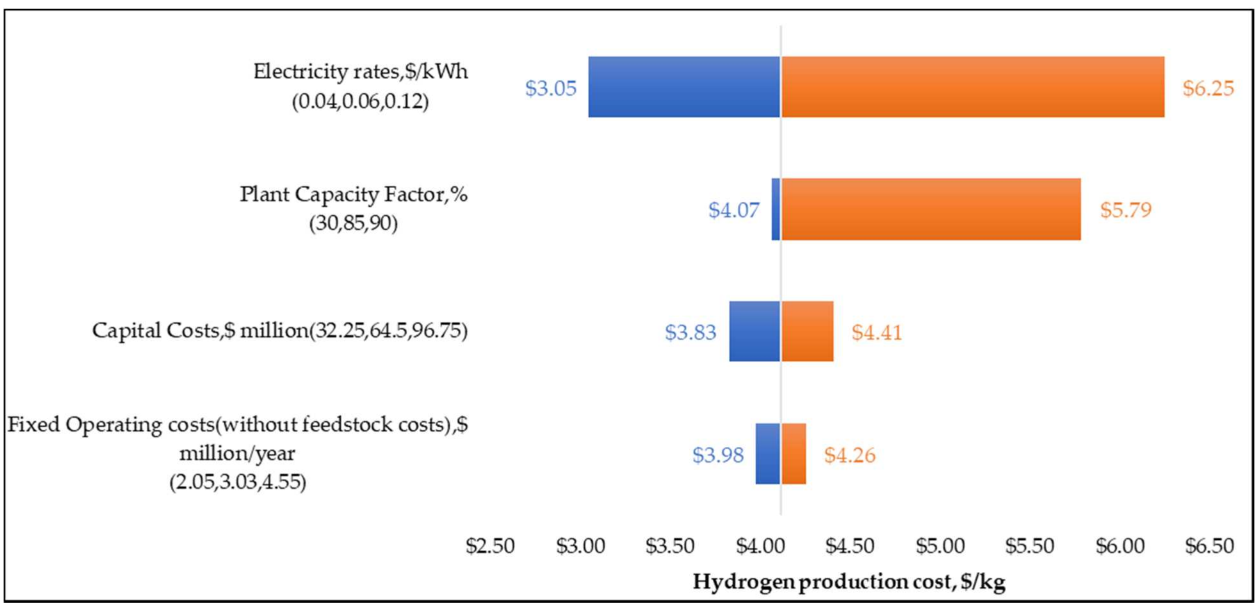

Figure 14: Range of hydrogen production costs for a 30 tpd central PEM electrolysis plant.

For a distributed/forecourt electrolysis plant (Figure 15), the trends are like 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 16), 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.

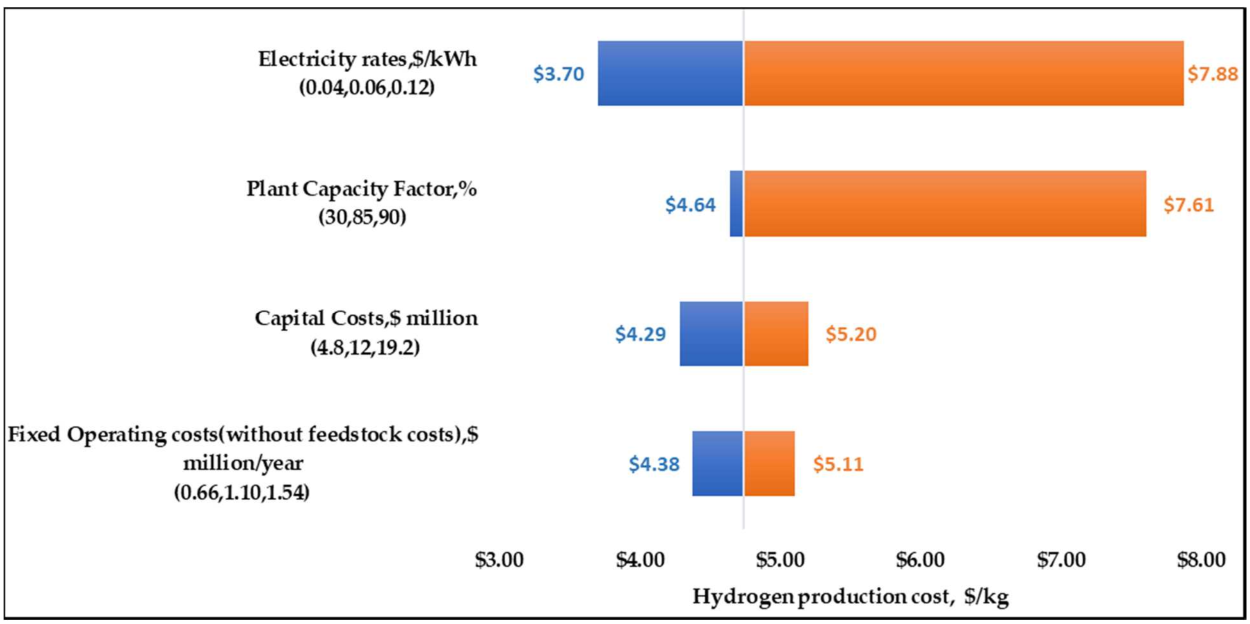

Figure 15: Range of hydrogen production costs for a 5 tpd forecourt electrolysis plant

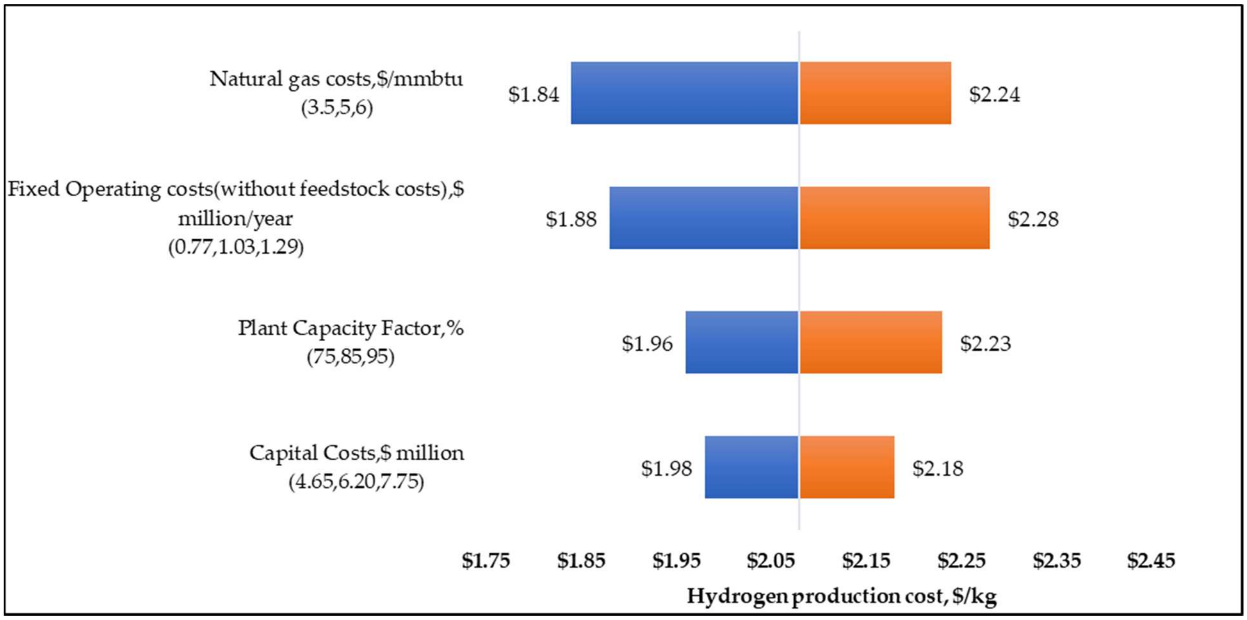

Figure 16: Range of hydrogen production costs for a 5 tpd forecourt SMR plant.

Figure 17, Figure 18 and Figure 19 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.

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.

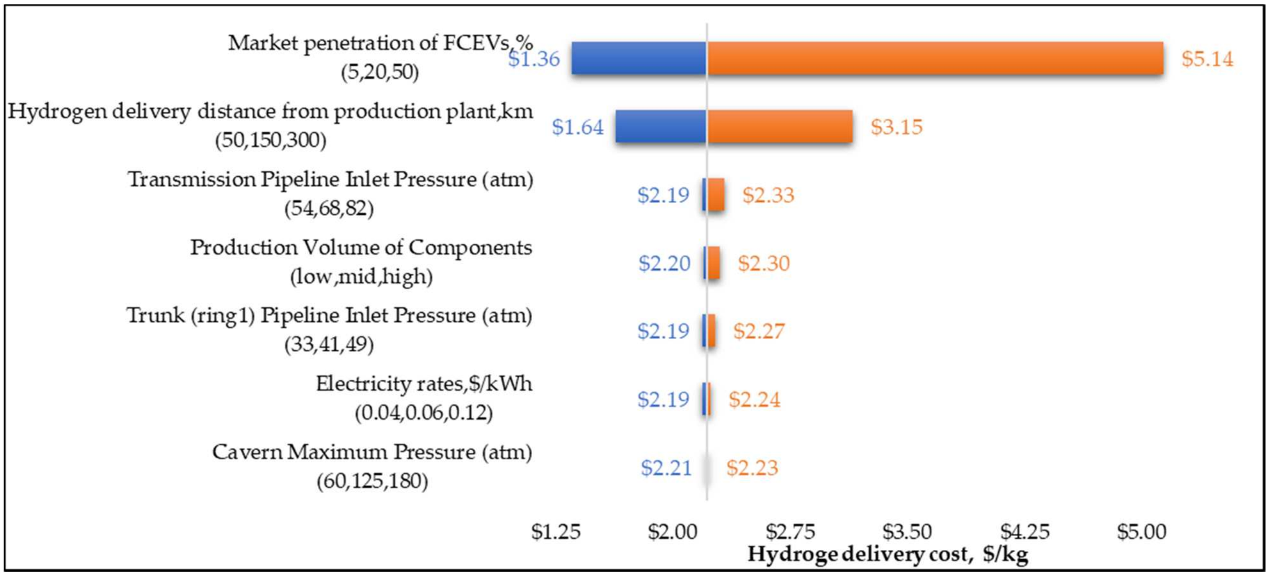

Figure 17: Range of pipeline delivery costs to a 1.5 tpd refueling station

For tube trailers, the cost reduction of equipment (compressors, tubes) due to larger production volume is the most influential parameter (refer Figure 18). 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

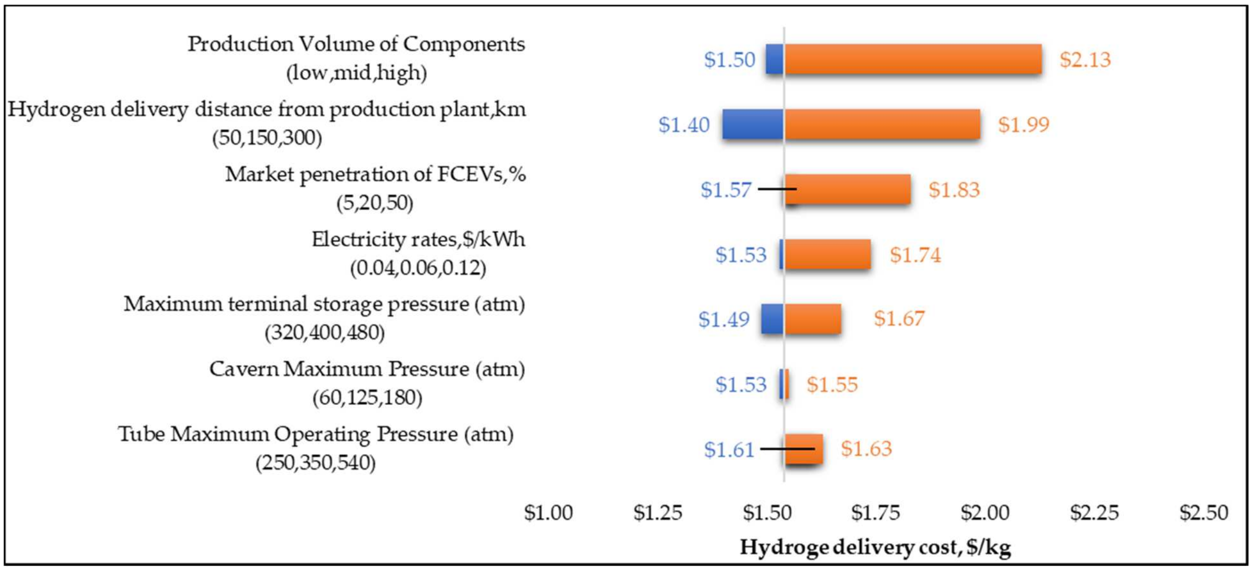

Figure 18: Range of gaseous tube trailer delivery costs to a 1.5 tpd refueling station

For liquid tankers, the delivery costs are more sensitive to electricity rates than either pipelines or tube trailers (refer Figure 19). 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 filing 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.

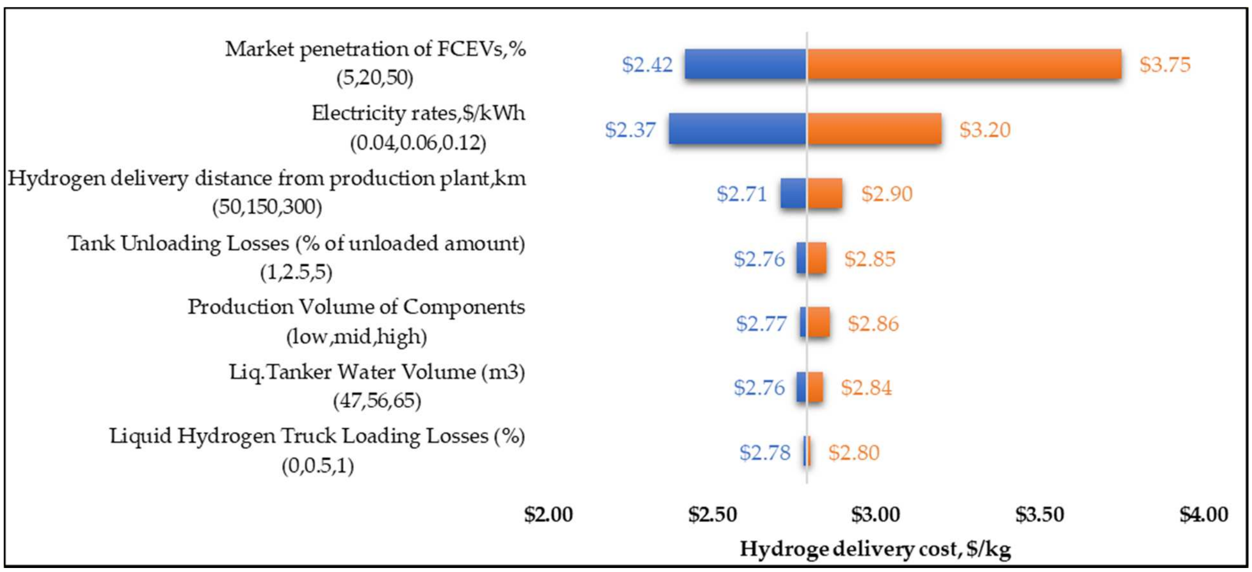

Figure 19: Range of liquid hydrogen tanker delivery costs to a 1.5 tpd refueling station.

Figure 20, Figure 21 and Figure 22 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 result 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.

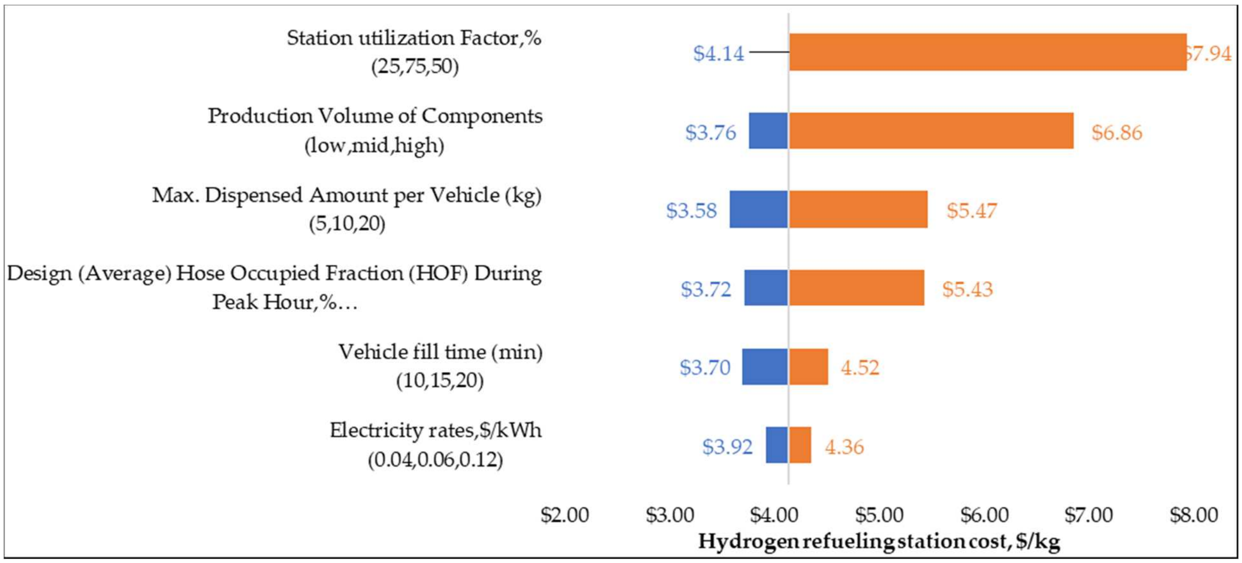

Figure 20: Range of refueling costs for a station receiving hydrogen through pipelines

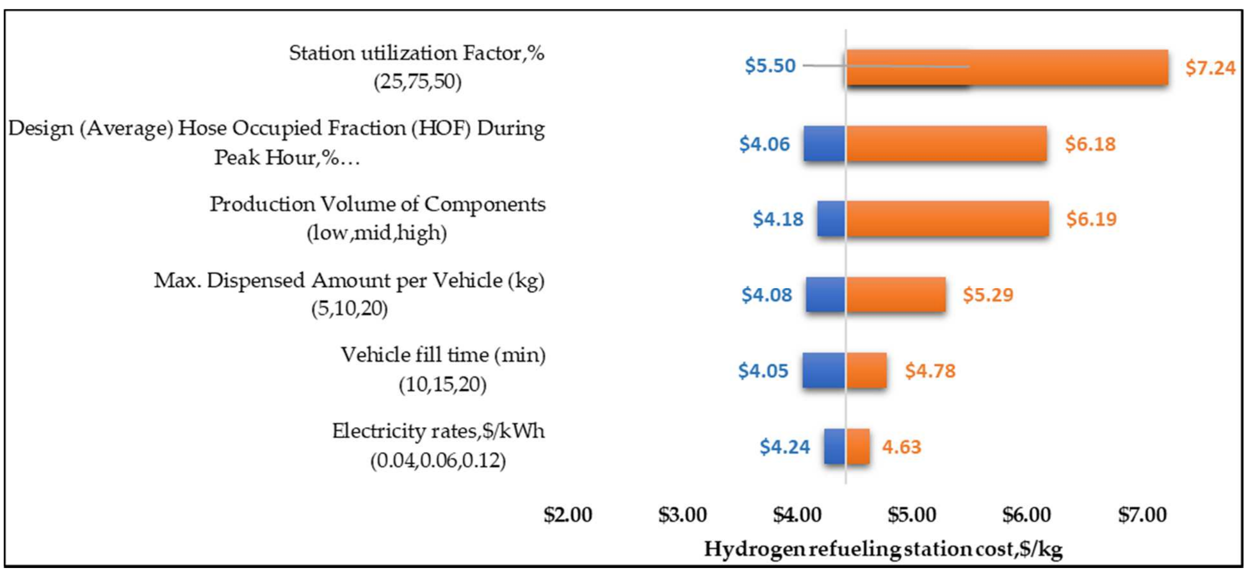

Figure 21: Range of refueling costs for a station receiving hydrogen in liquid tanker.

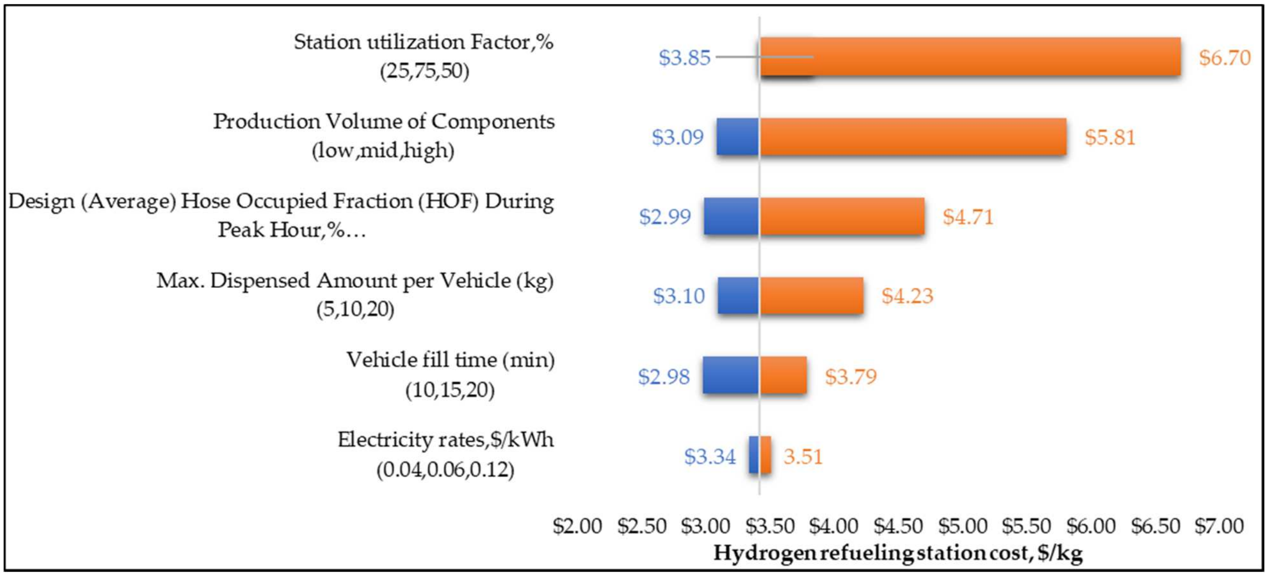

Figure 22: Range of refueling costs for a station receiving hydrogen through gaseous tube trailers.

1.4 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. In this chapter, I project future demand scenarios for hydrogen (low and high) in California from the transportation sector, in line with achieving the carbon neutrality targets for 2045. Further, I touch upon the infrastructure requirements and 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.

We assume that hydrogen use grows rapidly in the transportation sector after 2030. 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 (assuming a flat $125 per LCFS credit) 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 300 tpd and above. Hence the assumption of limiting maximum central plant capacity to 30 tpd may not be very realistic, especially as we look to model the system into 2050 when hydrogen demands could be substantial. 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.

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, 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 HSC 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 the analysis, focused on a full-scale spatial and temporal supply chain optimization for California.

Chapter 2. Understanding the impacts of demand uncertainties in the rollout of upstream supply chain infrastructure to meet on road hydrogen transport demand in California

2.1 Background

This section will build on the knowledge from the previous section to design and optimize an HSC by including various feasible hydrogen pathways and factors germane to California. I will employ the Scenario Evaluation & Regional Analysis (SERA 2.0) model, which I helped developing while interning at the National Renewable energy laboratory. SERA 2.0 is a cross-optimization model and is set up like models employed in other geographical regions for hydrogen supply chain optimization [20,21,24,31,84–87]. The HSC needs to be optimized on a spatial as well as on a temporal scale, to gain insights about hydrogen infrastructure requirements for the future. In this chapter, I will focus on answering the research question pertaining to the impacts of demand uncertainty on the buildout of infrastructure, using the SERA 2.0 model. A deterministic approach of problem formulation, using scenarios will be employed here.

Establishing a primary market for hydrogen in the transportation sector could be critical for California to achieve its goal of reaching carbon-neutrality by 2045, as mandated in 2018 by executive order EO B-55-18. This sector accounts for close to 40% of GHG emissions in the state [88]. Fuel-cell electric vehicles (FCEVs) operating on hydrogen is one among the other zero emission technologies that can help decarbonize the transportation sector in California. California has implemented several important policies like the Low Carbon Fuel Standard (LCFS), Zero emission vehicle (ZEV) mandate and more recently the Advanced Clean Truck rule (ACT) that directly or indirectly promote hydrogen as a transport fuel [7,9,89]. But the lack of supporting infrastructure has remained a major challenge to larger adoption of FCEVs.

California currently has close to 52 hydrogen refueling stations. Station reliability is lower than what the customers expect, especially when compared with traditional gasoline station reliability. [46] Hardware related issues at the station can be one reason for this but ensuring a continuous supply of hydrogen to these stations is another important aspect to improve station reliability. The question here then would be, where will this hydrogen come from and how will it be delivered to these stations. This is a complex optimization problem, with many underlying factors like technology feasibility, feeds stock prices and government policy. Further, these factors would evolve spatially and temporally. It is important to understand how a cost optimal hydrogen supply chain can be buildout with spatial and temporal resolution to serve on road transport demand in California. This would support decision making of investors as well as government policy makers.

Here I project future hydrogen demands in California (from both light duty and heavy-duty vehicles) that is both temporally and spatially resolved with a high degree of granularity. I use this as an exogenous input to SERA 2.0 and understand evolution of hydrogen supply chain in Western United States. Additionally, I also explore the impacts of perfect versus myopic demand foresights on the HSC along with other sensitivity cases which will be explained in the subsequent sections.

2.2 Modeling methods and data

Figure 23 depicts the overall modelling framework for this analysis. I soft link SERA 2.0 with an electricity grid model (GOOD) and feed in data generated from other models like STIEVE, HDSAM, HDRSAM etc. Additionally, SERA 2.0 requires information about the spatial attributes of the region under consideration, planning window and any policies that could drive the decision-making process. SERA 2.0 would then optimize and output the least cost system parameters including technology choice, capacity, infrastructure utilization and associated financial parameters like capital and operational expenditures.

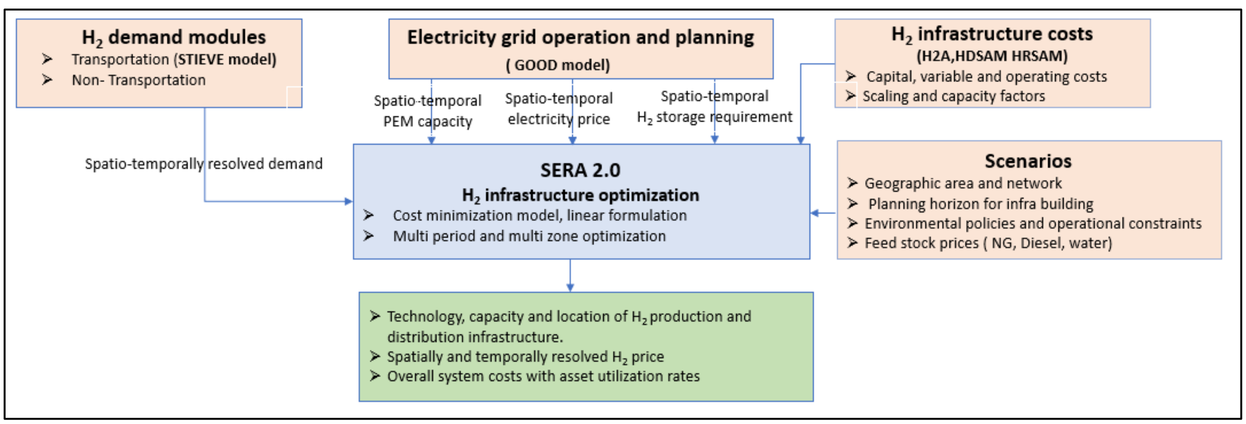

Figure 23: Super structure of the modeling framework

2.2.1 HSC infrastructure optimization: Scenario Evaluation and Regionalization Analysis model (SERA 2.0)

The SERA model developed by the National Renewable Energy Laboratory (NREL) fills a unique and important niche in temporal and geospatial optimization of hydrogen infrastructure [37]. It is complementary to other U.S. Department of Energy (DOE) HSC models, as there is compatibility in the technologies available across these models. SERA has a hydrogen demand generation module and an infrastructure optimization module. Here I employ SERA's infrastructure optimization module that estimates what infrastructure will be required to meet regional demands for hydrogen, at the minimum cost. Together with researchers at NREL, I upgraded this module of SERA to accommodate many additional capabilities (e.g., soft linking with other models, bulk hydrogen storage, policy constraints) and from here on is referred to as SERA 2.0.

Given annual hydrogen demands on a nodal basis, forecasts of feedstock costs, and a catalog of available hydrogen production technologies and delivery pathways, SERA 2.0 generates "blueprints" for hydrogen infrastructure buildout. SERA 2.0 minimizes the overall net present value of capital and operating costs for the system over a user-specified time frame. Considerations of economies of scale for the different technologies introduce nonlinearities in the problem formulation. We convert this nonlinear concave optimization problem into a linear formulation through approximations by iterations and heuristics, to arrive at near-optimal solutions without a huge penalty on accuracy and computation time. [31,90]

The total cost associated with hydrogen infrastructure includes the capital, fixed, and operating costs of the three main elements of the supply chain: production, storage, and distribution. The objective function minimizes the total discounted cost, as shown in Equation 1. The decision variables are capacities for hydrogen production, storage, and distribution, optimized both spatially and temporally. Additionally, SERA 2.0 also optimizes the operations of these infrastructures after they are constructed. Detailed model formulation can be found in supplementary material (S2, section 2.1).

Min

$$\sum_{y \quad Y}\left(\frac{1}{1+r}\right)^{y} (\ + \quad + \qquad (1$$

were

I = capital investment ($)

F = yearly fixed operating costs ($)

O = yearly variable operating costs ($)

r = real discount rate

y = years.

The objective function is constrained using mass balance equations (for hydrogen flows at each node) and operational requirements for production, distribution, and storage. Additional constraints are introduced to account for environmental policies, integration with the electric grid and locational feasibility for different technologies.

In SERA 2.0, the total optimization horizon (in this case 25 years starting in 2025) can be divided into discrete planning windows, as specified by the user. We explore a couple of planning windows like 5 and 25 years. The 5-year window corresponds to scenarios with limited demand foresight (myopic) whereas the 25-year window correspond to scenarios with perfect demand foresight.

2.2.2 Nodes and Network

Each SERA 2.0 analysis relies on a user-specified level of geographic detail. For the present analysis, we represent 491 potential supply, demand, and storage locations, modeled as nodes. We represent about 450 primary demand nodes for on-road transportation as projected by the

Spatial Transportation Infrastructure, Energy, Vehicles, and Emissions (STIEVE) model (details provided in section 2.2.4) [91]. Demand from other sectors is assumed to be concentrated across six hubs (aggregated demand nodes) in California. In some scenarios we aggregate all hydrogen demands (road transport and others) in these six hubs. The six locations are determined based of refineries, ports, and airports. The remaining nodes (about 41) are either hydrogen supply or storage locations spread across the Western Electricity Coordinating Council (WECC) region (refer supplemental material for Chapter 2, S2, Figure 77). For bulk storage locations(caverns), we use information from the U.S. Energy Information Administration [92] and from Lord et al [93].

In this analysis there are 1401 potential corridors or links for the transmission and delivery of hydrogen between these nodes. The length, route, and potential for links between nodes was computed using the Delaunay algorithm. [94] The algorithm connects the different nodes using straight lines but following the Delaunay triangulation principle to avoid making skewed connection links/lines. [95] Additional checks were performed using a Geographic Information System (GIS) tool, to ensure the links could be a reasonable representation of either pipelines or a truck route. The node and link network used in this study is depicted below.

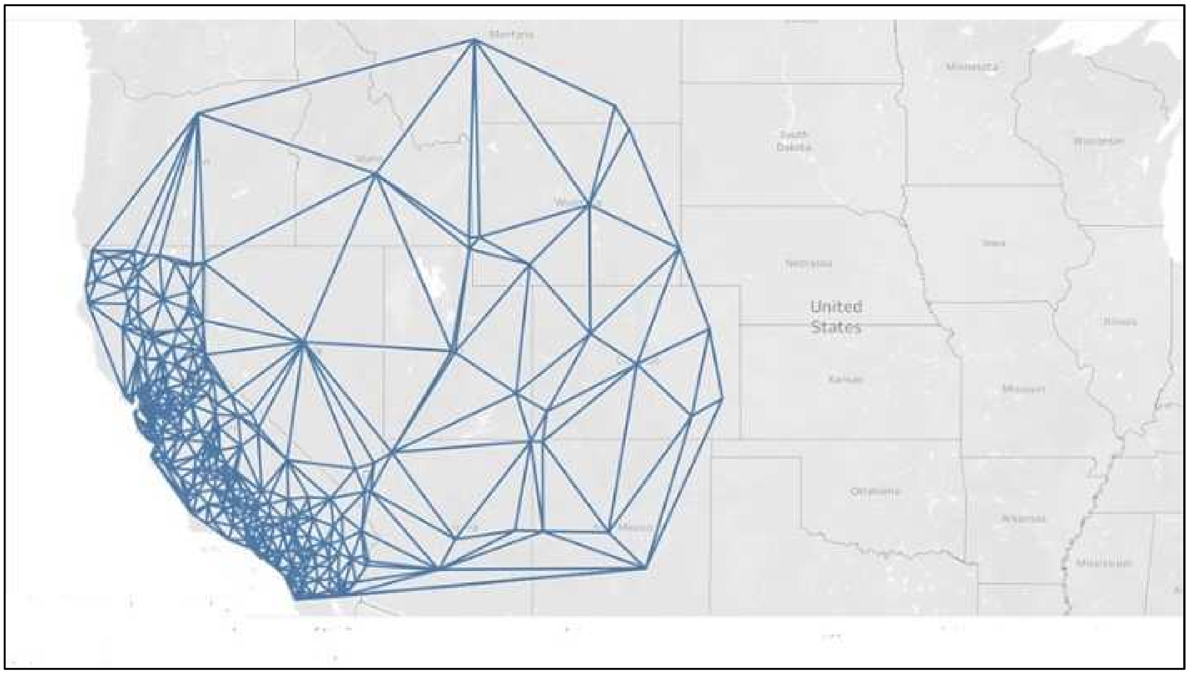

Figure 24: Potential corridors/links for transmission of hydrogen between nodes computed using a Delaunay algorithm

Each pathway consists of a sequence of components that move the hydrogen from the upstream production locations to the downstream demand locations along the network's links. The technology options considered along each pathway is based on my understanding of the status of technology and its feasibility in this region as explained in Chapter 1[96]. For production I consider both central and forecourt production using Steam Methane Reforming (SMR) with carbon capture and sequestration and Proton Exchange Membrane (PEM) electrolyzers. Transmission of hydrogen along the network takes place via three competing pathways for gaseous and liquid hydrogen: gaseous truck, liquid truck, and pipeline (see S2, Table 15). For on road transport demand, the last stage of delivery is the refueling station. SERA can build the last mile infrastructure to deliver hydrogen up to the refueling station. In this chapter I will focus on meeting on road transportation demand only.

In the next chapter, where I will be including both on road and other sectoral demands, I treat the last stage of delivery in a different way. The delivery network there is much more diverse with different end use applications like refineries, building/residential heating. Given the complexities of analyzing the last mile delivery of hydrogen to each of these varied applications, a simplifying assumption considering delivery up to the "City gate" is made. This is not perfectly aligned with reality but given the high levels of uncertainty of last mile deliveries within regions and the computational challenges of considering last mile delivery to all the different end uses this assumption is reasonable. Adding these last mile delivery options for demands from different sectors and enabling the model to differentiate the delivery pathways to meet transport and non-transport demand is work for future.

2.2.3 Hydrogen demand projection

Unlike in Chapter one, here I distribute hydrogen demand spatially. On road-transport demand is projected using the Spatial Transportation, Infrastructure, Energy, Vehicles and Emissions (STIEVE) model. In this chapter I will focus on the HSC development for meeting on road transportation demand in California.

2.2.4 Spatial Transportation, Infrastructure, Energy, Vehicles and Emissions (STIEVE) model

STIEVE is an optimization model, developed by researchers at the University of California, Davis, to deploy hydrogen refueling stations for fuel cell vehicles based on the characteristics of travel and attributes of the stations [91]. The model is based on a subset of empirical Origin-Destination (OD) data and route network data from the California Statewide Travel Demand Model (CSTDM). The CSTDM version 2.0 forecasts all personal travel made by every California resident plus all commercial vehicle travel made on a typical weekday in the fall/spring (when schools are in session). It is trip-based (recently updated to an activity-based model), which includes passenger trips, as well as heavy-duty truck trips. The model then distributes these trips through the internal and external zones, resulting in several OD matrices. The geographical division/zoning system for CSTDM is based on Traffic Analysis Zones (TAZs). Hydrogen demand is calculated based on the shortest route travelled between the TAZs, fuel economy of the vehicle and an assumed market penetration of fuel cell vehicles. The statewide market penetration numbers come from the TTM model, discussed in Chapter 1. Hydrogen demand at the TAZ level as determined by STIEVE is as an exogenous input to SERA 2.0. There is a low and a high demand scenario projection as depicted in Figure 25. Figure 26 and Figure 27 depict the spatial distribution (centroids of each TAZ) of demand in the high and low scenarios.

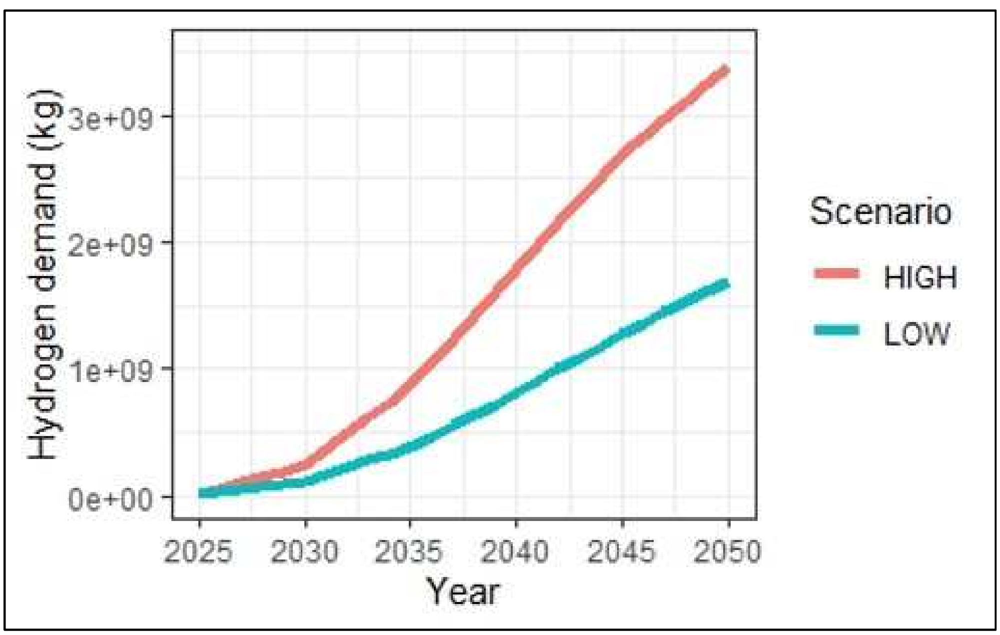

Figure 25: Annual hydrogen demand projections for on transportation in California (STIEVE model projections)

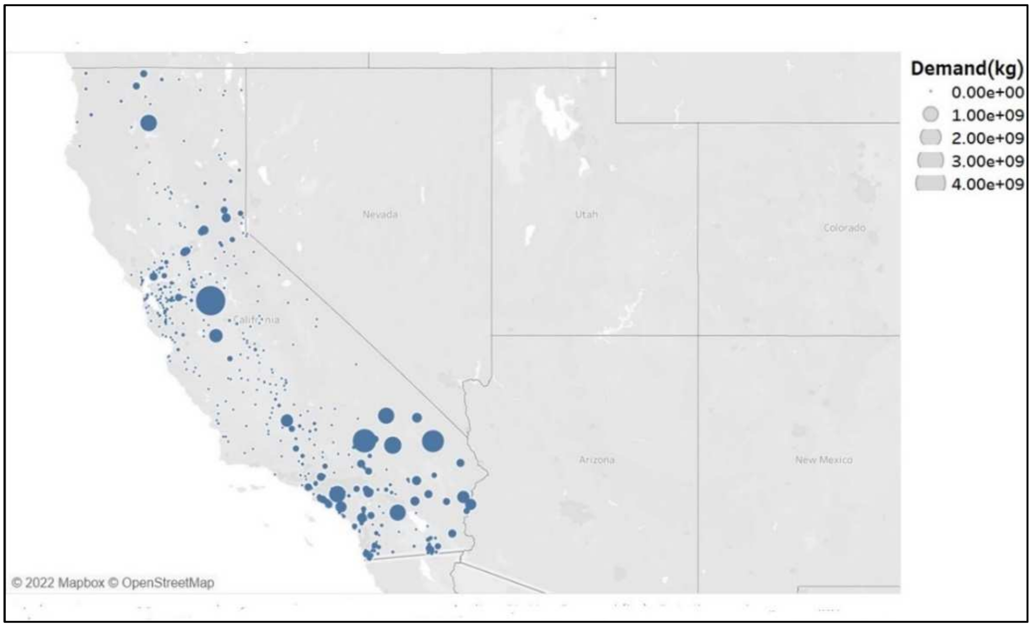

Figure 26: Spatial distribution (centroid of TAZs) of cumulative hydrogen demand for the high scenario (2025-2050)

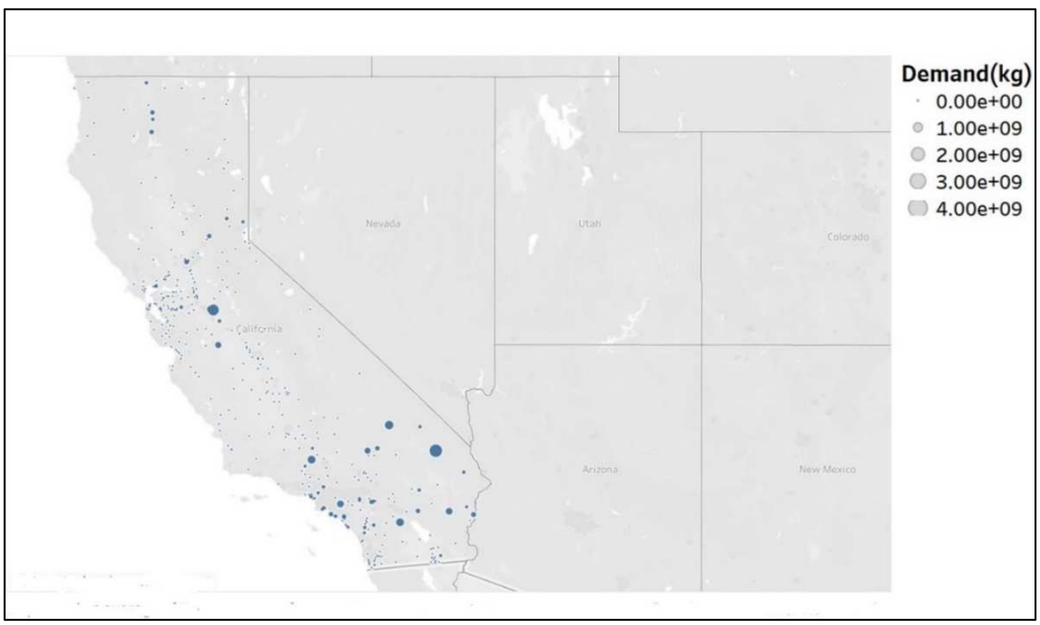

Figure 27: Spatial distribution (centroid of TAZs) of cumulative hydrogen demand for the low scenario (2025-2050)

2.2.5 Regional Electricity price forecasts

Regional electricity prices are a critical input to SERA 2.0. Electricity is one of the primary feed stocks for hydrogen production (through electrolysis) and for distribution network (truck terminals, liquefaction plants etc.). Ascertaining the electricity price as accurately as possible is critical, while SERA builds out the most cost-effective hydrogen infrastructures for future. Here I soft link SERA 2.0 with a full-scale electricity dispatch model to capture relevant parameters like electricity prices, electrolyzer capacity, and hydrogen storage.

Many previous studies have modeled the interaction between the HSC and the grid assuming that the HSC is a price-taker [29,97], which implies that electricity price at a given location is not impacted by hydrogen demand at that location, which can lead to sub optimal buildout of the HSC. Here I partially circumvent that by ensuring the electricity grid model is aware of hydrogen demands and the electricity costs the GOOD model (described below) are representative of both the electricity as well as hydrogen demands in a location.

2.2.6 Grid Optimized Operation Dispatch (GOOD) model

The GOOD model is a national level economic electricity dispatch model, that optimizes the operation of power generation units to meet the electricity demand at the minimum cost to the systems operator [29,98]. Electricity demand for a region at a particular time is an exogenous input and the model dispatches generating units according to the lowest marginal cost, given cross region bulk transmission constraints. The generation capacity expansion decisions are largely driven by the Renewables Portfolio Standard (RPS)[99].

For this study, the GOOD model is updated with a hydrogen module. The module includes PEM electrolyzers, hydrogen-driven gas turbines, and hydrogen storage as decision variables in the optimization. The model is run for the Western Electricity Coordinating Council (WECC) region. Hydrogen demand (from California) and electricity demand for WECC are exogenous inputs to GOOD and the model optimizes the grid operation to satisfy both demands in a cost optimal manner. A larger geographic area consideration for the electricity grid (beyond California) will have advantages. One, it will help leverage a wider transmission network hence helping to balance the grid between supply and demand. Secondly, a larger geographical span will mean a greater generation potential from renewables like solar and wind.

Regional electricity price is a critical input in SERA 2.0. Marginal electricity costs from GOOD are transformed into annual average electricity prices by including the additional costs of generation (capital recovery) and regional transmission and distribution costs. Adders ($/kWh) adopted from NREL's Regional Energy Deployment System (ReEDS) model[100] are used to transform the electricity costs from the GOOD model into regional commercial and industrial electricity rates (see S2, Figure 67 and Figure 68). Overall, in the WECC, between 2025 and 2050, electricity rates could decrease, largely driven by falling generation costs. California's electricity prices (annual average) are expected to remain well above the average of other WECC regions (refer S2, Figure 66).

In addition to generation costs, we use PEM electrolyzer capacity, hydrogen demand for electricity generation, and bulk hydrogen storage capacity from GOOD to constrain SERA 2.0 in the grid-integrated scenario, where I discuss the potential impacts of sector coupling on the HSC (Chapter 3).

2.2.7 Other feedstock prices

Apart from electricity prices, industrial rates for natural gas, diesel and water are important factors that affect the decision-making process in the optimization. For water, I assume a constant rate of $0.004/gal for all regions and time periods. I use regional prices from the U.S. Energy Information Administration's Annual Energy Outlook (AEO 2021)[101] for natural gas and diesel. Natural gas is the primary feedstock for producing hydrogen using SMR technology. Hydrogen delivery using trucks is an important mode of hydrogen distribution. It is assumed that all these trucks are powered by diesel. Unlike electricity, the prices of natural gas and diesel are expected to increase as we look into the future. Spatially and temporal variations of the prices are depicted in supplementary material S2 (refer Figure 67, Figure 68, Figure 69, Figure 70, Figure 71, Figure 72).

2.2.8 Infrastructure cost assumptions

SERA 2.0 optimizes from a range of user defined technology options for every echelon of the HSC. The user can define relevant technology costs and a suite of other operational parameters like nameplate capacity, scaling, and capacity factors. SERA 2.0 would weigh in each of these parameters in the decision-making process. I generate the lifecycle costs and operational parameters for different hydrogen production and delivery options, using standalone models as explained in Chapter 1. I employ the H2A, hydrogen delivery scenario analysis model (HDSAM) and Hydrogen Refueling Station Analysis Model (HRSAM) respectively, for hydrogen production, delivery and refueling costs. Levelized costs in $/kg for the different production and distribution technologies considered in this analysis can be found in in supplementary material (refer Figure 73, Figure 74, Figure 75 and Figure 76). To prevent SERA 2.0 from building unrealistic infrastructure capacities, we introduce additional maximum capacity constraints. For example, for central production we limit maximum sizes to 400 tpd.

One of the sensitivity cases here explore the impacts of onsite/forecourt production alongside refueling stations. Additional locational constraints are incorporated in SERA 2.0 for forecourt production of hydrogen, based on availability of land. Land availability is determined through separate GIS analysis by Tri dev (researcher at ITS). I use that information to locationally constrain SERA 2.0.

2.2.9 Hydrogen storage

Hydrogen storage is a critical piece to solving the puzzle of an optimized hydrogen supply chain. Large scale hydrogen storage options can offset the supply- demand imbalances in the network and help in sector coupling. Previous studies have indicated that hydrogen is amongst the most cost-effective options for large-scale and long duration storage needs of the electricity grid [32,34]. In this study I consider two hydrogen storage options: geological and line pack storage. Other storage options like cryogenic spherical vessels or pressurized cylinders will not be cost competitive [35], when we are considering grid level storage requirements, [36].

Four different geologic storage options exist: salt caverns, depleted oil and gas reservoirs, aquifers, and lined hard rock caverns. Salt caverns seem to be the most preferred choice for hydrogen storage. Globally, three out of the four operational salt caverns are in the United States, along the Gulf Coast. Salt caverns offer a virtually leak proof surrounding and offer minimal risks of hydrogen contamination. Hydrogen can be cycled multiple times (in and out of the cavern) in a year, thereby reducing the levelized cost of hydrogen storage [93]. A study carried out for the European Union ranks salt caverns as the most viable large scale hydrogen storage option in terms of safety, technical feasibility, and costs [102,103]. I use the information about salt deposits from the U.S. Energy Information Administration (EIA) [104] and from the work of Lord et al [103], for spatially determining locations that could be developed/mined into caverns (refer Figure 77).

Line pack storage refers to the inherent storage capacity contained within gas pipelines, by means of varying the overall pressure levels of these pipelines [105–107]. National and regional transmission pipelines, have greater line pack flexibility due to larger operating pressure ranges and pipeline volumes. Many studies have analyzed the possibility of leveraging existing natural gas pipelines for storing hydrogen, by suitably blending hydrogen into the gas stream [107–109]. This would be a reasonable intermediate step before we transition to building large scale dedicated hydrogen pipelines. Blending hydrogen into a natural gas stream has many technical and economic challenges, but could be a feasible for certain applications [110]. However, in this study I consider line pack storage for dedicated hydrogen pipelines only. Considering the time frame of this analysis, which extends into 2050, it is reasonable to expect the hydrogen demands to be high enough to justify the huge upfront capital costs for building dedicated hydrogen pipelines. For line packing, an additional constraint is introduced in the formulation of SERA 2.0 which sets a maximum limit to line packing in a pipeline based on process parameters. The maximum cap for line packing is determined through a separate process modeling effort by researchers at NREL, using the ASPEN model (refer Figure 78). The boundary conditions set for the process modelling are in line with the general pipeline building assumptions of HDSAM. Major assumptions here include a maximum pipeline operating pressure of 1000 psi with a 40% drop in pressures at the city gate. The pipeline system design includes two parallel compressors with one back up. I consider both line packing and salt caverns for hydrogen storage in the optimization problem.

2.2.10 Scenario Description

I follow a scenario-based deterministic approach to understand specific aspects of the HSC development. Table 6 describes scenarios that explore the impacts of demand uncertainties while planning for infrastructure to meet on-road transportation demand in California. Two main scenarios and three sensitivity cases are considered here. The two scenarios correspond to low and high travel demand estimated using the STIEVE model as shown in Figure 25. Sensitivity cases are run to understand the impacts of perfect demand foresight, allowing forecourt production, and excluding large-scale/bulk hydrogen storage. The delivery system here is modeled up to the last mile (i.e., up to the nozzle for vehicle refueling).

Table 6: Scenario and sensitivity case descriptions for HSC optimization to meet on-road transport demand in California

Scenario name	Planning window	Hydrogen demand profile	Hydrogen production	Hydrogen distribution	Sensitivity case description	Sensitivity case name
IOD_H	5 years	High (on-road transport only) in California	1. Central production using SMR with CCS and grid-connected PEM electrolyzers. 2. A 33% renewable hydrogen requirement is enforced (SB 1505).	1. Delivery using gaseous tube trailers, pipelines, and liquid tankers. 2. Bulk storage (salt cavern and line pack) is available. 3. Hydrogen delivered up to the nozzle for vehicle refueling.	With on-site/forecourt hydrogen production allowed	Onsite_allow
					With no bulk storage	No_Stor
					Longer planning window/perfect demand foresight of 25 years	IOP_25
IOD_L		Low (on-road transport only) in California				

2.3 Results

2.3.1 Hydrogen production

Figure 28 and Figure 29 represent the share of total hydrogen produced by different technologies. PEM electrolysis is found to be dominant over SMR with CCS in these scenarios (see Table 6 for descriptions). We identify two reasons that drive this trend. One is the existing renewable hydrogen mandate (SB 1505) that discourages building SMRs, especially in the earlier years. Secondly, SMRs with CCS tend to have better economies of scale over PEMs only after a certain plant size (approximately 50 tons per day and above). The highly distributed nature of on-road transport demand in California (see Figure 26 for details of spatial distribution of demand) that increases only incrementally does not incentivize building very large SMR plants with CCS. However, this trend could change with longer planning windows (e.g., 25 years), which guarantees perfect foresight of demand and encourage building higher capacity SMR plants. In such a scenario, blue hydrogen (SMR with CCS) could constitute nearly 42% of the entire hydrogen supply in 2050 (Figure 29).

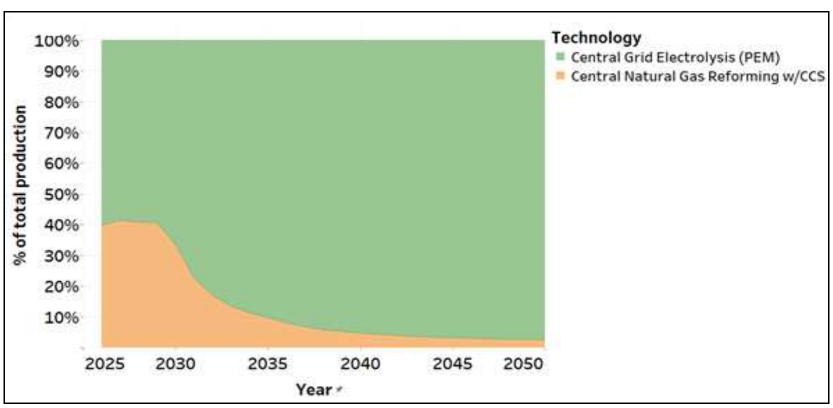

Figure 28: Percentage share of hydrogen production by technology type for scenario IOD_H (5-year planning window, on-road transport demand only)

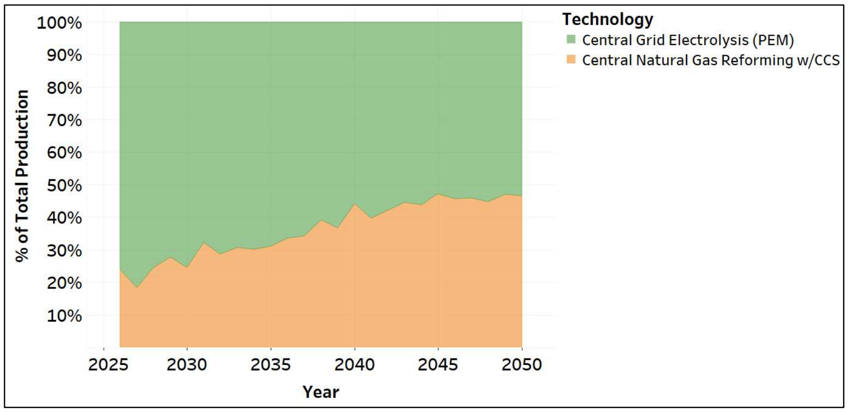

Figure 29: Percentage share of hydrogen production by technology type for scenario IOP_25 (25-year planning window, on-road transport demand only)

The technology choice for hydrogen production is primarily driven by feedstock prices in the region. In all scenarios analyzed here, we see that almost every SMR plant is built in California (see Figure 30 and Figure 31). The primary reason is that the industrial natural gas rates in California are comparable to what we see in other WECC states. On the contrary, the industrial electricity rates in California are much higher as compared to other WECC regions. This forces much of the grid-connected PEM electrolyzer capacity to be built outside California.

Additionally, we observe that the location and size of production plants are influenced by their proximity to demand and the planning window (5 or 25 years) that is available to potential investors. With a longer planning window, there is the benefit of perfect demand foresight which forces the model to build larger capacity production plants to leverage better economies of scale. I find that with perfect foresight, there are fewer plants being built, but the average plant size is substantially higher. For example, the average plant size with perfect foresight is more than 85 tpd, compared to less than 50 tpd with perfect foresight. Also, there are substantial number of very large plants (> 250 tpd) built with perfect foresight as compared to a maximum plant size of 100 tpd built with a 5-year planning window (myopic planning window).

In these scenarios, we only consider demand in California, which encourages building larger SMR plants (compared to PEM) in California, closer to demand. This begs an interesting question: how much hydrogen would be produced in-state versus regional imports?

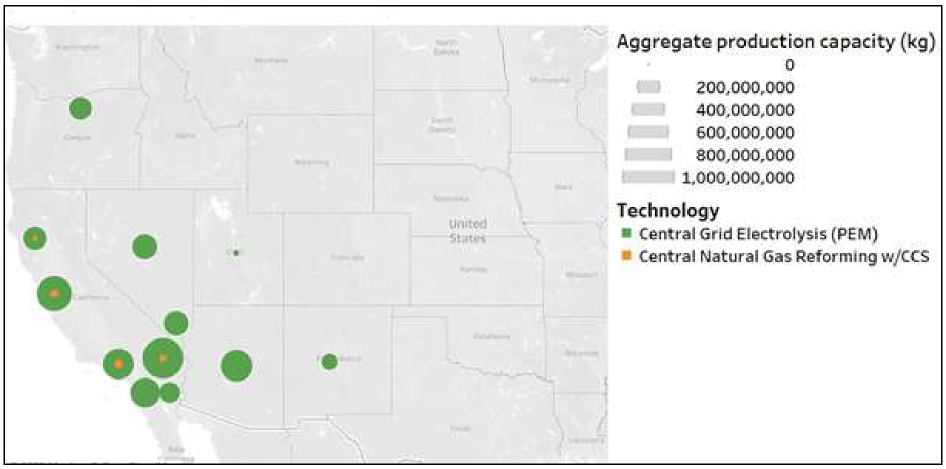

Figure 30: Cumulative hydrogen production capacity expansion over 25 years for scenario IOD_H (5-year planning window, on-road transport demand only)

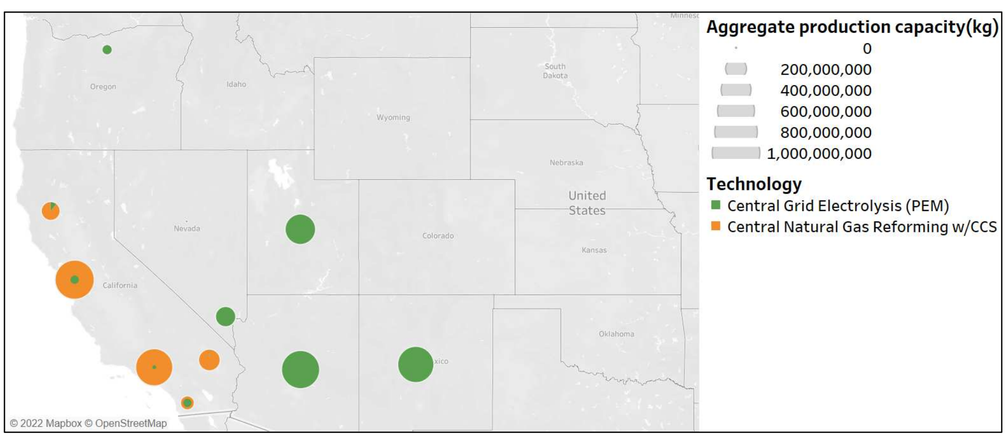

Figure 31: Cumulative hydrogen capacity expansion over 25 years for scenario IOP_25 (25-year planning window, on-road transport demand only)

In scenarios considered here, we find that California could end up importing a substantial portion (between 30%–70%) of its hydrogen from neighboring states. The imbalance between in-state production and regional imports is starker in the initial years, and though imports keep increasing, their shares gradually dwindle down over the years.

Interestingly, the levels of imports remain much higher when we have a longer planning window (

Figure 33). Much of the expenditure here is directed toward building a delivery network (e.g., truck terminals, pipelines) that would bring in the cheap hydrogen produced via electrolysis in regions where the electricity prices are at least half of what California sees. Also, much larger PEM electrolyzer plants are built out of state with a longer planning window (compared to 5-year planning window), which further incentivizes reginal imports.

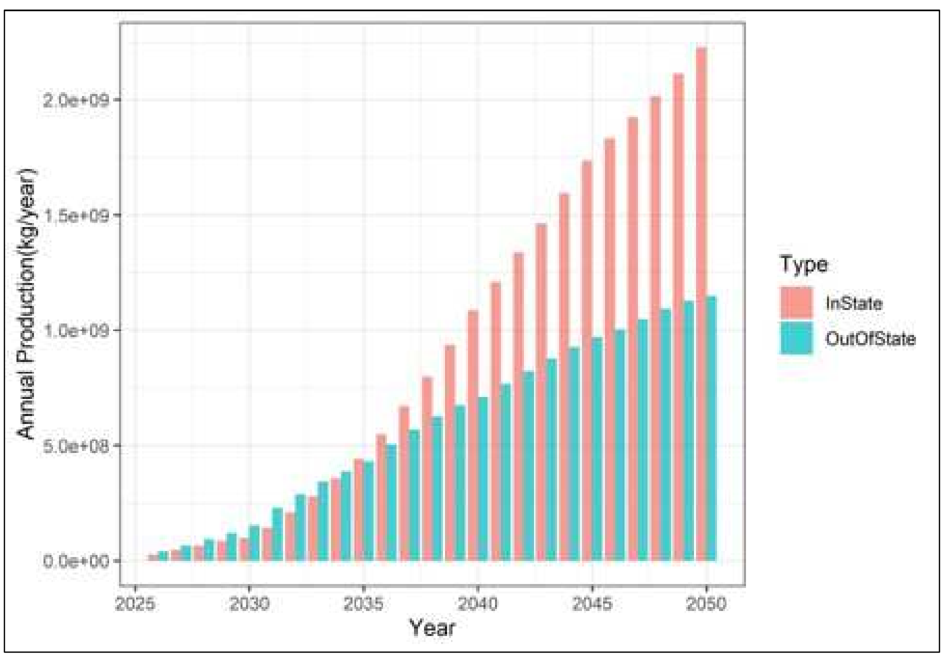

Figure 32: Distribution of in-state and out-of-state production/regional imports for scenario IOD_H (5-year planning window, on-road transport demand only)

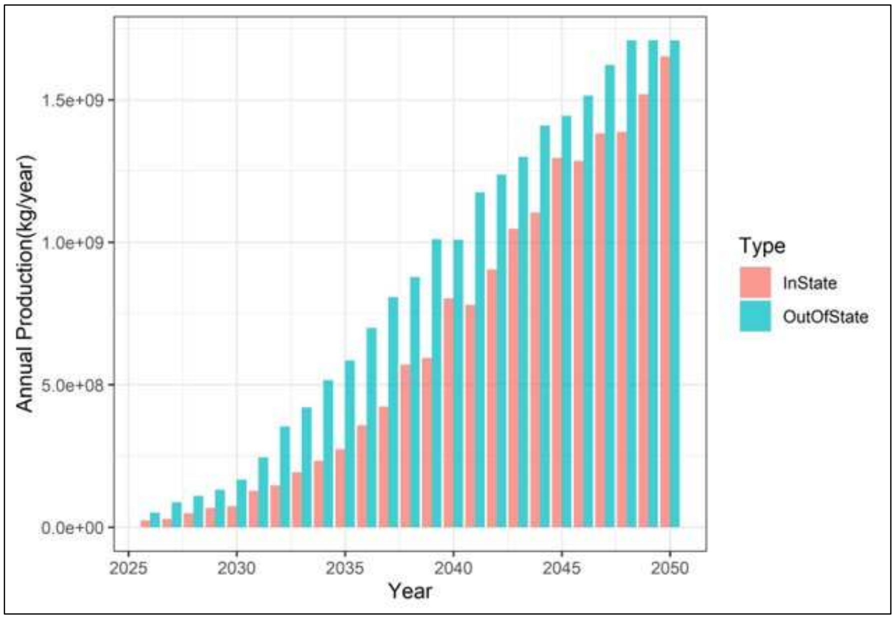

Figure 33: Distribution of in-state and out-of-state production/regional imports for scenario IOP_25 (25-year planning window, on-road transport demand only)

We find that with on-site/forecourt production allowed (sensitivity case Onsite_allow) alongside refueling stations, about 18% of the total production in 25 years would come from these plants (refer S2, Figure 79).

With lower demand (scenario name IOD_L), we see a greater shift toward electrolysis-based production (refer S2, Figure 80) and consequently higher levels of regional imports. With very small and incremental levels of demand, there is no incentive to build SMR plants with CCS which are more economic at larger plant capacities (say > 50 tpd).

It is worth noting that my analysis did not consider the possibility of utilizing any existing production plants in California. Most of the existing capacity is captive (within refineries), and their availability to satisfy external demand for hydrogen is uncertain. Nevertheless, I ran a sensitivity case considering the possibility of using 15% of the existing nameplate capacities, which did not have a substantial impact on the rollout of future HSC infrastructure because there needs to be substantial addition of new capacity to meet the projected transport demand (~ 4 million tons/ year in 2050 for the high case)

2.3.2 Hydrogen distribution

The most cost-effective hydrogen delivery option depends primarily on the amounts of hydrogen delivered, distance of delivery, and network effects. SERA 2.0 chooses the optimum delivery pathway after considering all these factors simultaneously. For the scenarios considered in this section, we model delivery up to the nozzle of the vehicle for refueling at 700 bars.

Figure 34 and Figure 35 depict the percentage share of hydrogen flowing through the three delivery pathways considered in this study: gaseous tube trailers, liquid hydrogen trucks, and gaseous hydrogen pipelines.

One key takeaway is that with a myopic planning window (5 years), wherein the delivery infrastructure would be built incrementally, hydrogen delivery using trucks is the most cost-effective option. Within trucking, the choice between liquid versus gaseous is largely a function of flow capacity. Larger flow rates incentivize liquid-based delivery because of its advantage to scale, both for delivery (larger capacities per truck) and at the refueling station. Hence, with a longer planning window, the liquid hydrogen delivery pathway is preferred to meet on-road transportation demand. On the flip side, a low-demand scenario (IOD_L), promotes delivery using gaseous tube trailers, because of its cost-effectiveness to serve incremental demands that are highly distributed.

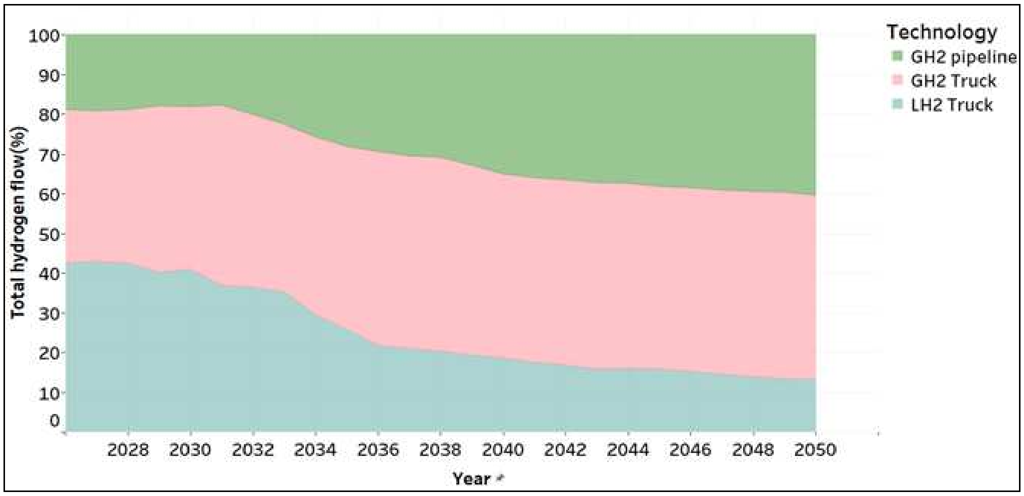

Figure 34: Percentage share of hydrogen distributed through different delivery options in scenario IOD_H (5-year planning window, on-road transport demand only)

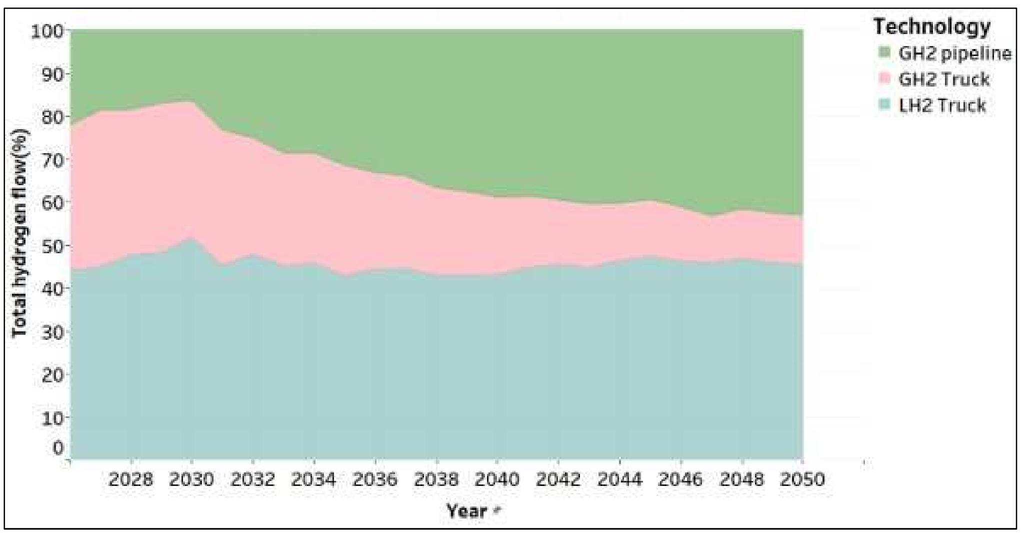

Figure 35: Percentage share of hydrogen distributed through different delivery options in scenario IOP_25 (25-year planning window, on-road transport demand only)

Building new hydrogen pipelines is very capital-intensive and becomes cost-effective only at higher utilization rates. One way to incentivize pipeline building is through farsighted policies that would guarantee some levels of future demand, to encourage investment decisions in new pipelines. We capture this in our modeling by running a scenario with a very long planning window of 25 years. Comparing Figure 35 and Figure 34, we can note that a long-term planning strategy would encourage building new pipelines. However, with the highly distributed nature of demand (for on-road transportation), even with a 25-year planning window, pipeline delivery would only account for about 40% in 2050. Also, the cost economics of the refueling stations are not very supportive of having pipeline-based delivery. Even with hydrogen delivered at 70 bars by pipelines, the cost of compressing this to 700 bar is substantial, and subsequently the refueling station costs become prohibitive, especially when compared to a similar capacity refueling station that has hydrogen delivered by liquid trucks (see S2, Figure 76).

A representative buildout of the hydrogen pipeline network for the 5 -year versus 25 -year planning window can be seen in Figure 36 and Figure 37. These figures represent the aggregate pipeline capacity that is built for the entire analysis period starting from 2025. The thickness of the network lines is proportional to the maximum pipeline capacity. It is evident that with a myopic planning window, much of the pipeline's network would be developed within state and will mostly be employed to transport hydrogen produced within the state. A longer planning window, incentive building interstate pipelines whereby California could access some of the cheap electrolytic hydrogen produced out of state. Also, these interstate pipelines could be leveraged as a hydrogen storage medium through line packing (refer S2, Figure 78).

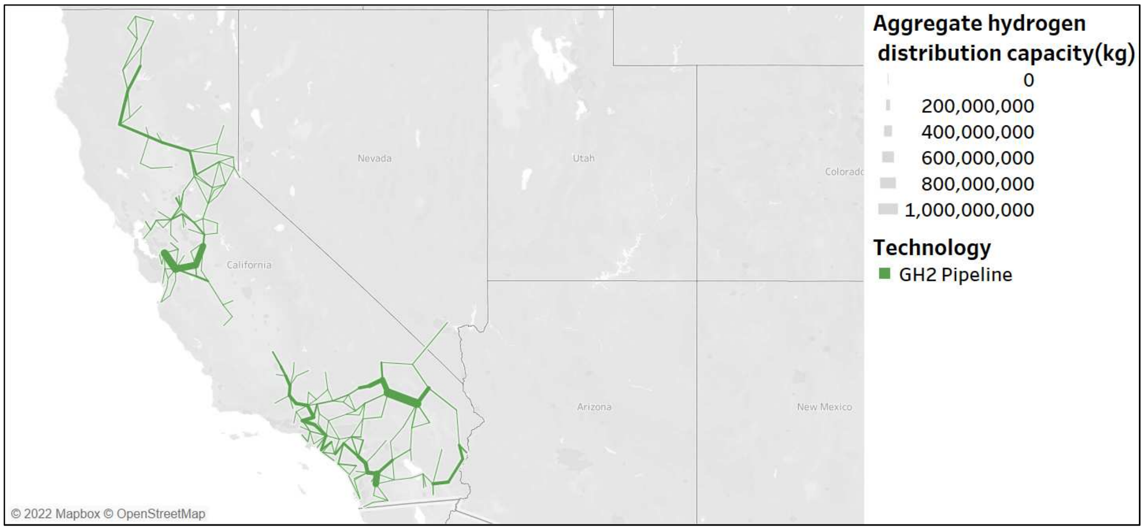

Figure 36: GH2 pipeline network expansion from 2025-2050 in scenario IOD_H (5-year planning window, on-road transport demand only)

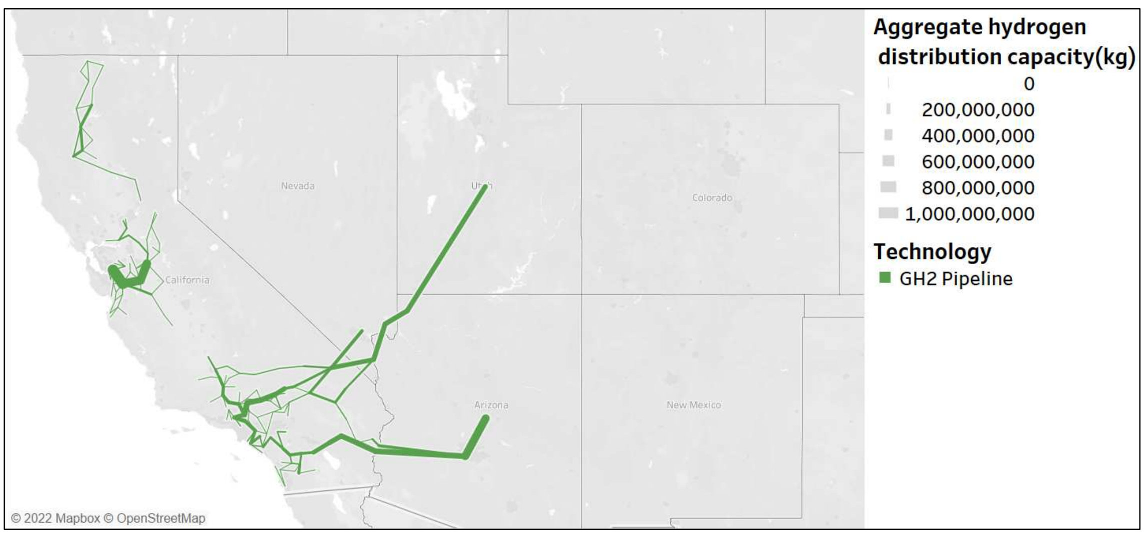

Figure 37: GH2 pipeline network expansion from 2025-2050 in scenario IOP_25 (25-year planning window, on-road transport demand only)

2.3.3 System costs

Figure 38 and Figure 39 provide a breakdown of expenditures/costs incurred for capacity expansion and operation of the HSC over the 25-year period. I present the results for one representative scenario (IOD_H), as the trends are similar across all scenarios and sensitivity cases.

Clearly, hydrogen production expenses dominate the overall costs (Figure 38). Also, we can observe that variable operating costs are significant (Figure 39), which are primarily due to feedstock consumption. Together, this means that the choice of hydrogen production is the primary driver for supply chain development, and that decision is largely dependent on feedstock prices. A deeper dive into how the source for hydrogen production would influence the decisions for supply chain development is presented in Chapter 3. It is also evident that capital expenditures (capex) are a major chunk of the total costs in the earlier periods. In the latter years, there is substantial capacity being carried forward, and therefore very sizeable capex investments are not needed moving forward.

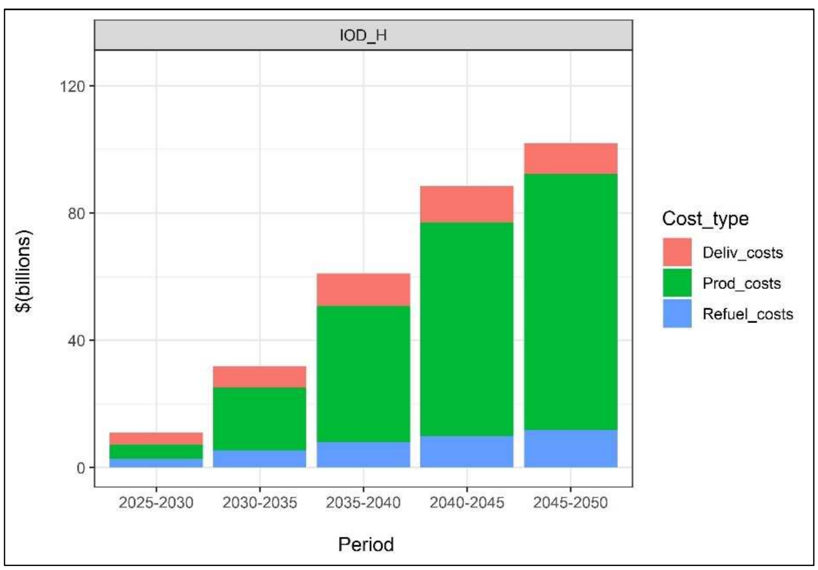

Figure 38: Breakdown of expenditure (production, distribution, and refueling) incurred in 5-year block periods for scenario IOD_H (5-year planning window, on-road transport demand only)

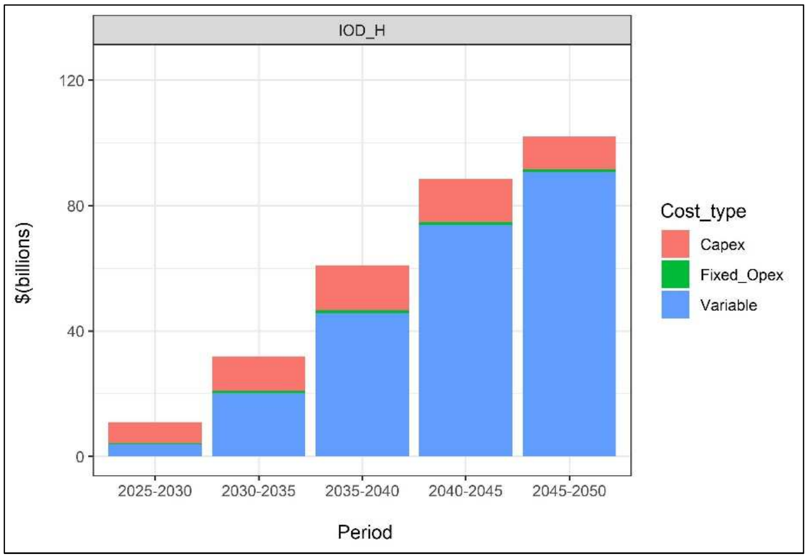

Figure 39: Breakdown of expenditure (capex, operating expenses, and variable) incurred in 5-year block periods for scenario IOD_H (5-year planning window, on-road transport demand only)

Figure 40 compares the total system costs across all the “on-road transportation” scenarios and sensitivity cases. I find that the scenario (IOP_25) with a longer planning window (25 years) turns out to be the least expensive to build. Long-term planning enables better economies of scale and asset utilization, driving down overall system expenditures. This would reflect on the retail price of hydrogen as well.

The scenario that allows on-site hydrogen production (Onsite_allow) incurs more expenditures. Once these small on-site plants are built (mostly during the initial years), they continue to operate to 2050, and are not as efficient as larger central electrolyzers. I calculate that the total system cost over the 25 years for this scenario is at least 10% higher compared to the base case (IOD_H) with only central production.

Additionally, I find that the total system expenditures for a supply chain without any bulk storage (scenario No_stor) are comparable to the base case (IOD_H). Therefore, with a highly distributed demand profile (as for "on-road transportation"), which only increases incrementally, we could have a system that either overbuilds capacity in production and delivery or have bulk storages to handle demand uncertainties.

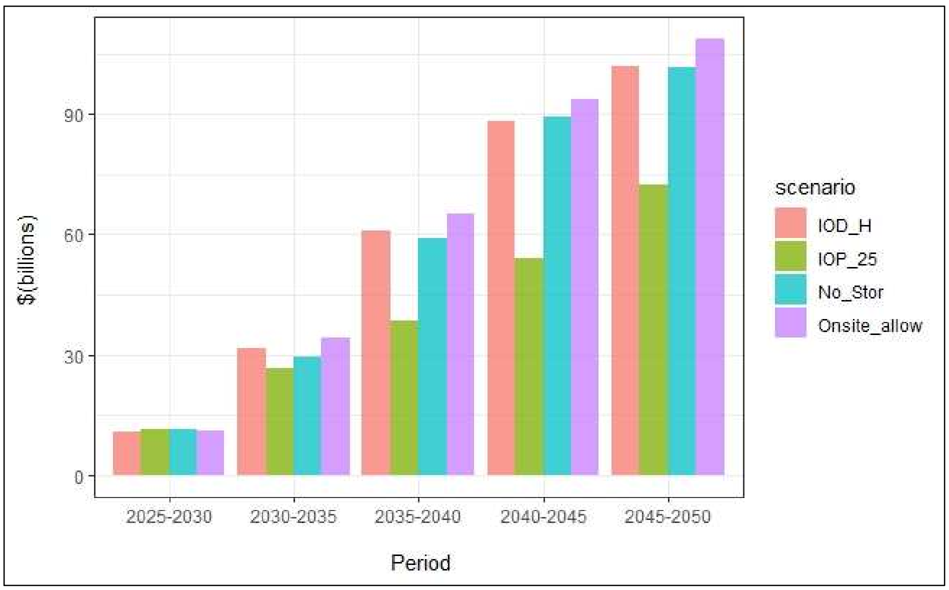

Figure 40: Comparison of HSC buildout expenditures to meet on road transportation demand

2.3.4 Demand weighted average hydrogen costs($/kg)

Figure 41 and Figure 42 depict the average costs of hydrogen, demand weighted against the expenditures incurred during the analysis period from 2025-2050. The costs are averaged out in five-year chunks. It is evident that with perfect foresight (scenario IOP_25), the average hydrogen cost can drop below $5 much earlier, than when building infrastructure incrementally based on a myopic foresight (scenario IOD_H). The primary reason driving this is that with perfect foresight, we can invest in building bigger infrastructure capacities that might be expensive initially, but then could leverage the economies of scale to drive down costs later. Examples include building larger capacity production plants or refueling stations can drive down the expenditures substantially in the future years. Thus, with long term planning (which could be driven by government policies) there is a possibility to reduce overall system level expenditures which would have substantial impacts on retail prices too.

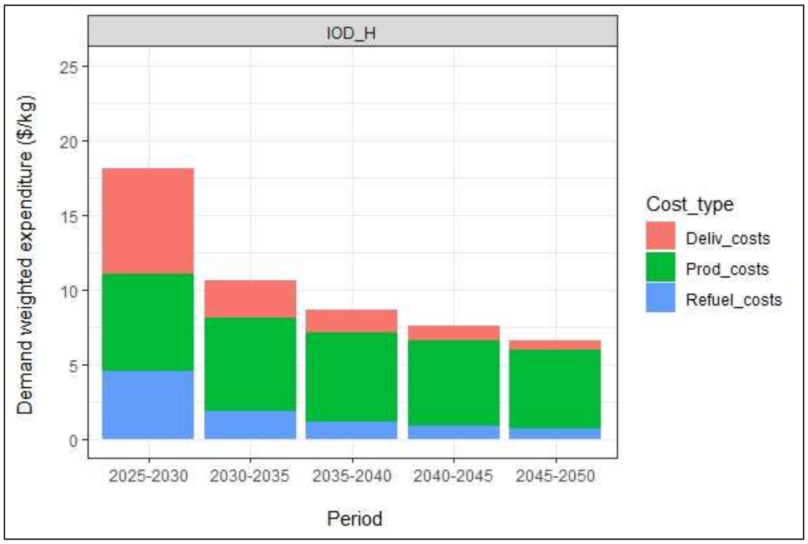

Figure 41: Demand weighted hydrogen expenditures/costs for scenario IOD_H

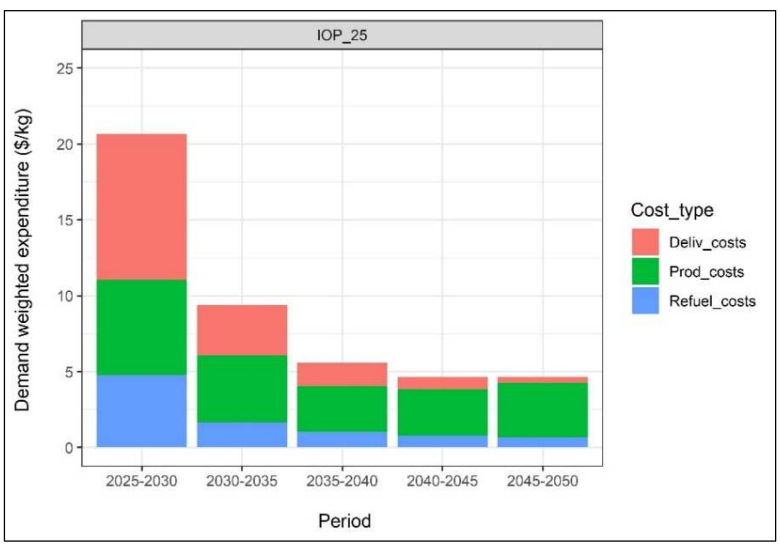

Figure 42:: Demand weighted hydrogen expenditures/costs for scenario IOP_25

2.4 Conclusions

Existing policies in California have been very encouraging for the uptake of hydrogen, especially in the transportation sector. But the availability of infrastructure to support a growing fleet of fuel cell vehicles is a major challenge to the success of hydrogen as a fuel in transportation. I employ NREL's SERA model to understand the buildout of HSC to meet projected hydrogen demands from on road transportation in California. The analysis is spread across 25 years, starting in 2025. This modeling effort provides numerous insights as to how, when, and where capacity expansion for hydrogen production and distribution would evolve under demand uncertainties. I also explore some additional sensitivity cases like the impacts of long-term planning, allowing onsite/forecourt production and bulk hydrogen storage availabilities on the supply chain buildout.

As we project the hydrogen supply into 2050, electrolysis-based hydrogen production dominates overall, owing to falling electricity prices and lower capital costs. We find a substantial amount of that production could happen outside California owing to lower electricity prices in those regions. Also, when the demand is low, electrolysis is preferred even more, since there is no incentive to build very large SMRs with CCS that are not cost competitive at smaller plant capacities. But when demand is high and when investments are planned with longer foresight, SMR with CCS gains prominence and could contribute nearly 40% of all hydrogen supplied even in 2050. In such scenarios, renewable hydrogen policies like (SB 1505) is found to be very effective in discouraging SMR based hydrogen supply into the system. Additionally, I find that when forecourt/onsite production is allowed (alongside refueling stations), it restricts the system from building larger capacity infrastructure that could leverage the benefits of economies of scale.

Hence the overall system buildout is more expensive as compared to a system with only central production.

The nature of on-road transportation demand (which is very distributed and increasing only incrementally) is a major driver, while choosing the cost optimal hydrogen delivery pathway. In many scenarios analyzed here, I find that electrolytic hydrogen distributed by trucks (both gaseous and liquid) is cost optimal to meet on-road transportation demand. Liquid truck delivery gains prominence as the system scales. However, with better demand foresight and a longer planning window (like 25 years), we could build more dedicated hydrogen pipelines. There needs to be high levels of demand certainty to incentivize building of pipelines. But once built and operated to near full utilization, pipeline delivery is the cheapest. Additionally, pipelines offer reasonable amounts of hydrogen storage opportunities which could help balance some of the supply-demand uncertainties. I find that during the initial years, when demand is growing slowly, short distance larger diameter pipelines are built. But as the market grows, longer interstate pipelines (that could store substantial amounts of hydrogen) are also constructed.

I compare the system costs/expenditures for hydrogen infrastructure buildout that would be incurred over a period of 25 years, under different scenarios. I find that there could be about 30% savings at a system level (owing to better economies of scale) if we plan long-term, instead of having a myopic 5-year planning window. Long term planning also encourages for building out a cost optimal delivery network (with substantial amount of pipelines) that could have greater access to cheap renewable hydrogen (from grid connected electrolyzers) produced outside California. Under high demand scenarios, the marginal costs of hydrogen could fall under \$5/kg in most locations in California after 2040 (refer S2, Figure 81 and Figure 82).

In this chapter I focus on the HSC buildout required to meet future on road transportation demands in California. But as discussed earlier, hydrogen's role in decarbonizing other sectors is also important. Hence in the next chapter I will consider hydrogen demand from other sectors in California (along with on-road transport) and investigate the impacts of sector coupling the HSC with the electricity grid to meet those demands. I will aggregate all demands onto six hubs spread across California and will also explore the impacts of renewable hydrogen policies in the buildout of infrastructure to support those hubs.

Chapter 3. Implications of sector coupling and renewable hydrogen policies on the evolution of supply chains to support hydrogen hubs in California

3.1 Background

Hydrogen is a very versatile molecule that has cross sectoral applications. An integrated hydrogen system can benefit from economies of scale and learning across these sectors. But given the nascent stage of hydrogen in the energy market, government intervention through suitable policy levers will be important to kick start the hydrogen economy. In the United States, recent legislation such as the Bipartisan Infrastructure Bill[6] has earmarked close to $8 billion for scaling up hydrogen technologies and establishing at least four hydrogen hubs (large, geographically concentrated demands) on a national level. Additionally, national-level cost targets, such as the "Hydrogen Shot," seek to reduce the cost of clean hydrogen by 80% to $1 per kilogram in a decade. Existing policies in California have been very supportive of hydrogen, especially in the transportation sector [7–10]. But recently, this is expanding to other sectors as well. Other notable initiatives like HyDeal LA, in which the Los Angeles Department of Water and Power is partnering with the Green Hydrogen Coalition to develop a green hydrogen supply chain, have catapulted California's prospects of becoming a future hydrogen hub [11].

In addition to hydrogen demand as fuel for the light-duty and medium/heavy-duty road vehicle sectors, CEC estimates that hydrogen could play a role in decarbonizing other sectors like aviation, building and industry [47,111]. The nature of the demand from these sectors, their potential growth, and the timing of that growth will affect the pace at the infrastructure is built and is therefore an important piece to the development of an optimized HSC. Vast majority of previous studies have attempted to model a HSC that is driven by demand from the transportation sector, predominantly by light duty vehicles [49,86,112]. I will model hydrogen hubs in California which would represent aggregated hydrogen demands from both on-road transportation and other sectors.

California's electricity grid is increasingly becoming renewables based. The CEC estimates that in 2019, 32 percent of the state's retail electricity sales were supplied by Renewables Portfolio Standard (RPS) eligible sources such as solar (14.22 percent) and wind (6.82 percent) [113]. The RPS standard mandates the renewable's share on the grid to grow to 60 percent by 2030. Grid reliability is one of the challenges associated with an increasing uptake of renewables, owing to the intermittency of power generation from these sources [32]. As the integration of solar and wind power into the electric grid increases, grid balancing will become increasingly difficult. Periods of over-generation will increase curtailment, while periods of lower renewable generation will require substitution through fossil fuel powered plants or power dispatch from energy storage systems [114]. These effects on the grid are often depicted in the "Duck Curve", named for the shape of the net electricity demand in the state as published by the California Independent System Operator (CAISO) in 2013 [115]. To ensure continued grid reliability, California has a procurement target for the deployment of 1.32 gigawatts of stationary energy storage by the end of 2024 [114]. Storage requirements could increase drastically as the share of renewable power generation increases. Finding a sustainable and lasting solution to store the otherwise curtailed excess renewable energy produced during peak generation times, followed by its use in later demand periods is a challenging task. This is where hydrogen could value as a flexible demand side resource and also as a suitable long duration storage medium [32,114]. Electrolyzers could soak up most of the curtailed electricity during peak generation hours to produce hydrogen and store it for later use. Earlier studies have analyzed the HSC in isolation, without proper integration with other supply chains, like the electricity grid [29,116]. I soft link SERA 2.0 with the GOOD model (as explained in section 3.2.2 of chapter 2), to explore how a HSC fully driven by the electricity grid would evolve overtime and how would that compare to other scenarios where there are more diversified hydrogen supply options (like SMR based hydrogen).

Driven by favorable policies, California could become a potential early producer for both green (electrolysis using renewable electricity) and blue (hydrocarbon-derived, with carbon capture) hydrogen. Policies such as SB 1505 (mandating 33% renewable hydrogen requirement for transportation) encourage green hydrogen [63]. The recently passed “Carbon Capture and Sequestration Protocol” within the LCFS encourages blue hydrogen production. But with increasing concerns of “fugitive methane emissions,” an HSC overly dependent on blue hydrogen could have serious environmental implications [117]. Currently almost the entire supply of hydrogen is fossil derived. At the time of writing this, the DOE has invited Requests for Information (RFI) for setting up of hydrogen hubs all across the United States, at an estimated budget of about $8 billion, mostly funded through the infrastructure bill and the jobs act [6]. Presently there are no binding renewable hydrogen policies for these hubs, at a federal or state level. Globally, countries like the UK and Spain have binding renewable hydrogen polices for hubs [118]. As such, I am interested to explore how similar renewable hydrogen policies could affect the HSC investment decisions while planning to set up hydrogen hubs.

In view of the above, I will use SERA 2.0 soft-linked with GOOD to understand the impacts of renewable hydrogen policies and sector coupling on the rollout of hydrogen infrastructure in the region. The analysis is spread over 25 years, starting in 2025. I follow a deterministic modeling approach using scenarios to find the least-cost technology mix across the HSC, while adhering to operational constraints and the spatiotemporal variations in demand, feedstock prices, and infrastructure costs.

3.2 Data and Methods

3.2.1 Hydrogen demand projection for other sectors in California

Current California demand for hydrogen is around 2 billion kg of hydrogen per year, primarily for use in oil refineries. Future demands for hydrogen will likely be diversified across many different sectors and varying both temporally and spatially. A number of recent hydrogen studies have projected the future hydrogen demand from non-transport sectors in California. [47,119–121] For this study, I rely on spatially and temporally aggregated demand data provided by Chris Yang, Lewis Fulton, and Tri dev Acharya (researchers at UC Davis), which were derived from existing literature and based on discussions with industry partners to allocate the demand spatially. These demands can be considered as incremental, over and above what already exists in California today

Two scenarios (high and low case) is assessed and the demand is projected up until 2050 (refer Figure 43, Figure 44 and Figure 45) across six different locations in California, simulating a "hydrogen hub-like" aggregation of these demands in the state. These six locations have been identified based of the magnitude of current hydrogen demand (refinery locations) and locations with ports and airports. The breakdown of hydrogen demand sector and location wise can be found in supporting material (S2, refer Table 16).

It is important to note that in this chapter I will aggregate both on road transport demand along with demands from other sectors to six locations/hubs. From Chapter 2, we see that on transport demand is spread across nearly 450 locations in California and here I aggregate them to six locations using a GIS tool (proximity analysis).

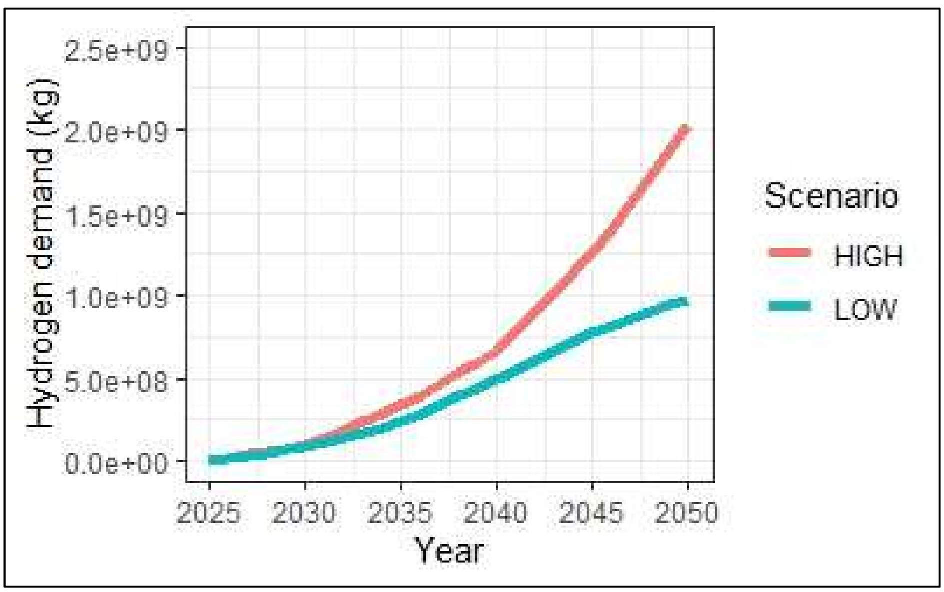

Figure 43:: Hydrogen demand scenarios for other sectors (excluding on road transport) in California

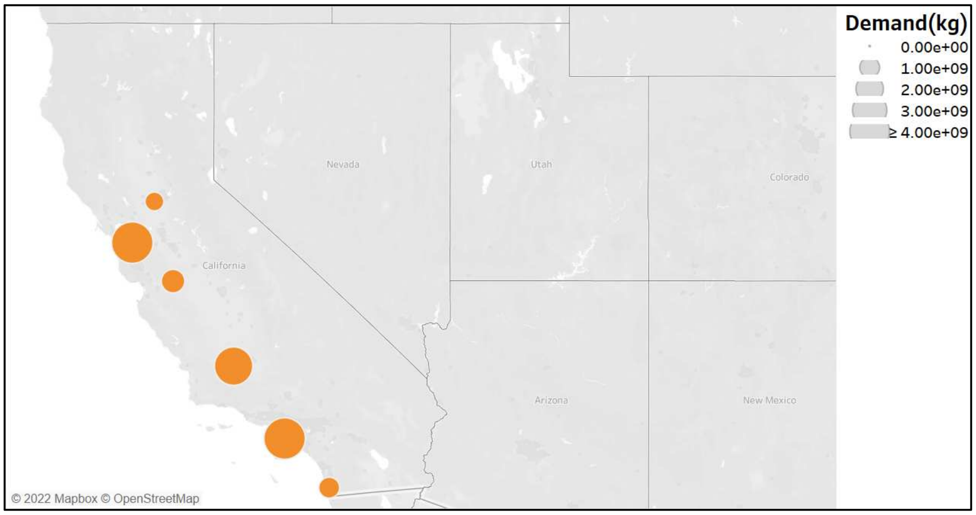

Figure 44: Spatial distribution of cumulative hydrogen demand (excluding on road transport) for the high scenario (2025-2050)

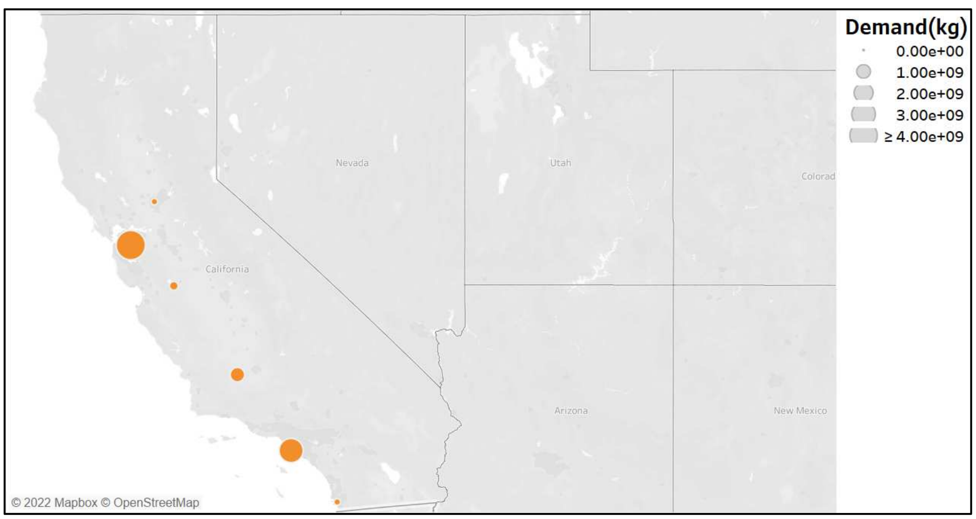

Figure 45: Spatial distribution of cumulative hydrogen demand (excluding on road transport) for the low scenario (2025-2050)

3.2.2 Soft linking SERA 2.0 with the electricity grid (GOOD model)

While some previous studies capture the effects of sector coupling, this is often done in a single modeling framework [31,49]. In such analyses, many components of the HSC (like infrastructure scaling and utilization) are not captured accurately, due to simplistic assumptions, to avoid prohibitive levels of model complexity and computation time. I will be soft linking the HSC and the electricity grid, through suitable insertion points which is considered to be an optimum approach [29,122–125].

From a modeling perspective it is critical to identify the appropriate "insertion points" through which the electricity grid can be integrated with the HSC. For the purposes of soft linking, I will use these three outputs from GOOD (electricity grid model) to optimize SERA 2.0 (hydrogen supply chain model): PEM capacity, hydrogen storage requirements of the grid, and hydrogen demand for electricity generation. Additionally, I will project regional electricity prices based on the generation costs from GOOD, as explained in Chapter 2. The electric grid is operated with information about hydrogen demand (both from on road transport and other sectors) at the different locations, and therefore PEM capacity and storage capacity requirements projected by GOOD are required for balancing the grid and to meet hydrogen demand (see Figure 85 for details of how the hydrogen system is represented in GOOD). I introduce additional constraints in SERA 2.0, which forces it to build as much PEM and hydrogen storage capacities as required by GOOD over the analysis period, (refer supplementary material S2, equations 18 and 19 in model formulation). By integrating these capacity requirements into SERA 2.0, I hope to understand the necessary infrastructures that would need to be put in place for delivering hydrogen to the end uses (on road transport, other sectors including for electricity generation). I also hypothesize here that SERA 2.0 would still build some additional production and storage capacity (over and beyond what GOOD is projecting), so an ensure the roll out of a cost-effective supply chain network.

3.2.3 Scenario description

Table 7 describes a set of scenarios and sensitivity cases designed to understand the impact of sector coupling between the electricity grid and the HSC. We have two main scenarios and two sensitivity cases. The grid-integrated scenario (GRID_integ_hub_H) simulates a fully coupled grid and HSC. I compare the grid-integrated scenario to a scenario where SERA 2.0 makes decisions independent of grid operation. Sensitivity cases are run to understand the impacts of perfect demand foresight. Hydrogen demands (road transport and others) in California for these scenarios are distributed over six major hubs. Additionally, hydrogen demand for electricity generation (projected by GOOD) is spread all over the WECC. The delivery system here is modeled until the “city gate.”

Table 7: Scenario and sensitivity case descriptions for HSC optimization with and without complete electricity grid integration

Scenario name	Planning window	Hydrogen demand profile	Hydrogen production	Hydrogen distribution	Sensitivity case description	Sensitivity case name
GRID_integ_hub_H	5 years	High [a]	1. Central production by grid-connected PEM electrolyzers only. 2. Total PEM capacity is lower bounded by requirements of the electricity grid (GOOD model output).	1. Delivery using gaseous tube trailers, pipelines, and liquid tankers. 2. Bulk storage (salt cavern and line pack) is available. 3. Total storage capacity is lower bounded by the requirement of the electricity grid. 4. Hydrogen delivered up until "city gate."	Longer planning window/perfect demand foresight of 25 years	GRID_integ_hub_25[b]
GRID_NOinteg_hub_H			Central production using SMR with CCS and grid-connected PEM electrolyzers.	Same as above but there is no minimum storage capacity requirement from the grid.		GRID_NOinteg_hub_H_25[c]

[a] On-road and other sectoral demands in California plus hydrogen demand for electricity production in WECC.

[b] Sensitivity case to scenario GRID_integ_hub_H.

[c] Sensitivity case to scenario GRID_NOinteg_hub_H

Table 8 describes scenarios that explore the economic and technological impacts in the buildout of hydrogen hubs in California, under different renewable hydrogen policy regimes. I have a "no policy" scenario and four different sensitivity cases. Both the policy scenario and sensitivity cases are run on a longer planning window (25 years) to understand how policies could affect longer-term planning decisions. The sensitivity cases correspond to different "command and control" approaches that enforce certain levels of renewable-based hydrogen in the supply chain. This draws from similar existing policies, like the RPS for the electricity grid and SB 1505 for transportation. I evaluate two types of policy regimes as sensitivity cases. The first regime follows the SB 1505 format, wherein we set a certain percentage (25%, 50%, 75%) of renewable hydrogen requirement starting in 2025, which remains constant through 2050. The second type of policy regime is like the RPS, where I gradually increase the renewables requirement to reach 100% by 2045 in a stepwise manner. Hydrogen demands (on-road transport and other sectors) in these scenarios and sensitivity cases are concentrated along six hubs in California, as described earlier. The delivery network here is modeled until the "City gate". These policy regimes are introduced as constraints in SERA 2.0. With a policy requirement, SERA 2.0 will would build enough capacity to ensure a certain level of renewable hydrogen in the supply (refer S2, equations 20 in model formulation).

Table 8: Scenario and sensitivity case descriptions for understanding the impacts of a renewable hydrogen policy mandate for the HSC

Scenario name	Planning window	Hydrogen demand profile	Hydrogen production	Hydrogen distribution	Sensitivity case description	Sensitivity case name
POL_0perc_hub	25 years	High (Road transport and other sectors) in California	1. Central production using SMR with CCS and grid-connected PEM electrolyzers. 2. No renewable hydrogen requirement (0%).	1. Delivery using gaseous tube trailers, pipelines, and liquid tankers. 2. Bulk storage (salt cavern and line pack) is available. 3. Hydrogen delivered up until "city gate."	Minimum renewable hydrogen requirement is 25%	POL_25perc_hub
					50%	POL_50perc_hub
					75%	POL_75perc_hub
					Renewable requirement increases from 25% in 2025, 40% in 2030, 60% in 2040, and 100% in 2045.	POL_step_hub

3.3 Results

3.3.1 Will a complete reliance on the electricity grid be a cost-optimal solution for the hydrogen supply chain, and will perfect foresight change the decision?

This section focuses on understanding the interdependencies between the electricity grid and the HSC, while deciding on the buildout of hydrogen infrastructures (see Table 7 for scenario descriptions).

3.3.1.1 Hydrogen production

Figure 46 depicts the production profile if the system were allowed to select the cost-optimal production technology based on capital and operational costs (GRID_NOinteg_hub_H). Blue hydrogen (SMR with CCS) production is very dominant early on when electricity prices are very high, particularly in California. Also, these trends would be more skewed toward blue hydrogen if we had a better foresight (i.e., if the planning window was 25 years). For the grid-integrated scenario (GRID_integ_hub_H), the system is forced to build only grid-connected PEM electrolysis plants, which can be suboptimal, especially in the earlier periods when natural gas prices are lower and electricity rates are high.

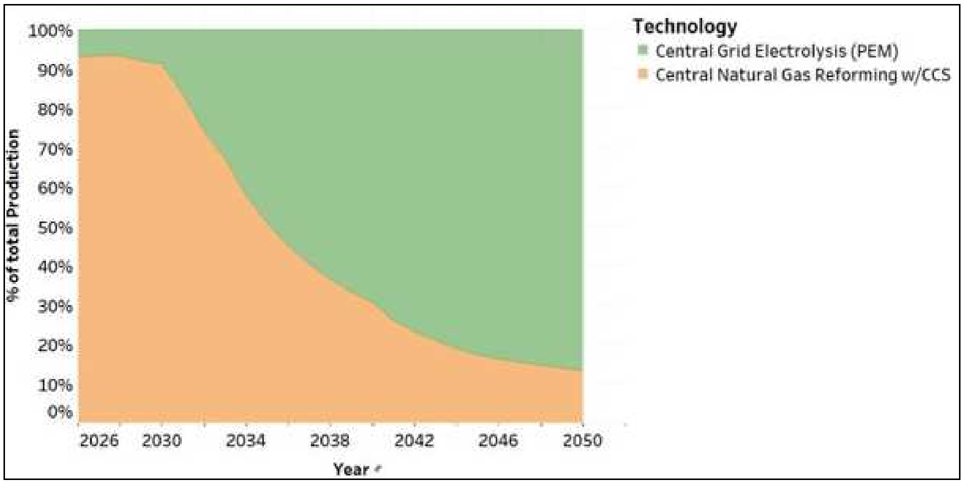

Figure 46: Percentage share of hydrogen production by technology type for scenario GRID_NOinteg_hub_H (no restriction to build only grid-connected PEM, 5-year planning)

Another key takeaway is the correlation of “grid dependence” with regional imports for California. From Figure 47 and Figure 48, it is evident that a greater reliance on the grid would mean that California imports a vast majority of its hydrogen. The operational constraints at the grid level may benefit from building PEM capacity in one region over the other, but the supply chain dynamics for hydrogen may not follow suit. Here we constrain SERA 2.0 to build enough PEM capacity (output from GOOD model) at a systems level, and this gives SERA 2.0 the flexibility to choose where to build it based on capital and operational constraints. Given these, we find that much of the PEM capacity is built outside of California due to lower electricity prices. This holds true across all scenarios considered here.

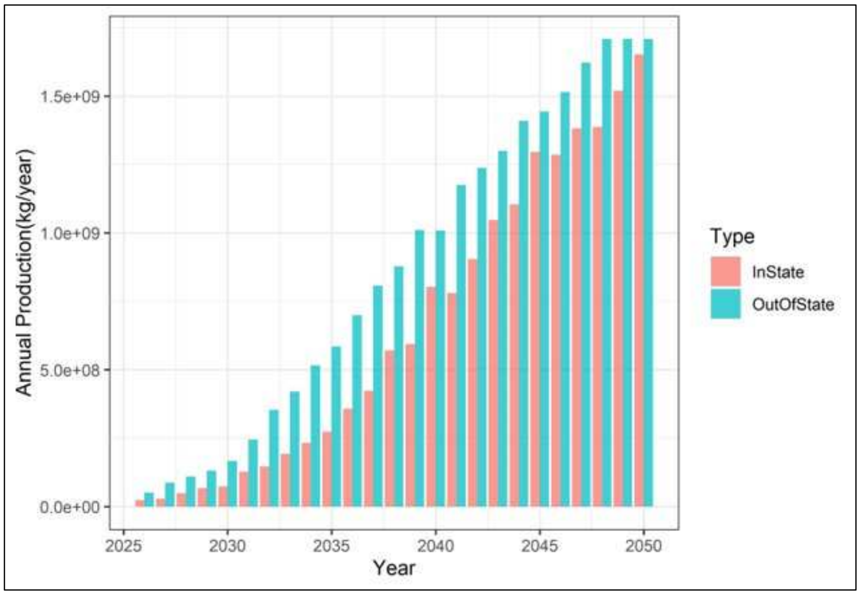

Figure 47: Distribution of in-state and out-of-state production/regional imports for scenario GRID_integ_hub_25 (restricted to building only grid-connected PEM, 25-year planning window)

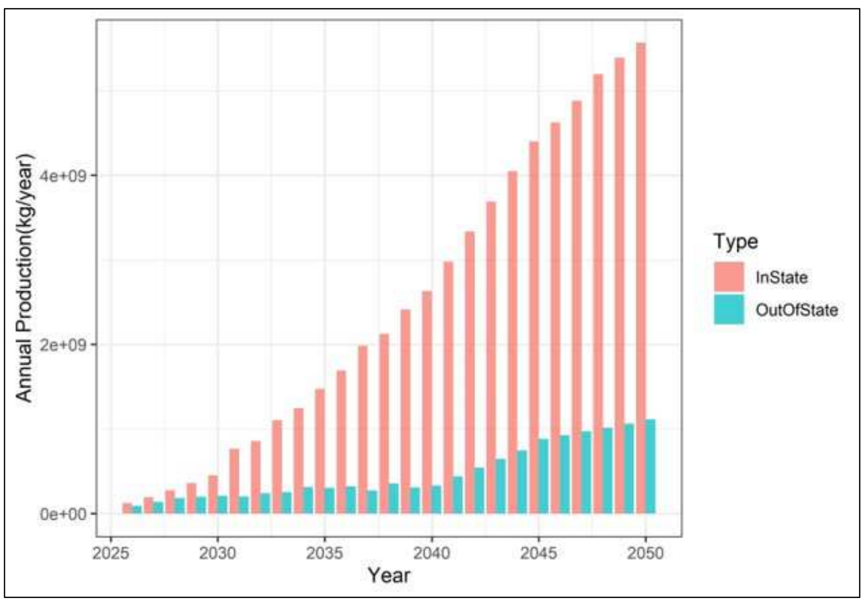

Figure 48: Distribution of in-state and out-of-state production/regional imports for scenario GRID_NOinteg_hub_H_25 (unrestricted, 25-year planning window)

3.3.1.2 Hydrogen distribution

I observe that when demand is concentrated (like for hubs), pipelines are a clear winner over any other distribution method (Figure 49). This holds true for all scenarios irrespective of uncertainties around demand and the source of hydrogen supply. This is in stark contrast to the scenarios considered in Chapter 1, where trucking was the preferred mode of hydrogen delivery to meet demand that was widely distributed. Therefore, having concentrated hydrogen demand is a primary driver for new pipeline construction. The levelized costs of pipeline delivery falls substantially with increasing flow capacity, which encourages SERA 2.0 to build dedicated hydrogen pipelines (see S2, Figure 74). Additionally, building larger capacity pipelines offer an opportunity for hydrogen storage through line packing. This would help optimize the overall system costs and hence encourage building pipelines.

Another key takeaway here is that hydrogen distribution in liquid form is found to be relatively more expensive in these scenarios, and hence it is not selected by SERA 2.0. This is primarily driven by the high costs of liquefaction. It is interesting to compare these results with the "on-road transportation demand only" scenarios (Chapter 1). There I see substantial amounts of liquid hydrogen delivery because in some scenarios, the high liquefaction costs were offset by the relatively lower refueling station costs (mostly at higher capacities). Therefore, in those cases, the total delivery costs by the liquid hydrogen pathway would be lower as compared to gaseous tube trailer or pipelines. However, with aggregated demand (hub-like) and with distribution modeled only until the "city gate," the liquid pathways become uneconomical. This could change with a more granular modeling approach that would capture every "last mile" delivery (e.g., to buildings, refueling stations, industry).

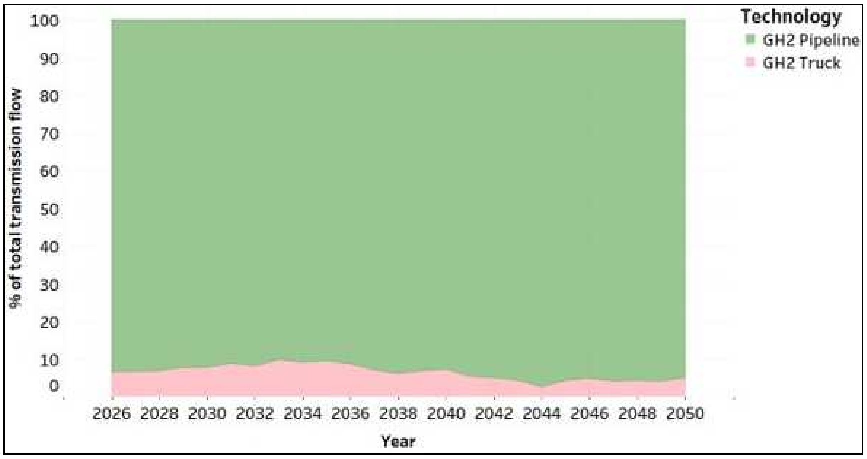

Figure 49: Percentage share of hydrogen distributed through different delivery options in scenario GRID_integ_hub_H (restricted to building only grid-connected PEM, 5-year planning window)

3.3.1.3 System costs

In Figure 50, I compare the total system costs/expenditures for the different scenarios considered in this section. We find that a hydrogen system that is completely grid-integrated is at least 10%–12% more expensive over the next 25 years. This holds true irrespective of the uncertainties in demand (low or high) or planning window (5 versus 25 years). It is worth mentioning here that I do not include the system costs from the electricity grid in our calculations. It could well be the case that the total system costs at the grid level could reduce by more than 10%–12% with the inclusion of PEM electrolyzers and bulk hydrogen storage. Our focus is more on the HSC development and hence does not include system costs from the grid side.

There is a fundamental difference in the decision-making process that an electricity grid operator makes versus a hydrogen infrastructure investor. The grid sees great value in building PEM capacity to satisfy demands (electricity and hydrogen) and to balance the grid, especially under high renewables generation regime. The distribution costs of hydrogen to the end-use demand point are not a major consideration for the grid operator. For a hydrogen infrastructure investor, the decision to build a PEM electrolyzer versus an SMR is largely driven by the price of feedstock (industrial electricity and natural gas rates) and distribution costs of hydrogen. I note that in California, though the cost of electricity generation could fall with larger intake of renewables (solar and wind), there is no indication that the electric transmission and delivery costs would reduce in the long term. In this analysis, I assume the transmission and delivery costs would remain constant throughout the 25 years (refer S2, Figure 66). If industrial electricity rates don't fall substantially over the years (as I assume here), it would be cheaper for California to have more blue hydrogen in its system, especially during the earlier years. Alternatively, California could incentivize grid-connected PEM electrolyzers through a favorable electricity rate structure.

Another possibility for California to reduce its dependence on the grid and thereby reduce overall system costs would be to encourage stand-alone/ "off-grid" electrolyzers. These electrolyzers could bypass the high grid rates if there is access to cheap wind or solar power very close to demand. However, we need to assess how large an impact such systems can have, and that qualifies for a deeper analysis in future.

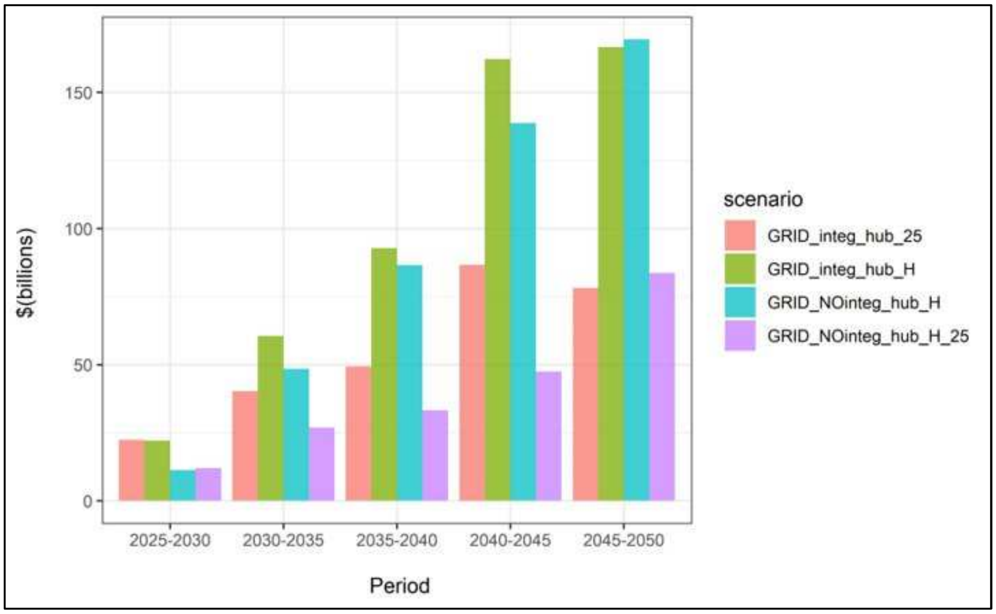

Figure 50: Comparison of HSC buildout expenditures with and without complete electricity grid integration

3.3.2 What would an RPS-like renewable hydrogen standard entail for the buildout of hydrogen hubs in California?

There are existing policies like the LCFS that could indirectly impact the buildout of hubs in California but understanding its impact on supply chain decisions is hard to quantify using this modeling framework. Since this is predominantly a supply chain analysis, I focus on policies that directly impact hydrogen supply. I explore how a renewables mandate (like SB 1505 or RPS) would assist in a quicker transition from blue to green hydrogen in the context of hydrogen hubs (see Table 8 for scenario descriptions).

I find that in the absence of any renewable hydrogen policy, blue hydrogen dominates, and its share could increase over time (Figure 51). I find very large SMR plants being built (all in California) whose utilization is low in the initial periods but then gradually increases. From an economic standpoint, building these large SMR plants with CCS (that have better economies of scale) to cater to highly concentrated "hub-like" demand looks very attractive. Another way of interpreting this would be to consider the existing grey hydrogen (SMR with no CCS) supply in the state to be converted into blue hydrogen, through some retrofit with CCS. Either way, having such large supplies from mostly a fossil-based source could be an environmental concern, especially with the chances of "fugitive methane emissions" being high. One way of addressing this could be through a renewable hydrogen mandate.

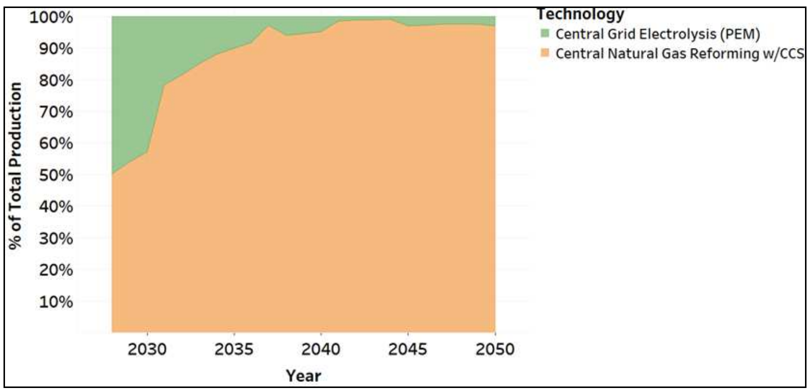

Figure 51: Percentage share of hydrogen production by technology type for scenario POL_0perc_hub (no policy mandate)

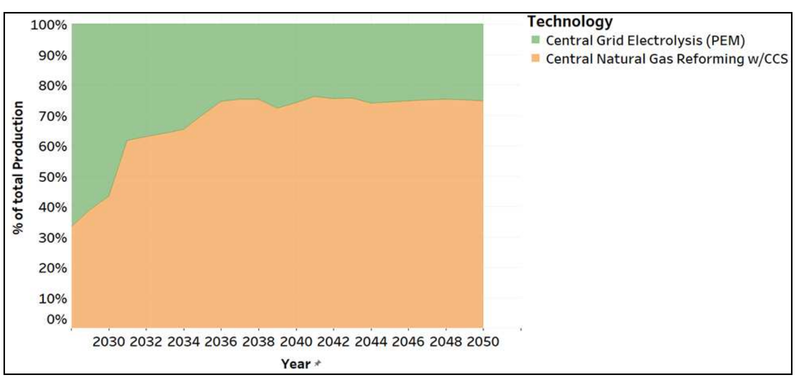

Figure 52: Percentage share of hydrogen production by technology type for scenario POL_25perc_hub (a flat 25% renewable hydrogen mandate)

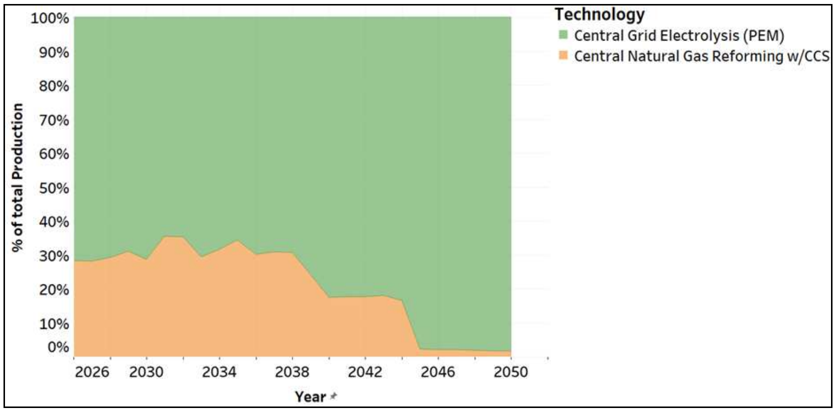

Figure 53: Percentage share of hydrogen production by technology type for scenario POL_step_hub (a stepwise increase in policy requirements, reaching 100% by 2045)

I find that even with a 25% renewable hydrogen requirement, the share of renewable hydrogen in 2025 is much higher as compared to a no-policy scenario. However, with a flat mandate (like 25%, 50%, or 75%), the share of blue hydrogen would continue to increase into the future (Figure 52). When I compare this against a stepwise increase in renewables requirement (Figure 53), I see a gradual reduction in blue hydrogen production over the years. I note that with a policy framework that aims to achieve 100% green hydrogen production by 2045 (scenario

POL_step_hub), investments in blue hydrogen wean off as early as 2035, unlike in other scenarios where the investments continue well beyond 2040 (Figure 54, Figure 55, and Figure 56).

I also see lower-capacity SMR plants being built under any renewable hydrogen policy regime as compared to a scenario with no policy. The nameplate capacities for SMR plants would decrease commensurately with increasing stringency of the renewable's requirement.

There is also a direct correlation between the levels of policy stringency and regional hydrogen imports for California. As expected, a more stringent mandate increases imports, and this could reach as high as 70% by 2050 (refer S3, Figure 83 and Figure 84).

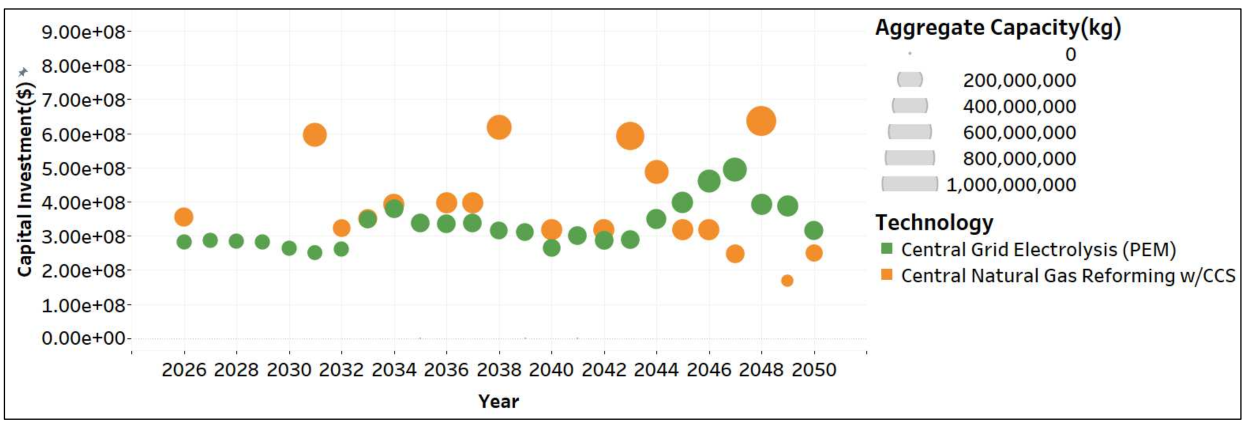

Figure 54: Capital investments for hydrogen production capacity expansion (technology wise aggregate), scenario POL_50perc_hub (a flat 50% renewable hydrogen mandate)

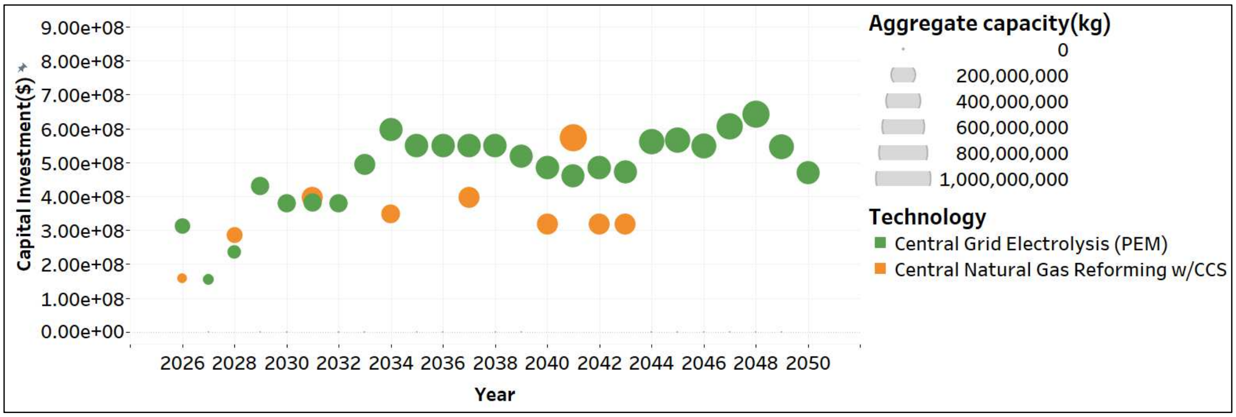

Figure 55: Capital investments for hydrogen production capacity expansion (technology wise aggregate), scenario POL_75perc_hub (a flat 75% renewable hydrogen mandate)

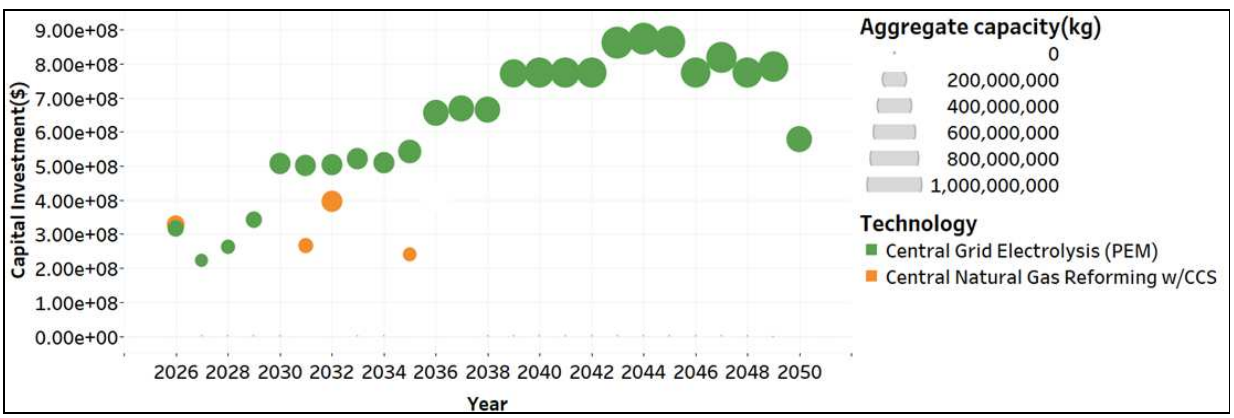

Figure 56: Capital investments for hydrogen production capacity expansion (technology wise aggregate), scenario POL_step_hub (a stepwise increase in policy requirements, reaching 100% by 2045)

3.3.2.1 System costs

The expenditure for system buildout is found to increase commensurately with increasing stringency of policy, as seen from Figure 57. However, I find that the cumulative expenditure incurred over 25 years under a stepwise policy regime is lower by at least 20% in comparison to a high and a flat renewable policy mandate (50% and above). This is driven by the fact that with gradual increments in renewable requirements, the system can build more renewable-based production capacity and at the same time have the flexibility to choose the cheapest option in the earlier years. This is true especially because blue hydrogen production is initially cheaper than green hydrogen but gets relatively more expensive in the latter years. A high and flat renewable mandate (e.g., 75%) could force the system to choose a more expensive solution in the early years, as there is very little flexibility for selecting other production options.

I note that the stepwise policy regime may be more expensive (compared to no policy or a very low renewable policy regime like 25%), but it is more effective in disincentivizing blue hydrogen production in the long term.

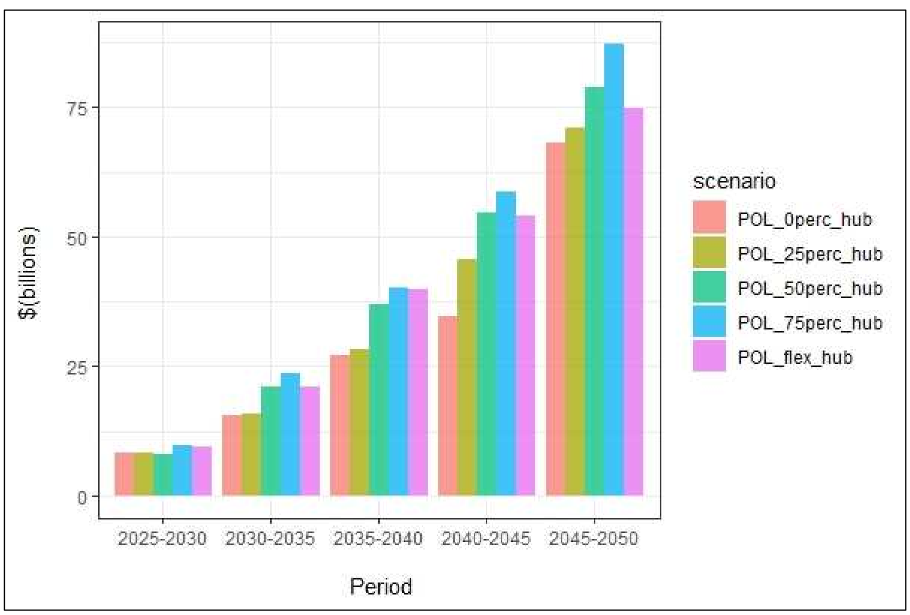

Figure 57: Comparison of HSC buildout expenditures under different renewable hydrogen policy regimes

3.3.3 Preliminary insights into hydrogen storage needs of California.

A portion of this work sought to build out a simplistic bulk storage analysis in SERA 2.0 that can handle both intra- and inter-year storage while optimizing the HSC. I note, to capture hydrogen storage requirements on a more granular time scale (hourly/diurnal/seasonal), SERA 2.0 would require inputs (demand, feed stock prices) in the same time scale. I continue to develop these capabilities for projecting more granular input parameters in our future analysis. However, for the purpose of this study, I model only inter-year bulk hydrogen storage (with a yearly time resolution), employing either salt caverns or line packing of pipelines as possible options. I then try to draw a perspective as to how and where hydrogen could be stored economically, given the supply chain dynamics.

In general, I find that a myopic planning window/limited demand foresight (5 years) does not incentivize building bulk hydrogen storage capacities. Here, it is more cost-effective to overbuild production capacity to meet incremental increase in demands. Figure 58 depicts the yearly amounts of hydrogens stored for one representative scenario. This is not the storage capacity but more indicative of utilization of built capacity to meet end use demand for hydrogen (excluding electricity generation). I also find that, the need for bulk storage steadily increases over time, more so after 2035, when rates of annual demand changes accelerate (Figure 25 and Figure 43) considerably.

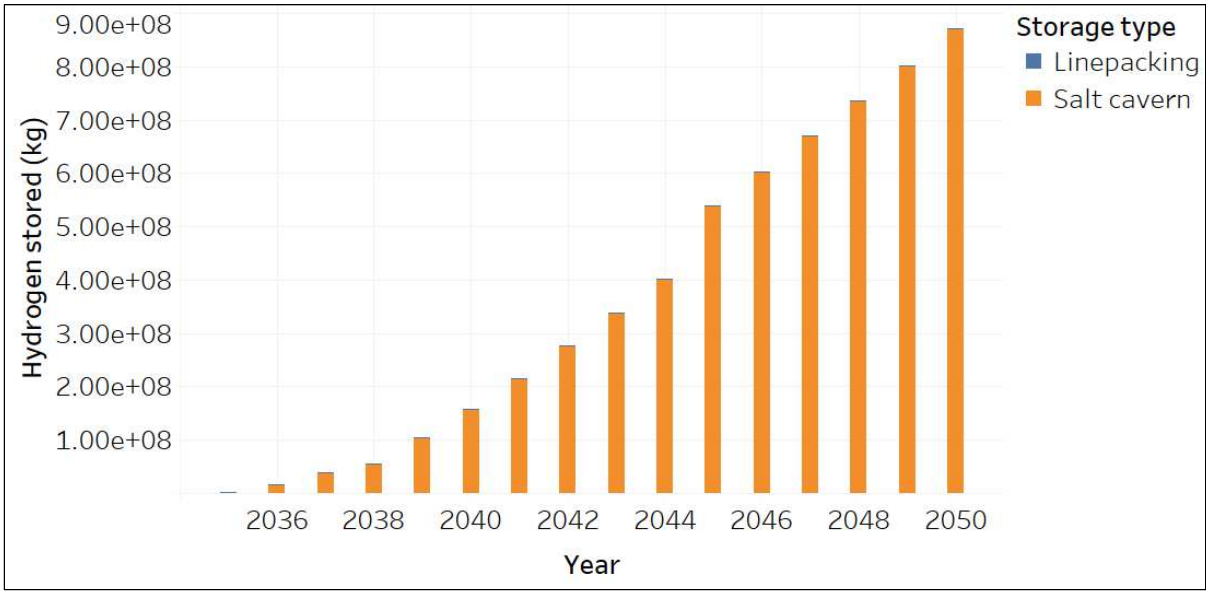

Figure 58: Hydrogen going into storage for scenario POL_step_hub (all types of demand aggregated along six hubs, with a stepwise renewable hydrogen mandate)

I understand that the choice of the storage type (salt cavern or line packing) is largely a function of both proximity of demand to supply as well as supply capacity with respect to fluctuations in demand, whether hourly, diurnal, or seasonal. California, with no “in-state” salt caverns (as of today), could utilize hydrogen pipelines for some of its storage needs, especially when most of the hydrogen supply is concentrated within California. In scenarios where there is more reliance on regional imports, salt caverns in states closer to California like Nevada, Arizona, and Utah, may benefit from higher utilization However, I do note that these inferences could change considerably if I were to broaden and deepen the analysis to include hydrogen demands for other WECC states with a higher time resolution into the analysis.

3.4 Conclusions:

In this chapter I employ SERA 2.0 soft linked with the GOOD model to understand capacity expansion of the HSC with sector coupling and under different renewable hydrogen policies. Hydrogen demand is concentrated along six hubs in California and the analysis is spread over 25 years starting in 2025.

Hub like concentrated demands promote substantial scale up of technologies across the HSC. Assuming there are no geographical constraints for carbon sequestration, I find that almost the entire supply of hydrogen will be fossil derived and mostly sourced within California. This is because California's industrial natural gas rates are comparable with most other WECC states and SMR plants exhibit better economies of scale as compared to PEM electrolyzers. But this trend could change with sector coupling (of HSC and electricity grid) or under renewable hydrogen mandates. I find that if California were to depend completely on the electricity grid to derive all its hydrogen (a fully coupled scenario), that could lead to building out a system that is at least 10%–12% more expensive as compared to having a more diversified hydrogen supply portfolio. This is driven by the fact that electrolysis-based hydrogen production is more expensive initially and having substantial amounts of this in the system would drive up system costs.

Any renewable hydrogen mandates would make the system buildout more expensive. But that is without considerations of externality costs imposed by high levels of fossil derived hydrogen. While GHG emissions could be limited by suitable carbon capture and sequestration, fugitive methane emissions could pose a significant environmental challenge as we plan for future hydrogen hubs. One way to address this could be through renewable hydrogen mandates.

I find that a carefully designed RPS like standard for renewable hydrogen can be cost effective and will enable the system to achieve near 100% renewable hydrogen by 2045.

Regional hydrogen imports for California could increase either with sector coupling or with renewable hydrogen mandates. Annual average industrial electricity rates in California are nearly twice as expensive compared to some WECC regions. If this trend continues, I find that California could end up importing anywhere between 30%–75% of its hydrogen needs from other WECC states. Suitable policy interventions like formulating a rate structure that considers the grid balancing benefits of PEM electrolyzers could incentivize building these in California and thereby help reduce the overall system costs.

Concentrated demand (like in hubs) promotes pipeline building. An extensive hydrogen pipeline network in the system can also serve as a hydrogen storage option via line packing. Building dedicated hydrogen pipelines could be a valuable proposition for California, which does not have access to some of the cheap underground bulk storage options (like salt caverns) within state.

I acknowledge that there is a whole array of future work that can build on this analysis. Although this study focuses on hydrogen demands in California, greater hydrogen demand might be realized from the decarbonization plans of other Western states. Those hydrogen demands will have different temporal and spatial profiles and thus may affect the hydrogen supply-demand balance in different ways. Second, investigating the last-mile delivery of hydrogen from the hubs is out of scope of this study but is definitely an important area of analysis. Last-mile delivery could vary substantially based on end use (building, industry, and transportation) and could tilt the balance in favor of one or the other supply chain choice. Third, modeling the combined effects of existing policies on the supply chain rollout could be critical. For example, I do not consider the impacts of the LCFS on the choice of hydrogen production technology and the size of the distribution system (like refueling station capacity). Having a holistic understanding of how these different policies impact the investment decisions could be very insightful. Fourth, I make initial attempts here to capture line packing of hydrogen pipelines as a possible storage option. Our analysis is static. I assume predefined operating pressures in evaluating the amount of hydrogen that can be line packed for a given length. A more transient analysis capable of capturing a wider range of pressures with higher time resolutions (to capture daily or hourly operations) could add more realism into the results. Lastly, modeling the combined effects of existing policies on the supply chain rollout could be critical. For example, I do not consider the impacts of the LCFS on the choice of hydrogen production technology and the size of the distribution system (like refueling station capacity). Having a holistic understanding of how these different policies impact the investment decisions will be very important while government policy makers and private investors strategize the rollout of HSC infrastructure for the future.

I understand that the hydrogen ecosystem is still very nascent. Major investments are required to build the system and much of that would be driven by policy. With a lot of overlap in system development across regions, it is paramount that I get an overall perspective of how the global hydrogen economy is shaping up. Therefore, in the next chapter I review global strategies and roadmaps of major economies and try to understand any commonalties or differences in their approaches to encourage a larger adoption of hydrogen across sectors.

Chapter 4. Creating a global hydrogen economy: Review of international strategies, targets, and policies with a focus on Japan, Germany, South Korea, and California

4.1 Background

Hydrogen is a very versatile molecule that has cross sectoral applications. An integrated hydrogen system can benefit from economies of scale and learning across these sectors. But given the nascent stage of hydrogen in the energy market, government intervention through suitable policy levers will be important to kick start the hydrogen economy. In the United States, recent legislation such as the Bipartisan Infrastructure Bill[6] has earmarked close to $8 billion for scaling up hydrogen technologies and establishing at least four hydrogen hubs (large, geographically concentrated demands) on a national level. Additionally, national-level cost targets, such as the "Hydrogen Shot," seek to reduce the cost of clean hydrogen by 80% to $1 per kilogram in a decade. Existing policies in California have been very supportive of hydrogen, especially in the transportation sector. [7–10] But recently, this is expanding to other sectors as well. Other notable initiatives like HyDeal LA, in which the Los Angeles Department of Water and Power is partnering with the Green Hydrogen Coalition to develop a green hydrogen supply chain, have catapulted California's prospects of becoming a future hydrogen hub.[11]

In addition to hydrogen demand as fuel for the light-duty and medium/heavy-duty road vehicle sectors, CEC estimates that hydrogen could play a role in decarbonizing other sectors like aviation, building and industry [47,111]. The nature of the demand from these sectors, their potential growth, and the timing of that growth will affect the pace at the infrastructure is built and is therefore an important piece to the development of an optimized HSC. Vast majority of previous studies have attempted to model a HSC that is driven by demand from the transportation sector, predominantly by light duty vehicles [49,86,112]. I will model hydrogen hubs in California which would represent aggregated hydrogen demands from both on-road transportation and other sectors.

California's electricity grid is increasingly becoming renewables based. The CEC estimates that in 2019, 32 percent of the state's retail electricity sales were supplied by Renewables Portfolio Standard (RPS) eligible sources such as solar (14.22 percent) and wind (6.82 percent) [113]. The RPS standard mandates the renewable's share on the grid to grow to 60 percent by 2030. Grid reliability is one of the challenges associated with an increasing uptake of renewables, owing to the intermittency of power generation from these sources [32]. As the integration of solar and wind power into the electric grid increases, grid balancing will become increasingly difficult. Periods of over-generation will increase curtailment, while periods of lower renewable generation will require substitution through fossil fuel powered plants or power dispatch from energy storage systems [114]. These effects on the grid are often depicted in the "Duck Curve", named for the shape of the net electricity demand in the state as published by the California Independent System Operator (CAISO) in 2013 [115]. To ensure continued grid reliability, California has a procurement target for the deployment of 1.32 gigawatts of stationary energy storage by the end of 2024 [114]. Storage requirements could increase drastically as the share of renewable power generation increases. Finding a sustainable and lasting solution to store the otherwise curtailed excess renewable energy produced during peak generation times, followed by its use in later demand periods is a challenging task. This is where hydrogen could value as a flexible demand side resource and also as a suitable long duration storage medium [32,114]. Electrolyzers could soke up most of the curtailed electricity during peak generation hours to produce hydrogen and store it for later use. Earlier studies have analyzed the HSC in isolation, without proper integration with other supply chains, like the electricity grid [29,116]. I soft link SERA 2.0 with the GOOD model (as explained in section 3.2.2 of chapter 2), to explore how a HSC fully driven by the electricity grid would evolve overtime and how would that compare to other scenarios where there are more diversified hydrogen supply options (like SMR based hydrogen).

Driven by favorable policies, California could become a potential early producer for both green (electrolysis using renewable electricity) and blue (hydrocarbon-derived, with carbon capture) hydrogen. Policies such as SB 1505 (mandates 33% renewable hydrogen requirement for transportation) encourage green hydrogen.[63] The recently passed "Carbon Capture and Sequestration Protocol" within the LCFS encourages blue hydrogen production. But with increasing concerns of "fugitive methane emissions," a HSC overly dependent on blue hydrogen could have serious environmental implications[117]. Currently almost the entire supply of hydrogen is fossil derived. At the time of writing this, the DOE has invited Requests for Information (RFI) for setting up of hydrogen hubs all across the United States, at an estimated budget of about $ 8 billion, mostly funded through the infrastructure bill and the jobs act [6]. Presently there are no binding renewable hydrogen policies for these hubs, at a federal or state level. Globally, countries like the UK and Spain have binding renewable hydrogen polices for hubs [118]. As such, I am interested to explore how similar renewable hydrogen policies could affect the HSC investment decisions while planning to set up hydrogen hubs?

In view of the above, I will use SERA 2.0 soft linked with GOOD to understand the impacts of renewable hydrogen policies and sector coupling on the rollout of hydrogen infrastructure in the region. The analysis is spread over 25 years, starting in 2025. I follow a deterministic modeling approach using scenarios to find the least-cost technology mix across the HSC, while adhering to operational constraints and the spatiotemporal variations in demand, feedstock prices, and infrastructure costs.

A concerted and coordinated effort to keep global warming well below 2°C, has become an urgent need. Achieving this target would mean an 85% reduction in global greenhouse gas (GHG) emissions by 2050 [126127]. Decarbonization would be required across sectors such as transportation, buildings, and industry. Hydrogen is a potentially important option for decarbonization plans given its versatility to be used across different sectors. Hydrogen's versatility suggests that significant increases in hydrogen use, with accompanying economies of scale and cost reductions, will aid countries in achieving their carbon targets and eventually building a carbon-neutral energy system. But building up this hydrogen system is challenging and infrastructure intensive. Strong early investments, with a clear vision of where the hydrogen system buildout is going, are needed. While many countries have latched onto this opportunity to incorporate hydrogen in their long-term energy and transportation plan, they are not all approaching this in the same manner, and no country so far has put all the pieces together.

I start by reviewing policy activities, targets, and strategies in eight of the world's most active economies, then focus on the "big four": Japan, Germany, South Korea, and California. These four are among the world's largest economies, with a combined gross domestic product (GDP) greater than $15 trillion [128,129]. The sheer magnitude of these economies will be an enabling factor to undertake large scale capital investments necessary for the initial commercialization and adoption of hydrogen into the energy portfolio. Notwithstanding differing emphases and patterns, these four economies share common policy drivers for hydrogen development and deployment: achieving strong climate mitigation goals, energy supply diversification, energy storage for renewables-based grid, and attaining technology leadership. Differences in their policy emphases has led to varying levels of hydrogen adoption across these economies, in different sectors, with different levels of progress. The present study analyzes the policy framework of these four jurisdictions, considering the following aspects.

1. Carbon mitigation targets and the role of hydrogen envisaged by each jurisdiction.
2. Hydrogen in transportation: fuel-cell vehicles and hydrogen refueling infrastructure.
3. Differing policy emphasis on blue and green hydrogen along with supply chain development plans
4. Hydrogen demand projections and underlying policy drivers

The study looks to draw policy parallels and contrasts, analyze the potential impacts, and provide plausible recommendations for the four jurisdictions to better align their decarbonization strategies using hydrogen. Since the policies around hydrogen are still evolving, the inferences made here is subject to change with future strategy and policy announcements by different regions.

4.2 Materials and Analysis

4.2.1 Global Overview of Hydrogen Policies, Strategies, and System Developments

Worldwide, many countries are aggressively pursuing hydrogen policies and system developments as seen from Figure 59. These take different forms, such as a focus on developing the transportation system with fuel-cell vehicles and stations, or a broader systems perspective, developing initial supply and demand side initiatives, or creating an overarching hydrogen supply strategy.

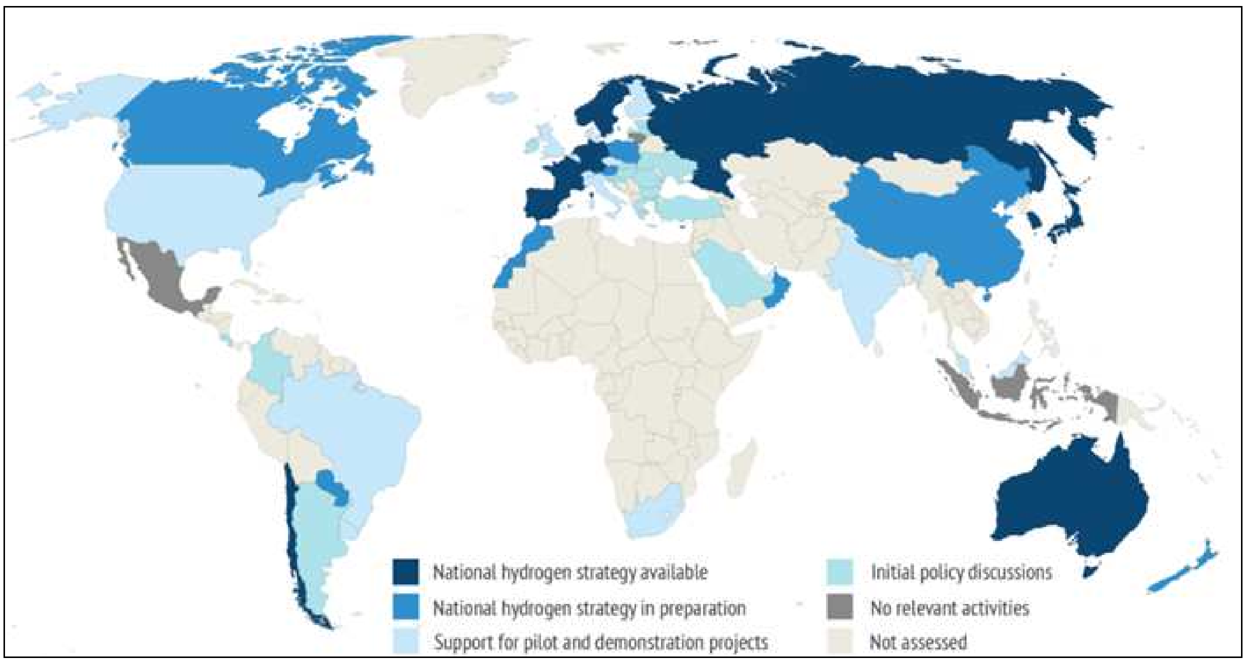

Figure 59: Status of hydrogen support/policy globally as of 2021 [130]

4.2.1.1 Japan

Japan is one of the first countries to roll out a comprehensive hydrogen strategy in 2017, and it has since set out specific plans to become a "hydrogen society" [2]. The strategy notably seeks to achieve cost parity with competing fuels, such as liquefied natural gas for power generation. In March 2019, the Government released its third strategic roadmap for hydrogen and fuel cells. Japan considers its domestic uptake of hydrogen as a viable way to increase its energy self-sufficiency; decarbonize its economy; increase industrial competitiveness; and position Japan as a fuel cell technology exporter. The key consideration for large-scale uptake of hydrogen in Japan will be cost. Japan is enroute to establishing a global supply chain for importing low-cost hydrogen mostly produced using fossil fuels and utilizing carbon capture and storage (CCS) technology which is currently more economically competitive than renewable hydrogen. Japan is interested in importing green hydrogen if the price is competitive, and at least one Japanese company has signed an investment deal for green hydrogen projects in New Zealand [131].

4.2.1.2 United States

Recent legislation such as the Bipartisan Infrastructure Bill [6] has earmarked close to \$8 billion for scaling up hydrogen technologies and establishing at least four hydrogen hubs (large, geographically concentrated demands) on a national level. Additionally, national-level cost targets, such as the "Hydrogen Shot," seek to reduce the cost of clean hydrogen by 80% to \$1 per kilogram in a decade. [132] California has been leading the US efforts to deploy hydrogen with transportation-focused policies that have resulted in among the most fuel-cell vehicles in the world through 2020. In California, policies such as the Zero-Emission Vehicle mandate, Low Carbon Fuel Standard (LCFS), Advanced Clean Trucks regulation, and Clean Vehicle Rebate Program have encouraged the uptake of hydrogen, especially in the transportation sector. [7–10] California has over 90% of both the fuel-cell vehicles and hydrogen refueling stations in the country. However, the currently high retail costs of hydrogen (over \$15/kg in many cases) have been a major impediment to the growth of fuel-cell vehicle sales. This is covered in more detail in the California-focused sections below.

4.2.1.3 European Union

The European Union has made hydrogen a key plank in its aim to eliminate its greenhouse gas emissions by 2050, with a major emphasis on installing zero-carbon-emissions hydrogen (via electrolysis) within and around the EU in the coming decade. To accelerate the development of clean hydrogen, on July 8, 2020 the European Commission adopted a new hydrogen strategy [133]. One specific goal is 80 GW of new electrolyzers by 2030, with half inside the EU and half near it, providing hydrogen to EU states. Almost all Member States have included plans for clean hydrogen in their National Energy and Climate Plans, 26 have signed up to the “Hydrogen Initiative”, and 14 Member States have included hydrogen in the context of their alternative fuels infrastructure national policy frameworks. Some have already adopted national strategies or are in the process of adopting one[134]. In addition, industry is playing a leading role in EU hydrogen planning and investments. A consortium of gas companies and researchers in the EU have developed a concept (and detailed design/costing) of a “hydrogen backbone” initiative, to encourage and support the development of an EU-wide hydrogen system by ensuring that a low cost transmission system is developed to connect supply and demand nodes[72]. Many other initiatives are occurring within member states, such as Germany. France and the Netherlands.

4.2.1.4 Germany

In June 2020, Germany rolled out a national hydrogen strategy that eyes a 200-fold increase in electrolyzer capacity—of up to 5 GW by 2030. An additional 5 GW of capacity may be added by 2035 and no later than 2040[3]. According to the IEA Future of Hydrogen Report, as of

2030 German hydrogen demand is expected to increase significantly, about 340 TWh between 2015 and 2030, with industry (+164 TWh) and mobility (+70 TWh) being the main growth contributors. Germany has been focusing on establishing a strong supply chain, backed by import agreements as well as by bumping up the production capacity of green hydrogen domestically. The technology development for hydrogen systems have been historically funded and supported by the National Organization for Hydrogen and Fuel-cell Technology (NOW).

4.2.1.5 France

To promote the deployment of industrial projects and supporting innovation aimed at decarbonization, France adopted the "Hydrogen Deployment Plan for the Energy Transition" in 2018. France committed to having 20,000 - 50,000 light-duty and 800 - 2,000 heavy-duty fuel-cell vehicles, as well as 400 - 1,000 hydrogen refueling stations by 2028[135]. Further, the plan stresses on achieving a 40% share of hydrogen from renewable sources by 2028. As part of government's €100 billion COVID 19 recovery plan, €7 billion was devoted to the development of green hydrogen for the period from 2021 to 2030. The "National Strategy for the Development of Decarbonized and Renewable Hydrogen", announced jointly by the Minister of Ecological Transition and the Minister of Economy in September 2020, set the 3 priorities of this investment: (1) decarbonizing industry by developing a French electrolysis sector, (2) developing the use of decarbonized hydrogen for heavy-duty mobility, and (3) supporting research, innovation, and skills development. France is targeting 6.5 GW electrolysis capacity by 2030.

4.2.1.6 Netherlands

In June 2019, the Dutch government presented the new climate agreement aimed at reducing CO_2 emissions in the country by setting a national reduction goal of 49% by 2030 and by 95% by 2050 compared to 1990[136]. Low-carbon hydrogen is set to play a major role in achieving these emission reduction targets. The Netherlands currently has significant hydrogen production from natural gas for the chemical and refining industry. Its vast potential for offshore wind generation, would enable a rapid scale up of low-carbon hydrogen production via electrolysis. The national climate agreement sets to scale up electrolysis to 500 MW of installed capacity by 2025 and 3-4 GW by 2030. In 2020, hydrogen fuel-cell vehicle fleet in the Netherlands comprised of about 400 vehicles, and 7 hydrogen vehicle fueling stations. The national climate agreement targets 15,000 fuel-cell cars, 3,000 heavy-duty vehicles and 50 filling stations in 2025, and 300,000 fuel-cell cars in 2030[137].

4.2.1.7 South Korea

In January 2019, Korea announced its Hydrogen Economy Roadmap [138]. The roadmap outlines the roll out of 6.2 million fuel-cell electric vehicles and 1,200 refilling stations by 2040. Additionally, the plan aims to roll out 2,000 hydrogen buses by 2022 and 41,000 by 2040. Korea aims to become the world's largest producer of hydrogen-powered vehicles and fuel cells by 2030 and eventually to develop hydrogen ships, trains, and machinery. Of the total 6.2 million vehicles to be produced by 2040, 3.3 million would be exported. To achieve these targets, the government provides a subsidy of about 50% of the purchase price of a hydrogen passenger vehicle and subsidizes up to 50% of the installation cost of refueling stations. In 2018, demand for hydrogen was 130,000 tons and is estimated to increase to 470,000 tons by 2022, 1.94 million tons in 2030, and 5.26 million tons in 2040. Korea has a limited domestic capacity for eco-friendly hydrogen production, and it plans to establish overseas bases for hydrogen production. By 2040, South

Korea aims to meet 70% of domestic demand through hydrogen from electrolysis and overseas production and 30% by reformed hydrogen.

4.2.1.8 China

In October 2016, China released the Energy Saving and New Energy Vehicle Technology Roadmap as part of the Chinese government's "Made in China 2025" 10-year plan. The FCEV Technology Roadmap (Chapter 4 in the document) outlines China's long-term goals regarding the deployment of fuel-cell vehicles and infrastructure. China's target for FCEV deployment is 50,000 FCEVs (80% passenger cars) and 300 refueling stations by 2025, and 1,000 refueling stations (50% of hydrogen production from renewable sources), and overall, 1 million FCEVs by 2030. Also, 5,000 FCEVs (40% passenger cars) and 100 refueling stations were targeted by 2020. Overall demand for hydrogen demand is expected to reach 35 million tons (Mt) in 2030 (at least 5% of China's energy consumption), 60 Mt in 2050, and 100 Mt (20% of the country's total energy consumption) by 2060 according to the China Hydrogen Alliance, a government-backed industry association[139].

A summary of jurisdictions' targets and strategies is provided in Table 9 below. The global picture is that of a nascent hydrogen market but with plenty of ambition. Among the most ambitious are California, Germany, South Korea, and Japan, though these four jurisdictions have different areas of focus and emphasis. I explore and compare these in more detail below.

Table 9: National/regional status and targets related to hydrogen, as of March 2022.

	EU	US (primarily CA)	Germany	France	Netherlands	Japan	Korea	China
Current FCEVs stocks [42,140]	-	CA: 12703 Cars, 76 Buses	1347 Cars, 54 Buses	382 Cars, 26 Buses	442 Cars, 25 Buses	6631 Cars, 110 Buses	16098 Cars, 108 Buses	7355 Cars, Trucks and Buses
FCEV LDV stock Target [141,142]	3.7 M by 2030	CA: 1 million(M) by 2030	-	5 K by 2025 20 K-50 K by 2030	15 K by 2025, 300 K by 2030	200 K by 2025, 800 K by 2030	100 K by 2025, 6.2 M by 2040 (2.9 M domestic, 3.3 M Export)	50 K by 2025, 1 M by 2030
FC Buses and Trucks targets[141]	45 K by 2030	-	-	200 by 2023, 800-2000 by 2028	3000 by 2030	1,200 Buses by 2030	40,000 Buses + 30,000 Trucks by 2040	-
Current number of Hydrogen Refueling stations (HRS) [42,140]	200	CA: 52	101	47	8	142	112	118
HRS target [2,46,141]	1,500 by 2025, 3,700 by 2030	CA: 179 by 2026	400 by 2025, 1000 by 2030	100 by 2025, 400 -1000 by 2030	50 by 2025	320 by 2025, 900 by 2030	1200 by 2040	300 by 2025, 1000 by 2030

Hydrogen production capacity/demand projections [3–5]	6 GW electrolysis cap. & 1 Mt Green H2 by 2025, 40 GW electrolysis cap &10 Mt Green H2 by 2030	-	5 GW electrolysis cap. by 2030	6.5 GW electrolysis cap. by 2030	3-4 GW electrolysis cap. by 2030	-	5.26 Mt 2040 estimated demand	-
Investment [141]	$ 4.3 billion by 2030	-	$10.3 billion by 2030	$8.2 billion by 2030		$ 6.5 billion by 2030	-	-

4.2.2 Drivers, present status, and road maps for the hydrogen economy in Japan, Germany, California, and South Korea.

4.2.2.1 Why **are these jurisdictions interested in hydrogen?**

Figure 60 provides a comparison of the GHG emissions on a per capita basis for the four jurisdictions. From 2000-2017, Japan reduced its GHG emissions by 6%, Germany by 14% and California by 23%. On the other side, South Korea's economy was expanding rapidly after 2000, which resulted in an increase in GHG emissions till 2010. All four jurisdictions have set very aggressive GHG reduction target for 2030. Scenario studies across the globe show that a higher constraint on GHG emissions is a precondition for greater penetration of hydrogen into the energy stream.

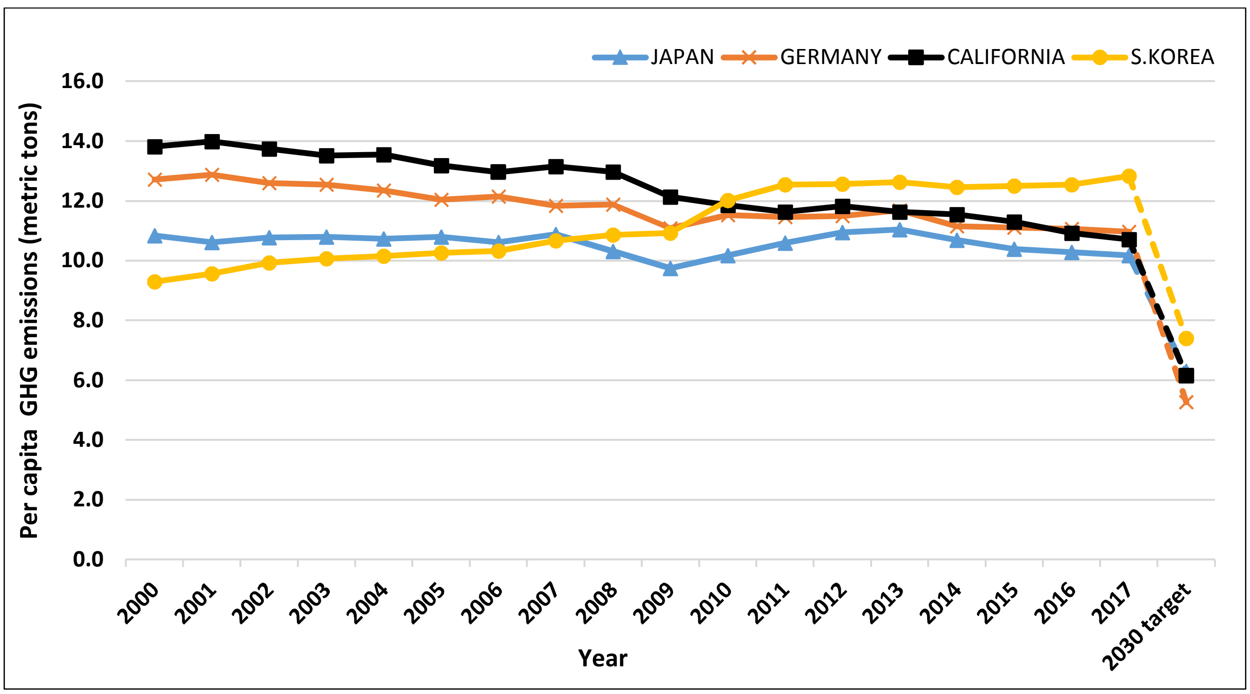

Figure 60: Region wise per-capita GHG emissions from 2000 to 2017 and targets for 2030[143–146].

Japan has the world's third largest GDP, but also the second highest dependence on foreign fuels among countries of the Organization for Economic Cooperation and Development

(OECD). Beyond energy efficiency efforts, the nation's most viable option to improve energy self-sufficiency had been nuclear power, but most of its reactors remain idle today due to the political aftermath of the Fukushima nuclear disaster in 2011. By 2050, Japan aims for an 80% reduction in GHG emissions (the base year is not clearly defined). The most significant decarbonization is expected in the commercial and residential sectors, followed by transportation. Also, the high import cost of energy is another pressing problem for Japan. Given this backdrop, Japan adopted "The Basic Hydrogen Strategy" in 2017: a plan to transform Japan into a world-leading "hydrogen society", a first of a kind comprehensive hydrogen policy. Japan pins its hope on hydrogen to achieve its climate as well as economic goals. The strategy underpins the necessity for developing a supply chain of zero carbon hydrogen, from its production to transportation and application in various sectors. An approximate $1.5 billion has been spent on hydrogen programs by the Ministry of Economy Trade and Industry (METI) over the last six years. In 2018, the ministry spent close to $272 million for hydrogen research and subsidies which amounts to 3.5% of Japan's energy budget. METI's funding is mostly directed to R&D programs and it is channeled through the governmental research institution, New Energy, and Industrial Technology Development Organization (NEDO)[2,147].

Germany has committed itself, together with the other European Member States, to achieving greenhouse gas neutrality by 2050. Germany has been pursuing a long-term shift towards a renewable energy ecosystem known as the Energiewende. Recently there has been increasing interest around the long-term role of hydrogen in the overall decarbonization plan. The National Organization for Hydrogen and Fuel-cell Technology (NOW) a handle of the German government acts as a link between politics, academia, and industry for promoting hydrogen technologies and sustainable mobility. One of NOW's key tasks is coordinating the National Innovation Program on Hydrogen and Fuel-cell Technology (NIP). The first phase of NIP ran from 2007 to 2016, with 700 million euros in funding for basic research and demonstration on hydrogen technologies. NIP II began in 2017 and is foreseen to run until 2026 with funding of 1.4 billion euros, predominantly contributed by the private sector. The transportation sector is the focus in NIP II, with majority funding directed towards market introduction and integration [148]. But in June 2020, the German federal government adopted the first German National Hydrogen Strategy with an overall budget of 9 billion euros, which expands hydrogen's role beyond transportation.

South Korea is pursuing a hydrogen-based economy to address its economic, energy and environmental challenges [149]. South Korea is one of the world's largest emitters of greenhouse gases on a per capita basis. With the world's lowest total fertility rate, South Korea's population is aging more quickly (even Japan), and this adversely affects its economic growth potential. Like Japan, South Korea is overall dependent on imports for its energy needs. With this background, the Hydrogen Economy Roadmap adopted in 2019 lays out plan to address each of these concerns and specifically targets greater hydrogen adoption in the transportation, industry, and power generation.

Unlike in Japan, South Korea or Germany, there is no overarching "hydrogen strategy" in California, but there are policy drivers that encourage the use of hydrogen in different sectors, notably in the transportation sector. This sector accounts for close to 40% of GHG emissions in the state [88]. Establishing a primary market for hydrogen in the transportation sector is critical for California to achieve its goal of reaching carbon-neutrality by 2045, as mandated in 2018 by executive order EO B-55-18. The state spent more than $300 million over the past ten years, funding rebates for purchase of fuel-cell cars, transit buses, and the construction of refueling stations. California has also passed legislations that encourage hydrogen in decarbonizing sectors other than transportation. Legislations like Senate Bill (SB) 100 which aims to achieve a zero-carbon electricity grid by 2045 encourage the uptake of hydrogen for electric power generation. Legislations like SB 1369 (promotes green electrolytic hydrogen production) encourage the expansion of hydrogen supply chains that could feed into both transport and non-transport sectors[150].

Overall, I find that concerns related to the environment, energy security, and economic growth is driving a clean energy transition employing hydrogen as one of the vectors in these jurisdictions.

4.2.2.2 Future hydrogen demand projections

Today, hydrogen is consumed predominantly by the refining industry. Chemical industry uses hydrogen for ammonia and fertilizers production. Hydrogen is also employed in metal production & fabrication, methanol production, food processing, and electronics sectors. Annual global demand for hydrogen has grown more than three folds since 1975, to reach 70 million metric tons (MMT) by 2018[151]. Currently, Germany and California have similar hydrogen demands of roughly 1.3-2 MMT/year and is used predominantly for refining. Japan and South Korea's annual demand are lower at about 200 metric tons per year and is mostly used in the power sector [47,149]. Future hydrogen demand projections in the four jurisdictions from existing literatures are illustrated in Figure 61. The scenarios project a high and low case demand for hydrogen across

2030 and 2050. Missing data (like for South Korea in 2050) was linearly interpolated. There was no information available for a possible low demand scenario in South Korea.

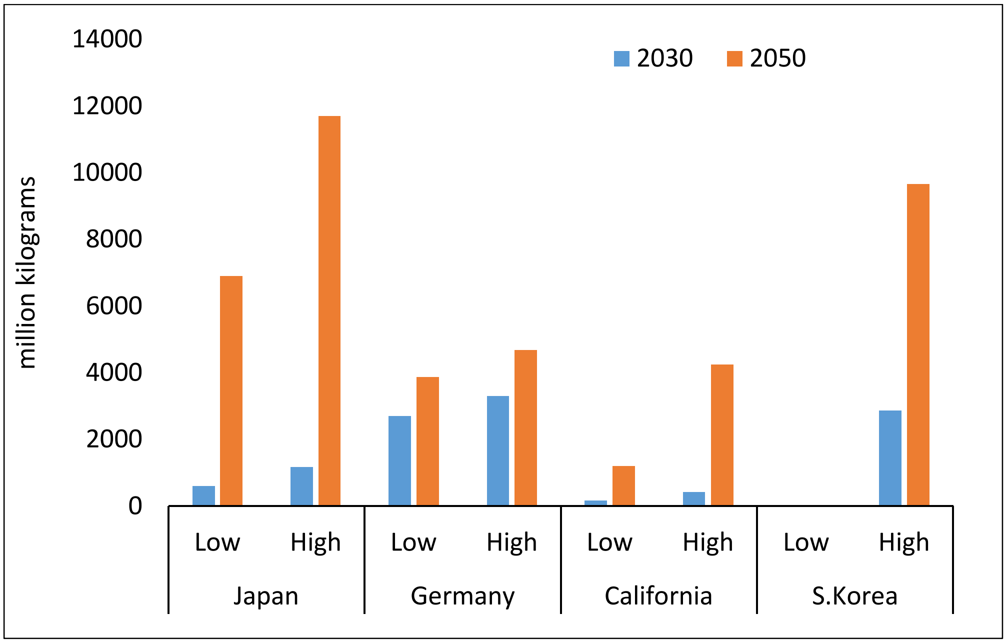

Figure 61: Hydrogen demand projections for low carbon scenarios in 2030 and 2050 [47,148,152]

In the German and Californian scenarios, hydrogen will be consumed mainly by the transportation sector, (followed by industry), while Japan's hydrogen demand will be driven by the power sector. Japan has been promoting hydrogen use in both grid connected and off grid power generation. Japan, which has historically been an epicenter of natural disasters have made a concerted effort through national programs such as ENE FARM, to incentivize fuel-cell-based power systems

While it is unclear if the hydrogen demand in South Korea will be dominated by transportations sector, the Korean roadmap places significant emphasis on the transportation sector. Globally too the transportation sector is projected to be the largest consumer of hydrogen by 2050 [15]. Hence, I will focus on this sector a bit more in detail for these jurisdictions.

4.2.2 FCEV and HRS: Deployment, targets, and policies

Currently, the fuel-cell vehicle population is only less than 0.05% of all registered vehicles in California, Germany, South Korea, and Japan. The FCEV numbers in these four geographies together account for nearly 60% of all on road fuel-cell vehicles and more than 60% of all installed hydrogen refueling stations across the globe.

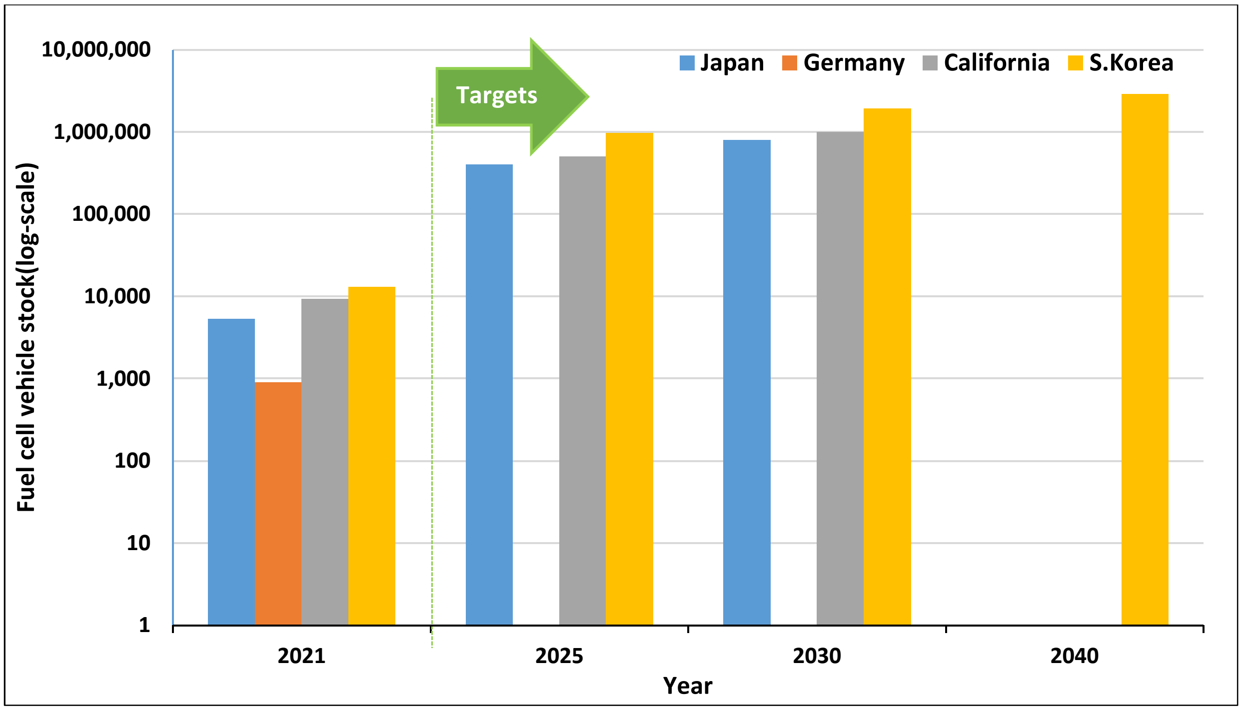

Figure 62: Actual and projected FCEV stock (dominated by light duty vehicles) [142,149,153]

Figure 62 shows the fuel-cell vehicle population in the four jurisdictions as of 2021 and projections/targets thereafter. Japan's hydrogen strategy targets the FCEV population to reach 800,000 by 2030. The state of California does not have specific targets for FCEVs, though they are part of the state's goal of five million zero emission vehicles (ZEVs) on the road by 2030. California's Fuel Cell Partnership (CaFCP), an industry-government collaboration formed to commercialize FCEVs, targets 1 million FCEVs in California by 2030. That would represent 20% of all ZEVs if the state's broader ZEV target is also reached. Germany has not publicly announced any sales targets for FCEVs. By 2040, South Korea's hydrogen road map projects production of 2.9 million vehicles for domestic use. Each jurisdiction has implemented a set of policies to promote FCEVs, though these vary considerably.

Japan introduced subsidies for fuel-cell vehicle purchases in 2016, as part of the national budget for clean vehicles including BEVs, hybrids and clean diesel vehicles. The total budget for their national clean vehicle program in 2018 was $117 million, with additional subsidies being provided by prefectural governments for FCEVs and fuel-cell buses. The total subsidies in Japan reduced the retail price of a fuel-cell sedan by 38% as of 2017. Exemptions on the annual vehicle tax is an added incentive for FCEV buyers. For taxi operators the subsidies are slightly more generous. FCEVs in Japan are also looked upon as a potential off-grid power generator for homes and hospitals during blackouts. This adds to the appeal of FCEVs for Japan, which is highly conscious of the importance of disaster readiness. FCEVs have higher kWh in comparison to a similar sized BEV, which further espouses its use as an off-grid power generator [154].

Germany targets a 100% ZEV fleet by 2040[155], but unlike Japan does not have exclusive targets for fuel-cell vehicles. At the national level, since 2016 the German government grants a 2,000 EUR subsidy (Umweltbonus) for the purchase of BEVs and FCEVs. From January 2019, taxes were reduced for new EVs that are used as company cars (which constitute nearly 64% of all new passenger cars in Germany). Several German states and cities provide additional EV purchase incentives which have triggered new registrations (predominantly BEVs) that reached nearly 10,000 a month as of October 2019. For BEVs, the increase in registrations strongly correlates with the availability of a wider range of models offered by car manufacturers (VW, Renault, Hyundai, and Audi), unlike FCEVs. Germany's ZEV incentive program is unique because the auto industry contributes a significant portion of the incentives. Germany has further increased the electric vehicle incentives as part of their post-pandemic stimulus package. At present, the total subsidy for purchase of a BEV/FCEV costing less than 40,000 EUR is 9,000 EUR. For vehicles above 40,000 EUR the subsidy is 7500 EUR. In this, the manufacturer's share of incentives is 3000 and 2500 EUR respectively [156,157]. Clearly, the current set of incentives have not encouraged a significant roll out of fuel-cell vehicles in the German market as is evident from Figure 62 , with less than 1000 FCEVs plying the road in 2021.

In South Korea, the central and local governments provide subsidies for consumer FCEVs, and while the incentives are available for any make, Hyundai provides nearly all FCEVs in Korea. Hyundai's most recent FCEV model, the 'Nexo,' has a starting price of 72 million Korean Won (57,000 US Dollars). The central government provides a 22.5 million KRW (18,000 USD) subsidy, while local governments provide subsidies ranging from 10 to 20 million KRW (8,000 to 16,000 USD). With all subsidies, Nexo model costs roughly KRW 32.5 million (26,000 USD) in Seoul[158]. Aside from end-user subsidies, the government offers additional incentives in the form of tax breaks. FCEVs are eligible for up to a 50% discount on public parking spaces as Type 1 low-emission vehicles. In addition, the Korea Expressway Corporation (KEC) offers a 50% discount on highway tolls to Battery Electric and Fuel-Cell electric vehicles. Thus, South Korea has the highest rates of subsidies for vehicle purchases among other jurisdictions compared here. This could be one reason South Korea currently leads other jurisdictions in terms on FCEVs plying on road (more than 16,000 as of March 2022).

California has several important policies that directly or indirectly promote FCEVs. Its Low Carbon Fuel Standard (LCFS), and ZEV mandate are two critical policy interventions that have encouraged the adoption of zero emission vehicles in the state. The LCFS Program requires at least a 10% reduction in the carbon intensity of transportation fuels that are sold in the state by 2020, and an additional 10% by 2030. This is by far the most stringent requirement for transport fuels in the US[159]. As of 2020, the incentives include credits for low carbon electricity and hydrogen, as well as refueling infrastructure "capacity" credits for stations selling these. The ZEV sales mandate requires auto manufacturers to sell a certain number of ZEVs and plug-in hybrids each year, based on their total sales volumes. Requirements are in terms of percent credits, ranging from 4.5 percent in 2018 to 22 percent by 2025[7]. The credit requirements make it difficult to assess the exact number of FCEVs that will be produced through this regulation. But nevertheless, these policies seem to have triggered the initial market for fuel-cell vehicles in the state, accounting for almost the entire US market for fuel-cell vehicles. The Clean Vehicle Rebate Project (CVRP) is an income based clean vehicle adoption program by CARB that provides rebates of $4,500 for purchase of FCEVs, which is higher than the rebates offered to a similar sized BEV. For low income individuals an additional $2,500 of rebate is provided [10]. A federal tax credit of up to $8,000 is also available for FCEVs. In absolute money value, the total rebates/subsidies available for purchase of an FCEV in California is higher than in Germany but lower than in Japan.

4.2.2.3 Medium- and Heavy-Duty FCEVs

While these jurisdictions have focused mainly on uptake of light-duty vehicle FCEVs, this is changing, particularly in California. In 2018, CARB awarded $41 million for the 'shore to shore' project, for developing 10 fuel-cell class 8 drayage trucks. More importantly, in June 2020, CARB passed the Advanced Clean Truck rule (ACT) which mandates that every new truck from Class 2b-8 sold in California to be zero-emission by 2045. CARB estimates CO_2e emissions reductions of 17.3 million -metric- tons by 2040, as a result of the ACT regulation enforced from 2024 [160]. The rule provides a schedule of increasing original equipment manufacturer (OEM) sales of ZEVs by truck class, with some classes (Class 4-8 straight trucks) required to reach 50% ZEV shares in 2030 and 75% in 2035.

South Korea's hydrogen road map projects 30,000 hydrogen trucks and 40,000 FCB to be produced by 2040. Hyundai's Xcient is marketed as the world's first mass produced fuel cell truck. These vehicles can travel 400 kilometres (250 mi) on a full tank and takes 8 to 20 minutes to refill. 56 (out of 1600) of these trucks have been exported to Switzerland starting in 2020 and have completed one million kilometers. The company plans to introduce different variants of these trucks globally and have initiated a demonstration project in California's Oakland port with 30 trucks (have a range of 500 miles). The project is funded jointly by CARB and CEC[161].

Medium- and heavy-duty vehicles(MHDV) population in Japan is close to 20%, but account for nearly 43% of GHG emissions from the transport sector[162]. Apart from the CO_2 emission regulations, there is no real policy push to roll out zero emission vehicles in this category. Incentives for fuel-cell based MHDV are still low, apart from a few instances, like the plans (in the Hydrogen strategy) to roll out 1,200 fuel-cell buses by 2030. Japanese OEMs like Toyota recently expanded its model range from light-duty FCEVs to FCBs and struck strategic partnerships for developing heavy-duty fuel-cell trucks but will require greater government support if these vehicles are to achieve significant market penetration.

Long-distance road-freight transport contributes nearly 20% of Germany's on road GHG emissions. Germany is part of the overall European plan to roll out 45,000 fuel-cell trucks and buses on road by 2030[163]. German OEMs, like Daimler, are also developing heavy duty fuel-cell vehicles, but like Japan, there are no specific policies for encouraging zero emission vehicles in this category.

With higher payload capacity and longer range, fuel-cell based MHDVs have some advantage over pure battery vehicles. But given the current high costs of these vehicles, greater government support is paramount and clear policy direction (like the ACT) will be required to successfully decarbonize this segment. Very few jurisdictions (like S. Korea and California) have targets set for this vehicle segment.

4.2.2.4 Hydrogen Refueling Station Deployment

A critical roadblock for the larger adoption of FCEVs is the unavailability of refueling infrastructure. Acknowledging this, all governments have taken steps to encourage buildout of a refueling station network to support growing fleets of FCEVs. Figure 63 depicts the current stations and the targets. All jurisdictions (except S. Korea) have very similar hydrogen station targets, between 900 and 1000 by 2030. South Korea’s commitment for 2040, is far sighted and would incentivize the build out of upstream supply chain infrastructure to support these stations which is also very important to ensure uninterrupted operation of the stations.

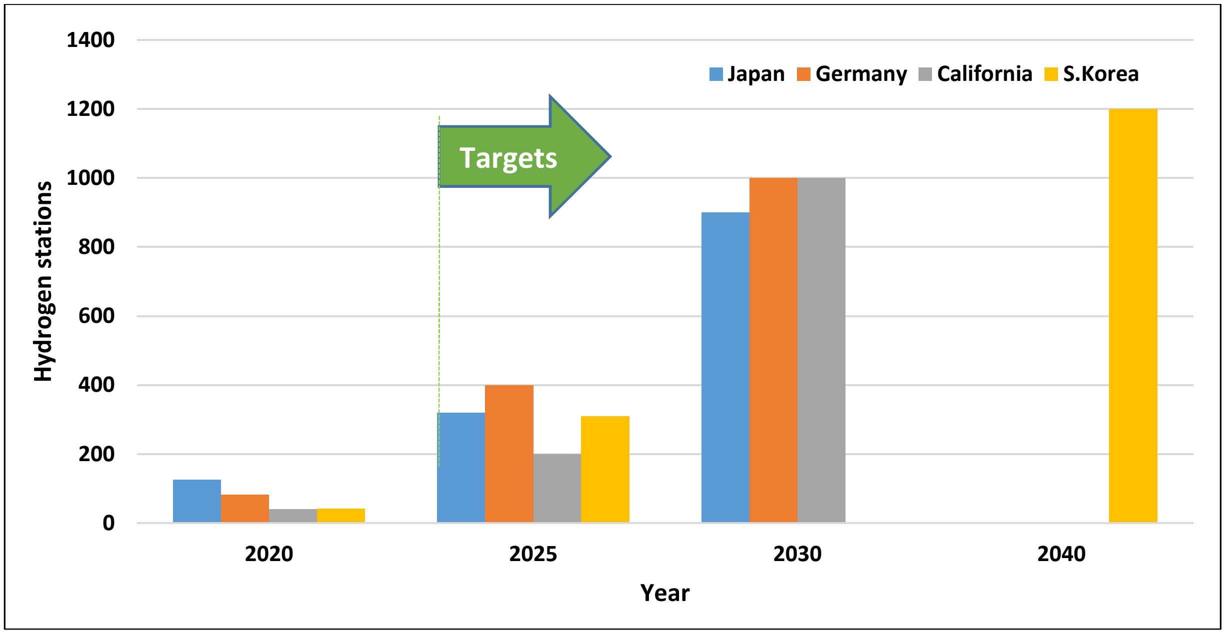

Figure 63: Current hydrogen refueling station deployment and government and industry projections through 2030

Like in other budding hydrogen economies, a major roadblock for the increase in the number of FCEVs in Japan is the lack of refueling infrastructure. But the situation in Japan is aggravated by very high costs of construction and operation of the refueling station. A hydrogen station in Japan is reported to cost two or three times the price as in Europe. The reasons for the high costs are twofold: hydrogen is a tightly regulated industrial gas, mandating high precision sensors and instrumentation (very expensive) use in the station. Manual refueling of cars by specialists licensed in handling high pressure gases (very few specialists available) limit the working hours of the fueling stations, drastically reducing the utilization rate of the station. A change in the existing law to allow automated fueling stations could go a long way in solving this problem. Of late, Japan has eased some of the regulatory roadblocks by allowing an increased storage pressure of hydrogen in refueling stations and modifying the High-Pressure Gas Safety

Act and the Fire Service Act to enable transport and storage of hydrogen in various forms. By 2025, Japan is targeting to establish 320 hydrogen refueling stations [164]. To create a funding ecosystem, a consortium of 11 Japanese automakers, infrastructure developers and investors established the Japan H2 Mobility (JHyM), as a joint venture in February 2018. JHyM also helps to standardize equipment, optimize driver usability, and support the deregulation of industry standards.

Germany hopes to build an initial hydrogen system, including refueling infrastructure for vehicles which would then encourage adoption of fuel-cell vehicles. Germany is part of various European initiatives which promote hydrogen technologies in the transport sector. Fuel Cells and Hydrogen Joint Undertaking (FCH JU), European Hydrogen Initiative, German– French cooperation on energy transition are a few noteworthy ones. In 2009, Germany established the H2 Mobility partnership – a conglomeration of vehicle manufacturers, energy companies and government institutions for developing a nationwide network of hydrogen refueling stations[165]. H2 Mobility receives funding from the Federal Ministry of Transport (through NIP) and the European Commission (through FCH JU). At present, Germany has the second largest public hydrogen refueling infrastructure in the world, only surpassed by Japan[166] as shown in Figure 63.

California started building its hydrogen refueling station network in 2005, based on the California Hydrogen Blueprint Plan [45] , but could not achieve its initial targets. Of late, California has revived its focus on developing retail hydrogen refueling stations through legislations such as Assembly Bill 8 and amendments to LCFS. AB 8 dedicates up to $20 million per year to support construction of the first 100 hydrogen fuel stations in the state. The 2018 LCFS amendments allow for Hydrogen Refueling Infrastructure (HRI) credits, with the goal of reaching 200 hydrogen stations by 2025. Station owners can claim credits for 15 years, based on the difference between the station's installed capacity and the actual hydrogen throughput, which is very encouraging [167]. At present, California has 52 operational refueling stations, a number lower when compared to Japan and Germany. California Fuel Cell Partnership (CaFCP), an industry/government consortium, projects 1000 hydrogen refueling stations in the state by 2030. Further, in a more recent report by CaFCP, it envisions a roll out of 70,000 heavy-duty fuel cell electric trucks supported by 200 hydrogen stations in-state by 2035[168].

4.2.2.5 Where and how will the hydrogen be sourced and distributed?

"Green" hydrogen is produced from renewable sources (mostly through electrolysis using renewable electricity) and "blue" hydrogen is produced from fossil fuel sources in conjunction with carbon capture and sequestration CCS[169]. "Gray" hydrogen is produced using fossil natural gas without CCS. This is a mature technology and currently is the predominant method of producing hydrogen. But with increasing focus on decarbonization, much of the policy support and funding is directed towards developing either blue or green hydrogen pathways. Beyond hydrogen production, absence of a cheap and reliable distribution infrastructure remains a challenge, in all budding hydrogen economies.

Japan's hydrogen strategy identifies power to gas (PtG) as a solution for storage and load balancing of excess domestic electricity from renewable energy sources. Power to gas (PtG) refers to the process of creating a gas fuel from electricity. PtG offers possibilities for integrating different sectors. Power from renewables like solar and wind could be used to produce green hydrogen through the PtG route, which could eventually power heavy duty vehicles, shipping etc. Japan has also set out concrete cost and efficiency targets per application, targeting electrolyzer costs of \$475/kW, efficiency of 70% or 4.3 kWh/Nm 3, and a production cost of \$3.30/kg by 2030. The lack of large, non-intermittent renewable electricity supply, high cost of renewable electricity generation and the lack of gas infrastructure (both natural gas and hydrogen gas pipelines) dampens the prospects of a fully-fledged uptake of PtG in Japan, at least in the near term. This has prompted Japan to focus on developing a steady hydrogen supply chain through imports. Until 2040, these imports are likely to be mostly blue hydrogen, with the intent to eventually develop a domestic supply chain for green hydrogen. Japanese companies have struck strategic partnerships in Australia, Saudi Arabia, Norway, and Brunei for hydrogen production from coal, oil and hydro power, and are testing carrier technologies for shipping the hydrogen to Japan [148]. The first liquid hydrogen ship was delivered in December 2019, and the first blue ammonia (ammonia from gas reforming with carbon capture) shipment arrived in September 2020[170].

The German hydrogen strategy targets 14 TWh of green hydrogen production by 2030. The strategy has exclusively focused on electrolytic green hydrogen [3], due to strong public opposition to the implementation of CCS in Germany. The European Hydrogen strategy, released shortly after the German hydrogen strategy, targets to scale up green hydrogen production using wind and solar energy to up to 10 million- tons in the EU, and forecasts the ramping up of electrolyzer capacity to 40 GW by 2030[4]. Germany will leverage its EU presidency to enable a vibrant green hydrogen market across the EU member nations. As of 2019, Germany has more than 50 PtG projects in planning or operation (versus 3 in Japan) and plans to drastically increase the capacity during the next few years. One study has identified many scenarios where Germany could rely on imports to fulfill a majority of its future demands [171]. In the background of the ensuing Russia-Ukraine conflict and its implications on energy security, it is paramount that Germany expands its import baskets for hydrogen. I note that Germany is revisiting an agreement with Morocco for supply for green hydrogen[172].

Germany's gas grid covers a total of 511,000 kilometers which can be leveraged for distribution and storage of hydrogen produced through the PtG route [4]. The largest PtG plant with hydrogen injection into the gas grid (6 MW) has been operational in Germany since 2015 [173]. At present, hydrogen is being blended into Germany's natural gas pipelines for use in power plants as well as heating applications. Germany's pipelines handle blends close to 10% of hydrogen and the plan is to extend this to 20%[174]. Pipeline safety studies indicate a safe blending window ranging from 5% to 20% by volume of hydrogen, depending on the specific design and age of the pipeline [109]. Apart from blending, Germany has been promoting other hydrogen distribution techniques like Liquid Organic Hydrogen Carriers(LOHC)[175] and also developing cross country hydrogen pipeline network across Europe [72].

In the backdrop of favorable policies such as SB 1369 (for renewable hydrogen production using electrolysis) and the recently passed Carbon Capture and Storage Protocol under LCFS, California is poised to become an early producer of both blue and green hydrogen. The production of green hydrogen using electricity grid connected electrolyzers might be expensive, given the high industrial electricity rates in California. This could prompt some regional imports (mostly green hydrogen) from neighboring states. Additionally, California has been trying to forge partnerships for possible low-cost hydrogen imports, for example with Chile[176] . Also, the definition of green hydrogen is broader in the Californian context with substantial amount of green hydrogen that could be produced from landfill and dairy biomethane.

California’s natural gas utilities have more than 100,000 miles of gas transmission and distribution pipelines. A first step towards establishing a hydrogen distribution network would be to enact policies (by the California Public Utilities Commission) to allow blending of hydrogen into the existing natural gas pipelines, much like in Germany. However, in the long-term dedicated hydrogen pipelines need to be constructed to serve the demands of industry, power plants, and hydrogen-refueling stations.

Currently, South Korea's hydrogen demands are met mostly by the petrochemical industry [149]. The government and industry regard renewable energy powered electrolysis as a key component of their long-term hydrogen production strategy. The Korean hydrogen roadmap also envisages imports of renewable hydrogen by 2030, but the global partners have not yet been identified. To meet growing demands in the early stages of market growth, South Korea would produce hydrogen using natural gas that is imported in the liquid form. It is not clear now, whether those production capacities would be coupled with some form of CCS or not. Recently, South Korean Ministry of Trade, Industry and Energy (MOTIE) announced reduced feed stock pricing for natural gas that would be employed for producing hydrogen needed by the transportation sector. The Korea Gas Corporation (KOGAS) is expected to spearhead plans to establish a steady supply of hydrogen for meeting future demands [177]. KOGAS is considering building new hydrogen pipelines (in addition to using existing natural gas pipelines) at the point of import to facilitate the domestic shipment of imported hydrogen. These and other proposed pipeline projects would be in addition to South Korea's existing 200-kilometer hydrogen pipeline.

At present, the majority of the global hydrogen production stems from CO_2-intensive processes based on fossil fuels. Capturing those CO_2 emissions (to make blue hydrogen) adds cost but may still be economically attractive in many situations. The long-term cost competitiveness of green hydrogen (electrolytic) over blue hydrogen largely depends on the capital cost reduction of electrolyzers coupled with very low electricity rates. Proponents of green hydrogen foresee such scenarios, by the end of the decade, when green hydrogen reaches cost parity (or even lower) with blue hydrogen. For blue hydrogen, the cost of carbon capture and the feasibility of geological storage of CO_2 is the key for cost reduction. Almost all future low carbon scenarios for Japan, South Korea and Germany assume most of the hydrogen demand to be fulfilled by imports, unlike for California where a vast majority of hydrogen demand could be satisfied through instate production or with regional imports. The availability of a low cost and reliable hydrogen distribution network is a challenge in all jurisdictions.

4.3 Policy and Strategy Summary

Figure 64 attempts to summarize the relative level of effort or focus on different areas of the hydrogen market by the different countries, and the emphasis and priority that each place on a range of strategies (uses a simple low, medium, and high classification). The figure could be subjective as these ratings are likely to change into the future (owing to the dynamic nature of the hydrogen market) but are meant to provide some sense on how the jurisdictions are similar and different from each other based on the data and discussions in the preceding sections.

S.No	Attribute	Japan	Germany	S.Korea	California
1	GHG reduction targets for 2030	Medium	High	Low	Medium
2	Drivers of future hydrogen demand				
	• Power generation	High	Low	Medium	Medium
	• Transportation	Medium	High	High	High
	• Industry	Low	High	Medium	Medium
3	Market penetration/ Present status of hydrogen technologies				
	• Fuel Cell vehicles	Medium	Low	High	High
	• Hydrogen refuelling stations	High	Medium	Low	Low
	• Stationary power generation units	High	Medium	Medium	Low
	• Power-to-gas (PtG) projects	Low	High	Low	Low
4	Policy emphasis for hydrogen production				
	• Blue hydrogen	High	Low	Medium	Medium
	• Green hydrogen	Medium	High	Medium	Medium
5	Domestic feasibility for cost effective hydrogen production	Low	Medium	Low	High
6	Potential to employ existing gas infrastructure for hydrogen distribution	Low	High	Medium	High

Legend	
●	High
▲	Medium
◆	Low

Figure 64: Summary of present status and future drivers of the hydrogen economy in the four jurisdictions

4.4 Conclusions

Enacting measures to keep global temperatures from increasing beyond 1.5 degrees Celsius requires immediate and unprecedented action. Hydrogen is increasingly attractive as a feasible decarbonizing energy carrier by major economies. I reviewed hydrogen-related activities, policy, present status, and targets in major economies around the world, with a focus on Japan, Germany, South Korea, and California. Achieving GHG emission reduction targets and ensuring economic and energy stability is what is driving these jurisdictions towards greater adoption of hydrogen. But the approach followed by every region is succinctly different.

Japan, South Korea, and Germany have an overarching “hydrogen strategy”, unlike California which has focused more on technology neutral zero-emission policies that could encourage hydrogen-based technologies. Japan’s efforts have focused more on stationary demand-side applications such as fuel-cell based off-grid power generation. Germany has been the most proactive on developing hydrogen supply systems, mostly through the green hydrogen (electrolysis) route. South Korea is poised to become a global leader in the production and deployment of fuel cell electric vehicles and large-scale stationary fuel cells for power generation and has the third-largest public investment in hydrogen after Germany and Japan. California's hydrogen strategy has centered primarily around the demand side, specifically the transportation sector, by promoting fuel-cell vehicle sales.

I identify specific challenges for each of these jurisdictions, as they expand their hydrogen ecosystem. The lack of supporting infrastructure (hydrogen distribution in particular) to meet projected growth in hydrogen demand is a common challenge for all jurisdictions. A major challenge for Japan will be to develop a cost-effective and self-reliant domestic hydrogen supply chain. Germany will need to incentivize a larger adoption of fuel-cell vehicles and diversify its low-carbon hydrogen import basket. California should aim to increase the role of hydrogen beyond transportation, such as in various industries and buildings. Policy directives encouraging hydrogen-based power generation (using fuel cells or in gas turbines) and permitting blending of hydrogen into existing natural gas pipelines can help incentivize investments in hydrogen supply and some of the hydrogen markets outside of transportation. Ushing hydrogen in hard-to-decarbonize sectors (such as steelmaking, shipping, cement, etc.) appears a potentially important direction for all jurisdictions, given their ambitious GHG reduction goals.

Overall, to be successful in rolling out a large hydrogen system, all these economies will need to develop a balanced approach, incentivizing both supply and demand of hydrogen, and prioritizing the infrastructure needs to make the system work. Strong communication and sharing of experiences, both successes and failures, is critical at this stage as these and other countries start to make major investments in hydrogen systems. Hydrogen's true potential is its versatility, and its ability to decarbonize sectors that are very carbon intensive. An integrated and holistic policy focus with a steady funding mechanism to promote hydrogen is paramount if regions are to achieve their deep decarbonization plans

Supporting Information

1. S1- Supporting Information for Chapter 1

1.1. Base assumptions in H2A

Table 10: Base assumptions in H2A [25,178,179].

	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_2) in SMR plants	0.1558
12	Electricity usage (kWh/kg H_2) for electrolysis	51

1.2. Feed stock price assumptions in H2A

Table 11:Feed stock prices [71,180,181]

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

1.3. Capital and operating cost assumptions in H2A

Table 12: 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

1.4. 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.

1.5. Inputs to HDSAM

Table 13: Parameters in 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 (ring 1) Pipeline Inlet Pressure (atm)	41
10	Service Pipeline Inlet Pressure (atm)	26
11	Liquid hydrogen Tanker Water Volume (m^3)	56
12	Tank Unloading Losses (% of unloaded amount)	2.5
13	Discount rate (%)	8

1.6. Parameterization in HRSAM and HDRSAM models.

Table 14: Inputs to HRSAM and HDRSAM

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
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

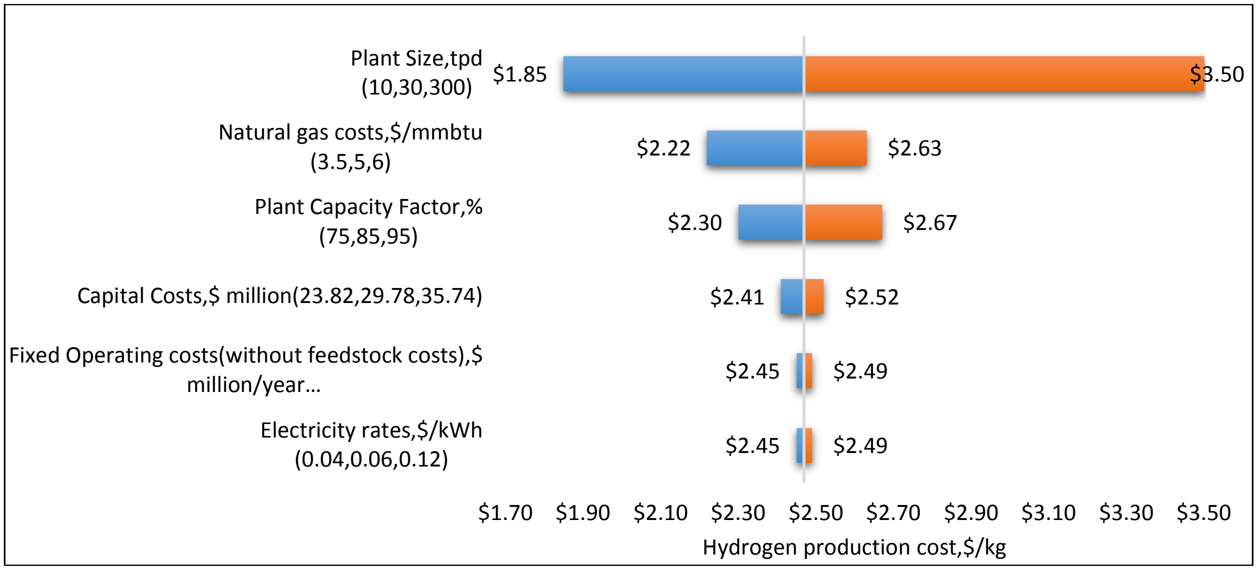

Figure 65:Sensitivity case exploring the effect of economies of scale (along with other factors) for a central SMR plant with CCS

2. S2- Supporting Information for Chapter 2

2.1. SERA 2.0 formulation

2.1.1 Sets

N: the set of all nodes

T: the set of all intra-year time periods

Y: the set of all years

PT: the set of all production technologies

PW: the set of all pathways

L: the set of all links

L_n: the set of all links connected to node n

PT_{clean}: the set of clean H_2 production technologies

S_{pw}: the set of all stages in pathway pw

S_{pw}^{unext}: the set of all un-extended stages in pathway pw

S_{pw}^{ext} : the set of all extended stages in pathway pw

4.1.1 Decision Variables

All decision variables are non-negative, unless stated otherwise.

4.1.1.1 Planning Variables

$K_{n,y}^{pt,new}$: New capacity of production technology pt added at node n in year y

$K_{n,y}^{s,pw,new}$: New capacity of unextended stage s of pathway pw added at node n in year y

$K_{l,y}^{s,pw,new}$: New capacity of extended stage s of pathway pw added at link l in year y

$K_{n,y}^{stor,s,pw,new}$: New capacity of storage at unextended stage s of pathway pw added at node n in year y

4.1.1.2 Operations Variables

$p_{n,t,y}^{pt}$: Total hydrogen produced by production technology pt at node n in time-period t in year y

$f_{n,t,y}^{s,pw}$: Total hydrogen flowing through stage s of pathway pw at node n in time – period t in year y

$f_{n,t,y}^{stor_{in},s,pw}$: Total hydrogen flowing into storage at stage s of pathway pw at node n in time – period t in year y

$f_{n,t,y}^{stor_{out},s,pw}$: Total hydrogen flowing out of storage at stage s of pathway pw at node n in time – period t in year y

$x_{n,t,y}^{stor,s,pw}$: Total hydrogen stored at at stage s of pathway pw at node n in time – period t in year y

$f_{l,n \rightarrow n'_l,t,y}^{s,pw}$: Total hydrogen flowing from node n across link l at stage s of pathway pw in time – period t in year y

$f_{l,n'_l \rightarrow n,t,y}^{s,pw}$: Total hydrogen flowing into node n across link l at stage s of pathway pw in time – period t in year y

${}_{l,n\rightarrow n'_l,t,y}^{stor_{in},s,pw}$: Total hydrogen flowing into storage in extended stage s of pathway pw across link l in time-period t in year y

${}_{l,n\rightarrow n'_l,t,y}^{stor_{out},s,pw}$: Total hydrogen flowing out of storage in extended stage s of pathway pw across link l in time-period t in year y

$x_{l,n\rightarrow n'_l,t,y}^{stor,s,pw}$: Total hydrogen stored in extended stage s of pathway pw across link l in time-period t in year y

4.1.2 Parameters

$C^{stor,s,pw}$: Investment cost of storage at un-extended stage s of pathway pw ($/kg)

C^{pt}: Annual fixed cost of production technology pt ($/kg)

$C^{s,pw}$: Annual fixed cost of un-extended stage s of pathway pw ($/kg)

$C^{stor,s,pw}$: Annual fixed cost of storage at un-extended stage s of pathway pw ($/kg)

$C^{l,s,pw}$: Annual fixed cost of extended stage s of pathway pw across link l ($/kg)

IC^{pt}: Investment cost of production technology pt($/kg)

$IC^{s,pw}$:Investment cost of stage s of pathway pw ($/kg)

$IC^{l,s,pw}$: Investment cost of extended stage s of pathway pw across link l($/kg)

OC^{pt}: Operating cost of hydrogen production technology pt ($/kg)

$OC^{f,s,pw}$: Operating cost of hydrogen owing through unextended stage s of pathway pw ($/kg)

$OC^{stor_{in},s,pw}$: Operating cost of hydrogen sent to storage at unextended stage s of pathway pw ($/kg)

$OC^{stor_{out},s,pw}$: Operating cost of hydrogen withdrawn from storage at unextended stage s of pathway pw ($/kg)

$OC^{l,s,pw}$: Operating cost of hydrogen owing across link l through extended stage s of pathway pw ($/kg)

$D_{n,t,y}$: Total hydrogen demand at node n in time-period t in year y (kg)

$Y^{s,pw}$: Hydrogen yield across stage s of pathway pw

$K_{n,y}^{pt,grid_{req}}$: Production capacity requirement determined by the grid model for production technology pt, at node n, in year t.

$K_{y}^{stor,grid_{req}}$: Total system wide H_2 storage capacity requirement determined by the grid model for year t.

α_{y}^{clean}: Fraction of total H_2 demand in year y to be satisfied by clean production technologies.

K_{max}^{pt}: Maximum annual capacity addition limit for production technology pt

$K_{max}^{s,pw}$: Maximum annual capacity addition limit for stage s of pathway pw

$K_{max}^{stors,pw}$: Maximum annual storage capacity addition limit for un-extended stage s of pathway pw

β_{min}^{pt}: Minimum utilization factor for production technology pt

$\beta_{min}^{s,pw}$: Minimum utilization factor for stage s of pathway pw

r: Discount Rate

4.1.3 Formulation

4.1.3.1 Objective function

Minimize the total investment and operating costs of producing and storing hydrogen and transporting it across the pathways to demand nodes. This is a NPV based cost minimization.

Min

$$\sum_{y\ \ Y}\left(\frac{1}{1+r}\right)^{y}(\quad+\quad+\qquad (1$$

were,

$$=\sum_{n\ \ N}\left(\sum_{pt\ \ PT} C^{pt}K^{pt,new}_{n,y}+\sum_{pw\ \ PW}\sum_{s\ \ S^{unext}_{pw}}\left(C^{s,pw}K^{s,pw,new}_{n,y}+C^{stor,s,pw}K^{stor,s,pw,new}_{n,y}\right)\right.$$
$$\left.+\sum_{l\ \ L}\sum_{pw\ \ PW}\sum_{s\ \ S^{ext}_{pw}} C^{l,s,pw}K^{s,pw,new}_{l,y}\right.$$

$$=\sum_{n\ \ N}\left(\sum_{pt\ \ PT} C^{pt}K^{pt}_{n,y}+\sum_{pw\ \ PW}\sum_{s\ \ S^{unext}_{pw}}\left(C^{s,pw}K^{s,pw}_{n,y}+C^{stor,s,pw}K^{stor,s,pw}_{n,y}\right)\right.$$
$$\left.+\sum_{l\ \ L}\sum_{pw\ \ PW}\sum_{s\ \ S^{ext}_{pw}} C^{l,s,pw}K^{s,pw}_{l,y}\right.$$

$$=\sum_{n\ \ N}\sum_{t\ \ T}\left(\sum_{pt\ \ PT} C^{pt}_{n,y,t}p^{pt}_{n,y,t}\right.$$
$$+\sum_{pw\ \ PW}\left(\sum_{s\ \ S^{unext}_{pw}}\left(C^{s,pw}_{n,y,t}\ {}^{s,pw}_{n,y,t}+C^{stor_{in},pw}_{n,y,t}\ {}^{stor_{in}s,pw}_{n,y,t}+C^{stor_{out},pw}_{n,y,t}\ {}^{stor_{out}s,pw}_{n,y,t}\right)\right.$$
$$\left.\left.+\sum_{s\ \ S^{ext}_{pw}}\sum_{l\ \ L_n}\left(C^{s,pw}_{l,y,t}\ {}^{s,pw}_{l,n\rightarrow n',y,t}\right)\right)\right)$$

4.1.3.2 Constraints

- Sum of H2 flowing through the first stage of all pathways at node n should be equal to the total H2 production at node n:

$$\sum_{pw\ \ PW}\ {}^{1,pw}_{n,t,y}=\sum_{pw\ \ PW} p^{pt}_{n,t,y}\ ,\quad \forall n,\forall t,\forall y \qquad (2$$

- Hydrogen balance at un-extended stages which are not the last stage of the pathway

$$Y^{s,pw}f^{s,pw}_{n,t,y}+f^{stor_{out}s,pw}_{n,t,y}-f^{stor_{in}s,pw}_{n,t,y}=f^{s+1,pw}_{n,t,y}\ ,\quad \forall pw,\forall s\in S^{unext}_{pw}\ \mid s\neq\ last,\forall n,\forall t,\forall y \qquad (3)$$

- Hydrogen storage evolution at un-extended stages:

$$x_{n,t,y}^{stor,\ s,pw} = x_{n,t-1,y}^{stor,\ s,pw} + f_{n,t,y}^{stor_{in},s,pw} - f_{n,t,y}^{stor_{out},s,pw} \quad , \qquad \forall pw, \forall s \in S_{pw}^{unext} \ , \forall n, \forall t, \forall y \qquad (4)$$

- Hydrogen balance at extended stages:

$${}_{n,t,y}^{s,pw} + \sum_{l\ L_n} \left(Y^{s,pw} \ {}_{l,n\to n_l',t,y}^{s,pw} - {}_{l,n_l'\to nt,y}^{s,pw} + {}_{l,n_l'\to n,t,y}^{stor_{out},s,pw} - {}_{l,n_l'\to n,t,y}^{stor_{in},s,pw} \right) = {}_{n,t,y}^{s,pw},$$

$$\forall pw, \forall s \epsilon S_{ext}^{pw}, \forall n, \forall t, \forall y \qquad (5$$

- Hydrogen storage evolution at extended stages:

$$x_{l,n\to n_l',t,y}^{stor,s,pw} = x_{l,n\to n_l',t-1,y}^{stor,s,pw} + {}_{l,n\to n_l',t,y}^{stor_{in},s,pw} - {}_{l,n\to n_l',t,y}^{stor_{out},s,pw},$$

$$\forall l, \forall pw, \forall s \epsilon S_{ext}^{pw}, \forall n, \forall t, \forall y \qquad (6$$

- Sum of net hydrogen flowing through the last stage of all pathways at node n should be equal to the total H2 demand at node n:

$$D_{n,t,y} = \sum_{pw \in PW} \left(Y^{last,pw} f_{n,t,y}^{last,pw} + f_{n,t,y}^{stor_{out},last,pw} - f_{n,t,y}^{stor_{in},last,pw} \right), \qquad \forall n, \forall t, \forall y \qquad (7)$$

- Hydrogen production capacity limits:

$$p_{n,t,y}^{pt} \le K_{n,y}^{pt} \quad \forall pt, \forall n, \ \forall t, \ \forall y \qquad (8)$$

- Hydrogen un-extended stage flow limits:

$$f_{n,t,y}^{s,pw} \le K_{n,y}^{s,pw} \ , \ \forall pw, \ \forall s \in S_{pw}^{unext} \ , \ \forall n, \forall t, \forall y \qquad (9)$$

- Hydrogen un-extended stage storage limits:
-

$$x_{n,t,y}^{stor,s,pw} \le K_{n,y}^{stor,s,pw}, \forall pw, \forall s \epsilon S_{pw}^{unext}, \forall n, \forall t, \forall y \qquad (10$$

- Hydrogen extended stage storage limits:

$$x_{n,t,y}^{stor,s,pw} \leq K_{n,y}^{stor,s,pw}, \forall pw, \forall s \epsilon S_{pw}^{ext}, \forall n, \forall t, \forall y \qquad (11$$

- Hydrogen extended stage flow limits

$$f_{l,n \rightarrow n_l',t,y}^{s,pw} \leq K_{l,y}^{s,pw} \quad \forall l,\ \forall pw, \forall s \in S_{pw}^{ext}, \forall n, \forall t, \forall y \qquad (12)$$

- Total production capacity evolution:

$$K_{n,y}^{pt} = K_{n,y-1}^{pt} + K_{n,y}^{pt,new} \quad \forall pt, \forall n,\ \forall t,\ \forall y \qquad (13)$$

- Total un-extended stage capacity evolution:

$$K_{n,y}^{s,pw} = K_{n,y-1}^{s,pw} + K_{n,y}^{s,pw,new},\ \forall pw,\ \forall s \in S_{pw}^{unext},\ \forall n, \forall t, \forall y \qquad (14)$$

- Total extended stage capacity evolution:

$$K_{l,y}^{s,pw} = K_{l,y-1}^{s,pw} + K_{l,y}^{s,pw,new} \quad \forall l,\ \forall pw, \forall s \in S_{pw}^{ext}, \forall n, \forall t, \forall y \qquad (15)$$

- Total un-extended stage storage capacity evolution:

$$K_{n,y}^{stor,s,pw} = K_{n,y-1}^{stor,s,pw} + K_{n,y}^{stor,s,pw,new} \qquad (16$$

- Total extended stage storage capacity: There is a max cap on the amount of hydrogen storage possible for a given length of pipeline based on Aspen model.

$$K_{l,y}^{stor,s,pw} = \left(K_{l,y}^{s,pw}\right) \qquad (17$$

Where f is a polynomial function of the installed extended stage capacity.

Grid connected constraints

- Nodal Production Capacity Constraint: may be turned off or on depending on the scenario

$$K_{n,y}^{pt} \geq K_{n,y}^{pt,grid_{req}}, \forall n, \forall pt, \forall y \qquad (18$$

- System-wide Storage Capacity Constraint: may be turned off or on depending on the scenario
-

$$\sum_{n\ N} \sum_{pw\ PW} \sum_{s\ S_{pw}^{unext}} K_{n,y}^{stor,s,pw} + \sum_{l\ L} \sum_{pw\ PW} \sum_{s\ S_{pw}^{ext}} K_{l,y}^{stor,s,pw} \geq K_{y}^{stor,grid_{req}}, \forall y \qquad (19$$

Renewable hydrogen policy constraint

$$\sum_{n \in N}\sum_{pt \in PT_{clean}}\sum_{t \in T} p_{n,t,y}^{pt} \geq \alpha_y^{clean}\sum_{n \in N}\sum_{t \in T} D_{n,t,y}, \forall y \qquad (20$$

Onsite Production Constraints:

$$\sum_{pt \in PT_{onsite}} p_{n,t,y}^{pt} \leq D_{n,t,y}, \quad \forall n, \forall t, \forall y \qquad (21$$

Table 15: Delivery pathways available in SERA

Pathway	Stage	Technology
Liquid hydrogen (LH2) truck	1	LH2 truck terminal with liquefaction and storage
	2	LH2 truck
	3	End use point (city gate/refueling station)
Gaseous hydrogen (GH2) pipeline	1	Pipeline compressor and salt cavern storage
	2	Pipeline (transmission)
	3	End use point (city gate/refueling station)
Gaseous hydrogen (GH2) truck	1	GH2 truck terminal with storage
	2	GH2 truck
	3	End use point (city gate/refueling station)

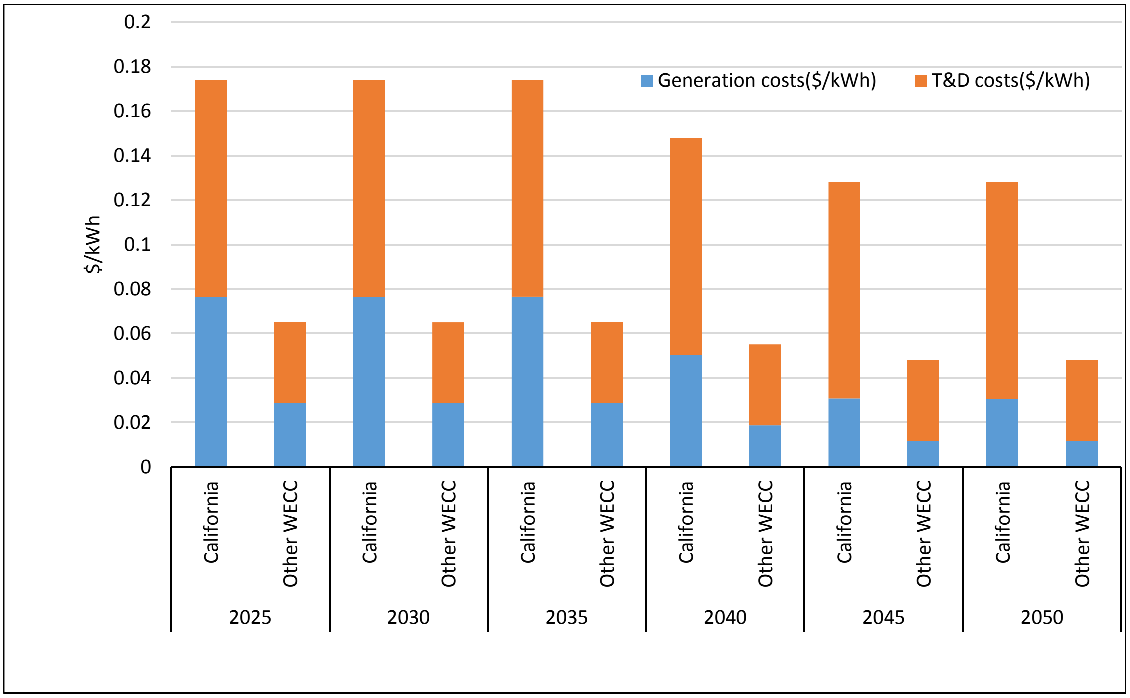

Figure 66: Breakdown of industrial electricity prices ($/kWh)

Table 16: Demand aggregation based on location

Location	Demand types
San Diego	Aviation, Residential/Commercial, others
Los Angeles	Marine, Refinery, Biofuel, Aviation, Residential/Commercial, others
San Jose	Aviation, Residential/Commercial, others
San Francisco	Marine, Refinery, Biofuel, Aviation, Residential/Commercial, others
Sacramento	Aviation, Residential/Commercial, others
Bakersfield	Refinery, Biofuel, Aviation, Residential/Commercial, others

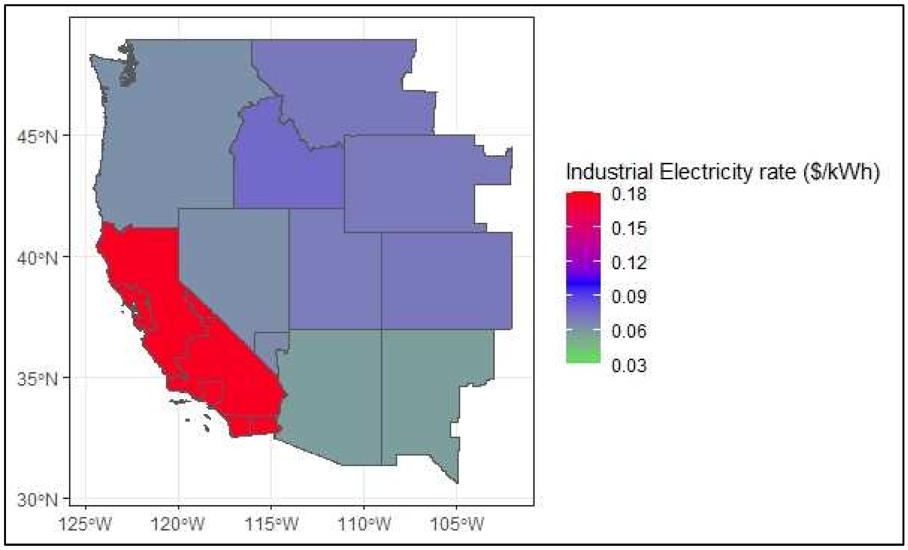

Figure 67: Regional industrial electricity rates in 2025 for WECC

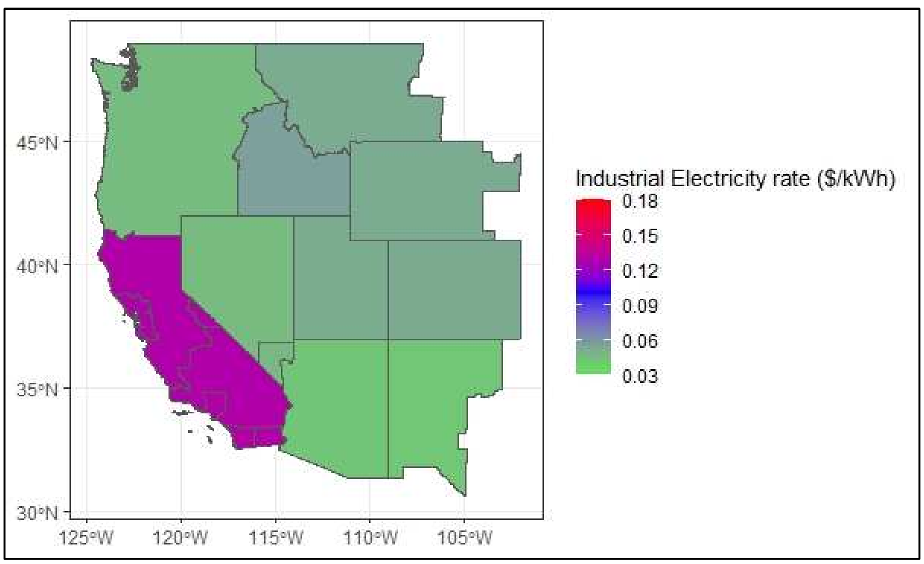

Figure 68: Regional industrial electricity rates in 2050 for WECC

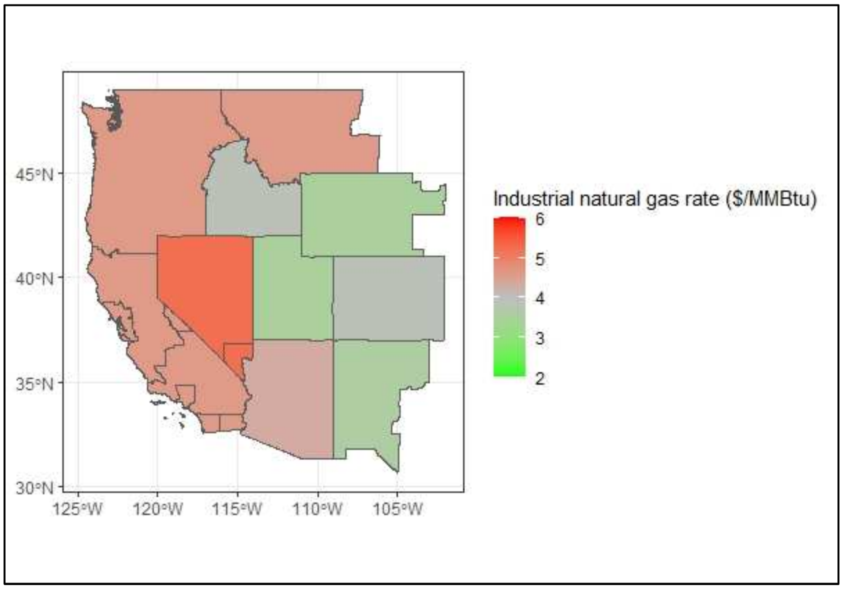

Figure 69: Regional industrial natural gas rates in 2025 for WECC

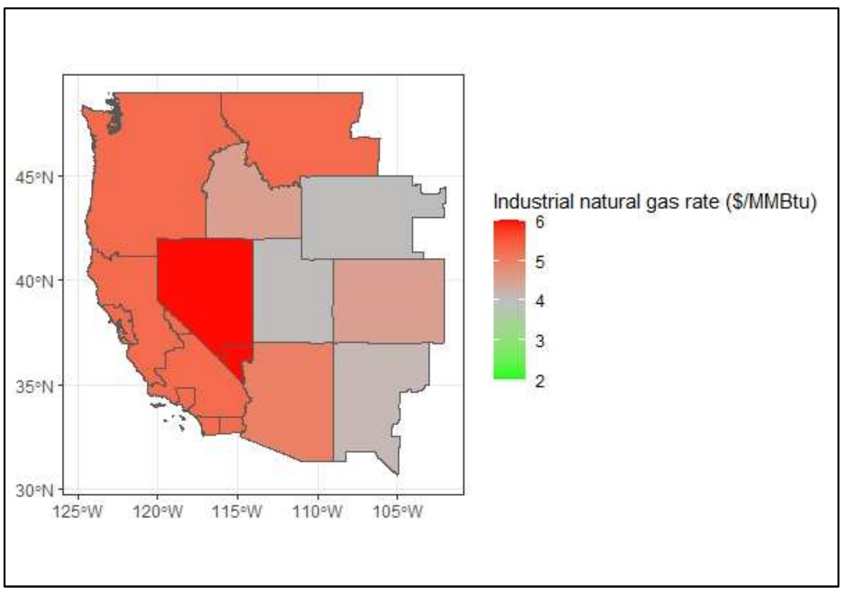

Figure 70: Regional industrial natural gas rates in 2050 for WECC

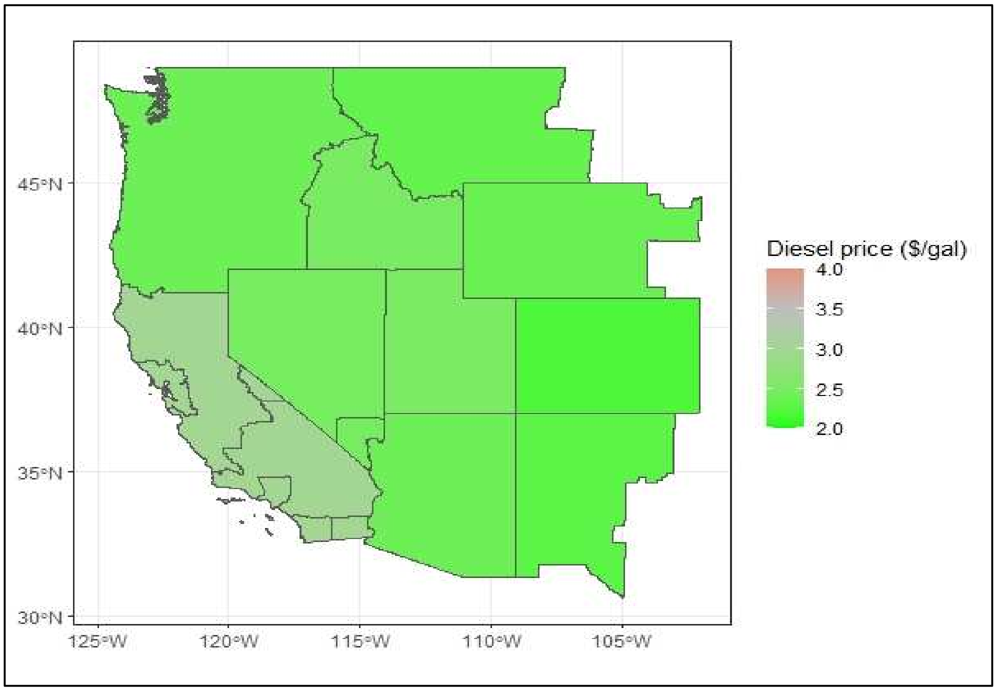

Figure 71: Regional diesel price($/gal) in 2025 for WECC

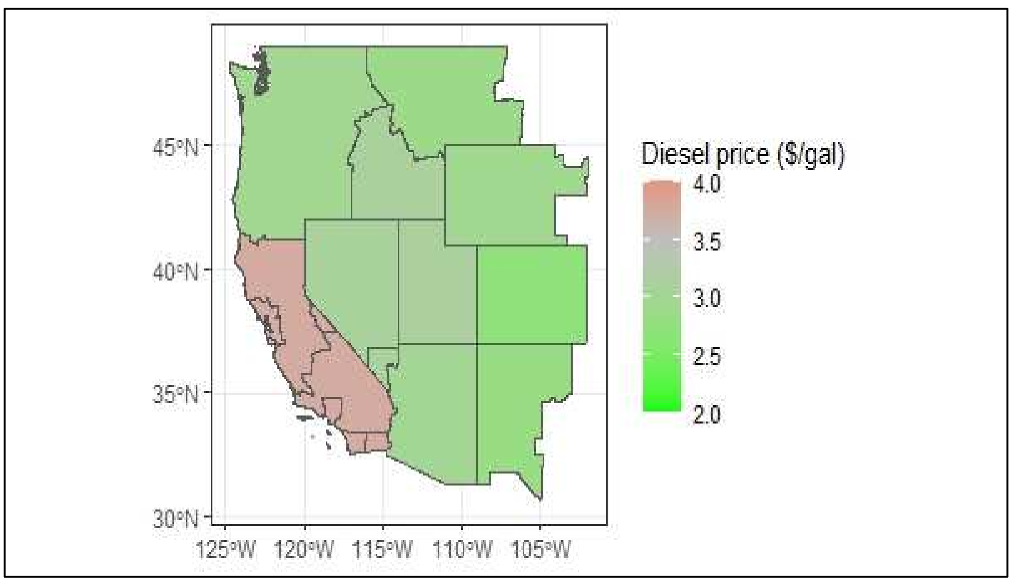

Figure 72: Regional diesel price($/gal) in 2050 for WECC

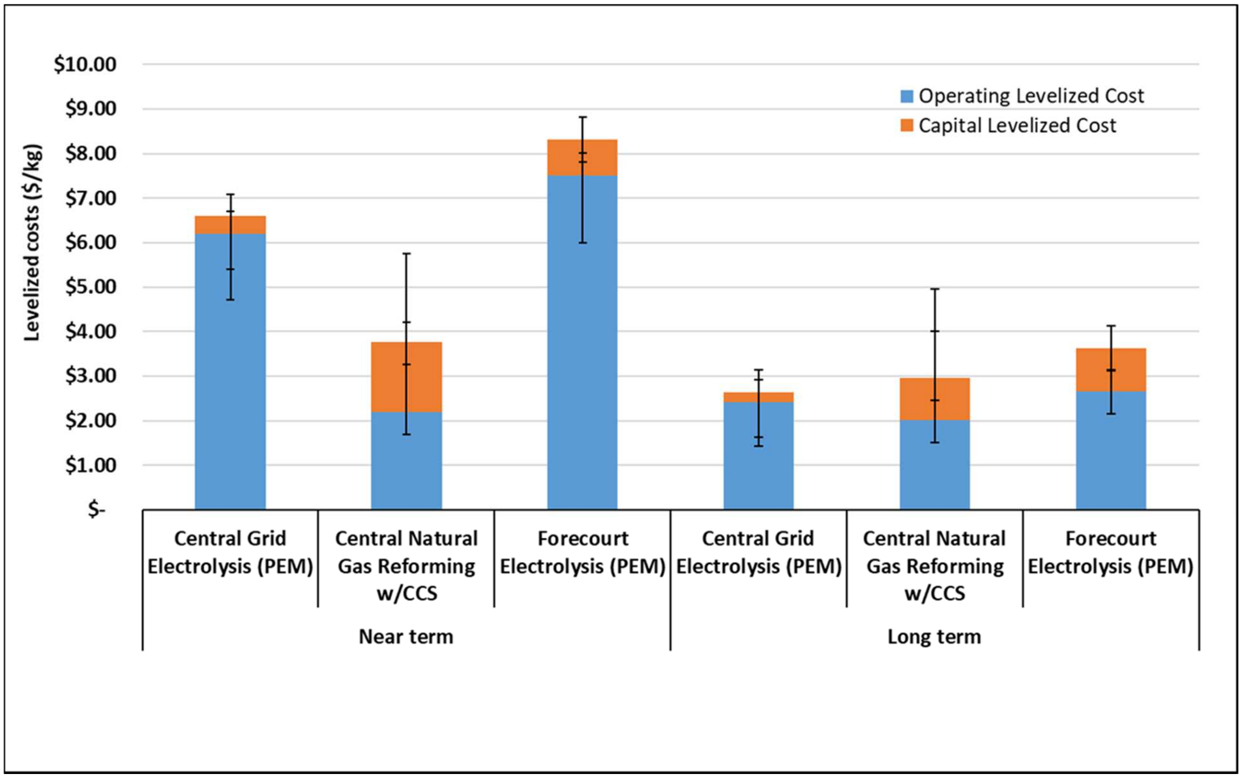

Figure 73: Levelized cost of Hydrogen production (input to SERA 2.0)

	Distance (km)													
Capacity (tpd)	**5**	**10**	**30**	**50**	**100**	**150**	**200**	**300**	**400**	**500**	**700**	**1000**	**1200**	**1500**
0.5	$ 11.01	$ 11.03	$ 8.23	$ 11.07	$ 11.14	$ 11.20	$ 11.30	$ 11.40	$ 11.53	$ 11.66	$ 11.98	$ 12.31	$ 12.63	$ 12.96
1	$ 8.20	$ 8.21	$ 5.95	$ 8.25	$ 8.30	$ 8.36	$ 8.44	$ 8.53	$ 8.64	$ 8.75	$ 9.03	$ 9.31	$ 9.59	$ 9.88
2	$ 5.38	$ 5.40	$ 3.68	$ 5.17	$ 5.47	$ 5.52	$ 5.59	$ 5.66	$ 5.75	$ 5.85	$ 6.08	$ 6.32	$ 6.55	$ 6.79
3	$ 2.57	$ 2.58	$ 1.40	$ 1.94	$ 2.64	$ 2.68	$ 2.73	$ 2.79	$ 2.87	$ 2.94	$ 3.13	$ 3.32	$ 3.52	$ 3.71
10	$ 2.33	$ 2.34	$ 1.05	$ 1.45	$ 2.41	$ 2.45	$ 2.51	$ 2.58	$ 2.66	$ 2.75	$ 2.96	$ 3.16	$ 3.37	$ 3.58
15	$ 2.09	$ 2.11	$ 0.70	$ 0.96	$ 1.79	$ 2.23	$ 2.30	$ 2.36	$ 2.46	$ 2.55	$ 2.78	$ 3.01	$ 3.23	$ 3.46
20	$ 1.86	$ 1.87	$ 0.35	$ 0.46	$ 0.82	$ 1.17	$ 1.70	$ 2.15	$ 2.25	$ 2.35	$ 2.60	$ 2.85	$ 3.09	$ 3.34
30	$ 2.00	$ 2.02	$ 0.29	$ 0.37	$ 0.65	$ 0.92	$ 1.32	$ 1.73	$ 2.27	$ 2.52	$ 2.78	$ 3.05	$ 3.31	$ 3.57
50	$ 3.20	$ 3.21	$ 0.23	$ 0.29	$ 0.48	$ 0.66	$ 0.95	$ 1.23	$ 1.60	$ 1.98	$ 2.92	$ 3.43	$ 3.48	$ 3.54
75	$ 3.59	$ 3.59	$ 0.21	$ 0.26	$ 0.42	$ 0.58	$ 0.83	$ 1.07	$ 1.39	$ 1.72	$ 2.52	$ 3.33	$ 3.91	$ 3.98
100	$ 3.97	$ 3.98	$ 0.19	$ 0.23	$ 0.37	$ 0.50	$ 0.71	$ 0.91	$ 1.18	$ 1.45	$ 2.13	$ 2.81	$ 3.49	$ 4.16
150	$ 3.24	$ 3.25	$ 0.16	$ 0.20	$ 0.30	$ 0.40	$ 0.55	$ 0.70	$ 0.91	$ 1.11	$ 1.62	$ 2.13	$ 2.64	$ 3.14
200	$ 2.51	$ 2.52	$ 0.14	$ 0.16	$ 0.23	$ 0.30	$ 0.40	$ 0.50	$ 0.63	$ 0.77	$ 1.11	$ 1.45	$ 1.79	$ 2.13
300	$ 2.86	$ 2.86	$ 0.13	$ 0.15	$ 0.21	$ 0.27	$ 0.36	$ 0.45	$ 0.57	$ 0.69	$ 1.00	$ 1.30	$ 1.60	$ 1.90
400	$ 3.20	$ 3.20	$ 0.13	$ 0.14	$ 0.20	$ 0.25	$ 0.33	$ 0.41	$ 0.51	$ 0.62	$ 0.88	$ 1.15	$ 1.41	$ 1.68

Mode of Delivery

GH2 Pipeline

GH2 Truck

LH2 Truck

Figure 74: Least Cost distribution mode without including station costs (input to SERA 2.0)

	Distance (km)													
Capacity (tpd)	**5**	**10**	**30**	**50**	**100**	**150**	**200**	**300**	**400**	**500**	**700**	**1000**	**1200**	**1500**
0.5	$ 13.57	$13.59	$10.79	$13.63	$13.70	$13.76	$13.86	$13.96	$14.09	$14.22	$14.54	$14.87	$15.19	$ 15.52
1	$ 10.76	$10.77	$ 8.51	$10.81	$10.86	$10.92	$11.00	$11.09	$11.20	$11.31	$11.59	$11.87	$12.15	$ 12.43
2	$ 7.94	$ 7.96	$ 6.23	$ 7.73	$ 8.03	$ 8.08	$ 8.15	$ 8.22	$ 8.31	$ 8.41	$ 8.64	$ 8.88	$ 9.11	$ 9.35
3	$ 5.13	$ 5.14	$ 3.96	$ 4.50	$ 5.20	$ 5.24	$ 5.29	$ 5.35	$ 5.43	$ 5.50	$ 5.69	$ 5.88	$ 6.07	$ 6.27
10	$ 4.89	$ 4.90	$ 3.61	$ 4.00	$ 4.97	$ 5.01	$ 5.07	$ 5.14	$ 5.22	$ 5.30	$ 5.51	$ 5.72	$ 5.76	$ 5.81
15	$ 4.65	$ 4.67	$ 3.26	$ 3.51	$ 4.35	$ 4.79	$ 4.85	$ 4.92	$ 5.02	$ 5.09	$ 5.13	$ 5.18	$ 5.22	$ 5.27
20	$ 4.42	$ 4.43	$ 2.91	$ 3.02	$ 3.37	$ 3.72	$ 4.26	$ 4.50	$ 4.52	$ 4.54	$ 4.59	$ 4.64	$ 4.69	$ 4.74
30	$ 4.30	$ 4.31	$ 2.85	$ 2.93	$ 3.20	$ 3.47	$ 3.88	$ 4.28	$ 4.39	$ 4.41	$ 4.46	$ 4.51	$ 4.57	$ 4.62
50	$ 4.17	$ 4.17	$ 2.79	$ 2.84	$ 3.03	$ 3.22	$ 3.50	$ 3.78	$ 4.16	$ 4.28	$ 4.33	$ 4.39	$ 4.45	$ 4.50
75	$ 4.55	$ 4.55	$ 2.77	$ 2.81	$ 2.98	$ 3.14	$ 3.38	$ 3.62	$ 3.95	$ 4.27	$ 4.74	$ 4.81	$ 4.88	$ 4.94
100	$ 4.93	$ 4.94	$ 2.75	$ 2.79	$ 2.92	$ 3.06	$ 3.26	$ 3.46	$ 3.74	$ 4.01	$ 4.68	$ 5.23	$ 5.31	$ 5.38
150	$ 4.20	$ 4.21	$ 2.72	$ 2.75	$ 2.85	$ 2.95	$ 3.11	$ 3.26	$ 3.46	$ 3.67	$ 4.17	$ 4.45	$ 4.51	$ 4.58
200	$ 3.47	$ 3.48	$ 2.69	$ 2.71	$ 2.78	$ 2.85	$ 2.95	$ 3.05	$ 3.19	$ 3.32	$ 3.62	$ 3.67	$ 3.72	$ 3.77
300	$ 3.82	$ 3.82	$ 2.69	$ 2.71	$ 2.77	$ 2.83	$ 2.92	$ 3.01	$ 3.13	$ 3.25	$ 3.55	$ 3.85	$ 4.10	$ 4.16
400	$ 4.16	$ 4.17	$ 2.68	$ 2.70	$ 2.75	$ 2.80	$ 2.88	$ 2.96	$ 3.07	$ 3.17	$ 3.44	$ 3.70	$ 3.97	$ 4.23

Mode of Delivery
GH2 Pipeline
GH2 Truck
LH2 Truck

Figure 75: Least Cost distribution mode including the cost of building a 1.5 ton per day station

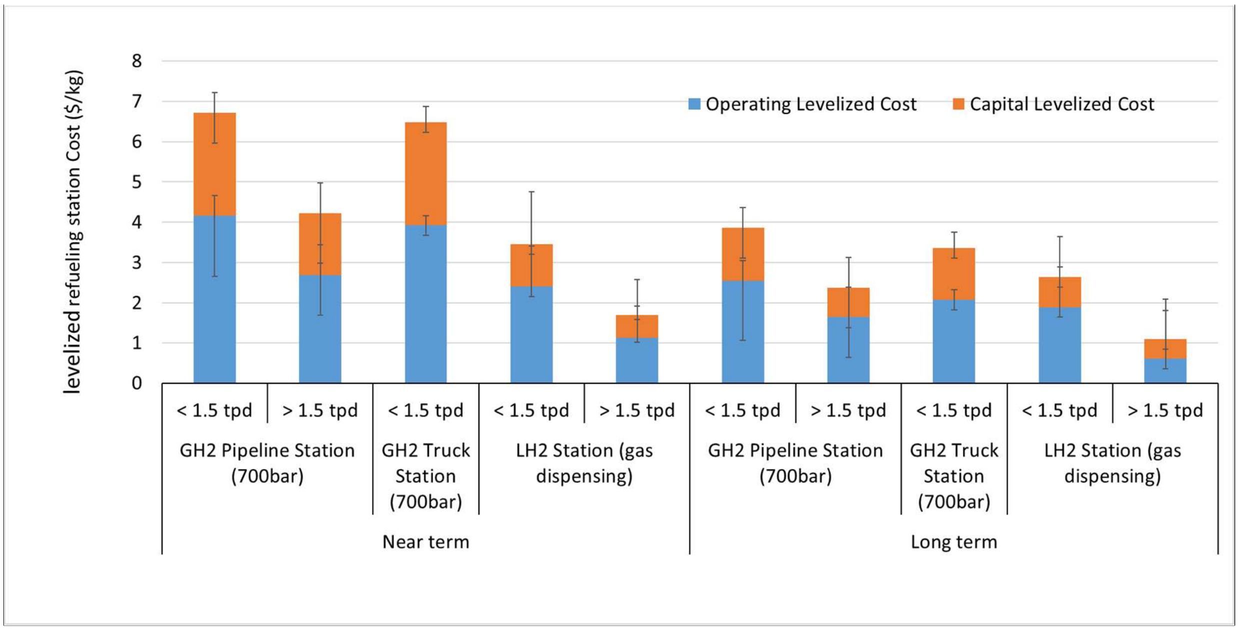

Figure 76:Levelized refueling station costs

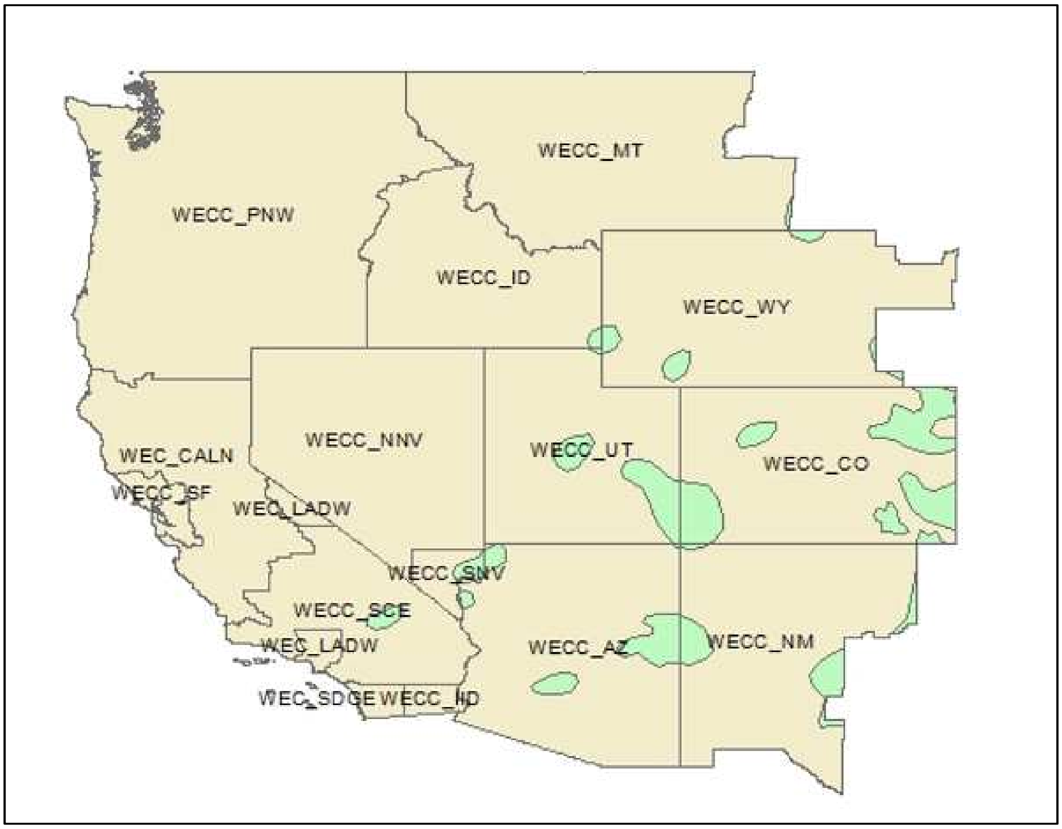

Figure 77: Western United States with possible salt domes/deposits

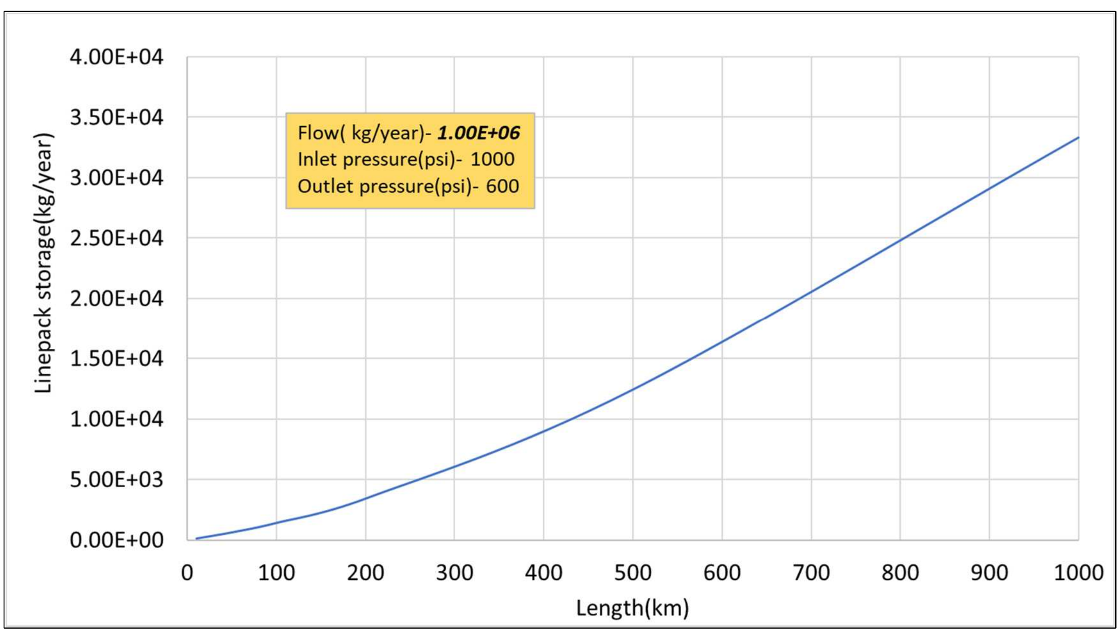

Figure 78: Variation of line pack storage with pipeline length for a one flow rate

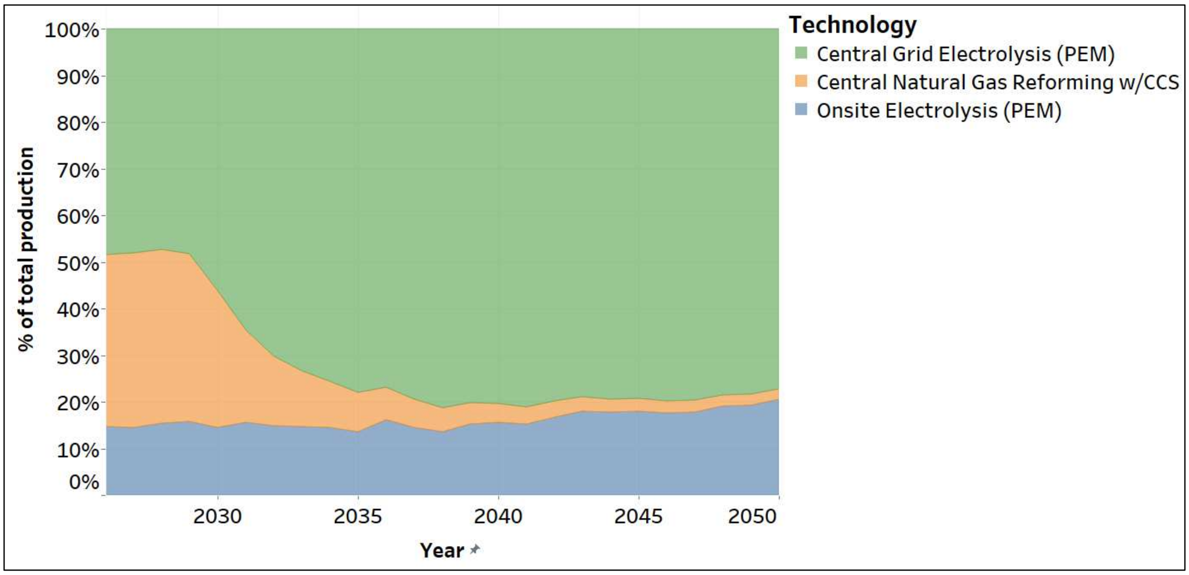

Figure 79: Percentage share of hydrogen production by technology type for scenario Onsite_allow (5-year planning window, on-road transport demand only)

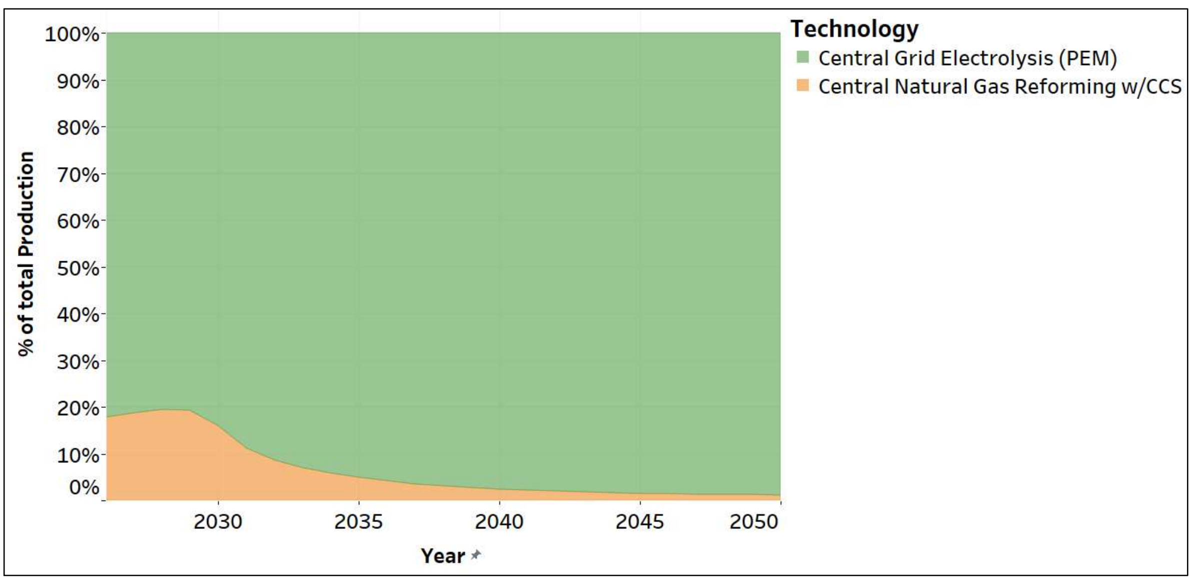

Figure 80:Percentage share of hydrogen production by technology type for scenario IOD_L (5-year planning window, on-road transport demand only)

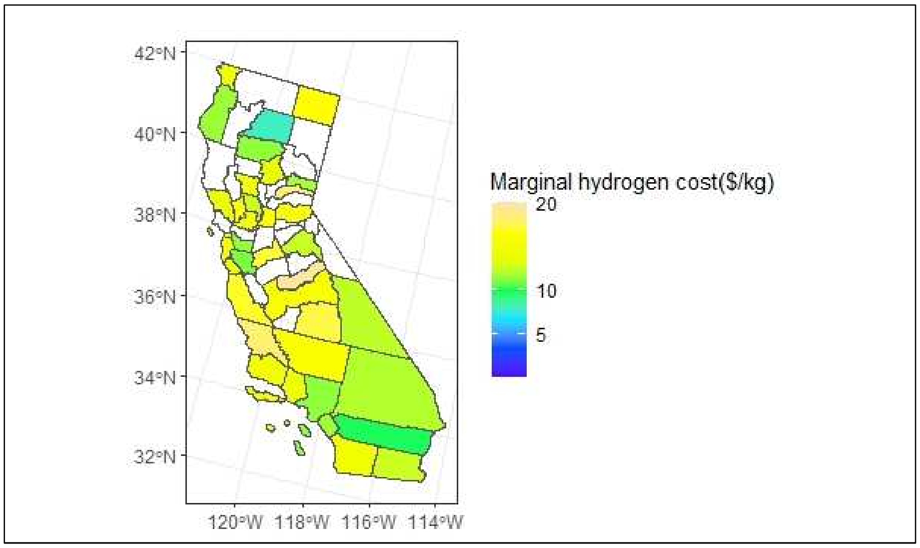

Figure 81: County wise marginal hydrogen costs in 2025 (on road transport demand only with 5-year planning window)

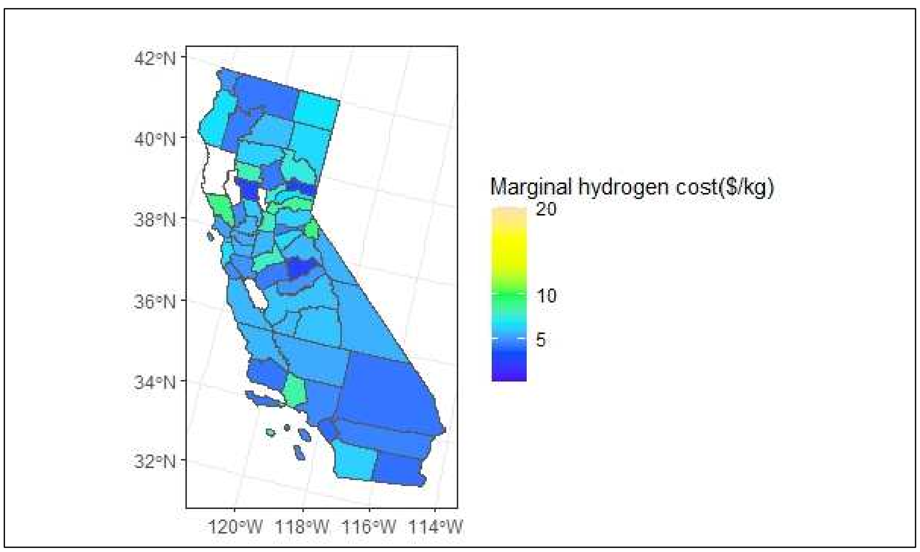

Figure 82: County wise marginal hydrogen costs in 2050 (on road transport demand only with 5-year planning window)

3 S3- Supporting information for Chapter 3

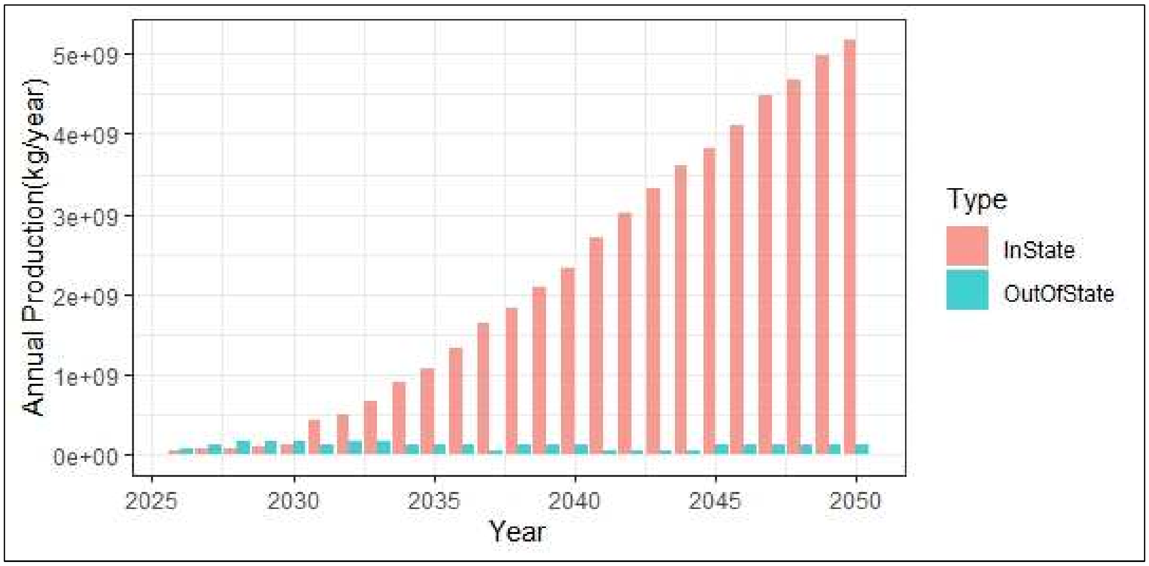

Figure 83: Distribution of in state and out-of-state production/regional imports for scenario POL_0perc_hub

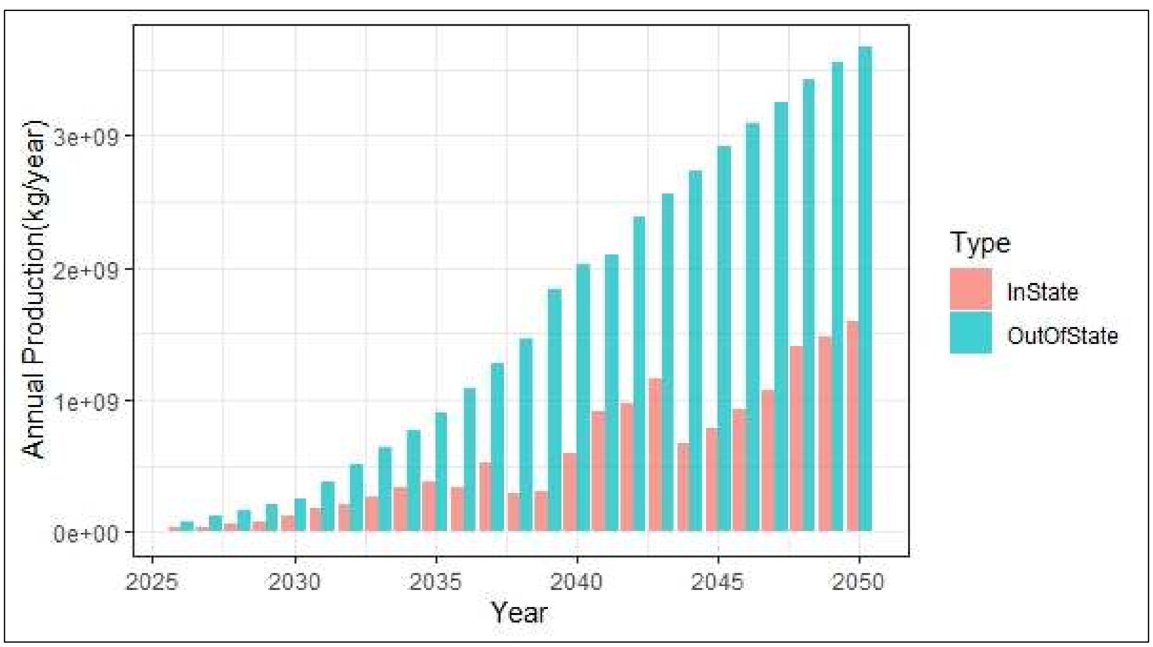

Figure 84: Distribution of in state and out-of-state production/regional imports for scenario POL_75perc_hub

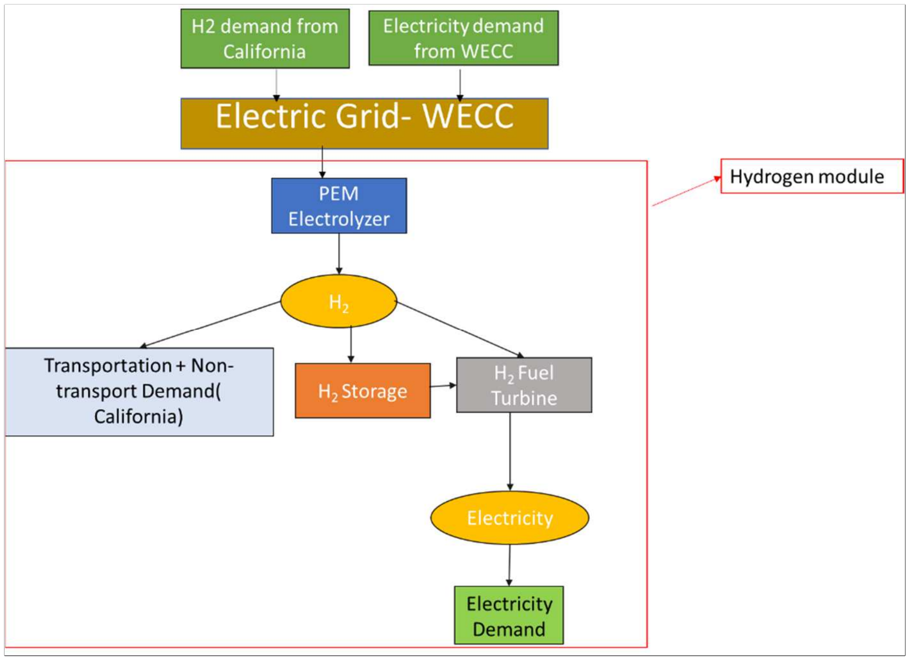

Figure 85: Hydrogen module in GOOD

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