EVALUATING THE BUSINESS AND SOCIETAL CASE FOR HYDROGEN INFRASTRUCTURE IN CALIFORNIA USING AN OPTIMIZATION APPROACH

Dissertation proposal submitted to

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Executive Summary

With increasing emphasis on decarbonization, hydrogen is enjoying unprecedented political and business momentum as a clean energy carrier and storage medium. This is evident from the number of recent large-scale projects and policy announcements by major economic actors (Japan, Germany, EU, Australia) earmarking billions of dollars to ensure greater penetration of hydrogen into the energy stream. Hydrogen's versatility and its deep decarbonization potential, especially in sectors like freight transport, shipping, and aviation has made it one of the central pieces to the decarbonization strategies of many countries. California, with its ambitious 2045 carbon neutrality targets, expects hydrogen to play a major role in helping it achieve those targets.

From a technology standpoint, hydrogen seems to be well positioned. Fuel cell and electrolysis technologies are well known but still expensive, while steam methane reforming technologies are mature. However, beyond traditional uses in petroleum refining and fertilizer production, adoption rates in new markets have been relatively modest in terms of total volumes of hydrogen. The insufficient roll out of infrastructure to support the demand, and the lack of economies of scale, are critical factors that have impeded the uptake of hydrogen. Strong early investments are required, with a clear vision of where and when the hydrogen system buildout will happen. Infrastructure requirements span across the supply chain including production, delivery, and distribution. From a policy perspective, it is paramount to understand the various factors that underlie the roll out of these critical infrastructures. The present study is focused on understanding these factors and establishing a suitable road map for the roll out of hydrogen infrastructure in California. Policies pertaining to the use of hydrogen in one sector can have cross-sectoral impacts, due to versatility of the molecule. A system-level analysis is required to capture the economic competitiveness and environmental impacts of adopting hydrogen across these sectors. This study intends to develop a hydrogen supply chain (HSC) optimization framework that will help answer critical policy questions such as: how many production and distribution facilities need to be built over a lengthy time horizon (say 2050), and when does it make sense to invest in these facilities?

The framework will include hydrogen production, delivery, and distribution pathways relevant to California. Hydrogen production will include technologies like steam methane reforming with carbon capture, and electrolysis using renewable and grid electricity. Geological hydrogen storage along with terminal and pipeline storage will be considered. Three main delivery methods will be analyzed: pipeline, tube trailer and liquid hydrogen tankers. A critical input for the analysis would be hydrogen demand, which will be exogenous and aggregated over transport and non-transport end uses. The HSC model (SERA) will be soft linked to an electricity grid model (GOOD) and a hydrogen refueling station siting model (STIEVE), to obtain critical inputs like electricity rates, carbon intensity, location of refueling stations, sizing of the electrolyzers, and storage capacity.

Two physical forms of hydrogen (liquid and gaseous) will be included in the analysis and the model will endogenously determine the most optimum form for storage and distribution of hydrogen. The optimization problem will minimize total system costs over time with environmental and economic constraints. A deterministic modelling approach through scenario building will be employed. This modelling effort will rely on data from a wide range of sources like solar/wind electricity generation patterns, investment costs of different facilities, feed stock availability, and geographic information on distribution networks. The study will feed from inputs and at times add value to existing hydrogen roadmap studies already published by government agencies and coalition groups like the Hydrogen council and California fuel cell partnership.

This work will look to answer some of the questions surrounding the “chicken and egg” enigma, associated with hydrogen infrastructure availability and hydrogen demand. Earlier works have delved into some aspects of this problem, but often, these studies treated many of the underlying factors in isolation. Most studies consider a singular end use application of hydrogen (like in light duty vehicles), leading to sub optimal outcomes. Currently most of the hydrogen infrastructure investments in the state are driven by the California Energy Commission (CEC) through the provisions of AB 8, and by the California Air Resources Board (CARB) through Low Carbon Fuel Standard (LCFS) hydrogen refueling infrastructure credits. As these agencies look to optimize their funding mechanisms, this study will aid them while making those critical investment decisions. Of late, there has been a spike in private investments for developing hydrogen refueling stations and production facilities. This study will offer prospective investors and policymakers a broad and comprehensive landscape of the suitable technologies and capacity expansion possibilities over time. Put together, this study will help synergize public and private investments for hydrogen infrastructure and thereby support California’s vision of achieving carbon neutrality by 2045.

Introduction

California's latest greenhouse gas data shows that the state was able to achieve its targets for 2020 as set out in the Global Warming Solutions Act of 2006 (AB 32) [1] [2] . But California being true to its reputation as a global leader in the fight against climate change, has set itself even more ambitious targets for the future. In September 2018, Governor Brown signed into effect the SB 100 and the EO B-55-18, to put California on track to achieve carbon neutrality for the electricity grid and other sectors by 2045. To achieve this, decarbonization strategies should be able to address an energy transition that transcends traditional boundaries and enable cross sectoral collaborations. Hydrogen molecule is a perfect fit for such a decarbonization strategy as it has cross sectoral applications, both as an energy carrier and storage medium. Hydrogen's role as a deep decarbonization opportunity is especially important in hard to electrify sectors like freight transportation, steel industry, shipping, and aviation. Hydrogen is being increasingly promoted as a feasible decarbonizing strategy by major economies and investments worth $300 billion (which is roughly 1.4 percent of global energy funding) are envisaged through 2030 [3]. All these are positive indicators to the role that hydrogen can play to decarbonize the future energy pathways. This is not to say that hydrogen adoption is devoid of any challenges.

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 "valley of death" aggravates the complexities of a hydrogen-based energy transition. One way to address these barriers is to strategize the roll out 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. It is widely acknowledged that early hydrogen infrastructure development will be inherently regional and will often be accomplished through public–private partnerships [4]. California has enacted several policies like the AB-8 and LCFS HRI credits to fund the early buildout of hydrogen refueling stations in the state. But refueling station development, though critical, constitutes only one part of a very complex and interconnected hydrogen supply chain.

Hydrogen supply chain network design (HSCND) also referred to as strategic supply chain planning is one of the most crucial aspects for the deployment of hydrogen infrastructure [5]. The complexity of hydrogen supply chain network design depends on modeling of the interactions that exist between the different echelons of the HSCN, that begins at the feedstock level and ends at the selling of hydrogen for different end uses in the transportation sector, building heating and other industrial applications. The different echelons in a HSCND are hydrogen production, storage, distribution, and end use. There are multiple choices available in each echelon. A typical analysis of a HSCN for the transportation sector would involve water (with electricity), natural gas, biomass, and coal as feedstock for the production process using electrolysis, steam methane reforming or gasification. Hydrogen in different physical forms (gaseous, liquid, liquid organic hydrogen carriers) could be stored in terminals or geological storages (salt caverns, aquifers, depleted gas fields) before being transported (via trucks, trains, or pipelines) to the refueling stations. Refueling stations could also have onsite hydrogen production. Therefore, with so many choices available at each level of the network, the selection process is a complex optimization problem. The complexity is further accentuated by temporal and spatial variations of these choices. The capacity expansion of the HSCN is greatly affected by hydrogen demand, which could be from various sectors like transportation, building heating, refineries and other industries [6].

The present study will design a HSCN for California based on feasible technology options for hydrogen production, storage, and distribution. The HSC will look to serve transport and non-transport hydrogen demand. The network will be optimized to reduce overall system costs and will look to answer questions on capacity expansion for the different echelons of the HSC through 2050. The study proceeds with a literature survey that describes the different approaches to HSCN optimization (refer Figure 1). Insights from the literature survey are used to formulate a set of research questions that are of interest in the Californian context. Chapters 1,2 and 3 describe the approach towards answering the research questions formulated in the preceding section.

Literature Survey

There are three broad categories of HSCND modelling approaches, using energy system optimization models, refueling station location models and geographically explicit optimization models [7]. Energy system models optimize hydrogen supply chains mostly at a national 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. Details of some of the seminal works in this area can be found in Appendix 1. 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. A large portion of studies focus on optimizing the roll out of hydrogen refueling stations (HRS) as the transportation sector is slated to be the major driver for hydrogen demand and the roll out of refueling infrastructure is a critical piece of this transition [8] [9] [10]. The different approaches to identifying optimal locations for HRS can be referred in Figure 1 and descriptions of earlier work in this area can be found in Appendix 2.

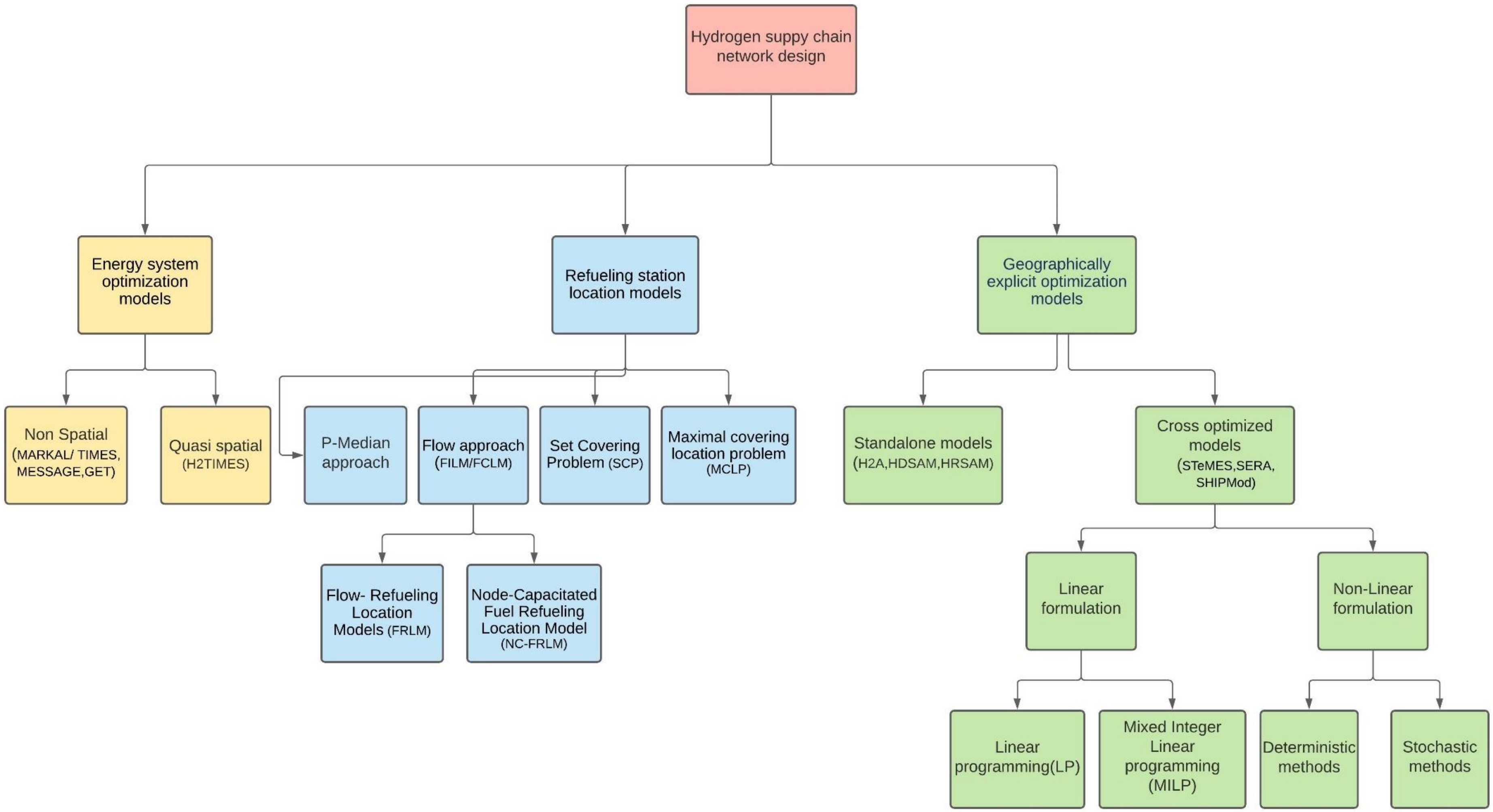

Figure 1: Approaches to HSCND and optimization

This approach only considers one echelon of the HSCN (i.e., refueling stations) and do not provide information on other critical infrastructure requirements for hydrogen production and delivery.

A more holistic approach, especially from an infrastructure point of view is considered in the geographically explicit optimization models. 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 implemented through a spreadsheet model (standalone) or by adopting a formal optimization methodology. The standalone models allow the computation of infrastructure costs, hydrogen prices and a series of additional metrics, like environmental emissions, related to a given hydrogen pathway. A formal optimization procedure (cross optimization) can incorporate all these indicators and additionally can optimize the configuration of the entire hydrogen system rather than being assumed exogenously [7].

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 publicly available, and users can assess the cost of producing and delivering hydrogen for different scenarios pertinent to the 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, hydrogen delivery scenario analysis model (HDSAM) and Hydrogen Refueling Station Analysis Model (HRSAM)respectively [11] [12] [13]. 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, distribution) are considered in isolation. A major drawback for these models is the inability to select a hydrogen pathway in an optimized manner. In fact, these models are setup in a way where the hydrogen pathway (production technology, delivery method, refueling station type) is a user defined exogenous input. But the outputs from these models can provide the necessary background information (capitals costs, carbon intensities, plant footprint) for the development of a full scale cross optimized model for a region.

Cross optimized models determine the optimal configuration of the HSCN, 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 2) [14]. Several regions have been used as back-drops to these models, arriving at different conclusions about what the ideal hydrogen economy might look like. This is suggestive of the fact that it is yet unclear as to what the hydrogen economy will look like and it is plausible that hydrogen pathways will be tailored according to the needs of each region [15]

Appendix 3 contains the methodological details for this modelling approach and how it has been implemented across different geographies like Great Britain, US, Germany, and the rest of the world.

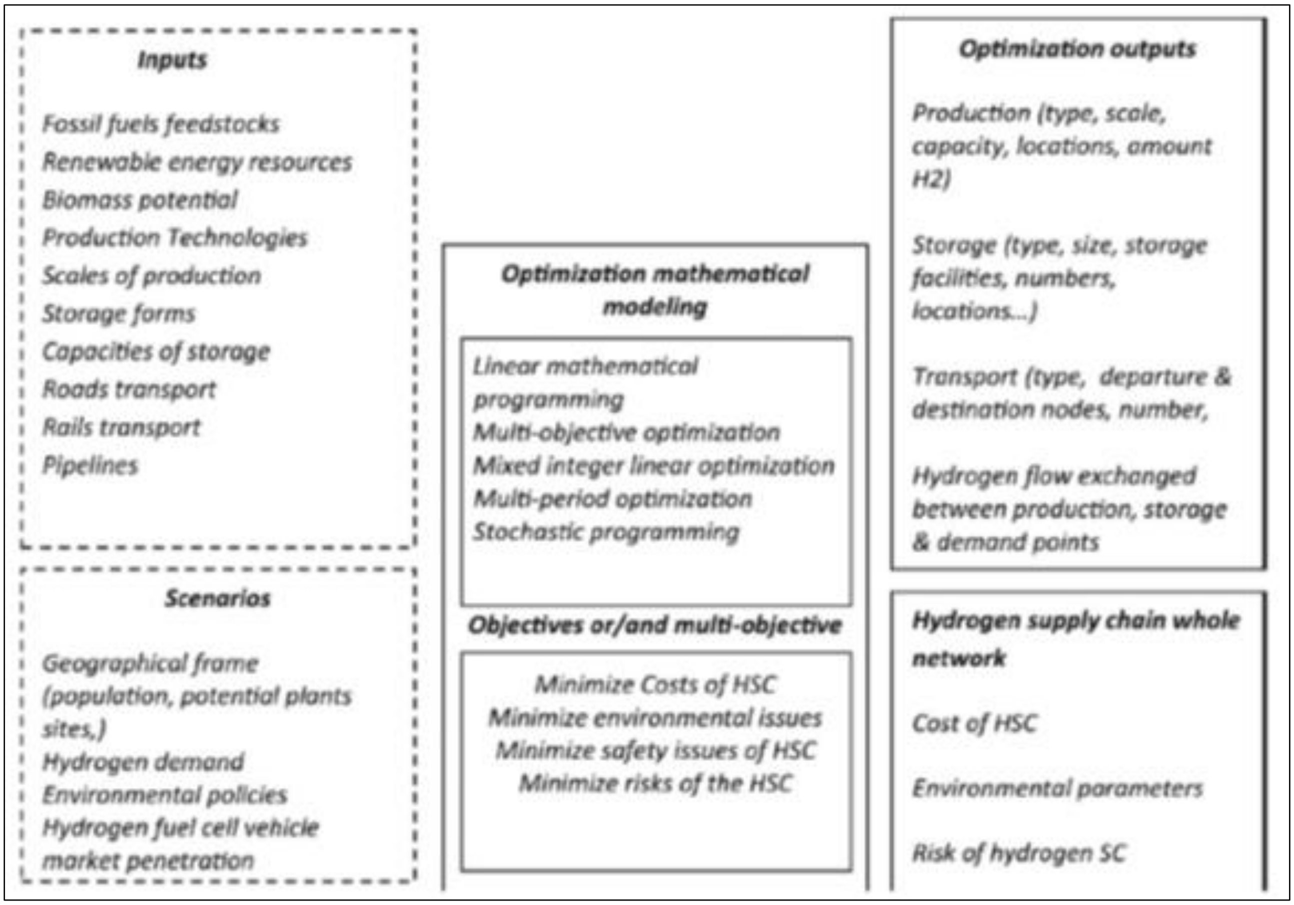

Figure 2: General layout of a cross optimization model with inputs and outputs[14]

Summary of literature findings and Research Questions

The motivation of this study is to evaluate the evolution of a future hydrogen supply chain network (from hydrogen production to end use) in California, given a certain projected demand for hydrogen. In this context, it is evident from literature that a cross optimization modelling approach would be more appropriate. Additionally, it is important to gauge the different hydrogen pathway options (production, storage, and distribution) that are available, and knowledge of their techno commercial viability is paramount before consideration into the optimization framework. Therefore, a scenario analysis of the various options using standalone models (H2A, HDSAM, HRSAM,HDRSAM) will provide the necessary background information and will also help inform the choices to be considered for the cross-optimization framework. It is evident from literature survey that such an optimization model must be able to accommodate:

- A long-term future planning horizon.
- State of the existing infrastructure, especially, the natural gas distribution network, and the electricity grid
- Multiple primary energy feedstocks and production technologies.
- Large-scale centralized and small-scale distributed/onsite/forecourt production.
- Different forms of hydrogen: gaseous/liquid
- Economies of scale for the different echelons of the supply chain.
- Geographical site allocation of technologies.
- Multiple performance indicators – financial, environmental, social – that can drive the decision-making.

In addition to the above, most studies have included certain specific components to the HSCN analysis that are relevant to the geography under consideration. Likewise, this study will incorporate three factors that are important in the Californian context. Firstly, hydrogen demand from non-transport sectors like power generation will be included in addition to demand from the transportation sector. As per the California Energy Commission's report [6], hydrogen demand as a combustion fuel for electricity generation would reach 500 million kilograms by 2050, which is nearly a quarter of the demand from the transportation sector for the same time period. The second factor that would be considered is global import and export of hydrogen. California's geographic location enables it to tap into both the import and export hydrogen market, and this would be a critical factor in the HSCND for the future [3]. Thirdly, the benefits of employing hydrogen as a seasonal energy storage medium will be explored. This is an important lever to balance the electricity grid as it becomes increasingly renewables based (solar and wind) to achieve carbon neutrality by 2045, as mandated by SB 100.

In short, this modeling effort will look to answer the following research questions,

1. Which are the cost-effective pathways for hydrogen production, storage, and distribution in the Californian context?
2. How, when, and where will the capacity expansion of hydrogen production and delivery infrastructures happen in California, over a 2050-time frame?
3. How can cross sectoral hydrogen demand from non-transportation sectors with provisions for imports, affect the roll out of HSCN in California?
4. To what degree can seasonal hydrogen storage (geological and line pack) enhance electricity production through wind and solar?

The subsequent sections are divided into three chapters. Chapter one will look to answer research question one, using standalone models H2A, HDSAM, HRSAM and HDRSAM. Chapter two will delve into building the full-scale infrastructure optimization framework and address research questions two and three. Chapter three will require modifying the initial optimization framework to include seasonal hydrogen storage and analyzing its effects on the overall supply chain.

Chapter 1: Scenario analysis of hydrogen pathways using standalone models.

Background

California has enacted several policies to encourage the adoption of zero-emission vehicles and low carbon fuels, such as the Zero Emissions Vehicle (ZEV) mandate, LCFS, Advanced Clean Truck regulation (ACT), and the Clean Vehicle Rebate program (CVRP). California accounts for almost the entire US market for fuel-cell vehicles, with approximately 9000 vehicles on road as of 2020 [16]. Globally as well as in California, the transportation sector is projected to be the largest consumer of hydrogen by 2050 [8] [6]. Hence, in this section hydrogen demand from the transportation sector in California is projected up until 2050 and a suite of plausible hydrogen pathways that can satisfy this demand is evaluated. This section will perform a scenario analysis to understand the cost implications of learning rates and scale up for different hydrogen pathways that are suitable for California. The modelling approach for this section is illustrated in Figure 3.

Modelling Methodology

Hydrogen demand for the transportation sector is projected using the Transportation Transition Model (TTM). TTM is a stock turnover model developed by researchers at the University of California, Davis, largely based on the VISION model by Argonne National Laboratory, but with additional modifications to simulate low carbon scenarios for California [17]. TTM allows for investigation of various scenarios of market penetration of new vehicle technologies through 2050. For the current study, a low and high scenario of market penetration of ZEVs is assumed for different vehicle categories. Assumptions of ZEV sales shares are driven by existing California policies, considering these policies achieve the targets in the respective vehicle category. Further, each scenario is associated with a certain market penetration of fuel cell vehicles within the overall ZEV sales share in the state. The ZEV and the FCEV sales shares in California for the low and high scenarios are tabulated in Appendix 4. TTM also projects fuel economy, vehicle stock and vehicle miles travelled (VMT)for each vehicle type through 2050. The yearly hydrogen demand is calculated for each vehicle category based on the vehicle stock, fuel economy and VMT. After this, the number of hydrogen production facilities and refueling stations required to satisfy this demand are projected through 2050. The next step in the analysis is to evaluate the different possible hydrogen pathways that are available to satisfy this demand. Hydrogen pathways may differ based on the type of production technology, mode of delivery or distribution type. Each echelon of the hydrogen pathway/supply chain is analyzed separately using standalone models. The pathways are evaluated for three different time periods. Near Term (2025-2030), mid-term (2030-2040), and long-term (2040-2050).

For hydrogen production, two low carbon technologies, namely steam methane reforming (SMR) of natural gas with carbon capture and electrolysis, are considered [18] [6]. The other low carbon hydrogen production technique that is relevant for California is the reformation of renewable natural gas (RNG). Previous studies show that the quantity of RNG that can be produced from dairy manure, municipal solid waste, wastewater treatment plants, and landfill in California will roughly amount to only four percent of the state's total gas demand [19]. Hence RNG is not considered as a possible feedstock for hydrogen production for this study. Central and distributed/forecourt mode of 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 the planning phase [20] [21]. H2A model developed by National Renewable Energy Laboratory (NREL) 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 tpd to 300 tpd) and can incorporate carbon capture calculations, whereas the distributed model is suited for smaller production plants (range of 0.5 tpd to 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. Researchers can choose the relevant technologies in their respective regions and modify the input parameters suitably to obtain the production costs. A recent study by CEC employed the H2A model to analyze the cost of hydrogen production using proton exchange membrane (PEM) electrolyzers [6]. H2A model inputs employed for this study are detailed in Appendix 5.

Hydrogen delivery is an essential component of any future hydrogen energy infrastructure. 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) 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.

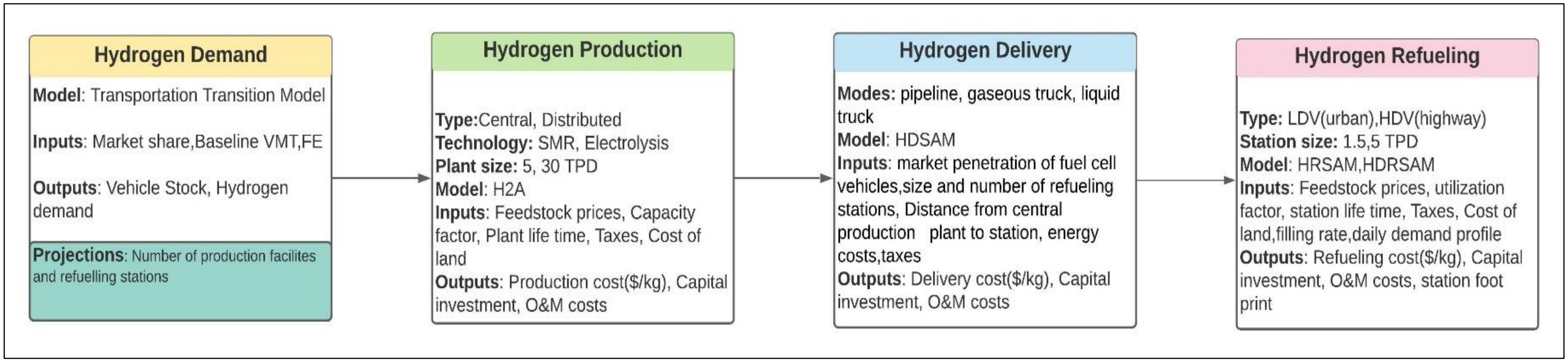

Figure 3: Modelling framework for scenario analysis of hydrogen pathways

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 and market penetration of fuel cell vehicles [22]. The present study considers three delivery options namely pipeline, tube trailer and liquid tanker. The detailed breakdown of the delivery pathways and the inputs to HDSAM are provided in Appendix 6: Inputs to HDSAM

The annual amount of hydrogen dispensed by retail hydrogen refueling stations in California has registered a multifold increase, growing from 27,400 kg in 2015 to more than 440,000 kg in 2017 [23]. Most stations currently in operation use gaseous hydrogen delivered from a central SMR plant. A very few stations today have hydrogen delivered using pipelines [24]. Delivered liquid hydrogen is likely to be a preferred configuration for stations with high throughput (i.e., kg per day) and limited space[25]. Given this background, the present study will consider both gaseous and liquid hydrogen delivery scenarios to the refueling stations. Two station capacities are considered, a 1.5 tpd and a 5 tpd station. The smaller station is representative of a typical urban refueling station catering mostly to light duty vehicles. This daily dispensing capacity is fairly in line with the upper limit eligibility for stations to qualify for LCFS HRI credits [26].

There are not many big stations (greater than 2 tpd) currently operating, but a 5 tpd station can be representative of a refueling station catering to heavy duty vehicle fleets [21]. These stations are expected to be built along highways or as a base refueling station for transit buses or truck fleets. Given the suburban nature of these stations, there could be sufficient land available to have onsite hydrogen production alongside the refueling station. Thus, onsite hydrogen production is accounted as a possibility for the bigger stations in this study.

The refueling cost component for dispensed hydrogen is calculated using HRSAM and HDRSAM, for the smaller and bigger stations, respectively [27]. 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 kilogram of hydrogen, years required to break even on investment, total capital investment, and the station footprint. Reddi et al [25] 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 [28] 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 the different station configurations in HRSAM and HDRSAM (refer Appendix 7: Inputs to HRSAM and HDRSAM).

Mixing and matching the different options available at each echelon of the HSCN (production, delivery and refueling) generates a total of fourteen hydrogen pathway scenarios. The details of the pathways can be found below in *Table 1*.

The cost estimates by H2A, HDSAM, HRSAM and HDRSAM models mask the fact that these values can range significantly depending on assumptions and depending on the circumstances that occur during actual construction and operation of the different hydrogen infrastructures. Therefore, a sensitivity analysis using tornedo charts is carried out to ascertain the relative importance of different underlying factors that determine the cost of hydrogen production, delivery and refueling.

Table 1: Hydrogen pathways identified for the analysis.

Pathway name	Production technology	Delivery mode	Refueling type
1.5 tpd refueling station			
STG	SMR (CC), central production	Tube trailer	Gaseous
SLG	SMR (CC), central production	Liq.H_2 truck	Gaseous
SPG	SMR (CC), central production	Pipeline	Gaseous
ETG	Electrolysis (PEM), central production	Tube trailer	Gaseous
ELG	Electrolysis (PEM), central production	Liq.H_2 truck	Gaseous
EPG	Electrolysis (PEM), central production	Pipeline	Gaseous
5 tpd refueling station			
SLL	SMR (CC), central production	Liq.H_2 truck	Liquid
SPG	SMR (CC), central production	Pipeline	Gaseous
ELL	Electrolysis (PEM), central production	Liq.H_2 truck	Liquid
EPG	Electrolysis (PEM), central production	Pipeline	Gaseous
SG	SMR, onsite production	-	Gaseous
SL	SMR, onsite production	-	Liquid
EG	Electrolysis (PEM), onsite production	-	Gaseous
EL	Electrolysis (PEM, onsite production	-	Liquid

Preliminary results

Figure 4 illustrates the projected annual hydrogen demand from road transport using the TTM model for the high fuel cell penetration scenario. Annual demand grows from 32 million kilograms in 2025 to 3671 million kilograms in 2050.

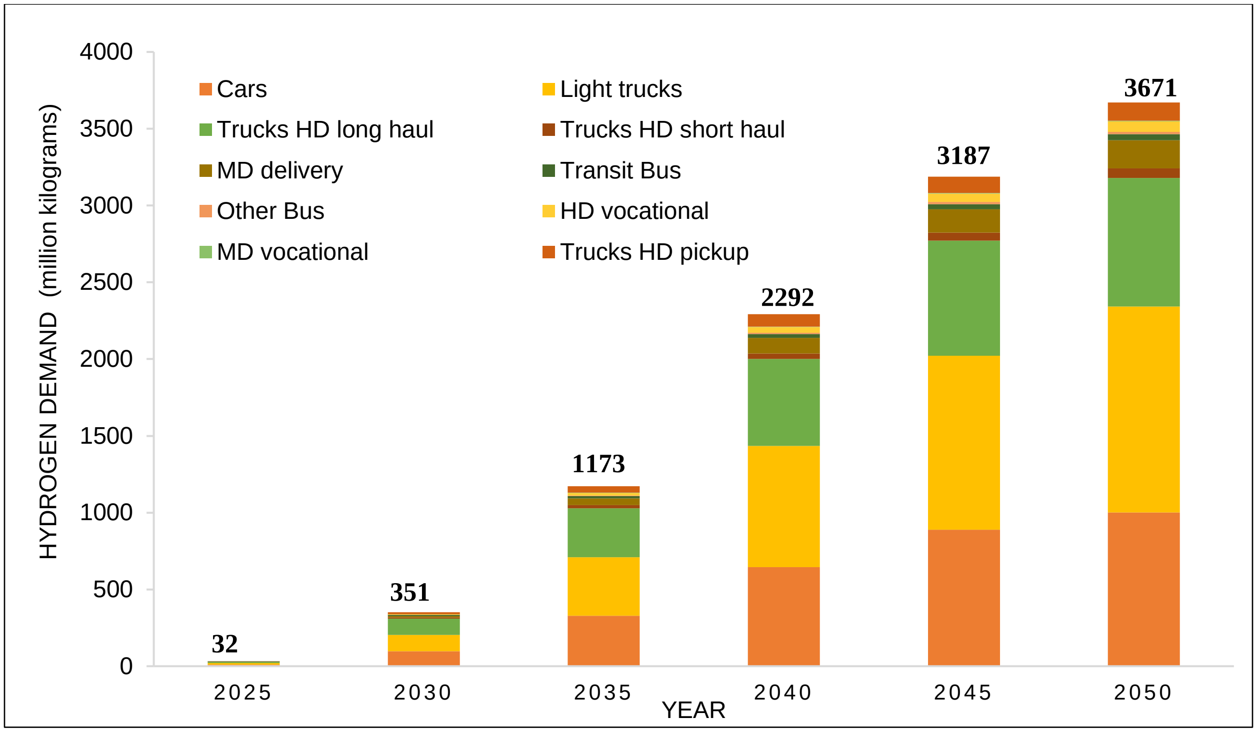

Figure 4: Annual hydrogen demand from the transportation sector in California (High case)

This is ~18% of today's demand for gasoline and diesel in California. Cars, light duty trucks and long-haul trucks are the major consumers of hydrogen for all time periods. The total demand of hydrogen projected are in line with some of the earlier studies done for the state [6]. But the disaggregation of demand among different vehicle categories as presented here is insightful, especially while planning for infrastructure requirements (like refueling) for these vehicles, which can be substantially different for each vehicle category.

Figure 5 and Figure 6 show the price of dispensed hydrogen using different hydrogen pathways at a refueling station with 1.5 tpd and 5 tpd capacities, respectively. The dispensed cost of hydrogen at the pump is found by adding production, delivery and refueling station costs. The costs for each function (production, delivery, refueling) is represented on a $ per kg basis. The cost of hydrogen at the nozzle falls to $3.68 (refer Figure 5) after 2040 in 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 and pipeline systems are built, and high-capacity factors are achieved across the supply chain. The cost at a bigger station (refer Figure 6) falls even lower to $2.49, owing to economies of scale achieved at the station level.

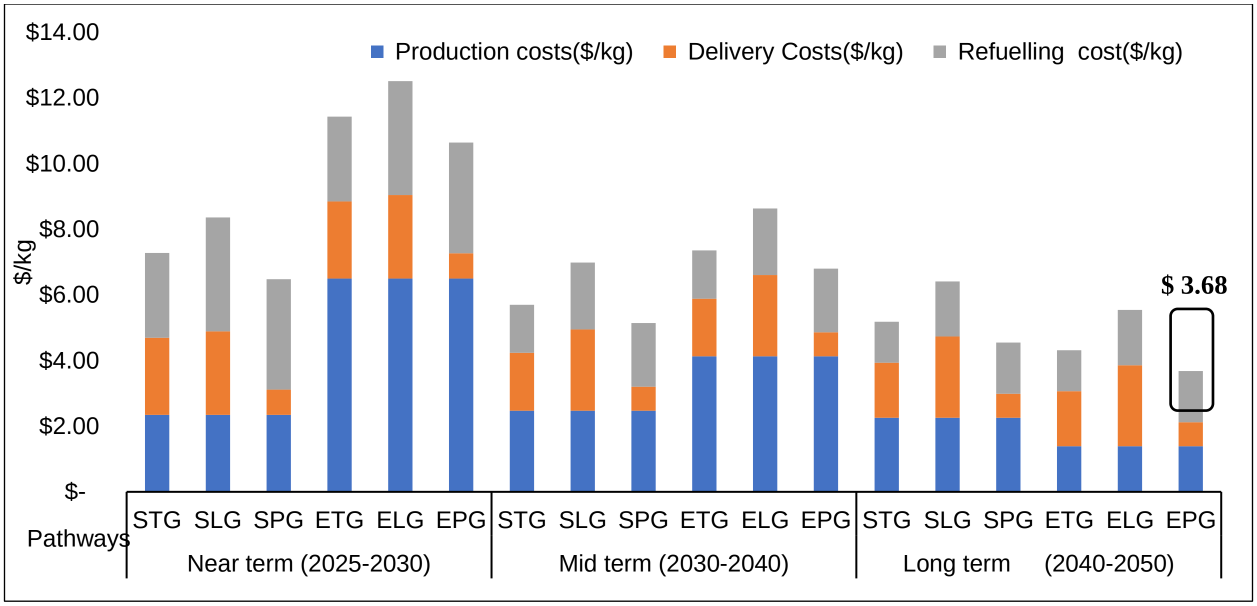

Figure 5: Hydrogen dispensed costs at a 1.5 tpd refueling station using different pathways.

Pipeline delivery of gaseous hydrogen is cost effective especially when utilization rates at the refueling stations are high. Refueling costs are found to vary considerably on the state of hydrogen (gaseous or liquid) delivered to the station. 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 and feedstock prices.

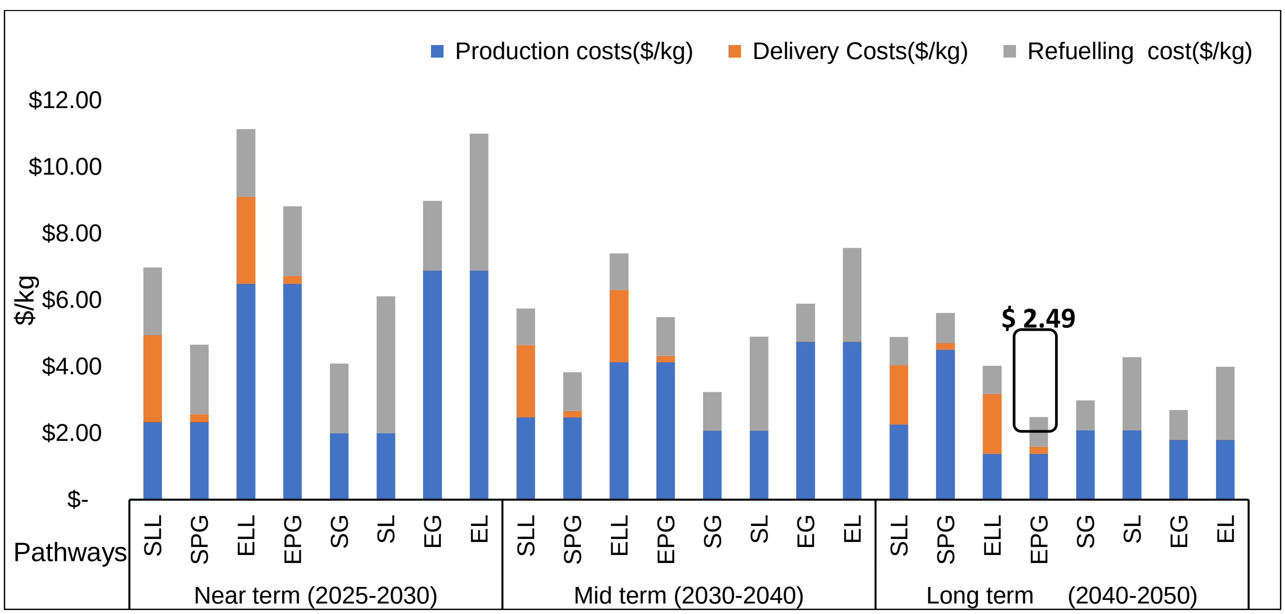

Figure 6:Hydrogen dispensed costs at a 5 tpd refueling station using different pathways.

Sensitivity analysis for hydrogen production costs.

Tornedo charts for four different production scenarios are plotted and analyzed. Sensitivity relationships for a central production plant using SMR and electrolysis technologies are illustrated in Figure 7 and Figure 8. A similar analysis for forecourt production is also carried out and the results are shown in Appendix 8: Sensitivity Analysis for forecourt hydrogen production costs. The range for each parameter chosen for the sensitivity analysis is indicated within the tornedo chart.

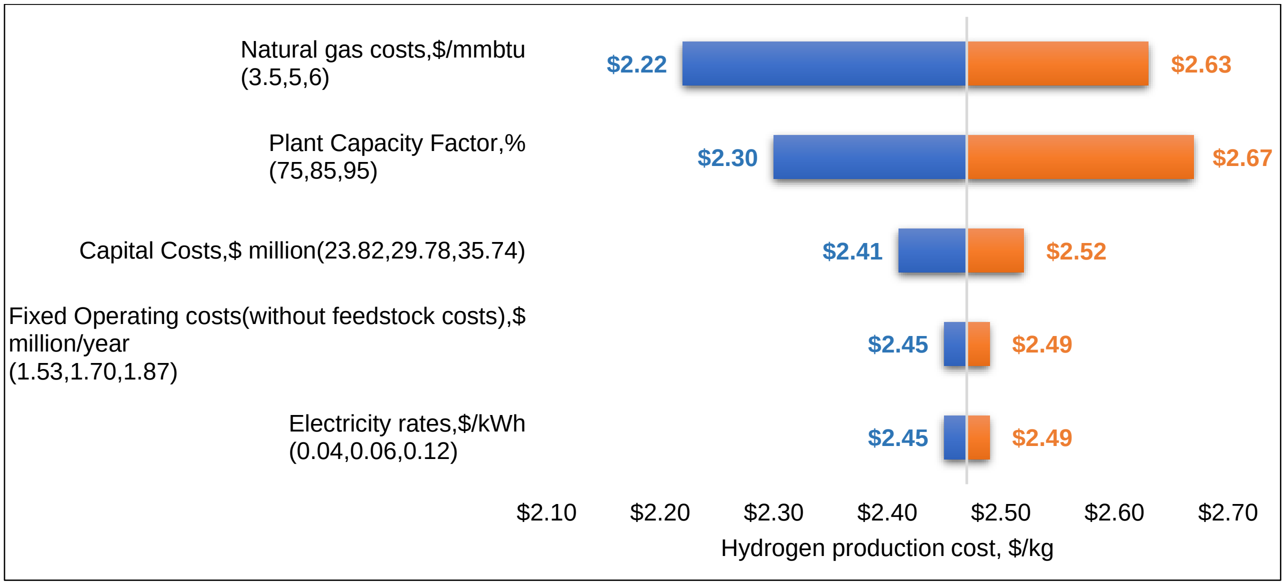

Figure 7: Range of hydrogen production costs for a 30 tpd SMR plant

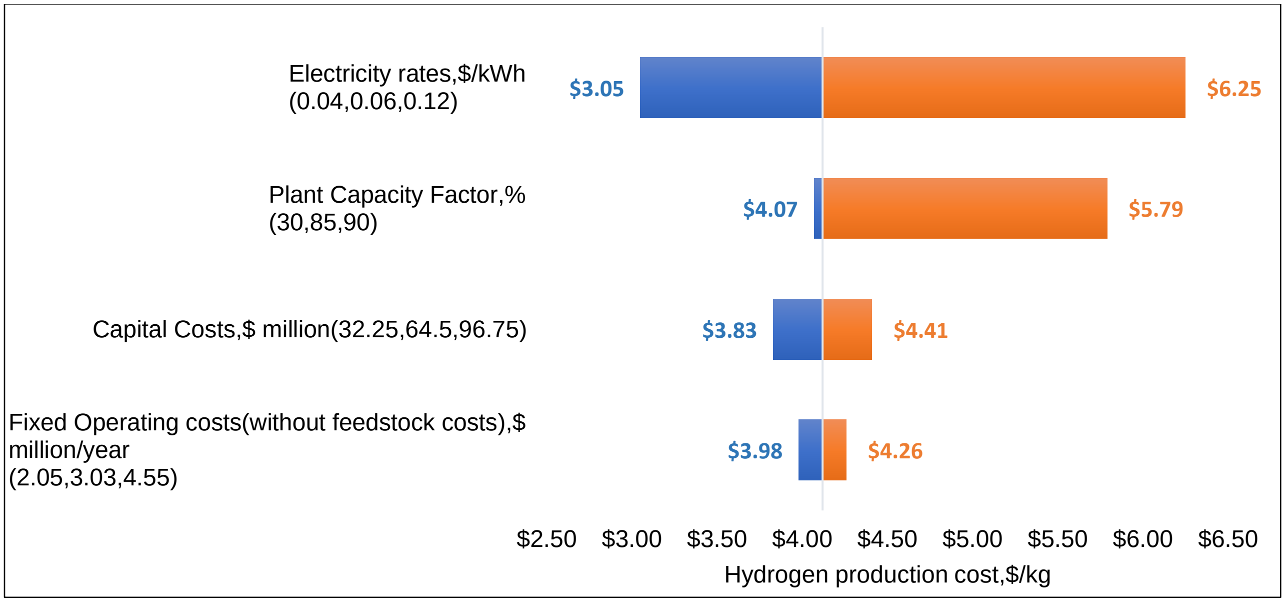

Figure 8:: Range of hydrogen production costs for a 30 tpd PEM electrolysis plant

Feedstock prices (natural gas and electricity) have the highest sensitivity ranking for centralized hydrogen production. This is followed by plant capacity factor and 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 wide 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.

Sensitivity analysis for hydrogen delivery costs.

Sensitivity analysis is performed for three delivery modes: Pipeline, liquid hydrogen tanker and gaseous trailer. Here, hydrogen delivery will be made to a 1.5 tpd refueling station located in Sacramento. The relative importance of the different factors affecting the delivery costs while employing pipelines is illustrated in Figure 9. Sensitivity results for the other delivery modes are provided in Appendix 9: Sensitivity Analysis for hydrogen delivery costs using tube trailer and liquid tanker

For pipelines, the market adoption of fuel cell vehicles is the most influential factor. Market adoption 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 share would result in 9 refueling stations in Sacramento. Similarly, a 20 % and 50 % market share will result in 36 and 89 stations, respectively.

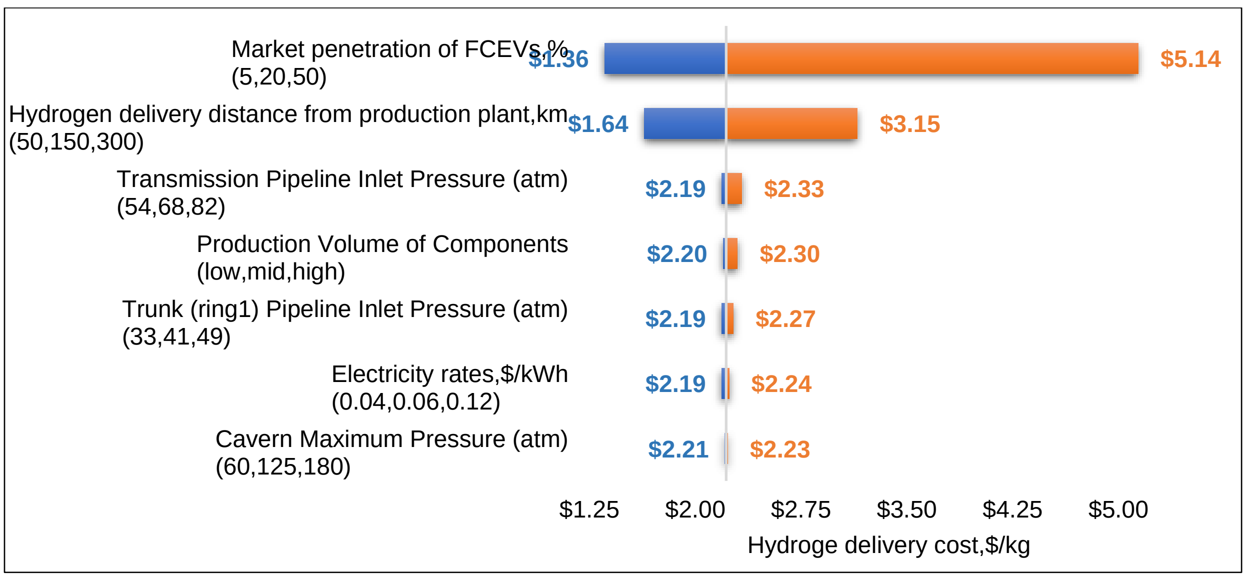

Figure 9: Range of pipeline delivery costs to a 1.5 tpd refueling station.

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.

Sensitivity analysis for hydrogen refueling costs.

Sensitivity analysis is 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 bar and the maximum filling rate per dispenser is 2 kg/min. Sensitivity analysis for a larger station (5 tpd) will also be carried out in future. Figure 10 illustrates the variation in hydrogen refueling costs for a station receiving gaseous hydrogen via pipelines. Results for other scenarios are shown in Appendix 10: Sensitivity Analysis for hydrogen refueling costs.

It is evident that station utilization factor is the most influential parameter for refueling station costs, on a $/kg basis of dispensed hydrogen. The capital cost to build a station is also a significant contributor to refueling station costs.

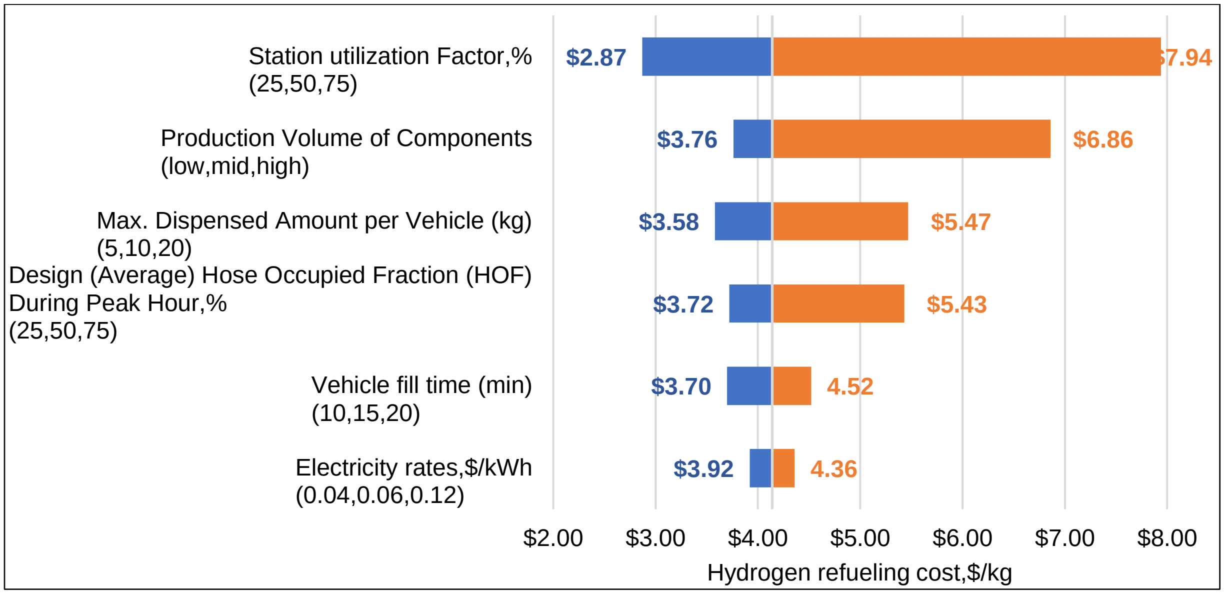

Figure 10: Range of Refueling costs for a 1.5 tpd station having gaseous hydrogen delivered using pipelines.

In this analysis, the variation in capital costs is captured 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. 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 0.23445, respectively. The subsequent cost reduction that happens for each basket is tabled in Appendix 11: Cost reduction factors for station components. Maximum dispensed amount of hydrogen per vehicle impacts both the cascade storage requirements at the station and the number of dispensers. Higher HOF reduces the number of dispensers required in the station. Vehicle fill time considered in this study includes the time to fill the tank and the dispenser resetting time after successive refills. It is observed that increased vehicle fill times results in higher refueling costs per kilogram 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.

Major learnings and Future Work

Hydrogen demand from the transportation sector in California is expected to be driven by cars, light duty trucks and long haul (Class-8) trucks in both low carbon scenarios analyzed here. Hydrogen production costs from an electrolysis plant fall drastically (from $6.5 to $1.5 per kg of hydrogen) from 2025 to 2050. SMR based plants remain the more cost-effective option until 2040. There isn't a substantial impact of economies of scale observed between the smaller (distributed) and larger central facilities for the plant sizes considered here (5 tpd versus 30 tpd). The benefits of scale kick in for much larger plant sizes like 200 tpd and above, and scale effects are more pronounced for electrolysis plants. The cost of carbon capture (without sequestration) in the larger SMR plants amount to roughly $.10 per kg. Sensitivity analysis on hydrogen production costs reveals a similar trend for both central plant technologies. Feed stock (electricity and natural gas) prices are the most dominant factor that contributes to the levelized cost of hydrogen production, followed by plant capacity factor and capital investment.

The cost of hydrogen delivery to the refueling station using pipelines is less than a dollar per kilogram of hydrogen, provided the pipelines are already laid and are operated close to its fullest capacities. The size of the hydrogen market does not scale linearly for delivery costs using gaseous tube trailers. This is because tube trailers have limited hydrogen carrying capacity (as compared to a similar sized liquid tanker or pipelines) and thereby limit the number of deliveries that can be made in a day to the refueling station. The sensitivity ranking follows similar trends for liquid tankers and pipeline delivery. The size of the hydrogen market and delivery distance are the most important factors that affect the delivery costs while using these options. For liquid tankers, the delivery 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.

On an average, the cost of dispensed hydrogen falls by 15% on account of 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 cost effective, 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 unequivocally 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.

Scenario analysis (using standalone models) will be continued and fine-tuned based on feedback from industry partners and other stake holders. While this analysis using standalone models provide critical insights on the techno commercial aspects of the HSCN, it does not answer questions like where to build a production facility, when to lay a pipeline and how does the capacity expansion progress over time. To analyze these questions a full scale HSCN needs to be designed and optimized both spatially and temporally. The data generated here (capital investments, carbon intensities, plant footprints) using standalone models will be used for the full-scale supply chain optimization work in the next section.

Chapter 2: Hydrogen supply chain network design and optimization with cross sectoral demand and global imports.

Background

This section will build on the knowledge from the previous section to design and optimize a HSCN by including different feasible hydrogen pathways and factors germane to California. The proposed HSCN is depicted in Figure 11. Building a supply chain involves defining a series of nodes and connecting networks within a geographical area (California in this case). The nodes could be infrastructure installations like hydrogen production facilities, refueling stations or storage terminals. Each node needs to identify itself with a technology description, name plate capacity and economic parameters like capital and operating costs. The network will connect the various nodes with suitable capacity constraints. For this study, the HSCN for California will be developed using the Scenario Evaluation & Regional Analysis (SERA) model. SERA is a cross optimization model and is set up like models employed in other geographical regions for hydrogen supply chain optimization studies (refer Appendix 3: Cross-Optimization models). The HSCN needs to be optimized on a spatial as well as on a temporal scale, to gain insights about hydrogen infrastructure requirements for the future.

Hydrogen is a very versatile molecule that has cross sectoral applications. A system level analysis should be able to capture the implications of adopting hydrogen across different sectors like transportation, the electricity and natural gas grids. As indicated earlier, this study will include hydrogen demand from transport and non-transport sectors. This would mean defining suitable nodes in the HSCN that will be demand points to which hydrogen will be delivered using the supply chain network. To identify demand nodes from the transportation sector, the Spatial Transportation, Infrastructure, Energy, Vehicles and Emissions (STIEVE) model will be employed. Non transport hydrogen demand such as for building heating and as a combustion fuel for power generation will be determined based on simplified assumptions, whereby hydrogen will be assumed to replace a certain portion of natural gas demand in the future [6]. Additionally, the possibility of hydrogen imports and exports also need to be suitably incorporated using specific nodes and by adding suitable constraints while optimizing the supply chain using SERA.

Hydrogen can also serve as a feasible long term storage medium to balance the electricity grid, as it becomes increasingly renewables based in the future [29]. To capture this in the supply chain, SERA will require spatially and temporally resolved inputs like the amount of hydrogen storage, electrolyzer sizing, carbon intensities and electricity prices. Therefore, in this study SERA will be soft linked to the Grid Optimized Operation Dispatch (GOOD) model, which is an electricity dispatch model.

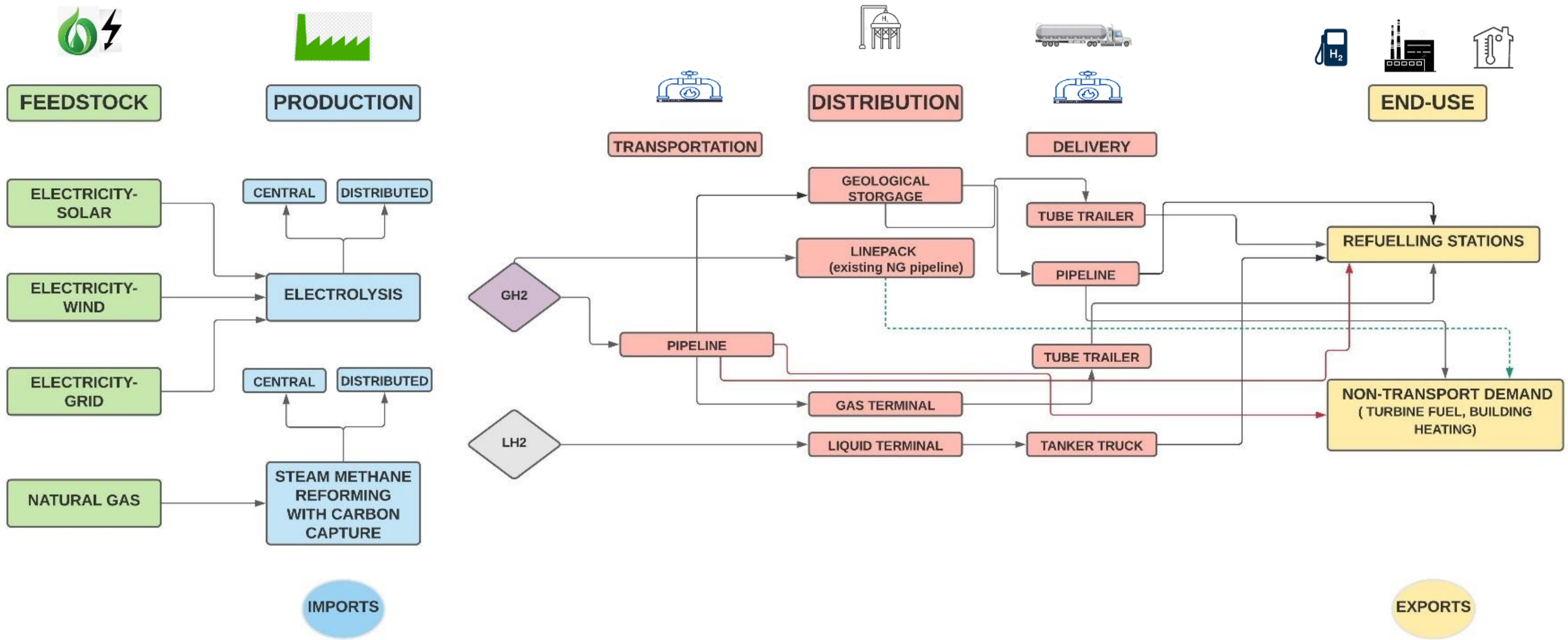

Figure 11: Proposed hydrogen supply chain network for California

The present study will integrate the following three optimization models to answer research questions pertaining to the roll out of HSC infrastructure in California: a) SERA is a hydrogen infrastructure optimization model and will play a central role in this analysis, b) GOOD is an electricity dispatch model and c) STIEVE is a hydrogen refueling station siting model. The subsequent section will describe each of these models in brief and more importantly elucidate how they will be soft linked to one another.

Model Descriptions and Modelling approach

Scenario Evaluation & Regional Analysis (SERA) model

The SERA model developed by NREL, fills a unique and important niche in the temporal and geospatial optimization-analysis of hydrogen demand, production, and delivery infrastructure build-out [30]. It complements well with the U.S. DOE's models (H2A, HDSAM, HDRSAM, HRSAM) and incorporates a hydrogen demand generation module and an infrastructure module. The present study will utilize SERA's infrastructure optimization module that estimates what infrastructure will be required to meet regional demands for hydrogen, at the minimum total cost. The layout of the model can be found be in Appendix 12: Layout of SERA and STIEVE models

The SERA model is flexible to incorporate user-defined production technologies, delivery components, environmental metrics, and pre-existing infrastructure. SERA uses graph-theoretic, linear-programming algorithms and heuristics to estimate how an optimal configuration of hydrogen infrastructure would evolve over time. Nonlinearities are induced due to economies of scale and thus an iterative method informed by approximations and heuristics is used to arrive at the near-optimal solution for infrastructure requirements. The optimization proceeds in two phases. In the first algorithmic phase, SERA considers all possible geographic realizations of the infrastructure pathways (production technologies plus delivery pathways, but without the possibility of storage) as a supply network and then uses a graph-theoretic minimum-cost-flow algorithm to estimate which of those potential geographic realizations provide cost-optimal satisfaction of the demands for hydrogen. The second algorithmic phase starts with this pattern of flows and infrastructure, but then adds and sizes hydrogen storage, in eligible locations, using a linear program that uses the marginal costs for adjusting the phase-one infrastructure to optimally locate and size the storage, downsize non-storage infrastructure, and recomputing the optimal flows. Overall, the resulting algorithm estimates the location and size of production, storage, and delivery infrastructure that meets the specified geographic demands for hydrogen at the lowest possible cost, accounting for the fact that production and consumption levels vary on sub-annual timeframes. SERA's output tabulates the locations, size, cost, flows, and environmental impacts of the resulting supply system.

Earlier works use the hydrogen demand generation module of SERA for optimally locating hydrogen refueling stations for light duty vehicles or use the demand values to feed into other supply chains like the electricity grid [31] [32]. Owing to the complexities and uncertainties of modelling upstream hydrogen infrastructure requirements, the infrastructure module of SERA (which will be employed for this study) is being constantly updated at NREL and there is not a lot of published work yet that uses this module of SERA.

The infrastructure optimization in SERA can progress at different geographical scales: National, Regional, or Intra-Urban as specified by the problem formulator. Existing literature and models like SERA follow different methods to divide the geographical area of interest. A region could be divided into rectangular grids, administrative segments, or demand clusters. The optimization works of Almansoori and Shah employed rectangular grids, where Great Britain was divided into 34 grid squares of equal size [33,34]. Administrative segmentation (into districts, counties, census tracts) is the most adopted geographic division methodology [35] [5]. Ogumerem et al [36]merged adjacent counties of Texas (total 254 counties) using the same logic as the Texas Department of State Health Service to obtain 11 regions, thereby leading to a substantial size reduction of the problem formulation without significantly affecting the accuracy of the optimization model. Konda et al [37] argues that the presence of population clusters usually warrants a reasonable hydrogen demand. The same logic was employed by Johnson and Ogden [38], and Parker et al [39] for accomplishing their geographic divisions using demand clusters. For the present study, the geographic division of California needs to be normalized across the three models, which currently work at different geographical resolutions. An important task would be to convert the spatial resolution of data from the STIEVE and GOOD model into a suitable form before feeding it into the SERA model.

The timelines for the optimization can be divided into discrete periods in SERA, as specified by the user. Typically, a five-year period is defined for the optimization since this roughly corresponds with the planning horizon of commercial entities. For the present study, the time frame of optimization will extend into 2050.

It is evident that uncertainty inherently exists for many of the inputs to the SERA model. Uncertainties could be associated with

- Hydrogen demand from the transportation and non-transport sectors
- Electricity demand on the grid and the levels of renewable's (solar and wind) share in power generation

To deal with these uncertainties, a deterministic approach of problem formulation using scenario analysis will be employed. The table below shows the different scenarios that will be considered for the optimization. These scenarios will hold true for simulations with SERA, GOOD and STIEVE models.

Table 2: Scenarios considered for optimization using SERA, GOOD and STIEVE models.

Scenario	**Description**
BAU	• FCEV market penetration increases from 1 % in 2025 to 5% in 2050. • Electricity demand grows from 317,000 GWh in 2030 to 379,000 GWh in 2050 [40]. • Hydrogen demand for power generation grows from 0% in 2025 to 10% in 2050. • Renewables share of electricity generation increases from 60% in 2030 (RPS requirement) to 75% in 2050. • Hydrogen imports is 25 % of total demand

GREEN 1	• FCEV market penetration increases from 5 % in 2025 to 20% in 2050. • Electricity demand grows from 263,000 GWh in 2030, increasing to 297,000 in 2050. • Hydrogen demand for power generation grows from 0% in 2025 to 20% in 2050. • Renewables share of electricity generation increase from 60% in 2030 to 90% in 2050. • Hydrogen imports is 10% of total demand
GREEN 2	• FCEV market penetration increases from 5 % in 2025 to 50% in 2050. • Electricity demand grows from 312,000 in 2030 to 473,000 GWh in 2050. • Hydrogen demand for power generation grows from 0% in 2025 to 30% in 2050. • Renewables share of electricity generation increases from 60% in 2030 to 100% in 2050. • Hydrogen imports is 5% of total demand

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 [41] [42]. The model is formulated as a linear optimization program with the power generated from each generator in a region at a given time and the power transmitted across regions as major decision variables. 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.

For this study, the GOOD model will include power generation using fuel cells (in addition to the existing generation technologies) and hydrogen storage requirements will be an additional decision variable. The model will be run for the Western Electricity Coordinating Council (WECC) region. A larger geographic area (beyond California) consideration for the electricity grid will have advantages. One, it will help leverage a wider transmission network hence helping to balance the grid between supply and demand. Secondly, considering the WECC region will enable tapping into some of the cheap geological hydrogen storage options like salt caverns, which currently are fewer in California as compared to other WECC states like Utah. Thirdly, a larger geographical span will mean a greater generation potential from renewables like solar and wind. This would mean a greater possibility of requiring large scale storage which could be satisfied through hydrogen in a cost-effective manner. The interaction of the GOOD model with SERA is depicted in Figure 12

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

STIEVE is an optimization model to deploy hydrogen refueling stations for fuel cell vehicles based on the characteristics of travel and attributes of the stations. 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). In the current version of CSTDM, California is divided into 5454 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.

A layout of the STIEVE model can be found in Appendix 12: Layout of SERA and STIEVE models. All the preprocessing and visualization are done in ArcGIS Pro 2.6 and the optimization and data parsing were performed using GAMS 25.1.2 and R 4.0.2 respectively. The optimization is formulated as a mixed-integer linear problem that attempts to minimize total system costs for a station operator based on installation cost ($c^{\text{stationCost}}$), of a particular station i along with the fuel cost (c^{fuelCost}). The model decides how many stations to install (x^{station})of each type in each region r alongside how much hydrogen fuel is dispensed in each region (x^{fueled}). This can be represented in the following objective function:

$$\min_{w.r.t: x_{ir}^{\text{station}}, x_{rvt}^{\text{fueled}}} \sum_i \sum_r x_{ir}^{\text{station}} c_i^{\text{stationCost}} + \sum_r \sum_v \sum_t x_{rvt}^{\text{fueled}} c^{\text{fuelCost}}$$

Additionally, the optimization is subject to operational constraints that ensure that station deployment will meet the demand for fuel along the route while simultaneously following capacity constraints (both at the dispenser and overall daily fuel limits).

STIEVE model will optimize station locations and capacities to satisfy demand from both light duty and heavy-duty fuel cell vehicles. The model will project the station numbers in California for the scenarios identified in Table 2. The station location and capacities identified by the STIEVE model will be inputs to SERA while defining the demand nodes from the transportation sector. Interaction between SERA and STIEVE models are depicted in Figure 12

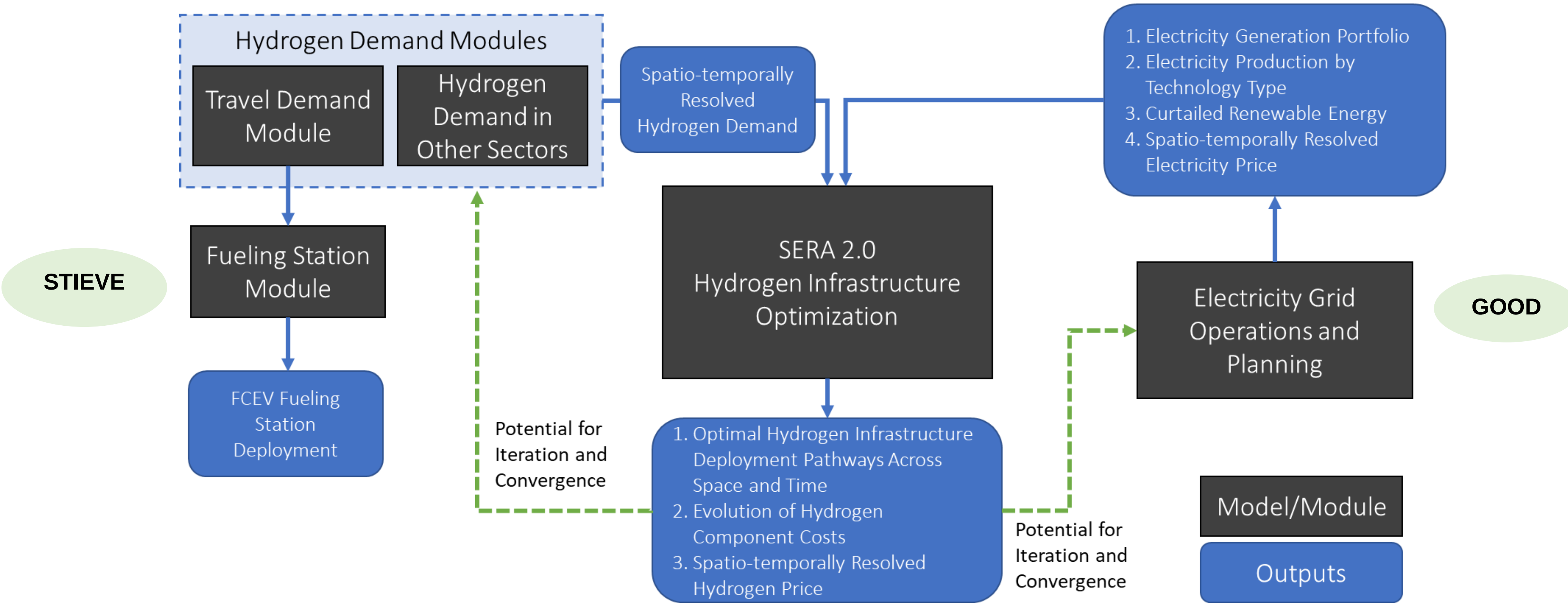

Figure 12: Interaction between SERA, GOOD and STIEVE models.

Chapter 3: Analyzing seasonal storage as a bridge between hydrogen supply chain and the electricity grid.

Background

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) [43]. 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 [29]. 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 [31]. 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 [44]. 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 [31]. Storage requirements will 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.

Different forms of energy storage can be used to ensure the stability of the grid. Prominent storage technologies include thermal storage, compressed air, pumped hydroelectric storage, flywheels, batteries, flow batteries, capacitors and hydrogen [29]. Battery energy storage is a good candidate to store small amounts of excess renewable electricity for short durations (hours to days) [45–47]. However, for large-scale and long duration storage needs, the current lithium-ion based batteries will have limited application. This is attributable to the insufficient global reserves of lithium and cobalt to produce enough batteries to meet all the storage requirements, challenges of self-discharge, challenges associated with battery recycling and the issues of lower energy densities [29]. Hydrogen on the other hand is a more cost-effective storage option for long durations [48].

Hydrogen could be produced via the P2G (power to gas) route, which involves the conversion of excess renewable electrical power into a gaseous energy carrier, through the process known as electrolysis. The hydrogen thus produced could be stored and can be employed for power generation (using fuel cells) when there is insufficient power generation from solar and wind to meet demand. Additionally, the hydrogen produced via P2G can also serve other end use sectors like transportation, building heating and as a combustion fuel for gas turbines to generate electricity. Hydrogen storage at a grid scale would imply large scale hydrogen storage. For regions like California or Germany this would imply storage requirements in double figure terawatts of energy [49]. In this study two such large-scale storage options for hydrogen are explored: geological and line pack storage.

In the United States, geological storage is used to store approximately 713 million barrels of oil as strategic reserves [50] and 1746 billion cubic feet of natural gas [51]. Geological storages have sizable volumes available for storage, which allows buffering of seasonal demands. It is a sizable financial asset that ensures continuity of energy delivery in case of disruption in the supply chain, and also controls congestion in the pipeline system [52]. But the storage of hydrogen within the same facilities currently used for natural gas may require additional modifications. This is due to the chances of hydrogen embrittlement of the steel infrastructure which will ultimately result in the leakage of hydrogen. Four different geologic storage options exist: salt caverns, depleted oil and gas reservoirs, aquifers, and lined hard rock caverns. Lined hard rock caverns are explored in regions where the other three underground options do not exist. Salt caverns seem to be the most preferred choice for hydrogen storage, with three out of the four global locations being in the United states located 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 an year, thereby reducing the levelized cost of hydrogen storage [53]. 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 [54].

The U.S. Energy Information Administration (EIA) data indicate that California does not have many suitable geological sites that could be developed into salt caverns, unlike states like Arizona, Utah, New Mexico, or Texas [55]. California could develop some of its depleted gas reservoirs and lined hard rock caverns to store hydrogen. Figure 13 shows the capital investment required to develop these geological formations to store hydrogen [53]. Alternatively, California could also import some of the cheap hydrogen stored in salt caverns from nearby states through pipelines or the road network.

Another widely discussed option for large scale hydrogen storage is line pack storage, that makes use of the extensive natural gas pipeline network in California. This can serve as a suitable storage option for hydrogen generated using renewable sources through the P2G route [56] [57]. The capacity of gas grid in California (like many other regions) is much larger relative to the electricity grid. For e.g., in 2019 the gas distribution system in California delivered 628.34 TWh of energy to its consumers as compared to 277.70 TWh by the electricity system (in state generation and imports) [58] [43]. Therefore, the gas grid can easily absorb some of the hydrogen produced from excess electricity.

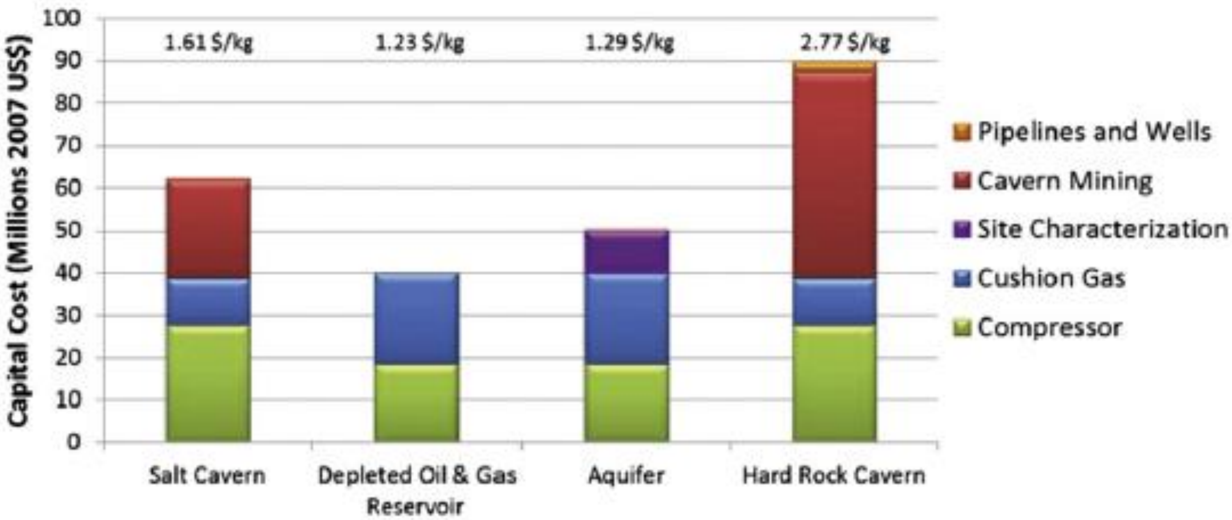

Figure 13: Capital investments and levelized cost for geological hydrogen storage[53]

Line pack storage refers to the inherent storage capacity contained within the gas pipelines by means of varying the overall pressure levels of these pipelines. National and regional transmission systems, have greater line pack flexibility due to larger operating pressure ranges and pipeline volumes [59,60]. Line pack storage in natural gas pipelines can be tapped by blending hydrogen (at certain blend ratios) into the natural gas streams, without substantial modifications to the existing pipeline network. This can defray the cost of building dedicated hydrogen pipelines during the early market development phase [56]. European countries like Germany allow hydrogen blending in NG pipelines up to 10 % and plans on extending this to 20% [61]. 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 [56]. California Public Utilities Commission is working alongside gas utility firms like SoCalgas on demonstration projects to study the impacts of hydrogen blending in existing NG pipelines and subsequently understand the optimum levels of hydrogen blending that is most economically feasible and safe [62].

Hydrogen blended natural gas can find direct application for building heating and as a combustion fuel to gas turbines for electricity generation. For other applications that require pure hydrogen such as the transportation sector, hydrogen needs to be extracted and purified (using techniques like pressure swing adsorption), which can substantially add to the cost of hydrogen to the end user [56]. Over time, as the hydrogen demand increases and when the maximum blending ratio exceeds the safety limit for the existing NG pipeline network, dedicated hydrogen pipelines will need to be constructed. But during the early phase of hydrogen adoption, utilizing the line pack storage capabilities of existing natural gas pipelines makes perfect economic sense [63].

Modelling Approach

In this study both geological and line pack storage options will be investigated in the Californian context. SERA model will be modified to incorporate these storage options. Additional constraints based on storage capacity, costs and the location will have to be defined in SERA. The HSCN will then be optimized to achieve the lowest system costs.

Salt caverns will be the main geological storage option that will be considered. These could be included as additional nodes in SERA along with capacity constraints and economic parameterization. Since California does not have any salt caverns, nodes along the state boundary will have to be characterized as hydrogen import points from nearby states that have salt caverns. These nodes will have added costs of hydrogen transport (using pipelines or trucks) from nearby salt caverns to the state boundary. Other geological storage options like depleted gas reservoirs will be under consideration but not a priority for this study.

Incorporating line pack storage into the supply chain will need analytical modifications in SERA, as these cannot be readily defined as nodes. Spatial data of existing NG pipeline network in California will be used. The primary function of pipelines is to transport and not storage. Hence to incorporate the storage capability in the pipeline network, physical parameters like pipeline operating pressures and energy density of hydrogen and natural gas needs to be considered. Earlier works that investigated line pack storage using MARKAL-type models have taken a simplified approach and lacked spatial representation of gas grids [64]. This approach tends to poorly represent pipeline infrastructure because the capital costs are specified as a function of the energy throughput while the actual pipeline costs are more dependent on the geography of the region and the design of the network.

One study that is relevant in the present context was carried out by Quarton and Samsatli using the Value Web Model (VWB) [57] They employed an innovative approach of defining a common "national infrastructure" which enabled modeling of both the storage and transportation capabilities of a gas transmission system with minimal complexity. The model was applied to the UK energy system that has an extensive gas grid along with multiple energy resources (including wind, solar, nuclear, natural gas) and stringent decarbonization targets. With heating (building and industry) as the primary demand, the study concludes that feed-in tariffs (a sort of credit to the gas supplier) of £20/ MWh of hydrogen injected would be sufficient to incentivize injection into the gas pipelines. A similar approach could also be followed here but there ought to be a way by which this can be defined in SERA. VWB is a Mixed Integer Linear Programming (MILP) formulation whereas SERA is a nonlinear optimization framework and hence the definition of line pack in SERA will be substantially different. Identifying a suitable way to incorporate line pack storage in SERA and thereafter optimizing the supply chain will be a key interest for this study.

Expected outcomes from this study.

This study hopes to provide critical insights for policy makers, industry, and coalition groups to strategize the rollout of hydrogen infrastructure in California, as part of the broader decarbonization plan. As CARB contemplates to extend the LCFS HRI credits to bigger hydrogen refueling stations (greater than 1.2 tpd), it would be important to understand the feasibility of developing an upstream supply chain to support these stations. Long duration energy storage using hydrogen will be evaluated in detail, which will have direct consequences to existing policy targets set through legislations like the SB 100. As California Public Utilities Commission (CPUC) drafts the standards (R.13-02-008) for the injection of renewable hydrogen into existing gas pipelines, this study will provide the much-needed system level perspective of its economic feasibility and impacts. Further, this study delves into many interesting and critical questions surrounding the evolution of hydrogen economy in California on a spatial and temporal basis. The balance between blue and green hydrogen production, extent of hydrogen imports and the relevance of non-transport-based hydrogen demand are all important questions that needs consideration, as California prepares itself to achieve net carbon neutrality by 2045.

Research Schedule and Milestones

This research work is expected to be completed in 18 months as described in Figure 14. The timelines are in line with ongoing research projects and the major task going forward will be the modeling work involving the SERA model which will be carried out in conjunction with NREL.

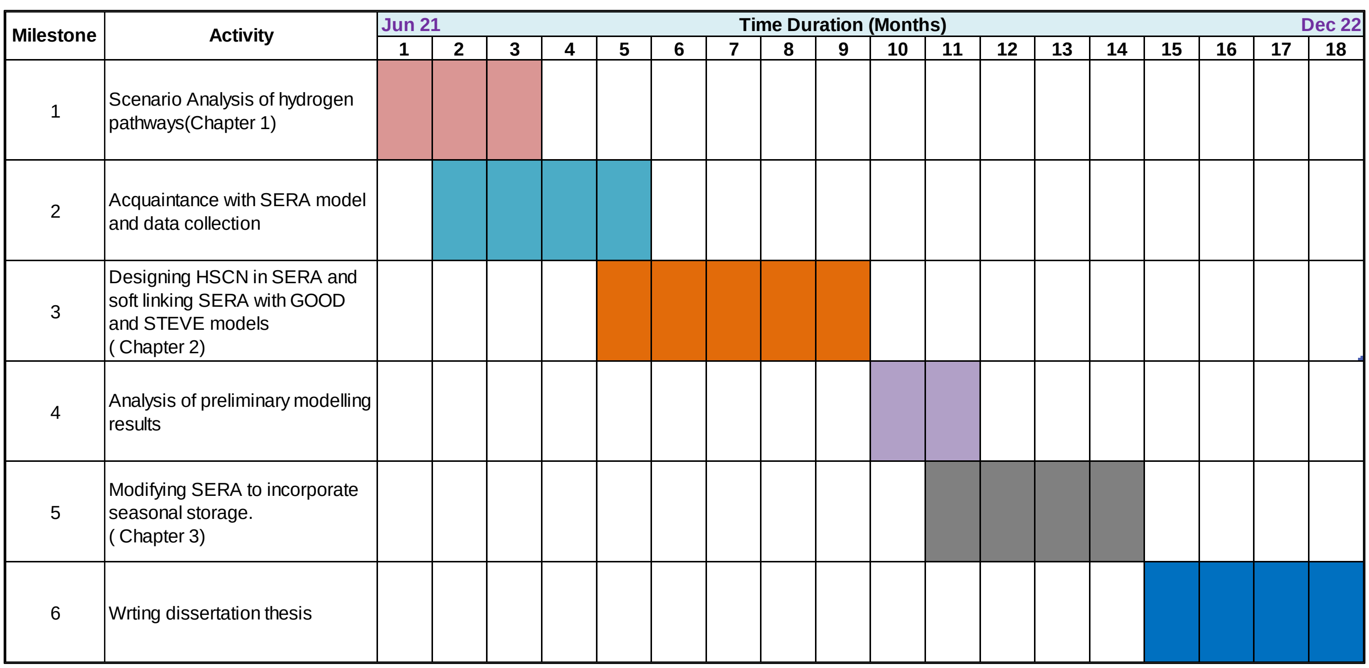

Figure 14: Research Schedule and timelines

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Appendix 1: *Energy system optimization models*

The optimization is typically either a linear or mixed integer linear programming problem that solves to find the energy system that meets energy service demands at the least cost. Detailed hydrogen supply chains can be represented in these models including various hydrogen production technologies, feedstocks, and modes of distribution. Different hydrogen end use technologies compete with others (such as electric vehicles in the transport sector) to meet energy service demands (such as demands for car transport), and thereby endogenously optimizing both hydrogen demand and supply. The MARKAL /TIMES family of energy system models developed by the International Energy Agency (IEA) is widely employed for hydrogen supply chain studies globally, with some tweaking to better reflect regional scenarios. This model has been employed to examine the prospects of hydrogen in Japan[65], Norway[66], Italy[67], Spain[68], China[69], the US[70][71], UK[72], and at global scales[73,74]. Other integrated energy assessment models that have been applied to hydrogen supply chain study include GET[75] and MESSAGE [76]. In general, these energy system models can determine the extent of role hydrogen can play within the energy system but given their size and complexity, these models tend to use a simplified representation of hydrogen infrastructure because of computational considerations.

To partially overcome this challenge, Yang and Ogden[77] employs H2TIMES model which is a quasi-spatial model using the TIMES modeling framework. H2TIMES model uses a clustering approach to divide California into seven clusters which is then used to estimate the extent of pipeline and liquid truck delivery distances needed to supply hydrogen to a network of refueling stations. The study projects the cost of dispensed hydrogen through 2050 and estimates the capital investments required to build out the delivery network. The authors also point out the limitation of using a clustering strategy as it may not be an actual representation of how infrastructure develops. Further the analysis ignores limitations of capital and information that individual firms may have, ignored the possibility of competition among firms, do not comment on the capacity expansion requirements for production and delivery networks and considers hydrogen demand only from light duty vehicles.

Appendix 2: *Refueling station location models.*

While the problem is often defined on a Mixed Integer Linear Programming Framework (MILP), there are two distinct approaches to the problem formulation. One assumes that consumers would refuel their vehicles near home (p-median approach), and the other that they would refuel along their ordinary driving patterns (traffic flow approach). The p-median approach of locating stations would minimize the average driving time or distance to the stations weighted by the population in the geographical area. The traffic flow approach, also referred to as Flow-Intercepting Location Model (FILM) or Flow-Capturing Location Model (FCLM) characterizes the demand along paths through a network instead of points of origin for trips to the facility and back, i.e., the logic used in the p-median models.

One of the earliest works that use the p-median approach was by Nicholas[78] for locating hydrogen stations in Sacramento County, California. Lin et al. [79] modified the p-median model, christened "fuel travel back" approach, where vehicle-miles-travelled was minimized to reach the nearest station. Hence, the quantity of used fuel takes the place of population as weights in the minimization problem. One of the criticisms of the p-median model is that by minimizing the average weighted distance or travelling time for the whole system, sparsely populated areas may be overlooked due to the relatively lower weightage in the objective function. Another class of facility location problem is the Set Covering Problem (SCP), that does not use heuristics (unlike P-median) and looks for the minimum investment to allocate facilities (or at least one facility) that can cover a set of demand nodes given a determined set of potential facility locations[80] . The maximal covering location problem (MCLP) maximizes the number of nodes, including their total population, covered by pre-defined facilities in a pre-defined distance[81]. Both SCP and MCLP methods have not been extensively employed for locating hydrogen refueling stations.

The FILM approach is based on the seminal work of Hodgson[82], who considers traffic as a demand flow, which starts, ends or passes by businesses that want to serve this demand. He employs origin-destination (OD) trips to embody the total (refueling) demand flow. These OD trips follow a path along (multiple) nodes, at which candidate facilities like hydrogen refueling stations can be located. On a highway network, for example, nodes can be referred to as highway entries, exits or intersections. A variation of the FCLM, called Flow- Refueling Location Models (FRLM) considers the range of the vehicles passing along a path[83]. The FRLM can either maximize the vehicle trips covered when locating a predefined number of stations in a network, or minimize the number of facilities needed to cover a given demand share[84]. Kluschke et al[85] extended the FRLM concept to a Node-Capacitated Fuel Refueling Location Model (NC-FRLM), to include station capacity restrictions on hydrogen refueling stations and projected the network of Heavy Duty Hydrogen Refueling Stations(HDV HRS) in Germany by 2050. The NC-FRLM model is then integrated with an electricity system model (covering electricity production and storage capacities, the transmission grid and current existing electricity demand) to analyze the interplay of a potential HDV HRS network with the electricity system. Another approach that relies on the theory of demand flow is the Network Interdiction model. The model identifies a sets of assets (at nodes) that have the greatest impact on a system's ability to perform its intended functions, once these assets were disabled or lost [86]. Hence, interdiction models focus on providing information about the criticality of some system components, but not about building up an optimal infrastructure across a network. The model does not consider vehicle range limitations. Upchurch and Kuby[87] compared the performance of the p-median and flow model approaches in the case of the Orlando, FL metropolitan area and Florida as a whole. The authors conclude that the flow model approach performs better leading them to conclude that this approach is better suited for locating refueling stations.

Appendix 3: *Cross-Optimization models*

Cross optimized models could either follow a linear or nonlinear formulation. formulations can be either Linear Programming (LP) or Mixed Integer Linear Programming (MILP) depending on the kind of the involved variables Linear programming problems can involve decision variables that can take integer or continuous values. When integer variables are restricted to the binary variables (0-1), the corresponding problem is called a binary integer programming problem. MILP have been extensively employed for investment planning, supply chain and logistics management, energy industry planning and production scheduling because of its capability to naturally capture logical conditions[88]. MILP approach is more common in HSC literatures and uses binary and integer decision variables to identify location of facilities, sizing decisions, selection of suitable production technology, and selection of transportation modes. Owing to the scale of HSC, MILP approach often requires substantial computing capabilities and the use of commercial optimization solvers like Gurobi or Cplex. Nonlinear formulations where some of the constraints or the objective function are nonlinear, can be tackled either through deterministic or stochastic algorithms procedures. Deterministic methods identify a local optimum whose objective function value differs by a constant ε from the global one, for a given ε>0. Stochastic methods identify global optimum within a window of probabilities. The stochastic models can incorporate uncertainty in parameters such as demand, feed stock costs, potential sites, and distances [89].

Great Britain

The work of Almansoori and Shah [90] is the seminal paper in this branch of literature, and their equations have been widely used by other researchers. The HSCN of interest was formulated as a mixed-integer linear programming (MILP) problem for Great Britain. This modeling effort was the first of its kind that integrated all components of the hydrogen supply chain within a single framework. The objective was the minimization of both capital and operating costs. Hydrogen demand, a critical input to the model was ascertained as a function of the total number of vehicles (light duty alone), average total distance travelled, and vehicle fuel economy. The demand was based on the asymptotic assumption that 100% of the vehicles would be powered by proton exchange membrane fuel cells. The demand was geographical distributed over 34 grid squares that covered the entire Great Britain. The authors refined the model[34] to consider the evolution of the network over time, rather than a snapshot of the network at one point in time. A multi objective MILP was employed by Guillen-Gosalbez et al. to analyze the HSC, accounting for the simultaneous minimization of cost and environmental impacts for hydrogen demand determined from light duty vehicles [91].

Samsatli et al. [92] developed a mixed integer linear programming network model, STeMES that determined the optimal HSCN structure and its operation, simultaneously considering for the long-term planning horizon and short-term dynamics. The spatial distribution and temporal variability of hydrogen demands, and wind-electricity are considered in detail and the total network cost is minimized subject to satisfying all the demands of the domestic transport sector. Samsatli et al [93] employed another spatio-temporal MILP optimization model(Value Web Model) to examine the future renewable hydrogen value chains for space and water heating applications. The required levels of investments, the optimal proportions of heat satisfied by electricity and hydrogen and the value of inter-seasonal storage of hydrogen were analyzed in detail. Value web model was integrated with Geographic Information Systems (GIS) tools to identify candidate sites for wind generation and is then used to optimize several scenarios for hydrogen production using onshore and offshore wind energy to satisfy the heat demands.

Spatial Hydrogen Infrastructure Model(SHIPMod) is a spatially explicit multi-period ,stochastic , mixed-integer linear programming model developed by Agnolucci et al [94] to analyze hydrogen supply chains for scenarios of hydrogen fuel demand in the UK. Unlike some of the earlier HSC optimization works, this model determined endogenously rather than assume exogenously the split between the liquid (LH2) and compressed gaseous hydrogen (GH2). Further, this was the first optimization framework to model CCS pipeline, i.e., CO_2 transfer through pipelines. M. Moreno-Benito et al[95] updated SHIPMod to include imports and additional hydrogen delivery modes – i.e. transmission and distribution pipelines.

Almaraz et al [96] developed a multi objective mixed integer linear programming model in which three objectives are involved, i.e., cost, global warming potential and safety risk. The optimal solution consists of a Pareto front, corresponding to different design strategies. Multiple choice decision making is then employed to find the best solution through an M-TOPSIS analysis.

United States

California's aggressive policies against climate change have evoked substantial interest in hydrogen, mostly for the transportation sector. Some of the most relevant HSCN analysis for California was carried out by J. Ogden and associates. Parker et al. [39] presents a fully-optimized MILP nonlinear model, maximizing profits from a waste-based HSC. Hydrogen price is an input to the optimization problem, that also considers costs of production, transportation (both local and intercity) and refueling stations. The model requires as an input the list of potential sites for feedstock availability, hydrogen production, storage terminals and demand centers. Constraints ensure that the optimal solution satisfies the capacity of the components of the HSC, after which one can compute the total costs. A similar logic is employed by Johnson and Ogden[38] to analyze pipelines as a mode for delivering hydrogen.

Dayhim et al[97] uses a Stochastic Multi-Period Model (SMPM) to analyze the HSC network under uncertain demand for the state of New Jersey. A Spatially Aggregated Demand Model (SADM) estimates the potential demand for hydrogen fuel cell vehicles at a household level. A demand-driven approach is defined for the network, implying that the production of hydrogen, and the development of storage facilities alongside the transportation links are directly proportional to the demand. The model minimizes the total social cost, while addressing demand uncertainty through a two-stage stochastic programming approach. The model can run many scenarios with probabilities that are defined by the user, but this could lead to an exponential growth of the model size if there are several potential scenarios in each time period. The authors circumvent this problem by considering a representative subset of scenarios generated by the sample average approximation (SAA) method. Using this method only 15 scenarios were considered to obtain reasonably good solutions.

Guannan et al[98] employs a HSN model with flexible scheduling for hydrogen trucks and pipeline, allowing them to serve both as hydrogen transmission and storage resources to shift demand/production across space and time. An array of production and storage options are explored, to determine the least-cost technology mix across the supply chain based on its operation under spatiotemporal variations in electricity inputs and hydrogen demands for the US Northeast. The study concludes that enabling trucks to be shared across zones both as a storage and transmission medium is critical for variable renewable energy (VRE) integration and HSC cost minimization.

Bodal et al[99] implements a least-cost capacity expansion model to evaluate the electricity and hydrogen infrastructure requirements to serve future electricity and hydrogen demands for Texas. The linear model considers multiple technologies associated with generation and storage of both energy vectors with high temporal resolution. The maximum variable renewable energy (mostly wind) share reaches 95.8% with increasing hydrogen demand and hydrogen production through electrolysis becomes the most cost-effective option to reduce overall carbon emissions. Reconversion of hydrogen back to electricity is found to be minimal, owing to the very low round-trip efficiency.

Ogumerem et al[36] developed a multi-objective, multi-period, mixed integer, linear optimization formulation to analyze a hydrogen supply chain network in Texas. The focus of the study was to evaluate the impact of oxygen as a valuable by-product while producing hydrogen through electrolysis. The ε-constraint algorithm was used in solving the optimization problem. The authors conclude that hydrogen production from electrolysis is an environmentally friendly and economically viable option, as its by-product (oxygen) is revenue generating.

Muratori et al[32] employed SERA to explore two alternative scenarios of fuel cell electric vehicle(FCEV) adoption: one in which FCEV deployment is limited to several major cities in the United States; and one in which FCEVs reach high levels of market adoption in the passenger vehicle segment across the US. Areas of potential hydrogen demand are aggregated into clusters and refueling stations are predicted to be deployed along major roads between the clusters (p-Median approach). The model projects the buildout of hydrogen refueling stations over time, to maximize coverage and access to potential FCEV early adopters across different geographic regions. Wang et al [31] employed SERA to analyze the possible benefits that FCEVs and hydrogen systems(electrolyzers) can have on the electricity grid especially with large-scale renewable integration. The study considered California's electricity grid in 2025 and focused on the benefits of employing hydrogen to mitigate the problems of peak shaving/valley filling, and ramping mitigation associated with the duck curve. The study concludes that oversizing electrolyzers can provide considerable benefits to mitigate renewable intermittency, while also supporting the deployment of FCEVs.

Germany

One of the earliest HSCN studies for Germany was done by Hugo et al [88]. A multi objective MILP formulation was employed to develop a long-term investment plan for future HSCs in Germany, accounting for economic costs as well as well-to-wheel greenhouse gas emissions. The study assumed that 25% of the light duty vehicle fleet will be powered by hydrogen and employed the ε constraint method to determine the optimal solution. The authors conclude that the optimal HSCN design and investment strategy should begin with small-scale on-site hydrogen generation by reforming natural gas.

Martin Robinius's group at the *Institute of Electrochemical Process Engineering*, *Jülich, Germany* has carried out extensive analytical work around various aspects of the HSCN in Germany. Reuß et al[100] analyzes a HSC that considers electrolysis for hydrogen production, large-scale storage for the temporal gap between demand and supply, the transportation and the fueling station facilities necessary to fill a 700 bar compressed gas tank. Furthermore, Liquid Organic Hydrogen Carriers (LOHC) are discussed as an alternative carrier system to investigate their impact on the supply chain. Based on a sensitivity analysis, the price of renewable electricity and the utilization of the station were identified to be critical factors in the HSC. Underground storage and LOHCs are economically viable storage solutions as compared to liquid hydrogen, especially at low charge cycles. A well-to-wheel analysis concludes that all the hydrogen supply chain pathways offer approximately a 30% reduction in GHG-emissions, as compared to conventional fossil fuel pathways within a European framework. Reuß et al extends this work, evaluating all parts of the HSCN, from production(Electrolysis) to refilling, storage, transmission pipelines and gaseous trailer distribution on a nation-wide scale for 2050[101].The results show that salt caverns, as well as transmission pipelines, are key low cost technology options for future hydrogen infrastructure systems. The study acknowledges that the total costs of the HSCN depend largely on the electricity costs (for electrolysis) and the investment costs for refueling stations.

Other Regions

Konda et al. [37] developed a multi-period optimization framework to investigate the spatio-temporal performance of H2 as a fuel in the Dutch transport sector. The problem is formulated as a MILP and solved using the General Algebraic Modeling System Environment (GAMS). The model includes refueling stations, CCS technology and hydrogen pipelines while considering economies of scale, and computes the delivered cost of H2, well-to-tank emissions and energy efficiencies of the different processes involved. Hydrogen demand is calculated as a function of population and the results from the model suggest that a transition towards a large-scale H_2-based transport system in the ***Netherlands*** is economically feasible.

The work of Kim et al[102] was one of the earliest attempts to incorporate demand uncertainty in HSCN design. The model evaluates future hydrogen supply chains for ***Korea***, through two different approaches: deterministic vs. stochastic. The model determines a configuration that is optimum for a given set of demand scenarios with known probabilities. A two-stage stochastic linear programming approach is employed to solve the multi-objective optimization problem considering cost and safety. The relative risk of hydrogen activities is determined by risk rating calculated based on a risk index method. The model outputs provide insights for the investment strategy towards an optimal supply chain configuration after considering the effect of uncertain demands.

Sabio et al. [103] developed a multi-scenario MILP, that considers the uncertainty associated with operating costs and raw materials prices, with the ability to handle the financial risks associated with market changes. The modeling framework and solution strategy is applied to a case study based on a hydrogen supply chain for vehicle use in ***Spain***. Results indicate that for a given level of costs, lower levels of risk can be attained by switching from steam methane reforming to coal gasification production plants. This modelling framework was further expanded to assess the environmental performance of the hydrogen supply chain based on eight life cycle assessment metrics[104]. The modelling proceeds in two main steps: in step one, a multi-objective MILP is constructed, and a set of Pareto solutions are generated that represent the optimal trade-off between the objectives considered in the analysis. In step two, a multi-variable statistical method is applied to detect and omit redundant environmental indicators without interfering in the main features of the solution space. The study offers insights into the environmental performance of hydrogen infrastructures across different life cycle damage categories.

Qadrdan et al[105] investigated the optimal hydrogen supply chain network and its environmental impacts for ***Iran***, by applying a linear dynamic programming technique. The model minimizes the total discounted costs of the supply system which includes capital, operation, maintenance, and externality of pollutants. An important takeaway from the study was that hydrogen produced by a biomass gasifier is mostly consumed in the transport sector, while hydrogen demand for producing electricity to meet residential and commercial demand is mostly satisfied by an onsite reformer.

The Hugo model was extended and considered as a basis for the supply chain optimization work carried out by Li et al. [106] for **China**. An additional hydrogen pathway involving the delivery of methanol to forecourt hydrogen dispensing stations for onsite hydrogen production is considered, owing to its specific suitability for China. The study concludes that the "methanol pathway" derived from coal, could improve the economic competitiveness of hydrogen infrastructure within a relatively subtle emission constraint.

Li et al [107] conducted a comprehensive review of the optimization models and identifies critical factors that tends to be overlooked during the problem formulation. International trade (feedstock and hydrogen), cross layer and intra-layer flow of material, the social dimension of the HSCN, integration with other supply chains (power to gas) and intertemporal integration are factors that need a greater amount of attention in view of their potential impacts on the supply chain network. The authors urge future research to focus on developing robust optimization techniques that capture the regional suitability of the different components of the HSN and identify cross-regional financing activities that are important for long term capacity expansion plans.

Appendix 4: *Market share of ZEVS and FCEVs*

Table 3: 100% market share target years set for this study.

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 4: FCEV share of ZEV sales in 2030 and 2040+ set for this study

	FCEV share of ZEV sales, Low.		**FCEV share of ZEV sales, High.**	
	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%

Appendix 5: *Inputs to H2A*

Table 5: Base assumptions for all production scenarios in H2A

	Parameter	Value
1	Plant Capacity Factor (%)	85
2	Lifetime(years)	30
3	Carbon capture efficiency (%)	90
4	Inflation (%)	2
5	Dollar year	2016
6	State tax (%)	6
7	Federal tax (%)	21
8	After-tax Real IRR (%)	8
9	Number of staff (central, distributed)	6,4
10	Cost of land for plant ($/acre)	50,000
11	Acres of land needed (central, distributed)	5, 1.5
12	NG usage (mmBtu/kg H2) in SMR plants	0.1558
13	Electricity usage (kWh/kg H2) for electrolysis	51

Table 6: Feed stock prices

Time frame	Electricity rates ($/kwh)	Natural Gas price ($/mmBtu)
Near-term (2020-2025)	0.12	3.5
Mid Term (2025-2030)	0.06	5
Long Term (2030-2035)	0.04	6

Table 7: Capital and operating cost assumptions

Time frame	Capital cost $millions				Fixed operating cost ($/year)			
	Central SMR plant (30 tpd)	Distributed SMR (5 tpd)	Central PEM plant (30 tpd)	Distributed PEM (5 tpd)	Central SMR plant (30 tpd)	Distributed SMR (5 tpd)	Central PEM plant (30 tpd)	Distributed PEM (5 tpd)
Near-term (2025-2030)	37.23	6.89	83.1	14.9	1.99	1.06	4.1	1.36
Mid Term (2030-2040)	29.78	6.20	64.5	12	1.7	1.03	3.3	1.1
Long Term (2040-2050)	23.83	5.58	17.8	4.6	1.46	1	1.9	0.77

Appendix 6: *Inputs to HDSAM*

Delivery Pathways

1. ***Gaseous Hydrogen Delivery***

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

✓ Central production-> compressor-> geologic storage for plant outages-> transmission & distribution **pipeline**-> GH2 fueling station.

2. ***Liquid Hydrogen Delivery***

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

Table 8: Inputs to HDSAM

S. No	Parameter	Value
1	Delivery location	Sacramento
2	Population	500,00
3	Distance from central production plant to station (km)	100
4	Electricity rate for the three-time frames ($/kwh)	0.1, 0.06 and 0 .04
5	Market penetration of FCEV for the three-time frames (%)	5,20,50
6	Production Volume of Components for the three-time frames	Low, med, high
7	Tube trailer Maximum Operating Pressure (atm)	350
8	Maximum gas terminal storage pressure (atm)	400
9	Salt Cavern Maximum Pressure (atm)	125
10	Transmission Pipeline Inlet Pressure (atm)	68
11	Trunk (ring1) Pipeline Inlet Pressure (atm)	41
12	Service Pipeline Inlet Pressure (atm)	26
13	Liquid hydrogen Tanker Water Volume (m3)	56
14	Tank Unloading Losses (% of unloaded amount)	2.5
15	Dollar year	2016
16	Discount rate (%)	8

Appendix 7: *Inputs to HRSAM and HDRSAM*

Table 9: Parameterization in HRSAM and HDRSAM models.

S. No	Parameter	Value
1	Station utilization rate (%)	100
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	H_2 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	Dollar year	2016
13	Total federal and state tax (%)	39
14	Land rent for refueling station	$3.23/m^2 per month
15	Max. Dispensed Amount per Vehicle for 1.5 and 5 tpd refueling stations (kg)	5 and 80
16	Production Volume of Components for the three-time frames	Low, med, high

Appendix 8: *Sensitivity Analysis for forecourt hydrogen production costs*

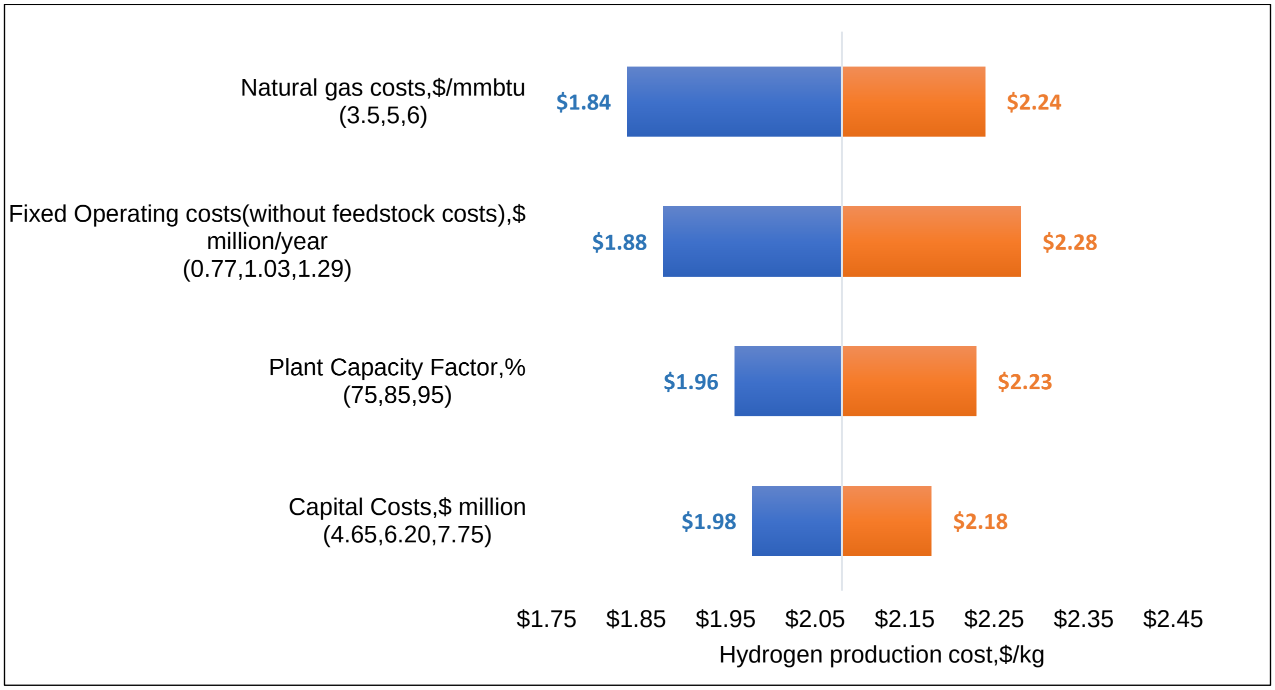

Figure 15: Range of forecourt production costs for a 5 tpd SMR plant

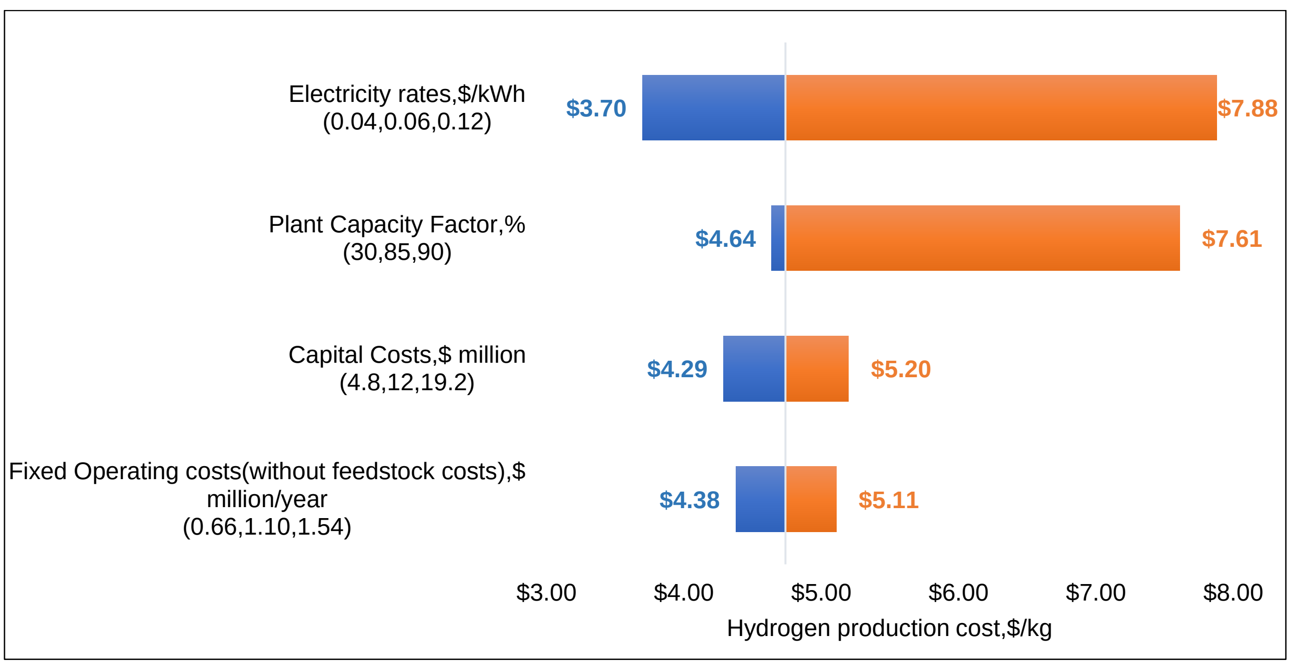

Figure 16: Range of forecourt production costs for a 5 tpd electrolysis plant

Appendix 9: *Sensitivity Analysis for hydrogen delivery costs using tube trailer and liquid tanker*

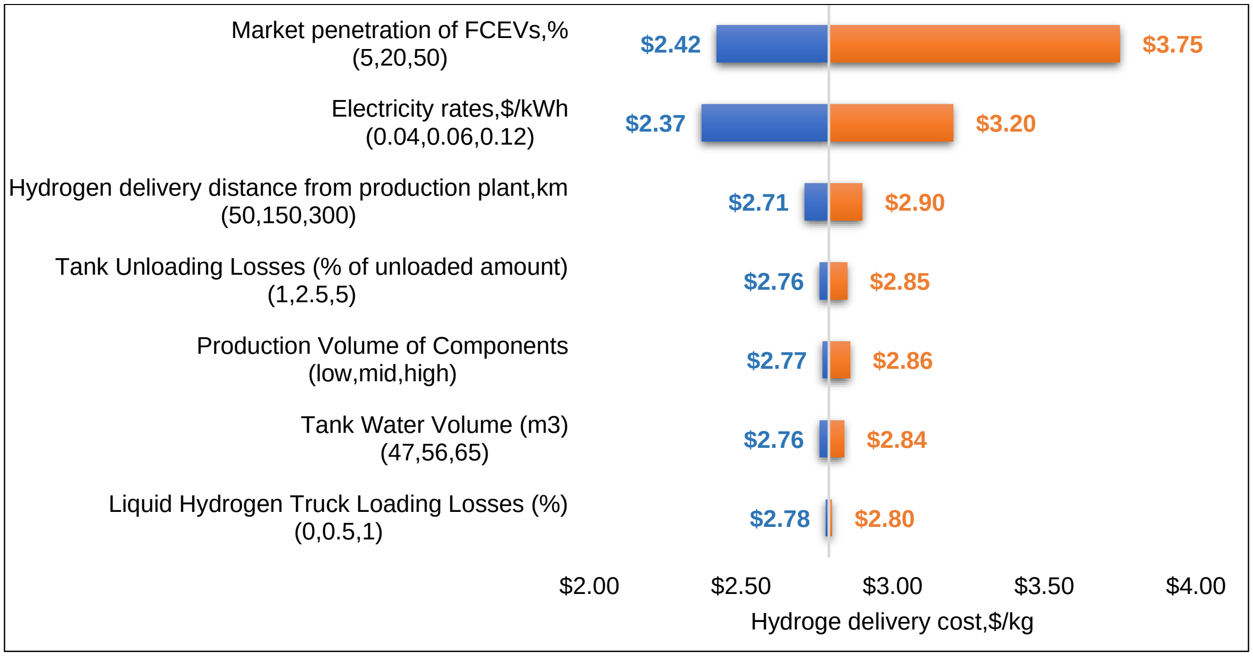

Figure 17: Range of liquid hydrogen tanker delivery costs to a 1.5 tpd refueling station.

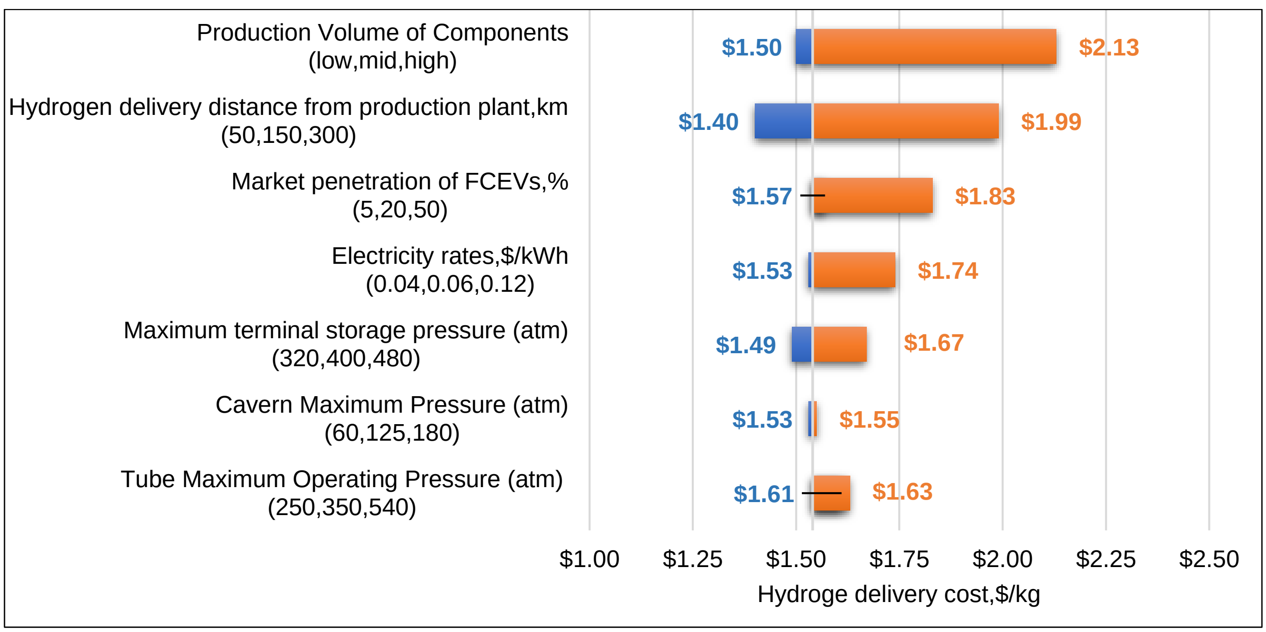

Figure 18: Range of gaseous tube trailer delivery costs to a 1.5 tpd refueling station.

Appendix 10: ***Sensitivity Analysis for hydrogen refueling costs.***

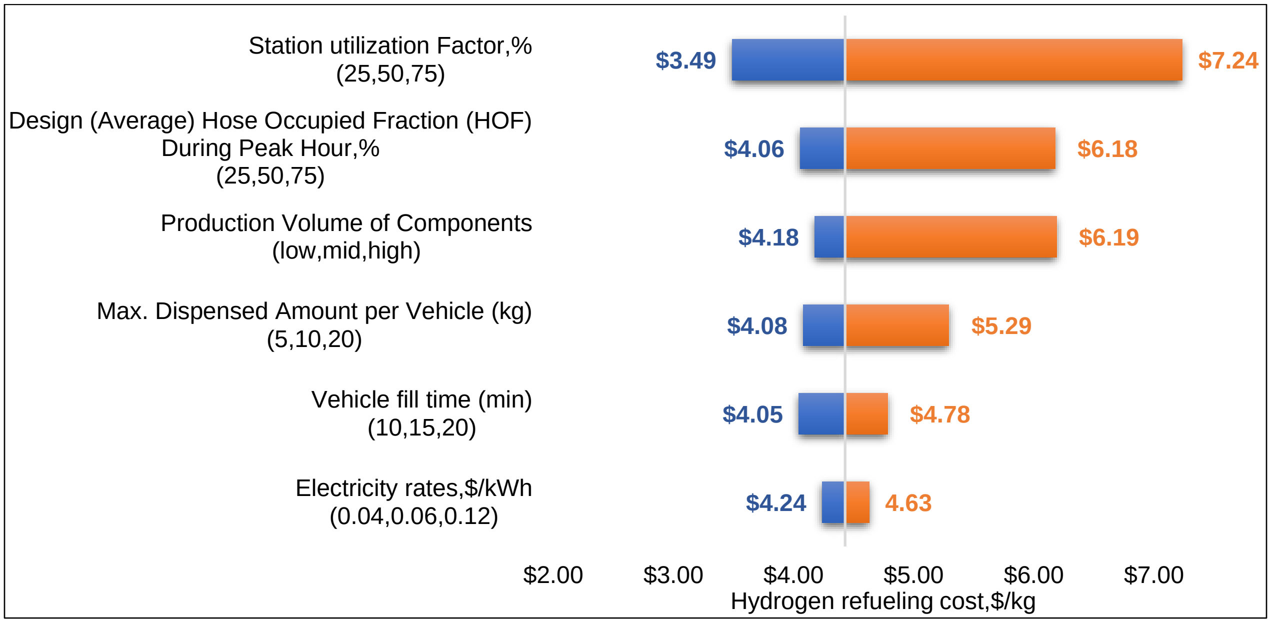

Figure 19: Range of refueling costs for a station receiving hydrogen in the liquid form.

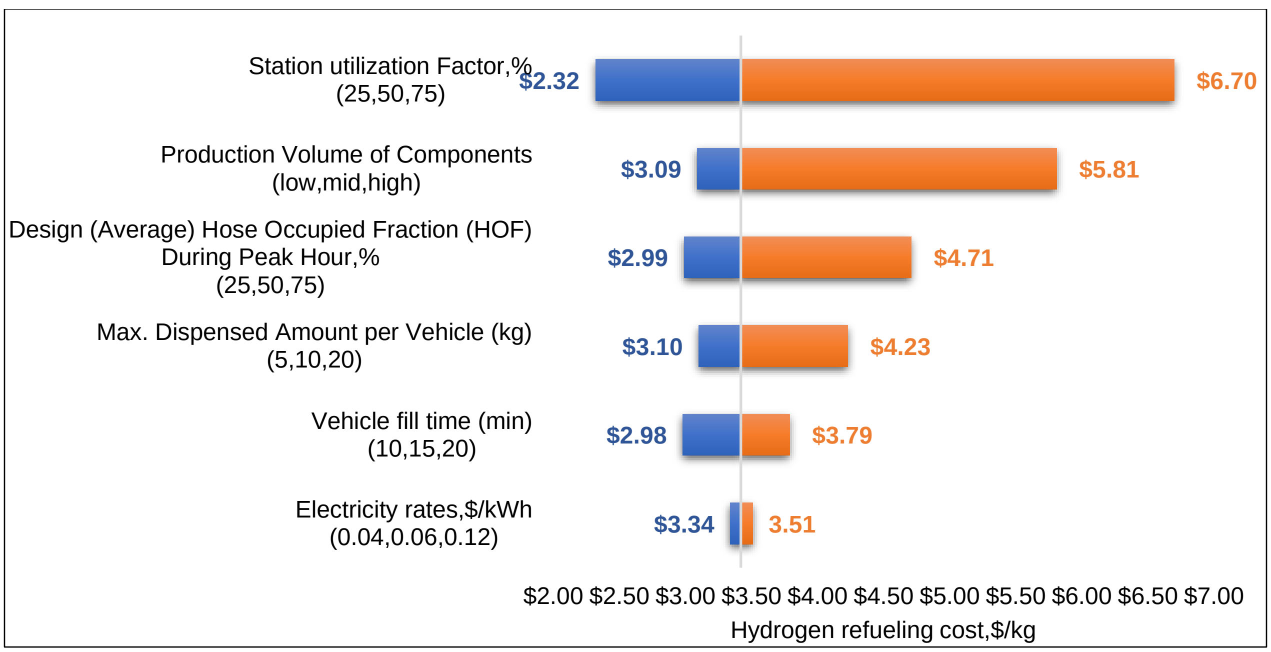

Figure 20: Range of refueling costs for a station receiving hydrogen through gaseous tube trailers.

Appendix 11: *Cost reduction factors for station components*

	Production Volume of Components		
	Low	Mid	High
Component cost reduction factors at three production volumes			
Components with significant industry experience (Technology Basket #1)	100%	79%	75%
Components with moderate industry experience (Technology Basket #2)	100%	61%	55%
Components with limited industry experience (Technology Basket #3)	100%	47%	40%

Figure 21:Cost reduction factors for station components

Appendix 12: *Layout of SERA and STIEVE models*

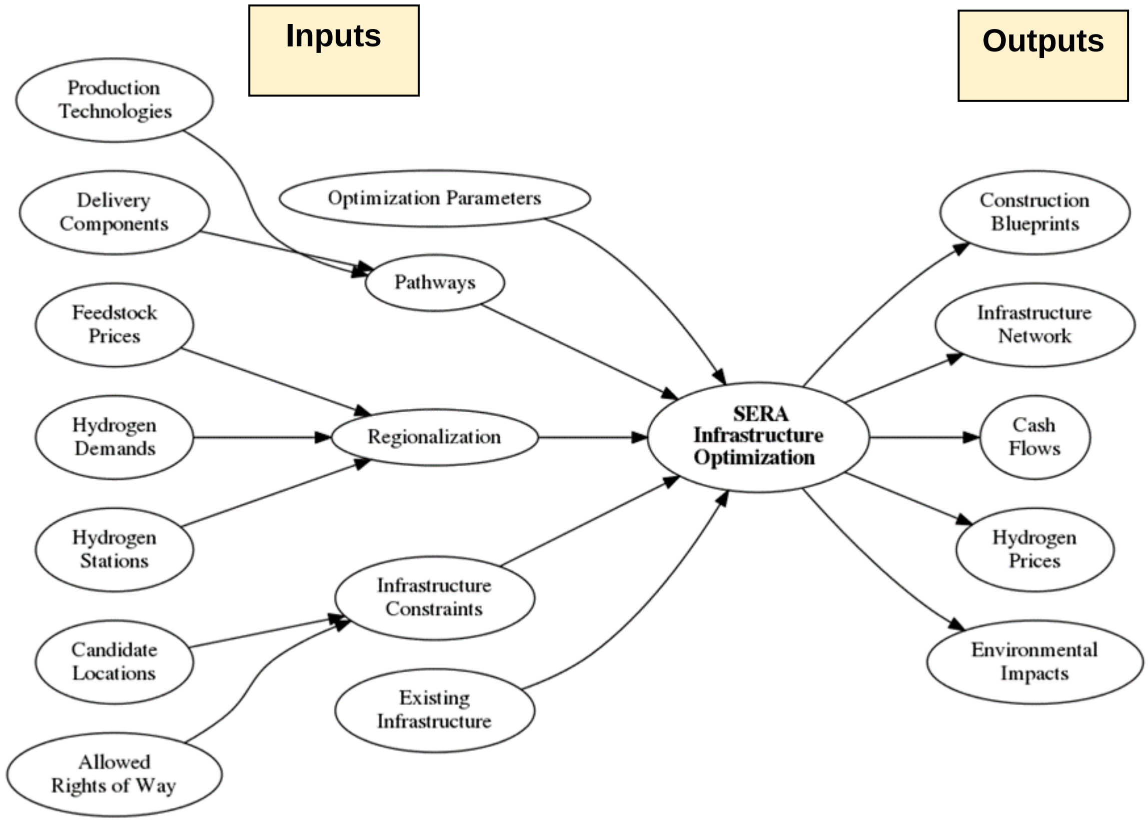

Figure 22:Layout of SERA infrastructure optimization model

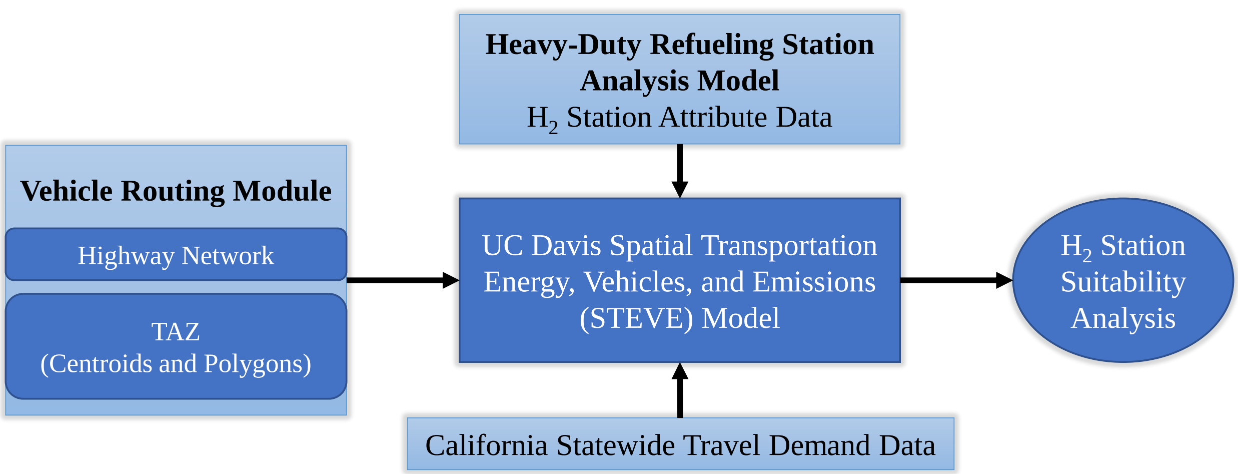

Figure 23:Layout of STIEVE model