Title

California Hydrogen Analysis Project: The Future Role of Hydrogen in a Carbon-Neutral California: Final Synthesis Modeling Report

Authors
Fulton, Lewis
Jenn, Alan
Yang, Christopher
et al.

Publication Date
2023-04-19

ITS UCDAVIS
Institute of Transportation Studies

California Hydrogen Analysis Project: The Future Role of Hydrogen in a Carbon-Neutral California

Final Synthesis Modeling Report

April 19, 2023

Reference No. UCD-ITS-RR-23-18

Prepared By:

Lew Fulton – Principal Investigator

Alan Jenn – Electric transportation sector modeling

Christopher Yang – Supply chain modeling

Andrew Burke – Technology analysis

Tri Dev Acharya – Spatial demand analysis

Xinwei Li – Electric transportation sector modeling

Joan Ogden – Technology advisor

Marshall Miller – Transition modeling

Josh Ira – Industry analysis

Beth Bourne – Project coordinator

Acknowledgements

We gratefully acknowledge funding and guidance from the following organizations in support of this study:

Air Products	Aramco
California Energy Commission	Chevron
General Motors	Honda
Hyundai	International Energy Agency
Leighty Foundation	NICE (Clean Energy Institute)
National Renewable Energy Laboratory	Shell
SoCalGas	South Coast Air Quality Management District
Toyota	

Abbreviations and Acronyms

AZNM - Arizona-New Mexico (region in the Western Electricity Coordinating Council)

BEV - battery electric vehicle

EV - electric vehicle

CARB - California Air Resources Board

CCS - carbon capture and storage

CCUS - carbon capture, utilization and storage

CO_2 - carbon dioxide

CSTDM - California Statewide Travel Demand Model

CEC - California Energy Commission

EIA - U.S. Energy Information Administration

EV - electric vehicle

FCEV - fuel-cell electric vehicle

GH2 - gaseous hydrogen

GOOD - Grid Optimized Operation and Dispatch Model - UC Davis

GW - gigawatt

H2 - hydrogen

HD – heavy duty

HDV - heavy-duty vehicle

HRS - hydrogen refueling station

IRA – Inflation Reduction Act

KMPA – Kentucky Municipal Power Agency (region in the Western Electricity Coordinating Council)

LCFS - Low-carbon Fuel Standard

LDV - light-duty vehicle

LH2 - liquid hydrogen

MDV - medium-duty vehicle

NREL – National Renewable Energy Laboratory

NWPE – Northwest Power Pool East (region in the Western Interconnection)

PEM - proton exchange membrane (fuel cell)

PEV – plug-in electric vehicle (includes battery electric and plug-in hybrid electric vehicles)

PHEV - plug-in hybrid electric vehicle

PNW – Pacific Northwest (region in the Western Electricity Coordinating Council)

RNG - renewable natural gas

RPS - Regional Portfolio Standards

SERA - Scenario Evaluation and Regionalization Analysis model - NREL, https://www.nrel.gov/hydrogen/sera-model.html

SMR - steam methane reforming

STIEVE - Spatial Transportation Infrastructure, Energy, Vehicle and Emissions model - UC Davis

TAZ - transportation analysis zone - system of spatial disaggregation to transportation and land use type areas

TCO - total cost of ownership

TTM - Transportation Transition Model - UC Davis Energy Futures

WECC - Western Electricity Coordinating Council, including a number of subregions with California as a specific region

ZEV – zero-emission vehicle

Table of Contents

Table of Figures

Executive Summary

Main Report

List of Tables

Executive Summary

Main Report

1 Executive Summary

Hydrogen system development and its planning have reached a critical point in California. While many end-investments have been made, there is no clear overarching concept or plan for what a full hydrogen system and supply chain infrastructure might look like 5, 10, or 20 years into the future. There is likely to be a system of some kind, given the value of having one for various end users (transportation, industry, buildings), and the possibility of low-cost renewable hydrogen to contribute to the state's goal of carbon neutrality by 2045. The state recently formed the ARCH$_2$ES partnership to further develop this system, a sign of the urgency of the moment.

This project seeks to assist the planning process by modeling potential future systems and how these systems could develop over time. It includes potential demands for hydrogen across sectors (but with a particular focus on transportation), potential types and locations of hydrogen supply, and how hydrogen could be moved and stored between supply and demand. It includes a detailed analysis of the transportation sector, the electricity sector, and supply chains from production to end-use. It is spatial and thus provides a picture of where supplies and demands may be located and the specific systems that would connect them.

Modeling potential hydrogen systems across supply and demand sectors is a complex undertaking and developing a credible but sufficiently detailed analysis is challenging. There are many possible configurations of hydrogen systems, depending multiple factors. Small changes in technology or cost assumptions can have a significant impact on results, and finding robust solutions and paths forward is difficult. This project provides examples of how specific scenarios could develop but it is also intended to give a better picture of how different configurations may make the most sense and be the most cost-effective under different conditions, and how these might be constructed over time. We are attempting to do this with more spatial detail, and at a higher resolution, than most studies have achieved to date, at least for California. The study is intended to provide policymakers with key insights useful for planning and policy making, and information for potential hydrogen investors and other stakeholders to make good and timely decisions.

This report follows our interim working report from May 2022, which provided an initial sketch of the key aspects of future hydrogen system potential and growth. This report provides an updated (though still often uncertain) analysis of this future. We share more detailed findings across all hydrogen sectors and supply chain components. Future analysis phases are possible with deeper investigation into various questions that are not yet fully addressed. A greater emphasis on near-term hydrogen system development is expected as one follow-on activity.

1.1 Modeling Approach

UC Davis has been researching hydrogen systems for over 20 years and has published numerous reports and papers (many by Joan Ogden and Chris Yang and their colleagues and students). This research has covered most major components of a system and many of the dynamics that would be involved in building one to serve fuel cell vehicles (FCEVs). However, we have not previously undertaken modeling that includes multiple end use sectors or provided a detailed analysis of renewable-intensive electricity systems in a hydrogen-oriented context. This project aims to do that with a focus on three connected modeling efforts:

- **STIEVE Model** - a California road network-based transportation demand model for California, used to project potential fuel cell vehicle sales, stocks, travel, and hydrogen demand, and the need for hydrogen stations - numbers, sizes, and locations - to 2050.
- **GOOD Model** - an economic dispatch electric grid model, used to model the electricity system with higher renewable penetration and with electrolytic hydrogen production and energy storage as part of a growing use of hydrogen.
- **SERA Model** - a hydrogen supply chain model, developed and maintained by the National Renewable Energy Laboratory (NREL) (2019), used to optimize the siting of hydrogen supply locations to meet demand and project how this hydrogen could be transported (e.g., truck or pipeline) and stored along the way.

With these three models, we have developed a detailed, spatialized characterization of a growing hydrogen system from today to 2050. We focus particularly on the electrolytic production of hydrogen, in part because California has made it clear that hydrogen in the state must eventually be 100% renewable, which will either need to be via a clean grid or from biomass. Our grid analysis and supply chain work in this study focus on electrolytic hydrogen.

We currently model hydrogen end-use using a "what if" approach, assuming for example certain numbers of FCEVs of various types by various dates. Supply and distribution of hydrogen are generally endogenous, with a range of input assumptions.

1.2 Key Findings of the Study

Some of the major takeaways from the study are summarized below, organized by stage of the supply chain of hydrogen (to stations and other end users, from hydrogen production).

1.2.1 Hydrogen Transportation-sector Demand

- **Transportation can lead.** A hydrogen system development led by strong demand growth in transportation (especially light-duty and medium/heavy-duty road vehicles) can support the development of a medium-scale supply and distribution system by 2030. At a scale of 300–500 tons per day, possible by 2030, this should be sufficient to cut hydrogen costs and prices toward their long term potential. Industry can also play an important role, but projects typically require large individual facilities with long lead times and may require lower hydrogen prices to trigger investments than transportation does.
- **Transportation is scalable.** Growth in light-duty and medium/heavy duty fuel-cell vehicles can be done rapidly and incrementally, with infrastructure such as stations added in parallel. The decentralized nature of a transportation-focused approach can help to develop a regional hydrogen production/distribution network which can then be scaled with more stations and eventually other "offtakers."
- **Strong early investment is needed.** In the early years of developing hydrogen systems for transportation, many refueling stations are needed to ensure adequate coverage so drivers can reliably find fuel as they make journeys. This can mean generally low utilization of stations and challenging station economics. This in turn may require policies to ensure that profitability can be achieved. The Low Carbon Fuel Standard (LCFS) credit systems, the Inflation Reduction Act (IRA) $3/kg production cost credit, and other incentives can help with this but the most important solution is to scale demand quickly.

- **Small light-duty vehicle (LDV) market shares can yield big demands.** As we show in our Base scenario, even at a relatively small percentage of sales (e.g., 5% by 2030), LDV FCEVs would require a large number of fueling stations and hydrogen supply (on the order of 200 stations, several hundred tons/day of hydrogen). Trucks (particularly medium and long-haul heavy-duty) at a somewhat higher market share could trigger the same kind of hydrogen demand. Transit buses can also help as they are among the earlier adopters and could achieve much higher market shares (approaching 50% by 2030).
- **On-going scale-up after 2030.** After 2030, with lower hydrogen costs and prices available, the market could scale in a profitable manner to reach much higher shares and hydrogen demand. If FCEVs succeed in growing to about 10% of LDV shares and 25% of truck shares by 2045, hydrogen demand could be a factor of 10 higher than in 2030, and refueling station numbers could eventually reach many hundreds or even thousands in California, depending on average station sizes. Moving to significantly larger stations (up to 20 tons/day, particularly along highways) can help reduce the overall station numbers needed, given that spatial hydrogen availability requirements are met.
- **Existing gasoline/diesel fueling stations should provide a solid Base for creating hydrogen stations, at least through 2030.** Converting or augmenting existing stations can be easier than starting with “greenfield” sites and can provide excellent locations. However, footprints for hydrogen stations can be more than some gasoline stations provide. Based on our station footprint analysis, it is possible that once large numbers of stations are required (e.g., 1000 or more), and especially if average station sizes continue to increase, locating suitable parcels that align with desired siting locations may become challenging and is worthy of further investigation.
- **Hydrogen will likely be delivered to stations.** Hydrogen could be produced on site at refueling stations but requires space for electrolytic (or SMR) systems, sufficient storage on site, and purchase of electrolyzers and use of retail electricity. In general, large-scale production from remote sites, selected based on scaling potential, renewable resource availability and hydrogen production cost, appears likely to be far cheaper than on-site production, especially for renewable (electrolytic and biomass-based) hydrogen; but the market must reach a certain size to support the development of large production sites.
- **Liquid hydrogen may play an important role.** Liquid H2 production/storage/station systems have significant advantages over gaseous systems, even if used to fuel gaseous-storage on board vehicles. One of the biggest advantages is the speed of refueling vehicles with liquid-based technologies. Another is the density of storage made possible with liquids. A third is the lower cost and larger volumes of liquid tanker trucks than gaseous tube trailers for delivering hydrogen to stations. However, liquid systems involve significantly higher conversion and storage losses than gaseous systems and may be more expensive, especially at small volumes. Light-duty vehicles are unlikely ever to be designed to store liquids on board and trucks may vary with the application. But this is not critical since gaseous vehicles can be compatible with a liquid hydrogen station system.

1.2.2 Hydrogen Demand in Industry

- **Refineries dominate current demand, but may be irrelevant for near-term growth.** By far the largest demand for hydrogen in 2023 in California is at refineries, with over one million tons per year (3000 tons/day) in use. However, this hydrogen is almost all from fossil natural gas (with steam methane reforming) and is produced at or close to refineries. It is not expected to play a major role in a growing system to serve various hydrogen needs in other industries or transportation uses around the state, unless refiners decide to link into a bigger system.

- **Other opportunities exist.** A range of industrial applications could be important for hydrogen integration because there are many practical uses for hydrogen in industry – both as a feedstock and as a fuel. Additionally, the state's industrial and manufacturing processes are some of the most energy and carbon intensive in the world, and lack pathways for clean, sustainable operation. This study has considered opportunities for near- and mid-term uptake of hydrogen in biofuel refining, chemical synthesis, process heating, and power generation.
- **Hydrogen use in turbine generators could be important in the near term.** The use of hydrogen to generate electricity (typically after being stored on a daily, weekly, or seasonal basis) may play an important role in grid management beginning soon, so rules allowing its use in gas turbine generators, such as allowing it to be treated as a renewable source if from renewable feedstocks, appears important. However, like any turbine generator, H2 turbines will generate NOx and this must be controlled, and permitting evaluated within the air control strategies of each district. Eventually, fuel cells may be competitive with turbines, but given their large installed Base, hydrogen use in turbines may be important for many years.
- **Large investments and long lead times.** It generally takes large investments and potentially long lead times to build individual hydrogen-based industrial facilities. Retrofits (such as for power turbines) can provide cost effective near-term strategies. Requiring green hydrogen complicates the scaling process and could require remote production to avoid stressing nearby grids.
- **Overall, industry should have a similar H2 potential as transportation.** Our scenarios show that, apart from refining, industrial demand for hydrogen could be on the order of 300-600 tons/day by 2030, mostly from its use in electricity generation, as a blend with or replacement for natural gas in power turbines. The potential out to 2035 and beyond is considerably larger, as hydrogen costs decline and there is more time to plan, permit, and build facilities.

1.2.3 Hydrogen Supply

- **Renewable hydrogen is the future.** Hydrogen produced and used in California is currently nearly all from natural gas. California has made it clear (via a range of policies and also via the ARCHES directives), that future growth must be renewable. This can include renewable natural gas, though electrolytic hydrogen is likely to play an important role in a fast growing system.
- **Electrolytic hydrogen costs should drop rapidly in a growing system.** Various studies indicate that electrolytic hydrogen, if built in a mass production fashion around the state and beyond, should become competitive by or before 2030. This reflects technology cost reductions for PEM electrolyzer technology and likely increases in natural gas feedstock costs over time. This cost reduction must be coupled with low-cost electricity (such as from solar or wind farms) and reasonable utilization rates to achieve low cost production of hydrogen.
- **A growing electric grid system can support electrolysis.** We estimate that the demand for electricity for a hydrogen system by 2030 is manageable given the size targets we consider. Building out a renewable-dominated power system beyond 2030 that can meet overall increases in California's electricity demand (including from hydrogen production but also electric vehicle growth and increased electricity use in other sectors) will require substantial capacity growth, in part to handle daily, weekly and seasonal variation in renewable resource availability (wind and

solar). Development of separate (though probably connected) renewable energy farms focused on producing hydrogen can reduce pressure on the grid.

- **Hydrogen can help grids in several ways.** Producing hydrogen for end-use markets as well as for energy storage within the electricity system can help to manage generator dispatching and grid management and cut the required amount of grid capacity growth significantly. Hydrogen could play a particularly important role in seasonal energy storage for the grid system, substantially decreasing the need for renewable peak-power generation (and overall capacity), and increasing overall hydrogen production by a factor of 2 or more, depending on its cost and demand from other sectors.
- **Western Electricity Coordinating Council (WECC) developments will matter.** Our electric sector modeling indicates that much of California's future electricity may come from outside the state, given the vast wind and solar resources around the western states. The further development of the Western Interconnection system will matter. (The WECC is made up of the Western Interconnection states—i.e., 11 western-most states in the contiguous US (CA, OR, WA, ID, NV, AZ, NM, UT, WY, MT; [see Figure 11 for a map].)The cost of overbuilding intermittent renewables vs using storage, and the extent to which the entire Western Interconnection system moves toward high levels of these intermittent renewables, will be important factors. Building out intermittent capacity in a strategic manner across the Western US may provide more seasonal generation balancing than is generally assumed, though hydrogen or other energy storage systems still appear likely to play a role.
- **Large scale hydrogen storage is not critical to meet transportation end-use needs.** Meeting hydrogen end-use demand (such as via refueling stations) appears unlikely to require large scale storage systems, since several-day storage is all that is likely to be needed, with demand being fairly predictable. In a pipeline-dominated system, the pipelines may provide all the storage needed. Terminals storing hydrogen in central locations are another approach to multi-day storage, though large stations will likely want some on-site storage. This is separate from considerations of hydrogen storage to assist power generation and grid management, which may be very important, especially as high shares of renewable power are reached around the WECC.
- **We may need "deep storage," but not right away.** In scenarios where most states require high shares of renewables in the future, the need for hydrogen storage within that WECC system may eventually be high enough to require deep storage of hydrogen, such as in salt caverns. We do not reach very high levels of storage (or of high value of storage) in our scenarios until 2040 or later. The specific amounts and locations would vary considerably with assumptions made for a scenario, and this aspect needs further study.

1.2.4 Hydrogen Transmission and Distribution

- **Trucks or pipelines?** Hydrogen can be moved as a gas or liquid by truck, or as a gas by pipeline; all of these options have advantages and disadvantages and are estimated to be the preferred options in certain situations. Pipelines can be the cheapest option but require large H_2 volumes to reach low costs per kg of hydrogen moved, and their costs rise with distance. Liquid hydrogen "tanker" trucks are generally much larger and cheaper than gaseous "tube trailers" and make sense once volumes moved exceed one tonne per day. For larger stations, tube trailers moving less than 1 ton per shipment (and then kept at the station as the storage system becomes part of the refueling system) would have to be changed out once or several times per day, adding significantly to cost and logistical challenges.

- **Liquid hydrogen transport can be competitive with pipelines.** Even in some large-scale, long distance transport situations, such as when point-to-point volumes are still modest, liquid hydrogen truck delivery may be cheaper than pipelines; but using trucks to transport hydrogen long distances could mean many hydrogen trucks on highways and in cities, which could be problematic. The numbers are unlikely to exceed the number of diesel and gasoline delivery trucks today, and the trucks could be made to run on hydrogen, which will help. However, at this time no hydrogen powered hydrogen delivery trucks are being produced.
- **Pipelines should go big.** In general, larger diameter pipelines are much more cost-effective than smaller ones but require large volume flows to achieve low costs. Reaching large volume flows will take time and the establishment of a few large users close to one another, or many small users connected to “hydrogen hubs” that serve as large scale demand/storage nodes. Considering a trunk line from a large production facility to a “hub” of end users may be the best way to begin a pipeline system.
- **Think long term if possible.** A short-term view of cost recovery (e.g., less than 10 years) tends to push investments toward smaller scale options, such as trucks and smaller system components; a longer-term view toward a large-scale system will tend to encourage investments in pipelines and larger storage facilities, which may take 10 or more years to achieve cost recovery. A shorter-term view may lead to suboptimal long-term outcomes from both an investor and a societal perspective, but subsidies and incentives may be needed to achieve this long-term trajectory, which is not without risks.
- **Uncertainty is a barrier.** Building out a pipeline network is dependent on known and expected end-use locations and demand levels, and planning requires a clear view of how these are expected to develop. A master plan of some kind seems critical to pipeline development. Creating hub designs to quickly achieve scale is an important aspect of developing a hydrogen system.
- **Speeding permitting times and addressing local concerns will be critical to make pipelines a reality.** Long distance pipelines can be cost-effective and may be needed to connect the lowest cost hydrogen production locations with key end-use locations, but the wide range of issues associated with siting, permitting, rights of way, community concerns, and other factors will need to be addressed to get such pipeline systems in place in a timely way. To speed up construction, reducing permitting and other time-delay factors will be important.
- **Using existing pipelines for blending or retrofit has challenges.** This project has focused mainly on describing new pipeline build strategies but has also considered ways to use existing pipelines. There are numerous technical challenges for blending or retrofitting existing pipelines for use with hydrogen, and economic questions regarding whether, for example, it makes sense to blend and then separate hydrogen and reach needed purity levels for some end uses. But these options should continue to be explored.

Each of these findings is explained further in the body of this report, along with a presentation of the modeling system and the various scenarios being investigated. The analysis results are presented along with assumptions and sensitivity cases. Further details will be made available in various documentation reports and shorter research papers.

1.3 A Transportation-focused Hydrogen Scenario for California to 2030 and Beyond

While there are many possible hydrogen futures within the state, some seem preferable (and more likely) than others. Here we lay out one such scenario, grounded both in our modeling and in our awareness that 2030 is only 7 years away, while 2045 is 22 years away, presenting a much wider range of possibilities in that time frame. In the body of the document, we consider additional scenarios and their impacts on the system in the future. This is our "Base case" transportation scenario, while a "High case" is also presented in the main report. It should be noted that these scenarios were developed for this project and do not necessarily match others, such as the California Air Resources Board (CARB) scoping plan, California Energy Commission (CEC) scenarios, or others.

There are several decision variables and key uncertainties for California's hydrogen future, and any one specific scenario must make some choices among these. Key assumptions for this scenario are shown in **Error! Reference source not found.**.

Table ES-1: Key assumptions and characteristics of the scenario

System aspect	2030	2045
Hydrogen demand	500 tons/day (180k tons/yr)	7,000 tons/day (2.5 million tons/yr)
Type of hydrogen	Dominated by electrolytic, trending toward 100% renewable	Fully renewable and net zero GHG
End uses	Dominated by transportation (around 50% light-duty and 50% medium/heavy duty) with some industrial/port demand	Wide range of demand types, but overall demand is still more than 50% in the transportation sector
Production locations	Mostly within California, mostly within 100 miles of end uses	Increasingly produced outside California in remote locations, to meet high levels of demand at low cost
Scale of production	25–50 tons per day in 10–20 locations around the state, with storage on site	Some much larger facilities 100+ tons/day feeding large systems of pipelines; possible deep storage
Type of delivery systems	Primarily liquid tanker truck; no dependence on pipelines in this time frame	Pipeline transmission into CA and within CA at least to terminals near end uses; tanker truck for final few miles
Transportation end uses	200,000 LDV FCEVs on road; 20,000 trucks of various types; 1000 FCEV buses and long-haul trucks accounting for half of H2 demand	3 million LDV FCEVs, hundreds of thousands of trucks; long-haul continued dominant for hydrogen demand; some rail, aviation, shipping
Key industries providing demand	Ports, bio-refining, and turbine electricity generation	Addition of chemicals, cement, possibly fertilizer (ammonia), steel, institutional buildings

FCEV, fuel-cell electric vehicle.

As shown in Figure ES-1, the growth in transportation hydrogen demand in this scenario is very rapid to 2030, and rapid growth continues thereafter out to 2050. About 5000 tons/day is reached by 2045.

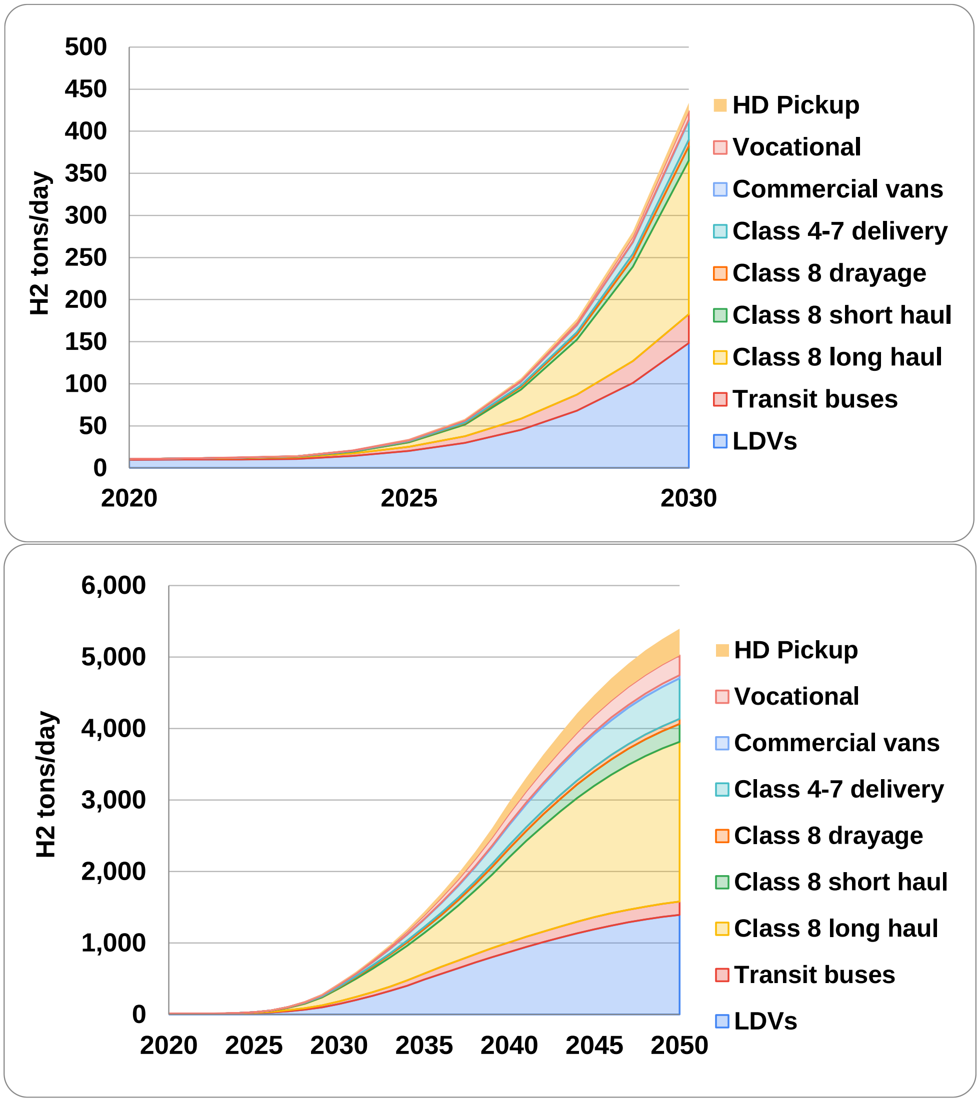
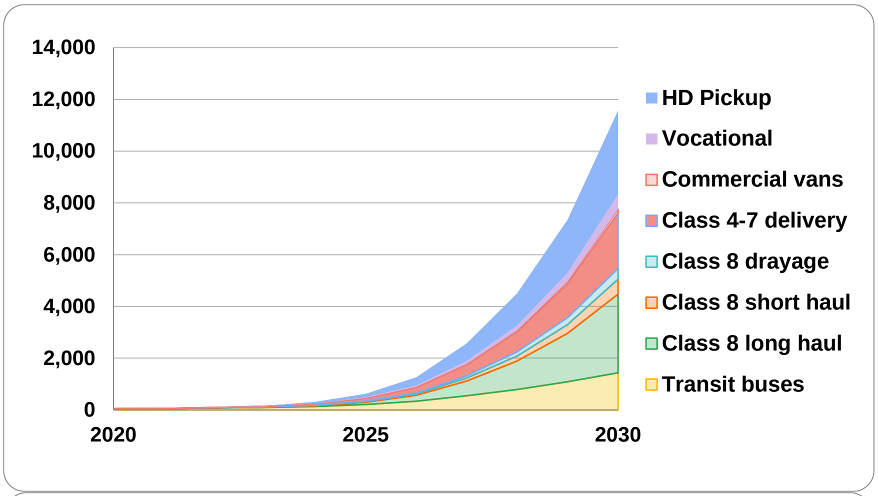


Figure ES-1. Hydrogen demand to 2030 (top) and 2050 (bottom) by vehicle type, tonnes/day

The stocks of various truck types associated with this hydrogen demand are shownFigure ES-2.Heavy duty trucks and buses reach about 10,000 stock by 2030 and over 100,000 by 2050; smaller delivery and commercial pickup trucks (with much larger markets generally) reach 30,000 in 2030 and over 600,000 by 2050. LDVs (not shown, since they would dominate and compress the other modes in the figure) reach 200,000 stock in 2030, 700,000 in 2035, and 2 million in 2050, about 5% of the stock of LDVs in California at that time.



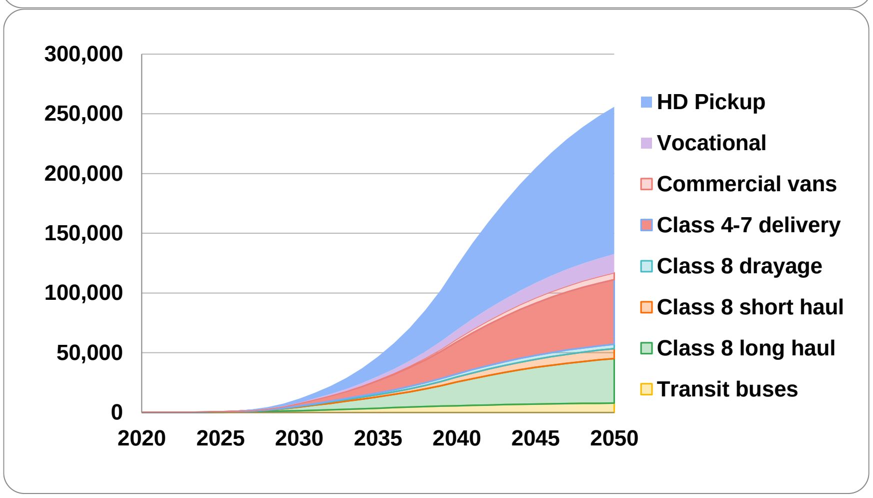


Figure ES-2. Fuel cell truck and bus stocks to 2030 (top) and 2050 (bottom) by vehicle type

These stock numbers relate to sales, which are affected by the rise in zero-emission vehicle (ZEV) sales mandates and the potential share of FCEVs of total ZEVs. The 2030 and 2045 ZEV sales shares, fuel-cell electric vehicle (FCEV) sales and stock shares by vehicle type are shown in Figure ES-3. These figures show four bars as follows:

a) The ZEV vehicle share of all LDV sales (that rises to 100% by 2035 and beyond),

b) The FCEV share of ZEV sales,

c) FCEV share of all sales (equal to the share of ZEV sales once ZEVs are 100% of sales), and

d) FCEV share of the total stock of vehicles (with the lag from stock turnover)

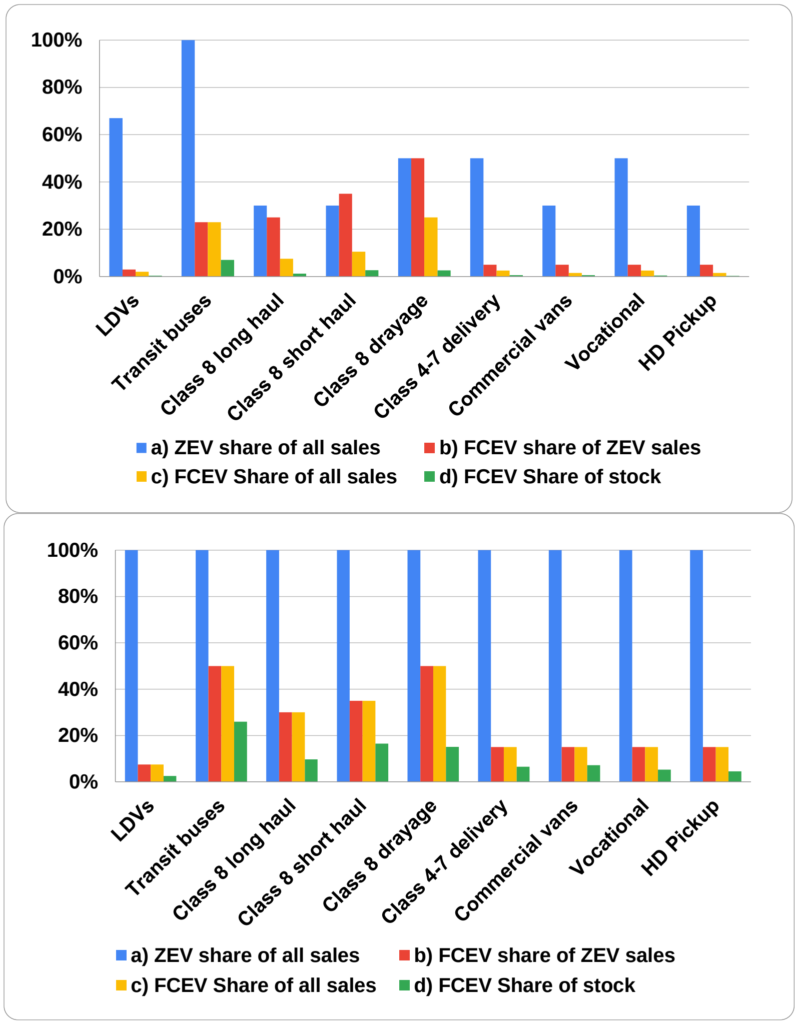


Figure ES-3. ZEV shares of sales, FCEV shares of ZEVs, for 2030 (top) and 2040 (bottom) in Base scenario

As shown in Figure ES-3, by 2030, the ZEV share of total sales reaches nearly 67% for LDVs, 100% for transit buses, and anywhere from 30% to 45% for various truck types. The FCEV share of ZEVs (and thus of total sales) is typically quite low, at about 5% for LDVs and other smaller trucks, and at 25% or 30% for larger trucks and buses. These shares are the key to the sales assumptions in this scenario and were set to provide a plausible yet significant trajectory for projecting FCEV sales. By 2045 they reach somewhat higher sales shares, typically double (or more) of the 2030 levels, and the stocks grow to catch up, reaching 20% or more for major truck types (and about 7% for LDVs, following 10% sales shares in that year).

The High FCEV case, shown in the body of this report, has about 2–3 × the ZEV sales shares for FCEVs by 2040 as shown in this scenario. This "Base" scenario is particularly interesting since it turns out to be sufficient to provide reasonably High hydrogen demand by 2030; demand that, as will be shown next, may be sufficient to achieve levels of production that can lead to a commercial market.

By 2040, manufacturers of all vehicle types will be required to sell only ZEVs; we assume FCEVs will reach an equilibrium share of ZEV sales by then, which varies by vehicle type. LDVs are lowest at around

10%; transit buses are highest at 50%, and trucks range from 20 to 30% of ZEV sales. This picture then remains fairly constant to 2050 (though stock shares still rise).

Two of the most important modes in terms of hydrogen demand are light-duty vehicles and long-haul heavy-duty trucks. Details for each of these are shown in **Error! Reference source not found.** and **Error! Reference source not found.** below, which provides the major assumptions and calculations in the Base case to get from vehicle sales, to stocks, to hydrogen use in a given year. Sales growth in each case is rapid from 2024 to 2030, and beyond. The combined hydrogen demand from these two modes in 2030 is about 375 tons/day. The combined demand of all the modes in 2030, as shown in Figure ES-1 above, is about 450 tons/day.

Table ES-2. Key variables in the scenario for LDVs

	2024	2027	2030	2035	2040	2045
Total sales (×1000)	1870	1849	1868	1886	1905	1924
ZEV sales share	20%	33%	67%	100%	100%	100%
FCEV sales share of ZEVs	2%	5%	8%	8%	9%	9%
FCEV sales (×1000)	7	31	100	151	171	173
FCEV stock (×1000)	24	80	276	806	1,339	1,726
Hydrogen (kg/vehicle/day)	0.70	0.70	0.70	0.70	0.70	0.70
Hydrogen (tonnes/day)	16.8	56.1	192.8	563.1	935.5	1205.7
Hydrogen (thousand tonnes/year)	6.1	20.5	70.4	205.5	341.5	440.1

Table ES-3. Key variables in the scenario for long-haul trucks

	2024	2027	2030	2035	2040	2045
Total sales	12,000	12,104	12,225	12,347	12,471	12,595
ZEV sales share	5%	15%	30%	40%	100%	100%
FCEV sales share of ZEVs	15%	20%	35%	35%	30%	30%
FCEV sales	90	363	1284	1729	3741	3779
FCEV stock	15	576	3041	9455	19831	30654
Hydrogen (kg/vehicle/day)	60	60	60	60	60	60
Hydrogen (tons/day)	0.9	34.5	182.4	567.3	1189.9	1839.2
Hydrogen (thousand tons/year)	0.3	12.6	66.6	207.1	434.3	671.3

1.3.1 Fuel Cell Vehicle Costs

Regarding the cost of light- and medium-/heavy-duty FCEVs, we estimated the incremental purchase costs along with operating (maintenance and fuel) costs, to derive an overall “incremental” cost of hydrogen vehicles vs gasoline or diesel vehicles in these scenarios (Figure ES-3). Here we report the incremental purchase costs, which are fairly high per vehicle in the early years (e.g., 2025) but drop to near-equal or even lower than gasoline or diesel as FCEV purchase prices reach parity or better. The relative prices are shown in Figure ES-5, for light-duty (upper left) and a range of truck types (upper right). The light-duty also illustrates the relative price of FCEVs to both gasoline and battery-electric vehicles, indicating they all reach a similar level by the early 2030s.

Though these incremental purchase prices start higher, their reduction over time as sales increase results in less overall incremental cost than one might expect. The overall cost of purchasing all the FCEV cars and trucks is shown in the lower two panels of Figure ES-4; total cost reaches $4 billion per year in 2030 and a steady $8 billion per year for new FCEV purchases by about 2040, when the system matures. But the incremental cost of these vehicles over their gasoline/diesel counterparts is $200 million, reached in 2035, and by 2040 they reach overall parity across vehicle types (net $0 additional purchase cost). Thus the net “investment” cost of these vehicles is far lower than their gross purchase prices would suggest.

Our modeling then goes beyond this basic cost to explore the overall system costs, focused on hydrogen delivery system and component costs.

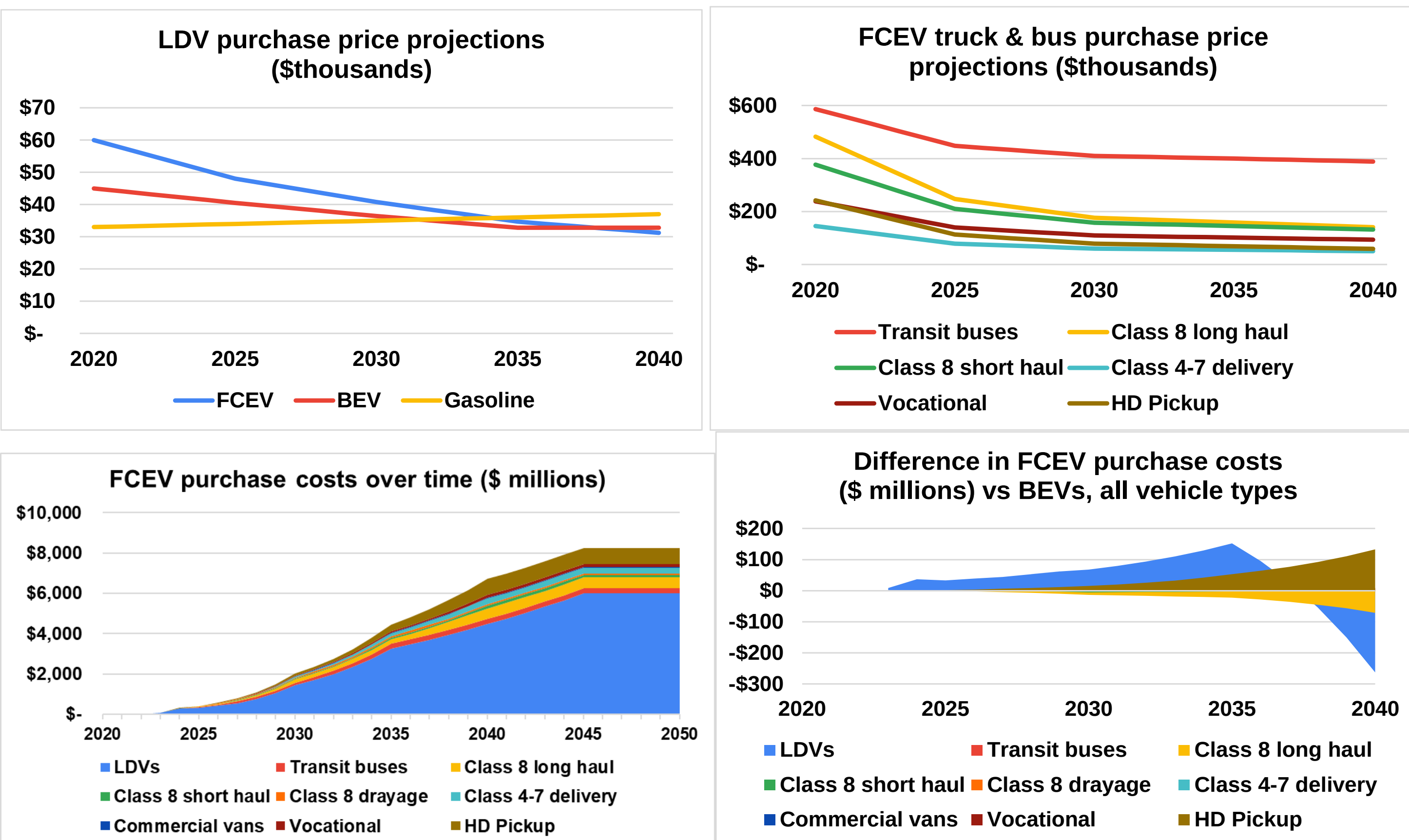


Figure ES-4. Vehicle prices and purchase costs in the scenario (HD, heavy-duty)

1.3.2 Hydrogen System Design and Cost

The hydrogen demand shown in Tables ES-2 and ES-3, along with demand from other vehicle types, reaches 450 tons/day in 2030 and nearly 6,000 tons/day by 2050. Focusing on 2030, is this enough hydrogen demand and system size to reach an economically sustainable and even prosperous hydrogen industry? Probably—a detailed cost analysis, presented in the body of the report, suggests this is likely. For example, ten production facilities of 25 tons of hydrogen per day and 5 sized at 50 tons per day by

2030 would be enough to supply the hydrogen for these vehicles, which is a reasonably large volume both in terms of the size and number of facilities. However, the scaling and learning effects, and thus the cost and price of the hydrogen, will ultimately depend on the production technologies and their costs, such as the cost per kW for electrolyzers, and the price of electricity, both of which depend on things that are outside the scope of this scenario. And yet, if California can develop a hydrogen market big enough to support a dozen large production facilities and distribution systems to get this hydrogen to end uses, the cost of this system should drop fairly dramatically compared to the current situation.

As shown in Figure ES-5, a range of possible system configurations is considered for delivering hydrogen from production locations to end uses. In these configurations, the following parameters are varied: (i) system size: either 500 or 1000 kg/day, (ii) distance of hydrogen production from end uses: near, and shipped by truck, or far, and shipped by pipelines to either terminals or end uses; (iii) whether the system relies mainly on gaseous distribution or liquefies hydrogen at terminals and handles it as a liquid up to the point of refueling (when reconverted to compressed gas on board vehicles).The costs associated with each segment of producing, storing, or moving the hydrogen were estimated using a range of models and off-line analysis described in the report.

The figure shows eight scenarios as described in the table below the figure. These different approaches to producing electrolytic hydrogen and delivering it to refueling stations (and onto vehicles) range in net, levelized cost delivered from about $5.00 to $6.25 per kilogram. This reflects a scaled system in 2030 and depends on a range of assumptions, such as the ability (in four of the scenarios) to construct long-distance pipelines in that time frame.

These scenarios also range significantly in terms of their estimated construction or investment cost—the up-front cost of building out the system. Using the cost models mentioned, investment costs for each stage of the supply chain were estimated for each of the scenarios shown in Figure ES-6, on a per kg/day basis and a total cost basis (taking into account that some systems shown are twice the size of others). On a per-kg-day of capacity basis, investment costs in 2030 for a somewhat scaled system vary between $5 and $8 thousand per kg of daily capacity. Investment costs are higher for liquid than gaseous systems, and for distance/pipeline than nearby/truck-focused systems. The larger systems also have some cost advantages over the smaller systems (3/4/7/8 vs 1/2/5/6), but not large savings, suggesting that scale economics can be largely achieved at the 500 kg/day level by 2030. Pipeline distance does have an impact on these costs and cost reduction since their cost scales more than linearly with length.

The total investment costs (Figure ES-7) are simply the per unit investment costs multiplied by system size. Larger systems are more expensive. The overall costs of constructing the components included in these system examples range from under $3 billion to over $7 billion during the 7 years from 2023 to 2030, if they were completed by that year.

	1	2	3	4	5	6	7	8
System size (tonnes/day)	500	500	1000	1000	500	500	1000	1000
Liquid or gaseous dominated	G	L	G	L	G	L	G	L
Nearby or distant production	N	N	N	N	DP	DPT	DP	DPT
Number of stations	300	200	600	300	300	200	600	300
Average station size (tonnes/day)	1.67	2.50	1.67	3.33	1.67	2.50	1.67	3.33
Average distance (km)	50	50	50	50	1000	500	1500	500
Electricity price	\$0.06	\$0.06	\$0.06	\$0.06	\$0.03	\$0.03	\$0.03	\$0.03
Electrolyzer cap factor	67%	67%	67%	67%	33%	33%	33%	33%

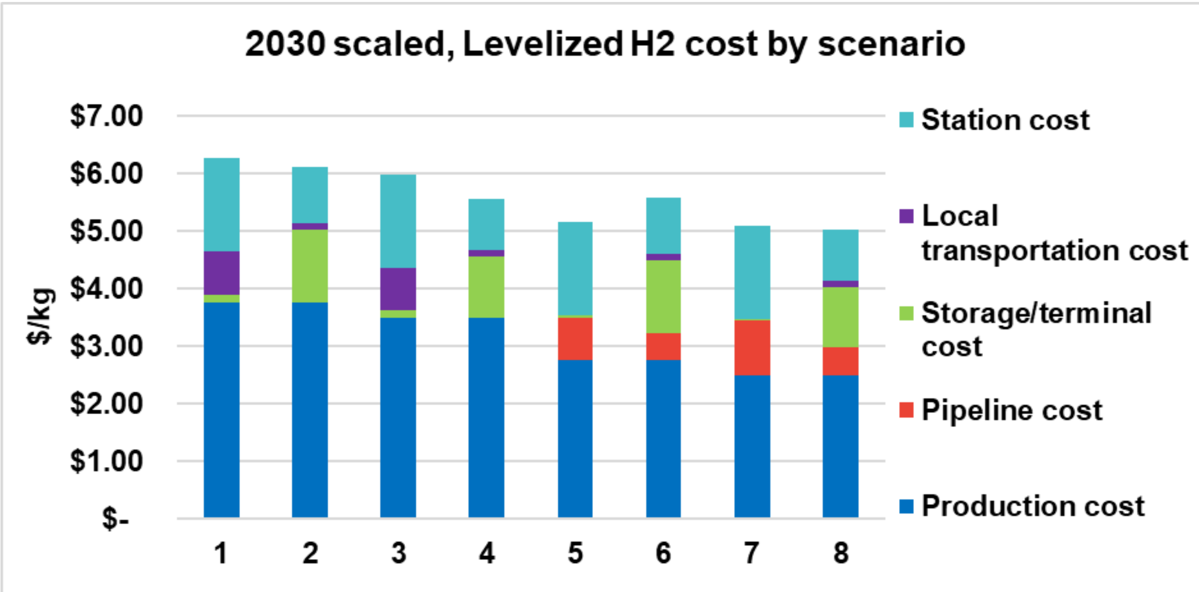


Figure ES-5. 2030 levelized H2 cost (\$/kg) by production/distribution scenario. (Notes: G=H2 transported as a gas; L= transported as a liquid; N=hydrogen produced nearby, DP=hydrogen produced at a distance and moved by pipeline; DPT= hydrogen produced at a distance, moved by pipeline and stored at a terminal.)

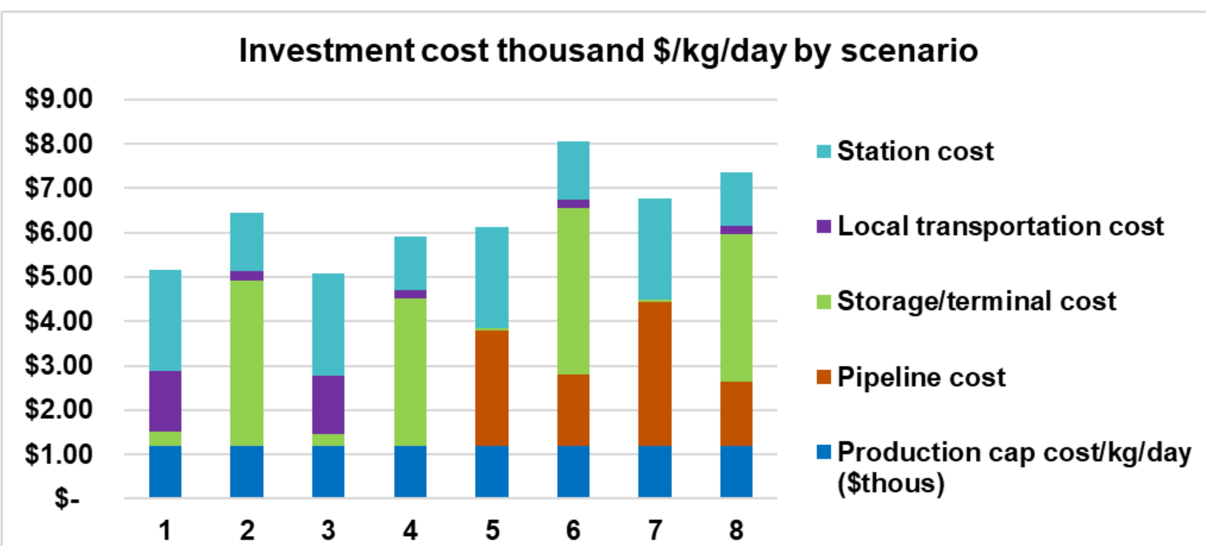


Figure ES-6. 2030 Investment cost per unit of H2 capacity by production/distribution scenario

	1	2	3	4	5	6	7	8
System size (tonnes/day)	500	500	1000	1000	500	500	1000	1000
Liquid or gaseous dominated	G	L	G	L	G	L	G	L
Nearby or distant production	N	N	N	N	DP	DPT	DP	DPT
Number of stations	300	200	600	300	300	200	600	300
Average station size (tonnes/day)	1.67	2.50	1.67	3.33	1.67	2.50	1.67	3.33
Average distance (km)	50	50	50	50	1000	500	1500	500
Electricity price	$0.06	$0.06	$0.06	$0.06	$0.03	$0.03	$0.03	$0.03
Electrolyzer cap factor	67%	67%	67%	67%	33%	33%	33%	33%

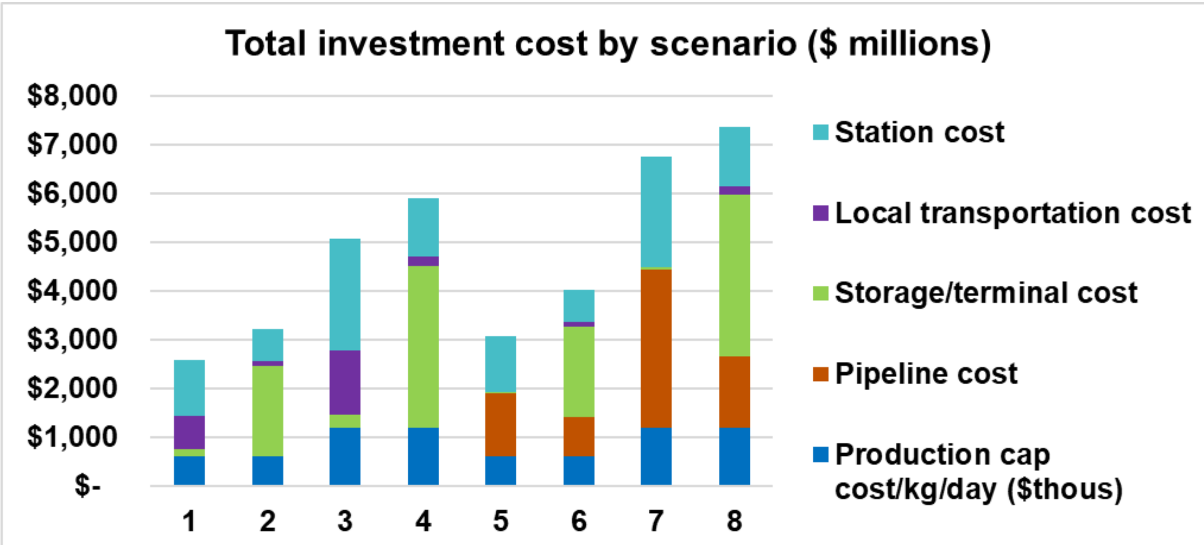


Figure ES-7. Total investment cost ($ millions) between 2023 and 2030 by production/distribution scenario. (The table above the figure is duplicated from ES-5 for reference to define scenarios 1–8.)

Overall, we have presented one example scenario, though with many possible variants in terms of fuel supply chain. This scenario provides a sense of the scale and costs for a hydrogen system that could be built by 2030 and serve the transportation sector in California. Larger systems are possible, and our High case in the main report considers such a scenario. There could also be a similar level of demand from investments in hydrogen for industry and especially for electricity generation, in the 2030 time frame. Scenarios including both transportation and industry are considered in the report.

Many additional aspects of analysis are presented in the report, while others are still needed and can be developed by building on the work presented herein. Follow-on research topics are outlined in the report's conclusions.

2 Introduction

UC Davis has undertaken hydrogen research for over two decades. In the past year, we have focused on developing a full characterization of a hydrogen system in California and addressing many questions surrounding how this system could and should be developed, taking into account the transportation sector but also other demand sectors, supply options, and H2 storage and distribution infrastructure. This project is ongoing, but we have produced this first full report on our analysis and modeling completed to date.

This project is intended to provide a time-dynamic, spatially-detailed hydrogen system analysis for California out to 2050 and, in essence, answer the question “Does a large-scale, carbon-neutral hydrogen system provide significant net benefits compared to a future without this system, across transportation, electric power, industry, and other sectors?” A number of related questions, regarding the scope and rollout of such a system, cost of components, policies needed to make it happen, and other aspects are included in the study.

The project’s geographic scope is focused on California but includes a detailed characterization of potential hydrogen production outside the state, for example covering electricity production from the Western Electricity Coordinating Council (WECC), aka the Western Interconnection, across the western states of the country. We are characterizing the hydrogen system supply across this larger region, identifying optimal points of production, storage, and transportation/transmission of hydrogen to markets in California. We consider the design, construction and operation of this system out to 2050. This includes a detailed transition and cost analysis, with comparisons across several scenarios. System, market and investment requirements, growth aspects and risks, and policy actions needed particularly over the next 5 years (while thinking to 2030 and beyond) are identified. Particular attention is paid to the development of the light-duty and heavy-duty fuel cell vehicle market, but other sectors are also characterized. The project's scope and scale allows an analysis of scenarios of the relative use of hydrogen and electricity infrastructure and each system's share of the total [energy + feedstocks] market, to achieve deep decarbonization for all sectors in California by the year 2050.

The primary goal of this study is to model a well-characterized, spatially-elaborated, low-carbon hydrogen system for California, with supply-chain component level detail. It also aims to produce a vision and plan for building out this system, including FCEVs, hydrogen use in power generation and industry, and hydrogen storage and distribution systems. It focuses on a long run equilibrium system (circa 2045) and a key milestone year along the way (2030). Other steps along the way are considered, using a 5-year time step. It includes hydrogen’s role in transportation, including in light, medium, and heavy-duty vehicles, as well as its use in industry and role as an emerging energy storage option for (intermittent) electric power. Another objective is to estimate the system investment, and operating costs, the net change in costs and benefits over a future without such a system, and the overall transition costs of building out the system.

2.1 Background: Hydrogen System Development in California

California has targeted a carbon neutral economy by 2045 and, as part of this, has significant initiatives for both battery electric vehicles (BEVs) and hydrogen fuel-cell electric vehicles (FCEVs). There are now over 1 million plug-in hybrid electric vehicles (PHEVs) and pure battery electric vehicles (BEVs) in the state. The hydrogen vehicle system is more nascent, but investments and interest are growing, including for trucks. In response to the recent announcement from the US Department of Energy (DOE) that it will fund up to 8 hydrogen hubs around the country, California has initiated "ARCH$_2$ES," a public-private partnership to fund and build a hydrogen hub at the state level, including hydrogen system clusters throughout the state. This effort is new, and the team submitted an initial concept paper to the DOE in November 2022, with the aim of receiving an invitation to submit a full proposal in April 2023. This effort and its vision are aligned with the vision being explored in this study and this report.

Additionally, state climate policies are driving the adoption of renewable power and low-carbon fuels, with a plan to reach a carbon-free electric grid[1] and economy-wide carbon neutrality by 2045,[2] creating increased interest in hydrogen storage to support the grid. ITS-Davis led a study of how to achieve carbon neutrality in transportation, with a report published in 2021 that shows a significant potential role for FCEVs and hydrogen in that transition. That study described low and high cases of FCEV penetration that we follow in modified forms in this study[3].

California's future could include large numbers of electric vehicles (EVs) and FCEVs powered by low-carbon energy. EVs and FCEVs may compete in some applications while having complementary roles in others. There appears to be significant value in having FCEVs in both light-duty and medium/heavy-duty applications, from the point of view that both types of vehicles are capable of helping to build large hydrogen markets. Many more light-duty vehicles (LDVs) are needed to reach a given demand level (given much lower hydrogen use per vehicle), but the potential market is much bigger.

Depending on the application and usage patterns, electric and hydrogen vehicles might add to electricity demands, further stressing a renewable-intensive grid, or offer opportunities for energy storage and better system management, with electrolytic hydrogen production providing potentially important seasonal storage. Hydrogen use in various industries may also increase significantly over time, and these sectoral demands must also be accounted for in an overall supply/demand analysis of hydrogen in the state. This leads to a series of more specific research questions.

2.2 Key Research Questions

We address a range of questions with this research, including (but not limited to) the following:

1. What might an efficient, large-scale hydrogen system look like in California in 2050 and the years leading to this?
2. What are the potential large-scale roles for FCEVs as light-, medium- and heavy-duty vehicles in California?

---

[1] https://ca100.org/

[2] https://www.ca.gov/archive/gov39/wp-content/uploads/2018/09/9.10.18-Executive-Order.pdf

[3] https://escholarship.org/uc/item/3np3p2t0

3. What is an optimal path to a hydrogen system with a large-scale role in transportation and other sectors?
4. How can scale-up in hydrogen supply infrastructure be optimized for vehicles and fueling stations?
5. How should supply chains evolve over time, and how should components and linkages (especially trucks vs pipelines) be scaled?
6. What role can sector coupling (such as transportation and industrial demand) play?
7. How can hydrogen assist in the integration of intermittent renewables into electricity supply?
8. What role can/should hydrogen storage play in the electric sector?
9. How should spatial considerations (e.g., siting of stations, hydrogen production locations, and distribution infrastructure) be taken into account in hydrogen system development?
10. What may be the system costs from the perspectives of stakeholders and society?
11. What policies are needed to guide system development and ensure economic viability/sustainability?

We have answered some of these questions in this study, though many remain to be explored further.

This study starts with the hydrogen demand sectors and builds a hydrogen supply and distribution system to serve this demand. Thus we attempt to provide a clear characterization of the role of FCEVs and hydrogen use in the decarbonization of transportation in the state, both in the long run (e.g. 2050) and as a growth pathway to that long run. This includes detailed consideration of both light-duty and medium/heavy-duty vehicles, and hydrogen use beyond vehicles to include buildings and various industries, and within this context the broader energy system that supplies them. The study provides a conceptual hydrogen infrastructure rollout plan that spatially accounts for hydrogen supply to end uses (e.g. refueling stations, stationary demand points) and the interactions of both seasonal storage and distributed and mobile vehicle storage with the power system.

Overall, a set of scenarios was developed that characterizes the build-out of the hydrogen system under different assumptions and circumstances, linked to demand scenarios. These include a detailed representation of hydrogen production, storage, and distribution. In this report we present a limited number of these scenarios, sufficient to support our findings so far.

We have also undertaken policy analysis to identify mechanisms to achieve the scenario milestones we create. The ramp-up of hydrogen demand and supply, and sales of the vehicles running on hydrogen are rapid in our High demand scenario and will not occur without strong policy support. This support may involve an expansion/strengthening of some existing policies (Low Carbon Fuel Standard [LCFS], cap-and-trade, zero-emission vehicle [ZEV] mandates) and/or may require entirely new approaches (more direct investments in infrastructure, vehicle purchase fees and incentives “feebates” for fleets, or other approaches). We will undertake a quantitative analysis of the potential impacts of different policy strategies and propose at least one combination, going out to at least 2035, that we believe could achieve the High hydrogen scenario we layout. We will also consider uncertainty via sensitivity and contingency analysis.

2.3 Recent Hydrogen Studies that this Project Builds from

Given the wide range of topics this project covers related to hydrogen system development, there are a number of relevant areas of literature, such as electricity sector modeling, supply chain analysis, component cost studies, transportation and FCEV research, etc. We covered much of these different types of literature in our forthcoming series of "tech briefs" that we will make available (at https://its.ucdavis.edu/research/uc-davis-hydrogen-fuel-cell-projects/) with this bigger report. Here we highlight a few major reports that have been published in the past 2–3 years that this project considers foundational.

2.3.1 California-focused Hydrogen Modeling Studies and Reports

Many important studies for California were published in the past two years that have important hydrogen-related analysis and modeling. We highlight five that we used extensively in developing our models and scenarios:

- Reed et al, UC Irvine (UCI, 2020) Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California released in June 2020, focuses on transitioning to a hydrogen energy system in California across all end-use sectors. It presents a roadmap for the buildout and deployment of renewable hydrogen production plants in the state.
- Lawrence Livermore National Lab, (LLNL, 2020), *Getting to Neutral: Options for Negative Carbon Emissions in California* provides a comprehensive analysis of technologies that can enable a carbon-neutral economy, and pathways to get there. It features carbon capture and sequestration in plants and natural lands as well as underground storage. It also covers reduced carbon-intensity energy systems and puts considerable focus on hydrogen.
- E3, (2020) *Achieving Carbon Neutrality in California*, produced this report for the California Air Resources Board. It provides a set of scenarios for achieving carbon neutrality across sectors within the state. They used their E3 PATHWAYS model and focused on scenarios achieving at least an 80% reduction in CO_2 emissions, balancing this with measures such as land management to remove CO_2 from the atmosphere. They produced 3 scenarios, ranging from 80% to 100% outright CO_2 reductions in emissions, with carbon neutrality achieved through carbon-removal measures. Transportation emissions are reduced by anywhere from 85% to 100%.
- The *LA 100 Study* (2021) of renewable energy futures in the city of Los Angeles, reaching 100% renewables in some scenarios. The role of hydrogen as a storage and electricity generation component is considered and found important but more expensive than using biofuels in this role.
- CARB (California Air Resources Board) produced the final version of its *Hydrogen Station Self-Sufficiency Report* (2021), showing that H2 stations in California could reach full economic self-sufficiency by 2030, if around $300 million is spent to help get to 200 or more stations, with sufficient levels of FCEVs in service to provide enough customers for these stations.
- CARB (2022) also produced its final 2022 Scoping plan that provides a blueprint for getting to a net-zero carbon future in California. Among other things, it shows a pathway leading to 100% ZEV sales shares for LDVs by 2035 and trucks by 2040, with considerable numbers of FCEVs as part of this ZEV mix. It also describes many policies and levels of investment needed to achieve targets.

2.3.2 US-focused Hydrogen Modeling Studies

Out of many US-level studies, we particularly relied on two hydrogen studies published in 2020:

- The national industry association FCHEA (Hydrogen Council) released *Road Map to a US Hydrogen Economy* in January 2020. This report was produced with analytic support from McKinsey and outlines market opportunities and policy requirements to achieve aggressive hydrogen market growth by 2030. It provides a fairly detailed roadmap at a national level for achieving a large-scale national hydrogen system, though it presents only a limited systems-level analysis of what this system will look like, how it would grow, and what would be its costs and benefits compared to a world without it.
- Department of Energy National Labs and NREL released *The Technical and Economic Potential of the H2@Scale Concept within the United States* (Ruth et al, 2020), that provides a deep economic analysis of a large scale hydrogen system at the US level, featuring demand and supply curves and other microeconomic fundamentals. The results include hydrogen potential demand and supply levels, feedstock mixes, and market clearing hydrogen prices under different scenarios.

2.3.3 International Hydrogen Modeling Studies

Internationally there has been a burst of research and planning related to hydrogen systems. A number of major national roadmaps, initiatives, and action plans have been released within the last few years. These include those by Australia, Japan, and South Korea, the Hydrogen Roadmap Europe report and the REPowerEU Plan (2022); and a *North Africa – Europe Hydrogen Manifesto* (2019). Other major international hydrogen reports released in the past three years include *The Future of Hydrogen* from IEA and it's more recent *Global Hydrogen Review 2022*; *Hydrogen: A Renewable Energy Perspective* (2019) from IRENA, and the Hydrogen Council's *Path to Hydrogen Competitiveness: A Cost Perspective* (2020). These all provide important insights and analysis but do not focus on California or provide estimates directly relevant to the situation in California.

3 Methodology: Analysis and Modeling Approach

ITS-Davis has developed or has access to several analytical tools and models that can support a detailed study of the development of a hydrogen system and system components. These are being used to consider the roll-out of a hydrogen system in California over the next 30 years, to 2050. To support the modeling effort, we have undertaken an ongoing literature review and background analysis of technologies and fuels. Many specific analytical activities are underway, with progress reported in previous internal reports (such as our "quick scan" report and the May 2022 working paper) that are available on our hydrogen project web page. This effort has included:

1. Reviews of reports and other sources describing H2-related policies and activities occurring around the world (trends, investments, feedstock development, H2 integration into electricity/gas sectors, investments in distribution/storage/retail and end use, demand growth).
2. Development of databases of cost estimates for key components based on the existing literature and raw data available within and outside California that can be used in our study.
3. Technology characterizations of existing and future fuel cell cars and trucks, including updated cost analysis and projections. In a later phase, a vehicle choice modeling exercise (for light-, medium- and heavy-duty vehicles) may be used to create more endogenous scenarios and narrow the scope of potential FCEV sales trajectories, but for now the projections have been created in a simplified fashion.
4. Use of Argonne National Laboratory's hydrogen refueling station simulation tools (HRSAM, HDSAM, and HDRSM) to model refueling station configurations and costs.
5. Use of NREL's H2A and "FastSIM" hydrogen production models to estimate the cost of hydrogen production with different technologies and in different situations.
6. Use of our Energy Futures' Transportation Transition Model (TTM) to establish state-level transition scenarios to very low well-to-wheel CO_2 emissions that our more detailed analysis is calibrated to. An overarching cost/benefit analysis of each scenario, and comparison across scenarios, have been undertaken with this model.
7. Use of our spatial model (STIEVE) of car and truck travel in California to evaluate commercial station siting, sizing, and provision with hydrogen supplies. This model can also be used to analyze H2 infrastructure, such as the various ways to provide H2 from production facilities to refueling stations, depending on where these are located, and how this system may evolve with system growth.
8. Use of our GOOD model of the Western Interconnection (WECC) electricity grid, an economic dispatch model with storage and capacity expansion capabilities. The model allows for a spatial representation of future expanded use of variable renewable generation, electricity storage options, and how this system would integrate with a hydrogen economy.
9. Development of NREL's SERA hydrogen supply chain model, analyzing hydrogen refueling, production, distribution and storage systems over time. SERA is a spatially articulated model capable of optimizing the construction size, time, and location of hydrogen production relative to resource location and demands that must be served. It also represents the hydrogen transmission and distribution system needed to connect supplies with demands, also integrated into the optimization function. It has been used to help lay out how hydrogen systems must evolve to match a particular growth pattern of stationary H2 demand growth and growth in use

of H2/FCEVs around the state. Estimating costs and identifying policies that help achieve the scale-up of all system components represent a major effort in this analysis.

This modeling system has been used to create scenarios covering a transition from 2020 to 2050 for California road transportation and energy (especially electricity) systems, and how these can be developed and interact.

3.1 Initial Transportation Scenario Development

The "quick scan" phase of the project was mostly completed by Fall of 2021, and on-going supportive analysis continues, which in part updates the initial work. A series of technical briefs and other short reports are being published alongside this report. Some components have already been published and are on our web page. Aspects of this work have included:

- **FCEV projections:** We created a low and High case set of FCEV demand scenarios to explore a rapid rate of increased demand for hydrogen and the infrastructure to provide this hydrogen. These scenarios extend through 2050, with a particular focus on the next 10–15 years. The likelihood of achieving either the low or High case are being explored using vehicle choice modeling, with a separate report in preparation on that aspect. We are estimating the vehicle total cost of ownership (TCO) for FCEVs of different types and comparing these to gasoline, diesel, and electric vehicles. We will begin to explore a range of non-cost attributes important to consumers, such as range, refueling time, and fuel/charging availability.
- **Vehicle/fuel cost analysis:** We also made estimates of total vehicle and fuel costs within the scenarios, annual investments needed, and the implications for achieving market sustainability in refueling station operation, vehicle manufacturing, and fleet operation of FCEVs. Comparing the two scenarios with each other and with a range of other possible demand scenarios varying transportation and stationary hydrogen demand by type and location can help to generate estimates of impacts, costs, and benefits for alternative system structures and demand-related growth patterns.
- **Hydrogen system scenario development:** We have developed supply and infrastructure scenarios to align with the demand scenarios mentioned above. These scenarios reflect different possibilities in terms of how and where hydrogen is produced, how it is stored and moved, and ultimately the full system configuration based on assumptions for the particular scenario and the modeling results based on the scenario inputs.
- **Spatial transportation modeling:** Based on the trajectory of FCEV sales, use, and aggregate hydrogen demand, we then used the STIEVE model to create scenarios of hydrogen fueling station deployment (5 year intervals to 2050), which produces a map of stations by location, size, and annual hydrogen dispensing. This optimization effort has included an analysis of land requirements and availability for stations depending on, for example, if hydrogen were made on site or delivered by tube trailer, liquid truck, or pipeline. It considers available current refueling stations, in terms of whether they could be expanded or converted to include storing and dispensing hydrogen, and how this relates to the number and location of stations needed out to 2050.
- **Hydrogen supply scaleup and supply chain analysis:** We have worked with NREL and used their SERA model to provide a spatial representation of the necessary supply chain to provide hydrogen to end uses. As the system grows, it will need to adopt much larger-scale production and distribution systems. Production will be located in optimal locations (such as low cost wind

farms in Plains states), and the hydrogen stored and moved to end use markets (mostly focused on California). This ultimately leads to a large-scale system with pipeline transportation and delivery introduced along with least-cost supply options. Scenario variations on demand potentials provide insights into hydrogen supply chain dynamics and economies of scale and scope.

- **Investment analysis:** In addition to these scenario results, an overlay of necessary investments and total investment costs has been made that reflect the changing costs of equipment over time (given learning and scale) and the total amount of equipment needed to be built in each five year period. This is also linked to a hydrogen "levelized" cost that can be achieved by 2030 and beyond.
- **Policy needs** have been assessed to reduce investment risks and improve infrastructure planning decisions. These will be developed in consultation with key stakeholders and policymakers and applied to the development and analysis of scenarios and strategies. The policy landscape has changed considerably over the past two years, with both Infrastructure Investment and Jobs Act (IIJA) and Inflation Reduction Act (IRA) federal legislation providing funding and incentives for hydrogen systems. How these may affect the economics of hydrogen and what other policies may be needed are considered.

Additional details regarding technology and other assumptions used in the study and the various tools employed will be provided in annexes to this document.

3.2 Modeling System Employed in the Analysis

As shown in Figure 1 through Figure 4, there are four major modeling components to this analysis that interact in various ways:

1. The Transportation Transitions Model, a California state-level transportation transitions model, capable of providing aggregate projections and comparisons of scenarios for light-duty and heavy-duty vehicle sales, stocks, energy use, and CO_2 emissions.
2. The Spatial Transportation Infrastructure, Energy, Vehicle and Emissions model (STIEVE), which can be used to characterize and project light duty and heavy duty vehicle travel, fuel demand, refueling station requirement, and emissions, spatially around California, and can be linked to spatial supply models.
3. NREL's SERA model, a supply-chain model that can be used to characterize hydrogen production facilities by type, size and location, and link these to demand locations for hydrogen, such as refueling stations. It is capable of optimizing the entire supply chain system to meet a spatially articulated set of demands. By running demand and supply models for multiple years, the evolution of hydrogen supply can be investigated. Whether the "natural" evolution is indeed on an optimal long-term path will be investigated.
4. The GOOD model is used to link hydrogen demand and supply to the need for electricity to produce the hydrogen, and also the potential for hydrogen to be used within the electric sector to help balance the system, provide seasonal storage, etc. GOOD is a national model that has recently been calibrated to the Western Interconnection (WECC) system and the potential to reach high levels of renewable generation throughout this system, out to 2050. The model now has more regional detail, including connections to electricity demand in California broken into 5 main regions. An air-quality simulation model component was also developed to track emissions

from the electric sector and compare these to those from the transportation sector; results from this exercise are included below.

The nature and logic of the full modeling system are provided in the flow charts below that show connections between travel/industrial hydrogen demand, hydrogen supply and distribution, and electric sector connections to this hydrogen system. In the first chart, the circles give a sense of the different models involved. The second chart presents the logic of demand-side modeling leading and driving supply side modeling, which ensures sufficient hydrogen is provided to meet supply.

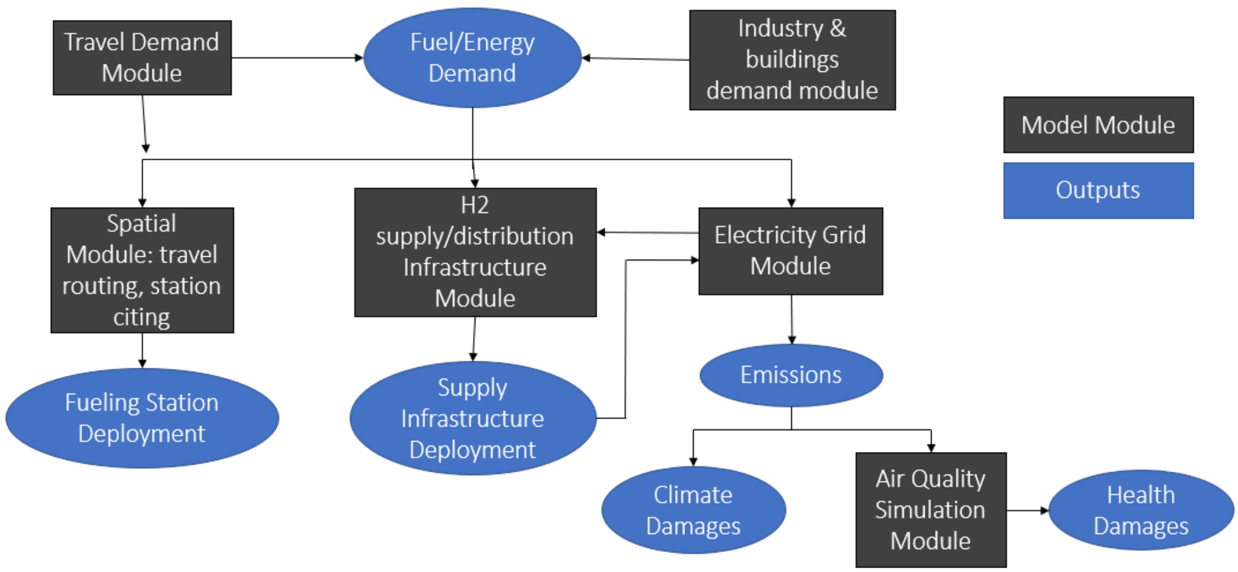


Figure 1. Hydrogen modeling system flow chart

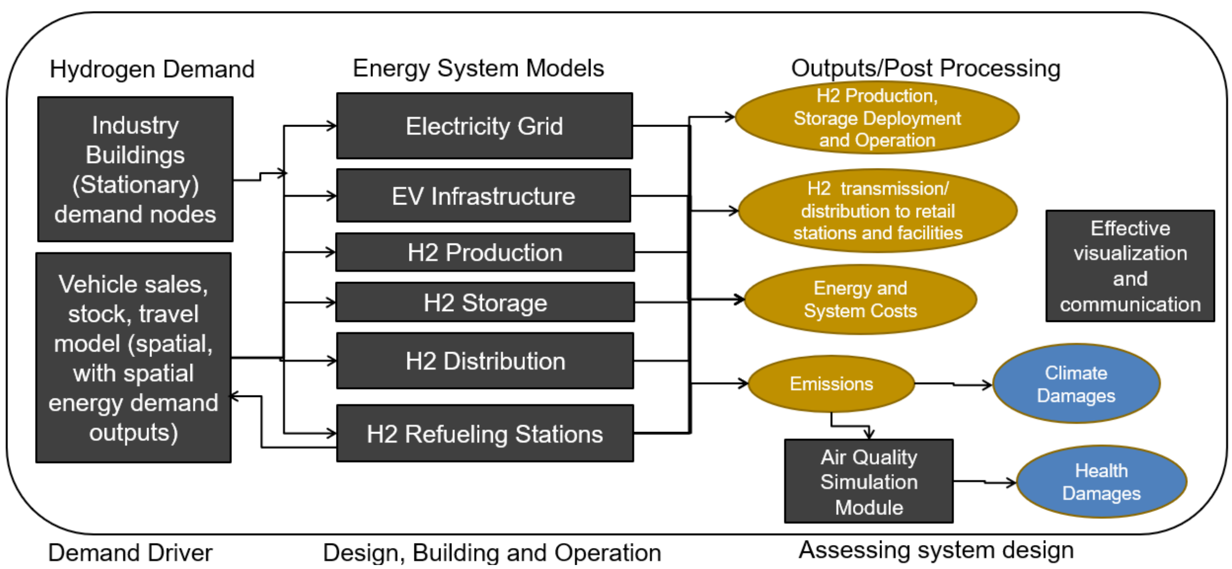


Figure 2. Another way to view the modeling system

The three major spatial models being used in this study are connected as shown in Figure 3. STIEVE produces hydrogen demand for transportation and feeds these on a spatial and temporal basis to both

GOOD and SERA. GOOD provides the main electricity response to these demands (along with providing electricity for all other purposes within WECC). SERA also uses demand from STIEVE and electrolysis projections provided by GOOD, sites this electrolysis more specifically, considers other potential sources of hydrogen (such as steam methane reforming of natural gas or renewable natural gas), and then routes all hydrogen from production locations to demand locations.

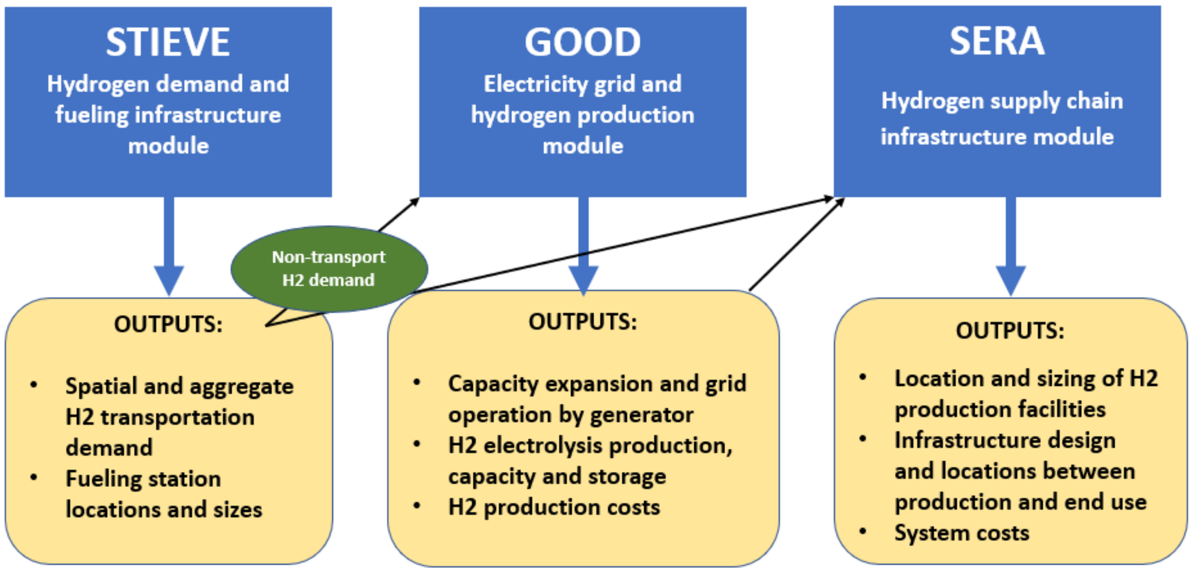


Figure 3. Relationship of three spatial models in the analysis

Some details for these individual models are provided below. Separate documentation of the models is in development and, as the next phase of the project begins, more details on each model and how they interact will be provided.

3.3 TTM Modeling of Aggregate Scenarios of FCEVs and Hydrogen Demand in California

Our Transportation Transitions Model (TTM) is a California-wide stock turnover model that allows us to investigate various scenarios of market penetration of new technologies through 2050 (Figure 4). The scenarios include projections of sales shares for three LDV vehicle types and eight truck and bus types (e.g. long-haul, medium-duty delivery, transit bus, heavy-duty pickups, etc.). The model includes projections of vehicle capital cost, vehicle fuel economy, and stock for each vehicle type through 2050. In addition, an associated fuel module projects the cost and carbon intensity for a range of present and advanced fuels. For any scenario, the model outputs stock by vehicle type, capital and fuel costs, fuel consumption by fuel, and greenhouse gas emissions.

In a multi-UC campus study for the State of California *(Driving California's Transportation Emissions to Zero,* CalEPA, 2021*)* the TTM was used to investigate scenarios to reduce California's on-road transportation carbon emissions by nearly 100% by 2045. This included identifying the potential ramp up of ZEVs overall and the relative role of battery electric vs FCEVs. This includes scenarios where fuel cells play a modest role and others where they play a bigger role, especially for trucks. In one scenario ("High FCEV"), hydrogen accounts for the most fuel used compared to any other energy type in California's transportation system in 2045. The model has been used to model various parameters such as fuel cell cost, battery cost, fuel costs, and other factors on market penetration rates and overall scenario costs.

For this project, the TTM has been used to create the basic projections of LDV and HDV sales, stocks and hydrogen use for the two main transportation scenarios in this study. This in turn has been used to calibrate our spatial analysis, notably the numbers and types of FCEVs assumed to be sold and used in our STIEVE spatial transportation and hydrogen station modeling of California. An outline of the components and linkages within TTM is shown below.

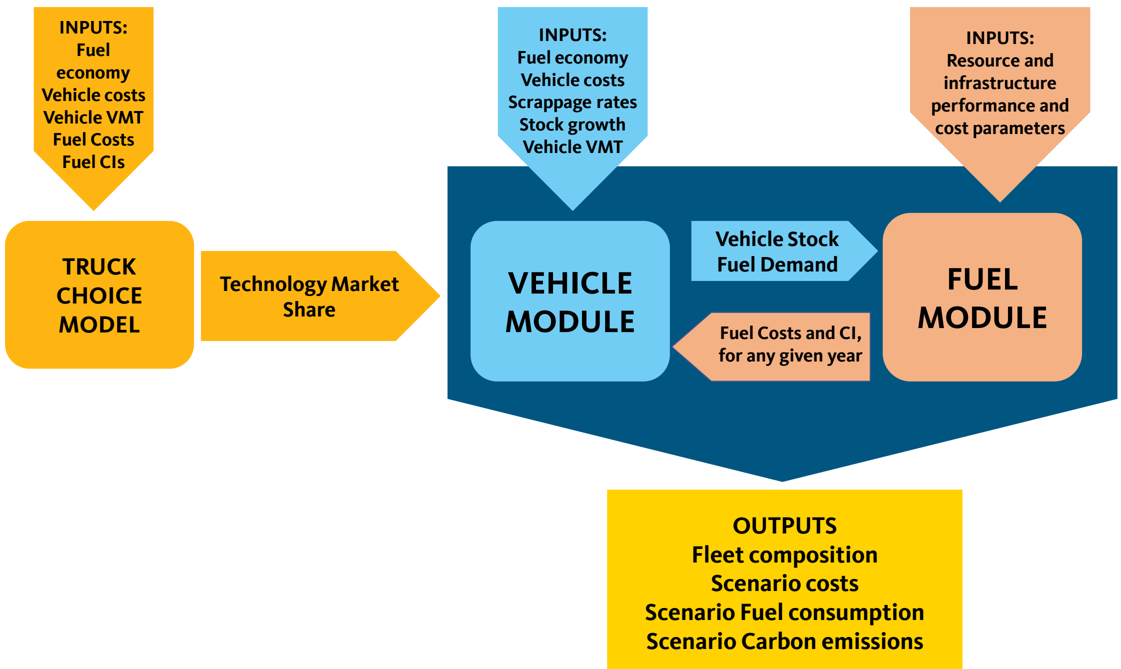


Figure 4. TTM Model structure and linkages

The basic picture of ZEV market penetration by vehicle type, given California policy, is shown in Figure 5. These reflect requirements in policies such as the Advanced Clean Cars II (ACC II) and Advanced Clean Trucks (ACT) regulations, that must be met with increased sales and market shares of ZEVs. Below we show how this is broken down by technology shares for sales and stocks, and resulting hydrogen demand, for our Base and High case scenarios. Both scenarios use these underlying projections of ZEVs, so the main difference is the relative shares of FCEVs and plug-in vehicles out of total ZEVs.

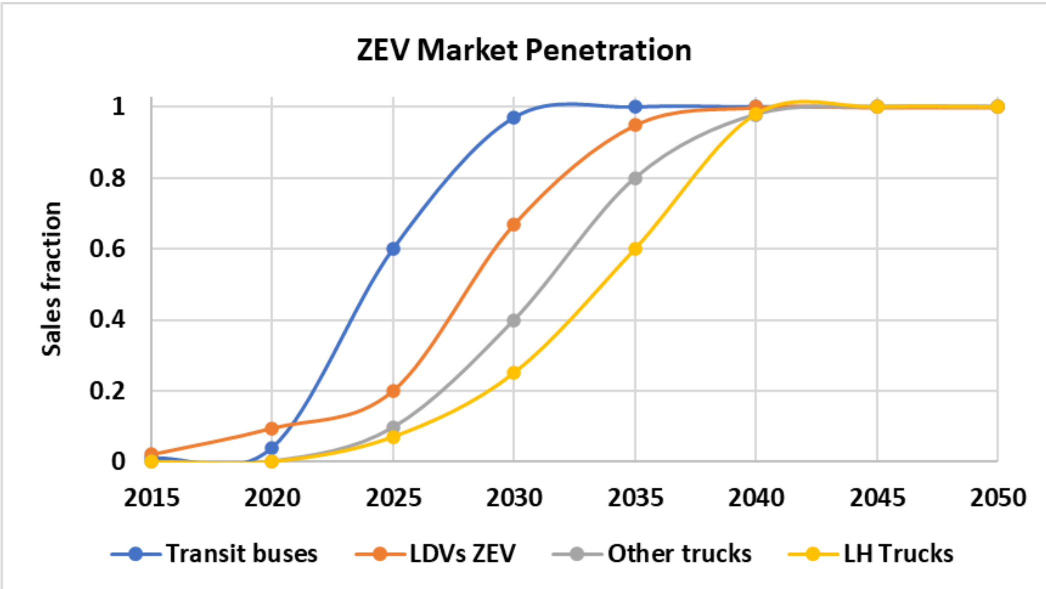


Figure 5. ZEV market penetration by vehicle type, all scenarios (LH, long-haul)

3.4 STIEVE Model for Spatial Transportation Analysis in California

UC Davis operates our Spatial Transportation Infrastructure, Energy, Vehicle and Emissions Model (STIEVE) for California. This model is capable of producing spatially detailed transportation scenarios for cars and trucks across several thousand geographic districts within the state and solving for the optimal configuration of refueling stations to meet the energy demand of these vehicles. STIEVE produces projections of hydrogen refueling demand and station needs on a spatial basis, using a "Transportation Analysis Zones (TAZ)'' level of detail. There are a total of 5454 TAZs within inland California utilized in this study. TAZs are identified by traffic modelers as areas having roughly homogenous travel characteristics.

The model, as shown in Figure 6, works in three steps: estimating the demand for hydrogen fuel based on the shortest distance travel pattern of current vehicle stock, finding the optimal number and size of stations within the driving range covering the maximum demand, and performing suitability analysis using various geospatial data for the station deployment on the ground.

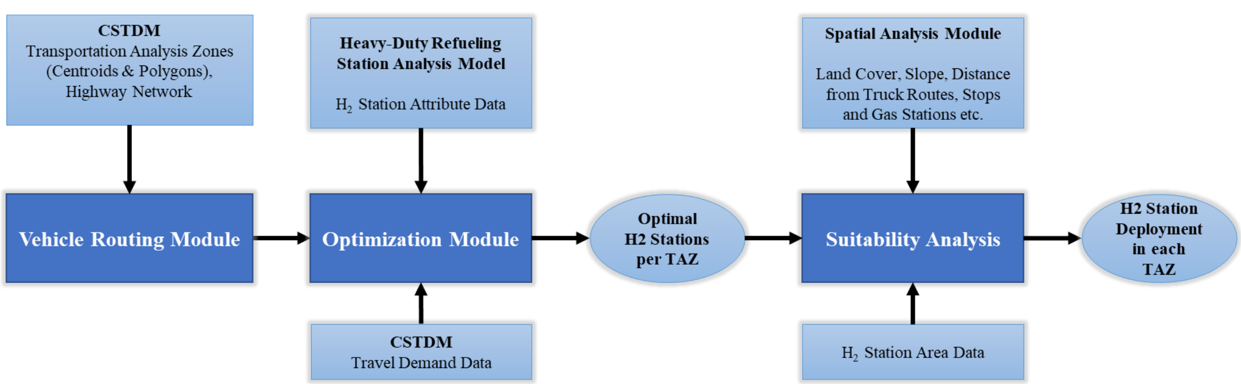


Figure 6. STIEVE Model Logical Flow (CSTDM, California Statewide Travel Demand Model)

Documentation of STIEVE is available separately (Acharya et al, 2021), but as shown in the flow chart, the model starts from an independent projection of vehicle stocks and travel from the California State-wide Travel Demand Model (CSTDM). This includes origins and destinations. A sampling of this data is used to generate routes that are then expanded over the full population of vehicles in the state, as projected in 5-year increments to 2050. The route choices are based on an optimization algorithm within STIEVE. Meanwhile, stations are developed based on rules about station size and characteristics, including the cost of building and operating stations, and constraints on where stations can be located using a land-cover and distance-from-routes algorithm. The resulting suitability analysis is combined with the vehicle routing and hydrogen demand module results to generate a projection of where and of what size stations should be built in each 5-year period. The model simultaneously solves for the number, size, and location of these stations in a given time period and builds future stations based on the situation at the start of each 5-year period.

An example of how the model translates inputs to outputs is shown in Figure 7 and Figure 8 below, with 7 showing the density of trips by TAZ, which is a major determinant of where vehicles are likely to choose to refuel. Based on these trip densities, Figure 8 shows the TAZs that would have stations sited in them. The daily capacity and number of stations located in a TAZ in 2030, indicated by various symbols and their size at the TAZ centroid, are shown for a particular projection of FCEV car and truck travel, and the resulting hydrogen refueling demand from those vehicles. As the number of vehicles increases over time, so too will the number (and sizes) of stations. This is estimated by the model in 5-year increments. Large stations near the California border are truck stops, suggesting that trucks coming into the state refuel at that point regularly. This means that these trucks would have to be able to refuel with hydrogen in neighboring states, which has not been considered (yet) in this study.

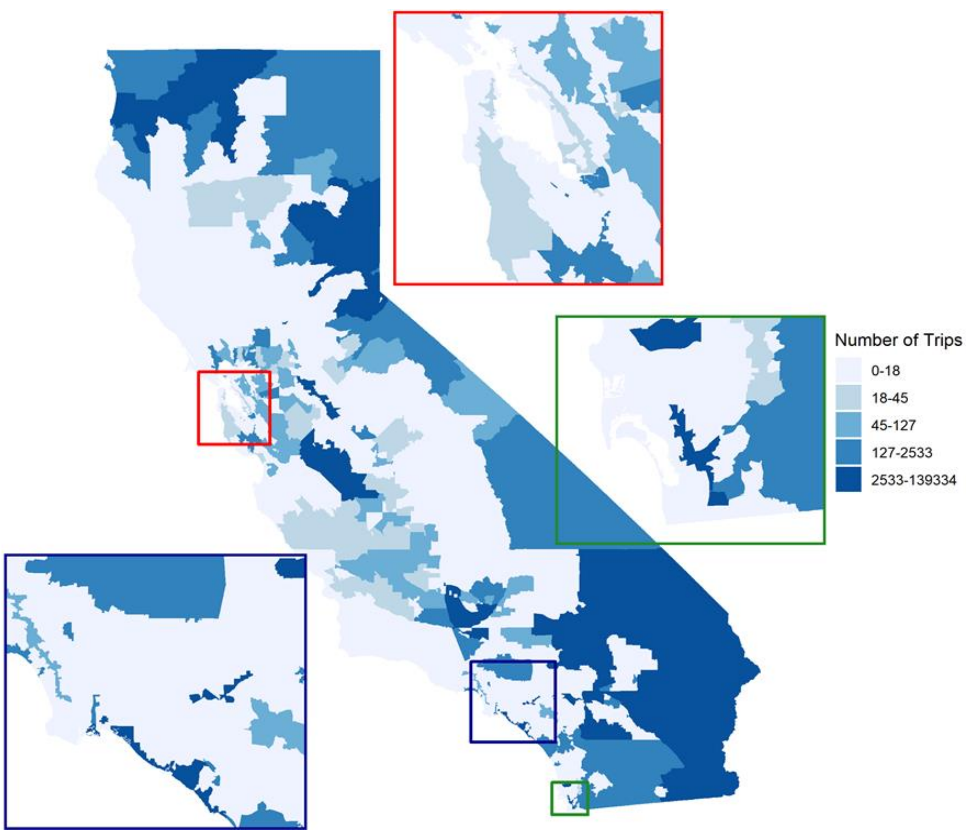


Figure 7. Trip density by TAZ within California, 2030 Base case

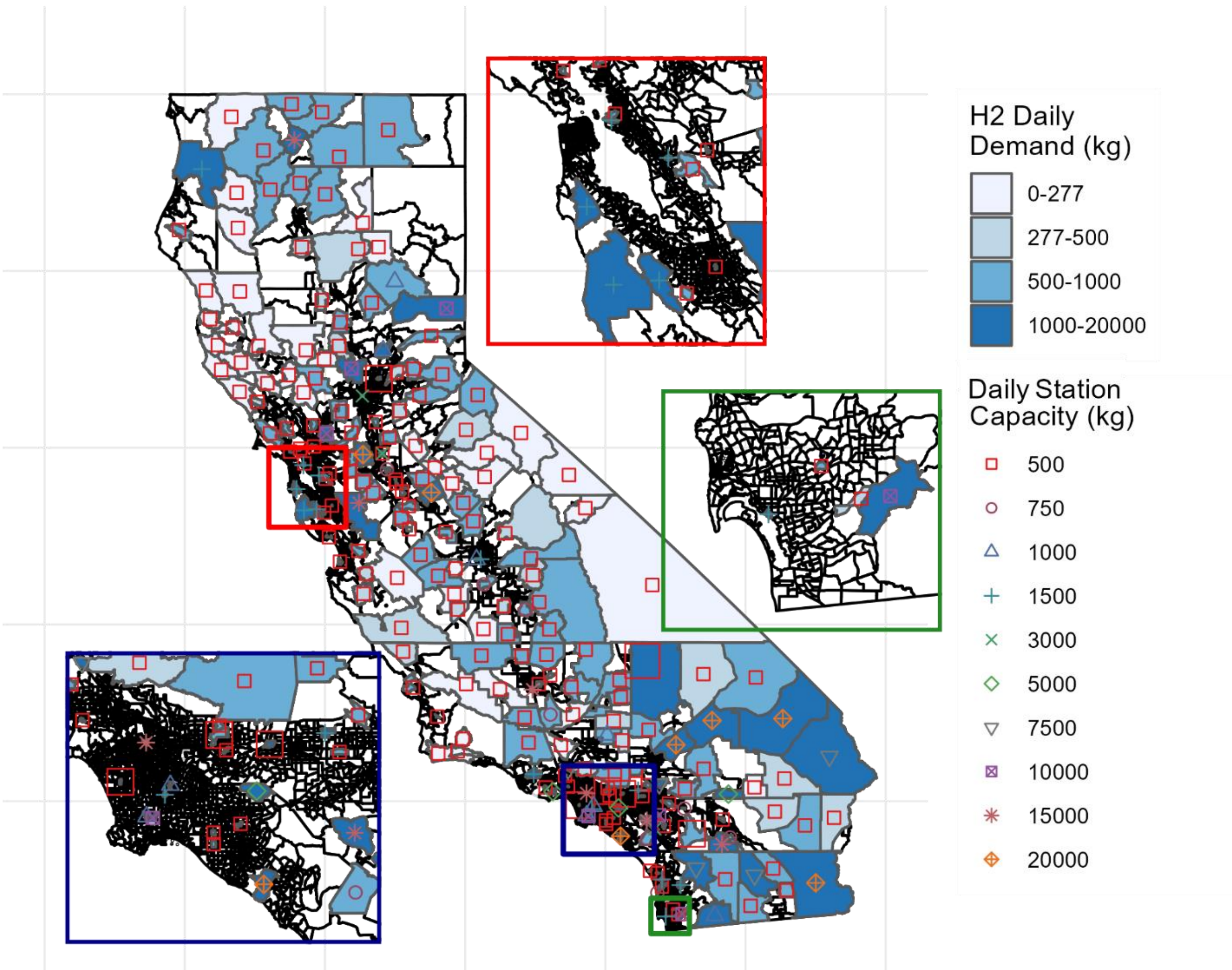


Figure 8. Station distribution and fuel demand, 2030 Base case

Individual hydrogen station sizes and locations were planned by determining the minimum area required, based on the recommendations of the National Renewable Energy Laboratory (NREL) in their H2FIRST report (Hecht and Pratt, 2017). Figure 9 shows NREL's model H2 stations with modular electrolyzer, SMR, and cylinders. Adopting these specifications, we determined the minimum area requirement for single and double dispenser island stations that can accommodate both light- and heavy-duty vehicles. We also determined whether existing gasoline station parcels have a sufficient area to be adapted to hydrogen stations. Figure 10 shows the schematic and specifications for calculating the minimum area for hydrogen refueling stations considering a modular PEM electrolyzer of 2 tons per day. This design is probably suitable for up to 5 tons or possibly 10 tons per day, but above this size, on-site production or use of tube trailers may become impractical or reach quite large footprints. Thus, above this size, we assume hydrogen is either delivered by pipeline or liquid tanker truck and stored as compressed or liquid hydrogen at the station.

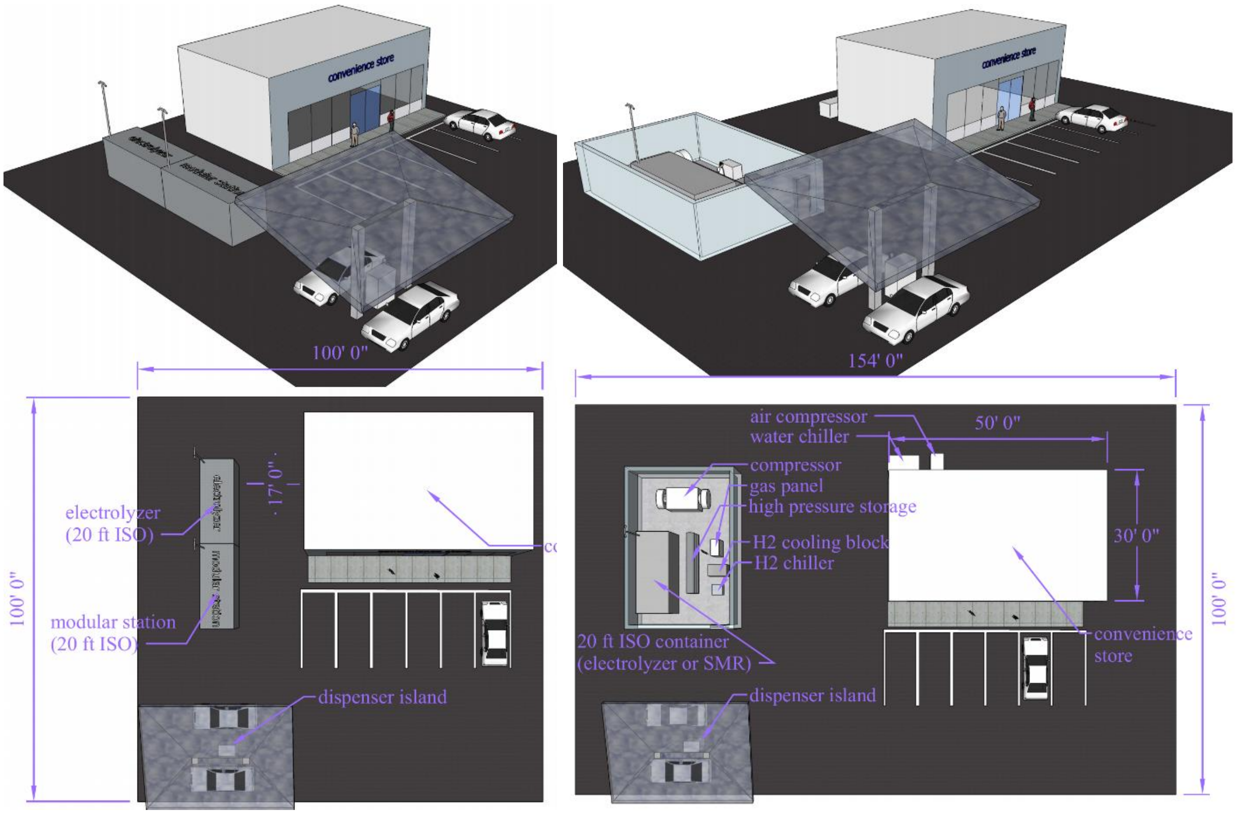
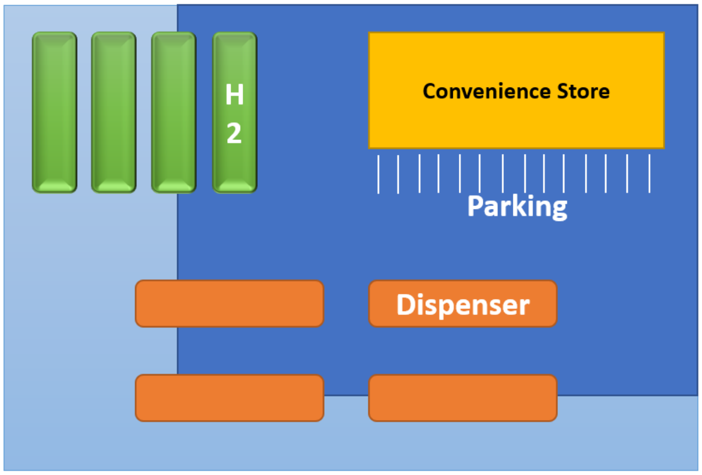


Figure 9. Hydrogen station design and specifications for modular PEM, SMR, and cylinders, according to the H2FIRST project of National Renewable Energy Laboratory (Hecht and Pratt, 2017)



Some specification from H2FIRST report:
PEM: 136 x 7 sq. ft for 20MW (4x 5 MW blocks)
Convenience store: 50 x 30 sq. ft
Area for 4 dispensers: 24 x 42 sq. ft
Minimum distances:
- Property line to H_2: 13-25 ft
- Fence line to H_2 : 7.15 ft
- Dispenser to H_2 /parking: 22 to 31 ft
- H_2 to convenient store: 29 to 64 ft
- H_2 to road: 63 to 74 ft
- Front spacing: 12 ft

Figure 10. Schematic of a station for our study with minimum requirements based on H2FIRST specifications (Hecht and Pratt, 2017).

3.5 GOOD Model for Electricity Sector

The UC Davis Grid Optimized Operation and Dispatch (GOOD) Model is an economic dispatch model that simulates the operation of the electricity grid. As mentioned above, while previous versions of the model simulate the entire US, for this project we focus on the "Western Interconnect" set of western-most states in the contiguous US, which forms the WECC. The balancing regions in the WECC are all multi-state regions, with the exception of California, which is divided into three primary balancing regions. A total of 8 sub-regions are tracked. The model has been used in this project to project electricity use for producing electrolytic hydrogen for end uses, as well as hydrogen use within the electricity system for energy storage purposes.

The regional simplifications and smaller overall areas allow the model to integrate several additional features that would be too complex to run for smaller regions or a larger overall area (e.g., the entire US). These additional integrated features include hourly storage operation across a full year as well as capacity expansion capabilities for renewable power across the entire WECC. For this project, the model simulates the operation of each specific generator in the region from 2020 to 2050 in 5-year increments. It includes potential future directives to dramatically increase renewable energy generation (such as wind and solar) as part of a decarbonization strategy that may occur at national or state levels, with high renewables uptake as a function of Renewable Portfolio Standards (RPS). The model solves in hourly intervals across all 8760 hours of each year.

Currently installed electricity generators as of 2020 within the WECC are shown in Figure 11. These generators together comprehensively represent all power generation available to produce electricity for all the balancing regions within the WECC. Power generation assets are not uniformly located throughout the balancing areas: the Pacific Northwest has substantially more hydropower resources, and there are no operating coal plants within California (though some coal plants exist to the east), but there is a substantial presence of natural gas and solar resources in California. In addition to the power generators, we include existing transmission constraints to limit power flow based on the true capacity of transmission lines connecting each of the regions within our model.

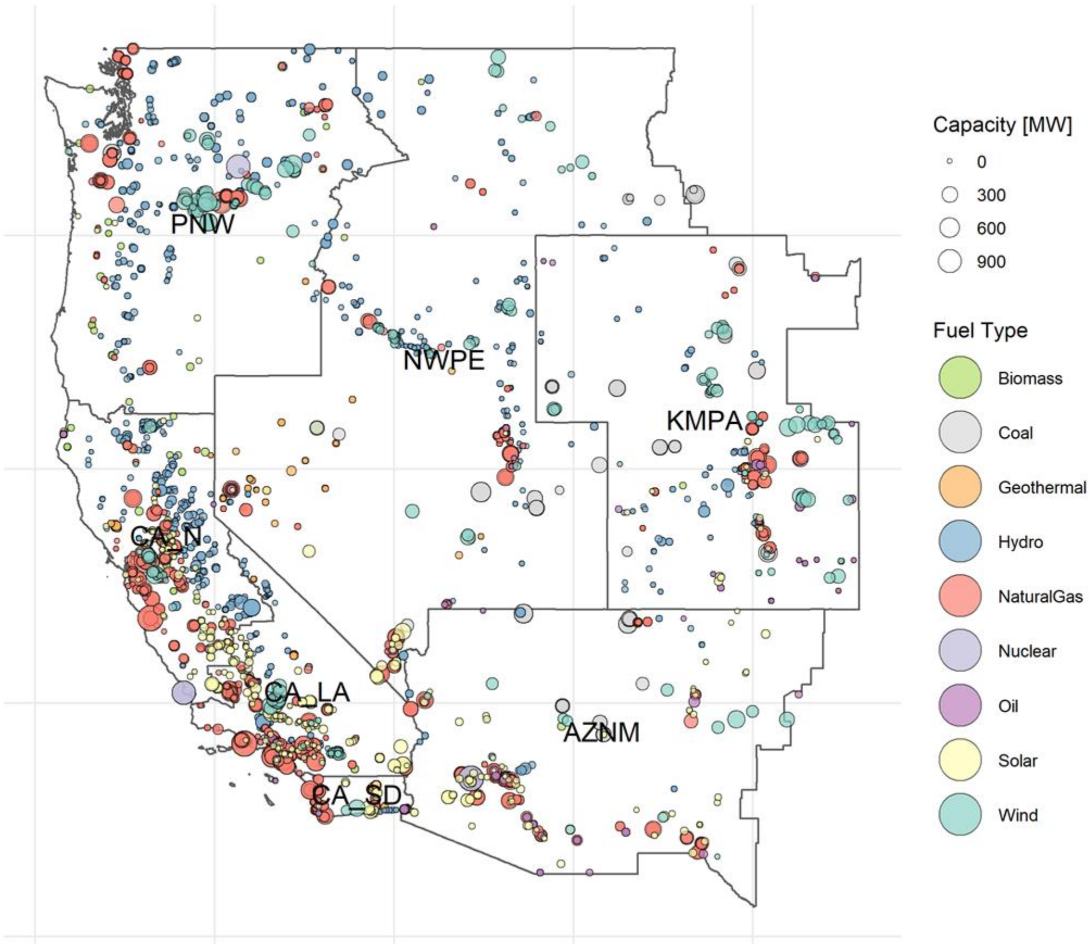


Figure 11. Regional breakdown of balancing areas and corresponding generators in the GOOD model(AZNM=Arizona-New Mexico; CA_LA= California-Los Angeles; CA_N=Northern California; CA_SD=California-San Diego; KMPA, Kentucky Municipal Power Agency; NWPE, Northwest Power Pool East; PNW, Pacific Northwest)

3.5.1 Characterization of Renewable Power

One of the notable improvements for this version of the GOOD model is the use of higher resolution and locationally sensitive profiles for renewable resources. We employed both solar and wind data from the National Renewable Energy Laboratory (NREL) that improved our resource profiles and introduced substantial seasonal variability into our resource availability profiles–something that was missing in previous versions of the model. As shown in Figure 12, data includes hourly and seasonal variability for both types of renewable generation.

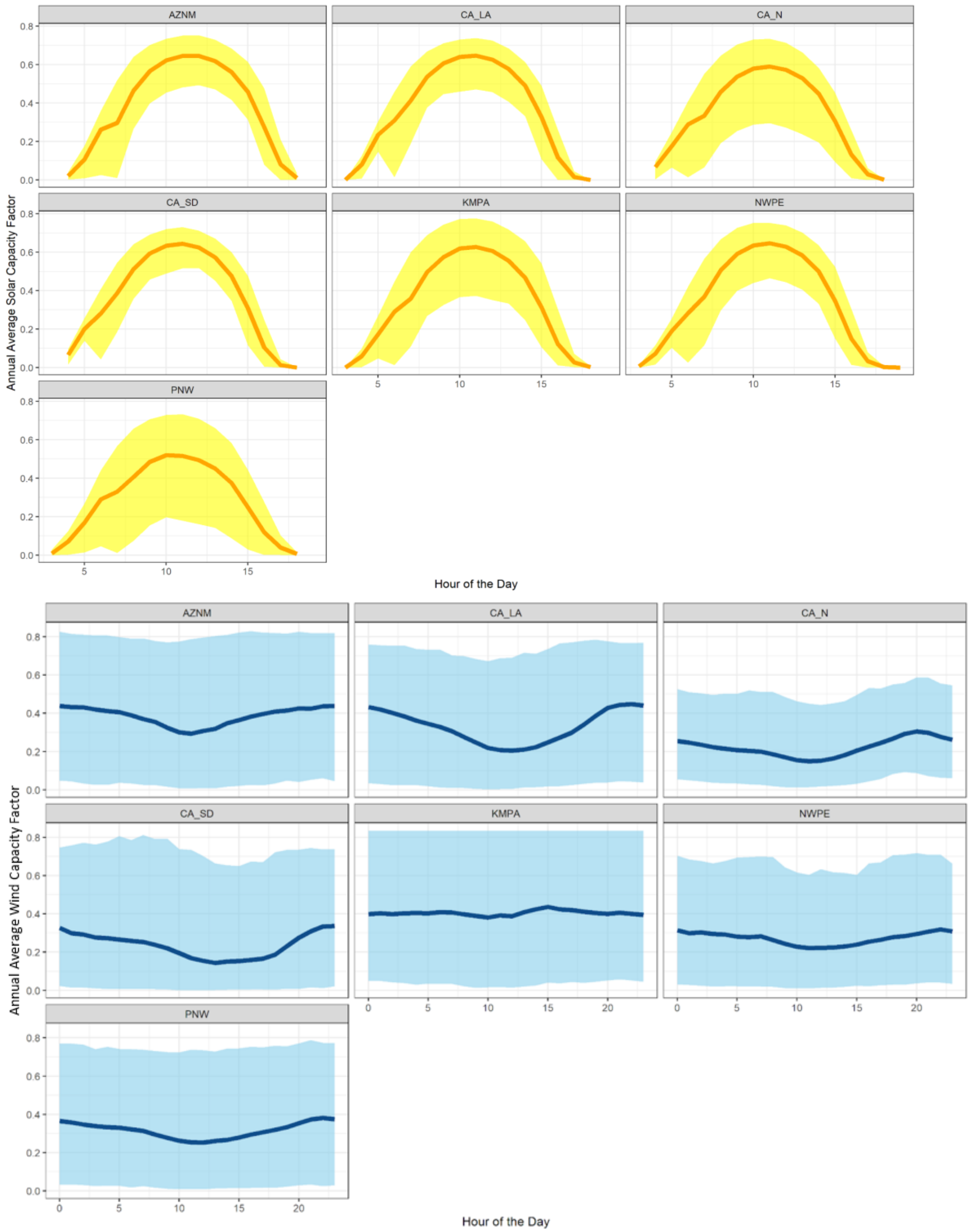


Figure 12. Average and 95th distribution of capacity factors in a 24 hour time period over one-year for all WECC balancing areas for solar (top) and wind (bottom) resources. (AZNM=Arizona-New Mexico; CA_LA= California-Los Angeles; CA_N=Northern California; CA_SD=California-San Diego; KMPA, Kentucky Municipal Power Agency; NWPE, Northwest Power Pool East; PNW, Pacific Northwest)

3.5.2 Electricity Transmission

The GOOD model includes a characterization of the transmission system at the wholesale generation level, with constraints between the balancing areas represented in the model. This aggregated characterization allows for bottlenecks in electricity transmission between the largest balancing areas, though it does assume that within the balancing regions defined by the model, electricity flow is relatively unconstrained. Figure 13 shows an example of electricity flows and the average saturation of transmission capacity (defined as the total electricity flowing through the lines over a period of time divided by the maximum amount of allowed electricity that could flow through the lines in the same time period). Note that transmission lines between NWPE (Northwest Power Pool East) and KMPA (Kentucky Municipal Power Agency), as well as AZNM (Arizona-New Mexico) and NWPE exist, but have negligible transmission of electricity in the scenario being shown and therefore do not appear in the figure.

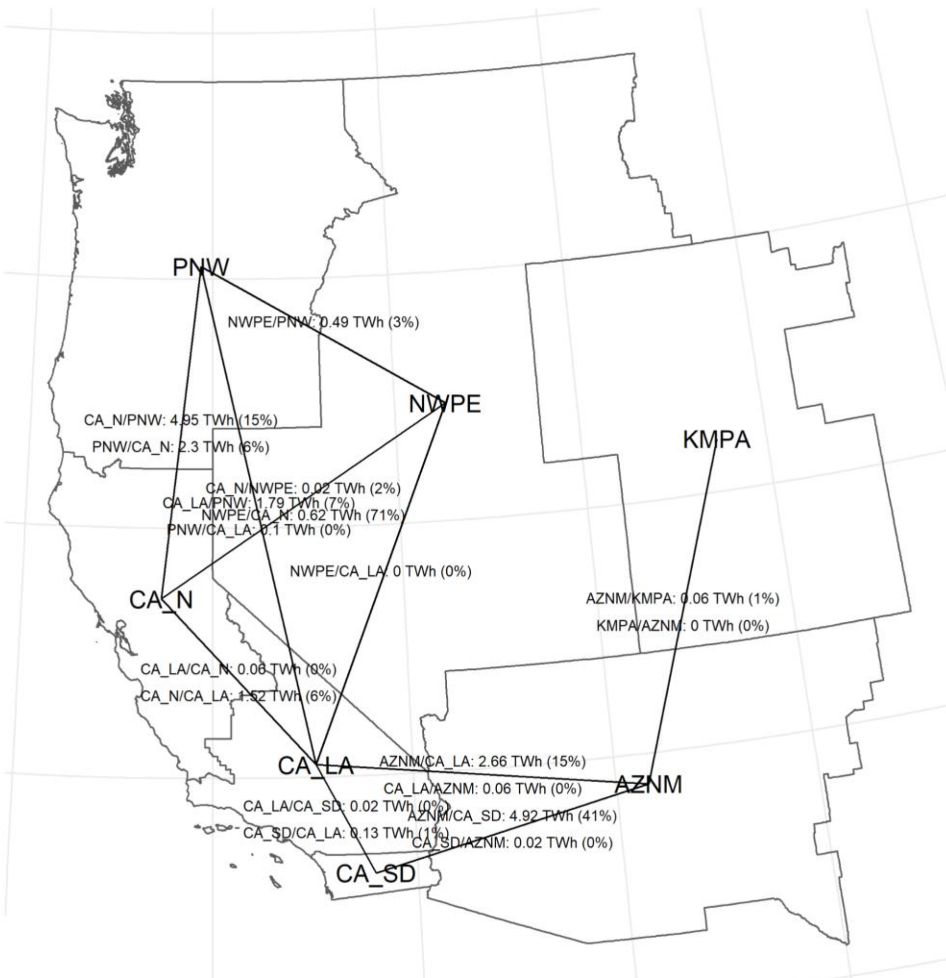


Figure 13. Example connections and average saturation of transmission capacity between regions in 2025. (AZNM=Arizona-New Mexico; CA_LA= California-Los Angeles; CA_N=Northern California; CA_SD=California-San Diego; KMPA, Kentucky Municipal Power Agency; NWPE, Northwest Power Pool East; PNW, Pacific Northwest)

3.5.3 Energy Storage in GOOD

Energy storage can assist in integration of variable renewables, for example, by decreasing curtailment and decreasing overall capacity needed to meet RPS). GOOD estimates energy storage requirements to help balance grid demand given a wide range of generating options. In scenarios with increasing shares of variable renewable power capacity, energy storage becomes increasingly important, to the extent that it is less expensive or of better reliability than adding more generators. For this project, energy storage is characterized on an hourly, daily, and seasonal storage basis. Hydrogen storage is specifically considered for longer than daily storage. GOOD generates hydrogen using electrolysis and stores it in un-specified ways and locations but with assumed storage costs. Thus the model generates hydrogen both to meet transportation demand (coming from the STIEVE model) and also to store for re-conversion back to electricity as needed. This treatment of hydrogen is shown in Figure 14.

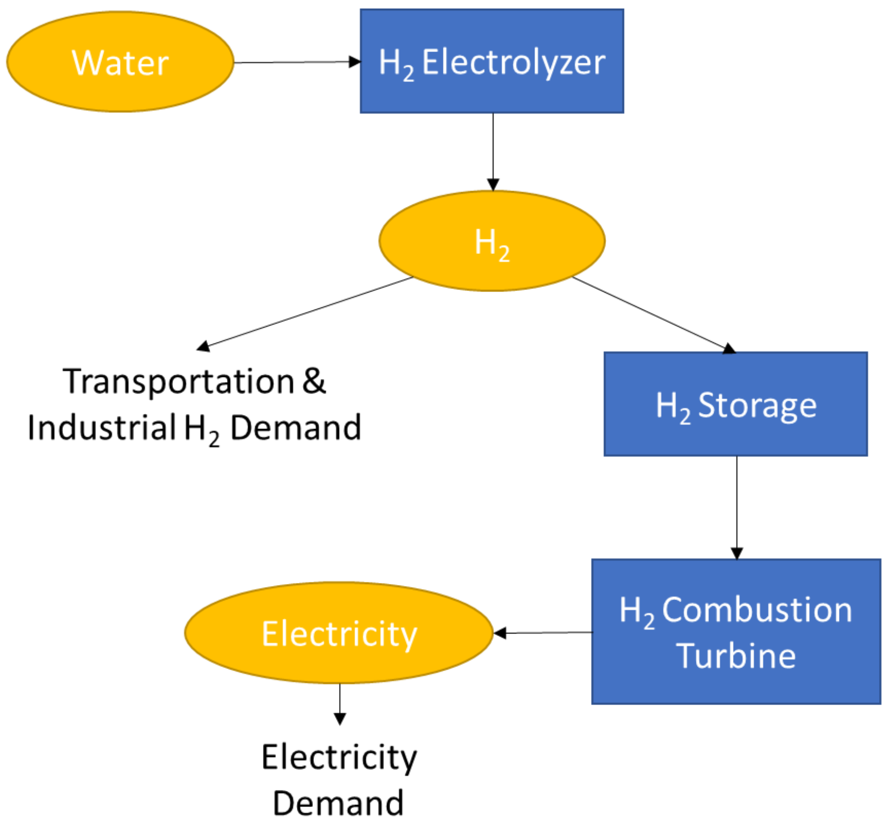


Figure 14. GOOD model algorithm for producing and using hydrogen

3.5.4 Emissions Estimation in GOOD

To better understand the environmental benefits of adopting FCEVs powered by a green energy system, we analyzed the statewide environmental impacts from the reduction of on-road emissions (from reducing ICEVs) and the increase in power plant emissions for producing hydrogen. The avoided emissions from adopting FCEVs is estimated based on the emission factors of the ICEV fleet (or stock) projected by the California Air Resources Board's (CARB's) latest emission inventory model EMFAC2021 and the electrified miles within each region. The extra electricity for producing hydrogen allows for the isolation of generation responding specifically to refueling FCEVs. The pollution corresponding to hydrogen demand from FCEVs is then derived based on the location and emission rates of the generators from the consequential analysis. Since the pollutant emission rates are a function of the amount of fuel used (or energy provided), the dispatch model provides the inputs necessary in a straightforward secondary calculation to derive the quantity of upstream pollution associated with FCEVs. The model allows for estimating local air pollutants (SO_2, NOx, and $PM_{2.5}$), and greenhouse gasses (CO_2, CH_4, and N_2O).

3.6 SERA Model for Hydrogen Supply Chain Analysis

The SERA model is operated by NREL, with UC Davis using it under a license agreement. Recently SERA 2.0 became operational, adding various capabilities over the previous version. SERA has a wide range of capabilities but its use in the current study is focused on its "supply chain" capabilities—routing hydrogen from generating locations to end uses. SERA's siting capabilities for this hydrogen generation are also used. It also contains an electricity grid module and a transportation module that are not used in this study, since we have our own models to cover these aspects of the system.

The role of SERA in the context of the modeling system used in this study is shown in Figure 15. It serves as a central supply-chain optimizing model, connecting to STIEVE (demand model) and the GOOD electricity models. SERA itself is not shown in any detail here, except for the basic needed inputs and supplied outputs. There is considerable complexity in the manner in which SERA will "talk" to these other models, and the details of this interaction are still being developed. A more detailed framework will be provided when they are fully developed.

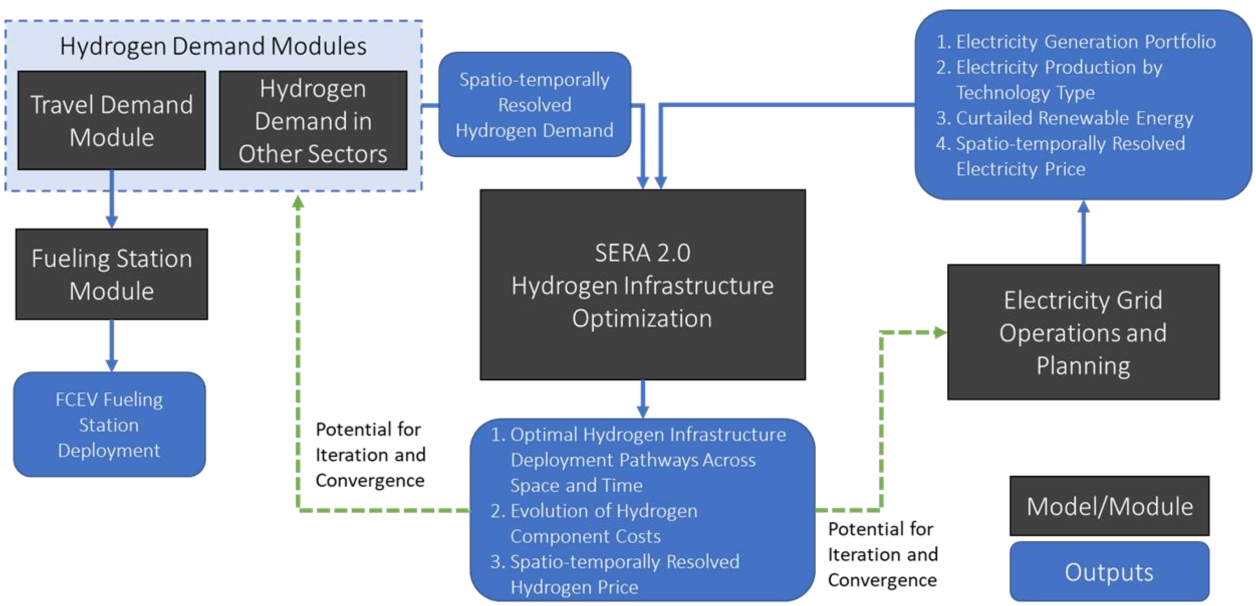


Figure 15. SERA Model position in broader modeling environment for this project

The basic flow of inputs and outputs using SERA are shown in Figure 16. Based on a locationally explicit set of hydrogen demands within California, SERA optimizes the placement of hydrogen production facilities and the infrastructure to move this hydrogen to end uses, using a spatially structured optimization algorithm, with 5-year intervals and a user-adjustable level of planning horizon in optimizing future buildout strategies. Hydrogen infrastructure includes truck and pipeline delivery options, and deep storage and pipeline "packing" as forms of storage. SERA optimizes to minimize costs, with a wide range of constraints that can be placed on the system. By changing assumptions a number of scenarios can be considered with the model, as described in the Scenarios, Analysis and Related Results section of the report. For example, foresight is an important aspect of estimating optimal system buildout, with, for example, pipelines playing a larger role when the planning horizon is longer.

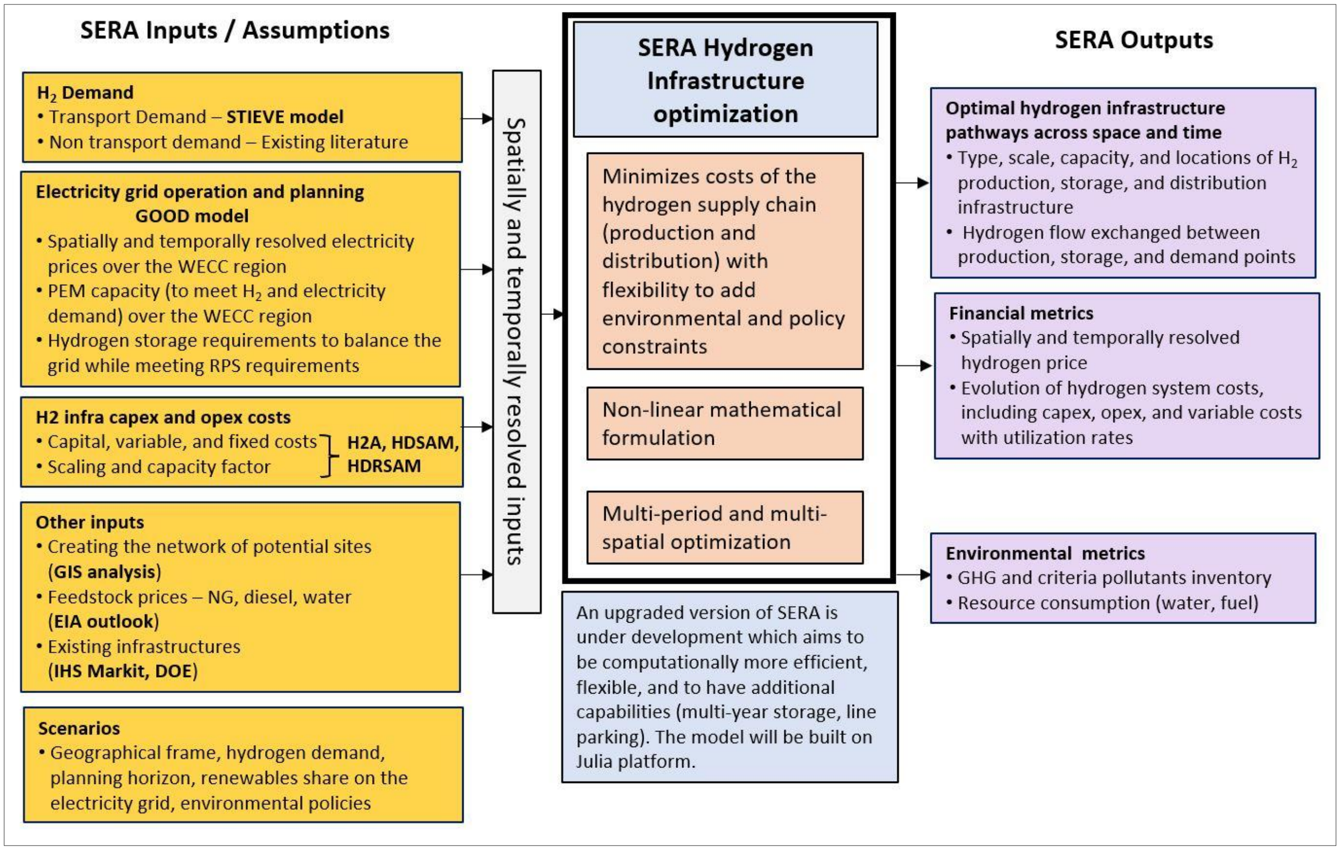


Figure 16. SERA Model Structure with Inputs and Outputs

3.7 Scenarios, Analysis and Related Results

3.7.1 General Outline of Scenarios

The three models that are run for this research are used in tandem but do not all consider identical sets of scenarios. There are some aspects of the scenarios that are included in all three, some in two, and a few in only one model. The basic approach is as follows.

Scenarios across all models:

- Low vs High H2 demand from transportation (and industry, with transportation and industry demand run in various combinations)
- A range of sensitivity cases that vary somewhat across specific models

Scenarios across supply models (GOOD and SERA)

- Limits to non-renewable H2 (from within/outside the state, even in the presence of carbon capture and sequestration [CCS]) in SERA, and all H2 from electricity in GOOD (and thus renewable to the extent that electricity is renewable)
- Availability of large-scale hydrogen storage (coupled with the cost of pipelines, vs electricity transmission into California and H2 production much closer to end-use); varying storage cost assumptions

GOOD only:

- High renewable electricity generation across the WECC by 2045

SERA only:

- Heavy early build-out of key H2 supply/transmission/storage infrastructure with supported investments vs a more market-oriented approach (i.e., long-run optimization vs shorter-run decision making)
- Centralized delivery of hydrogen (hydrogen hubs-oriented system).

4 Hydrogen Demand Scenarios

4.1 TTM Fuel-Cell Vehicle Sales, Stock, and Hydrogen Use Scenarios

As described above, the FCEV sales, stock, and resulting transportation hydrogen demand projections were developed in discussions with the project advisory board early on, and spatial analysis of this demand has been undertaken with the STIEVE model. The Base and High Case scenarios are meant to illustrate how various sales shares translate into hydrogen demand across the state, which can then be used for all subsequent project analysis. An effort to estimate the vehicle attributes and policies needed to bring about these scenarios (and FCEV market shares in given years) is reported separately and will be the subject of a future paper.

Some key results from these projections are shown in Figure 17 to Figure 20 below. Figure 17 shows increases in ZEV sales market shares by vehicle type and technology, for 2030 and 2045, for the Base and High cases. A similar set of breakouts is shown for vehicle stocks in Figure 18.

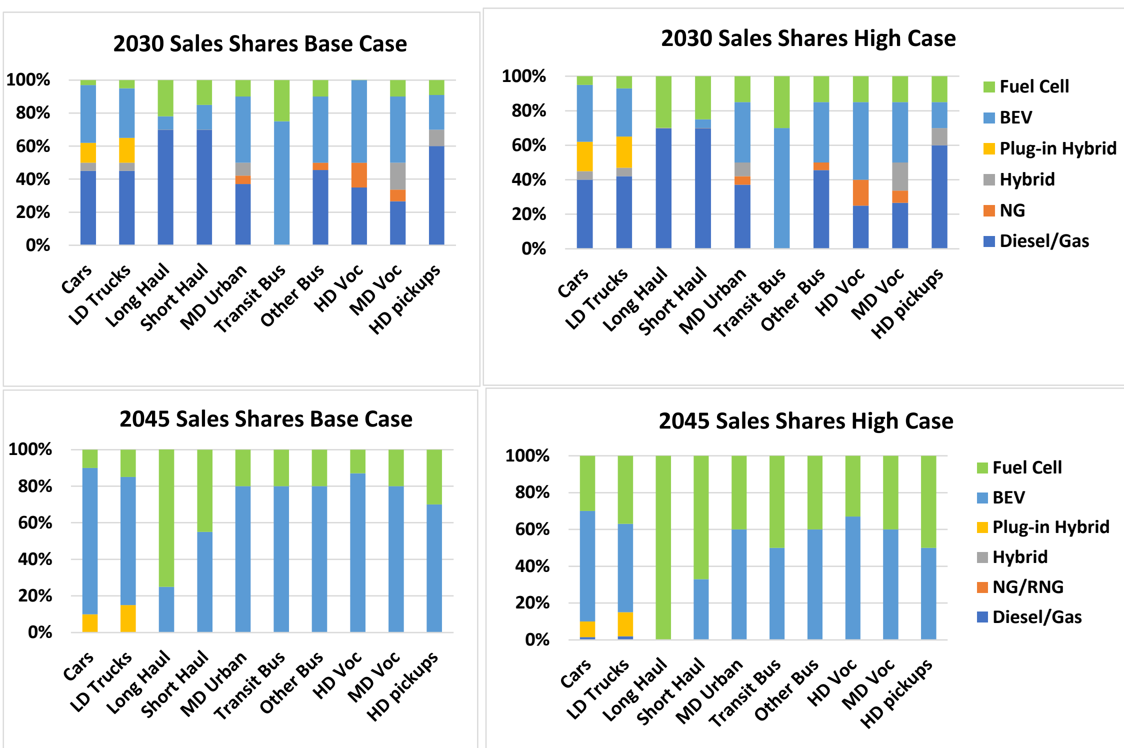


Figure 17. Sales shares by vehicle type and technology, 2030 and 2045, Base and High FCEV case (Note: LD=light-duty; LH= long-haul truck; SH=short-haul or regional/drayage truck; MD=medium duty; HD=heavy duty; Voc=vocational)

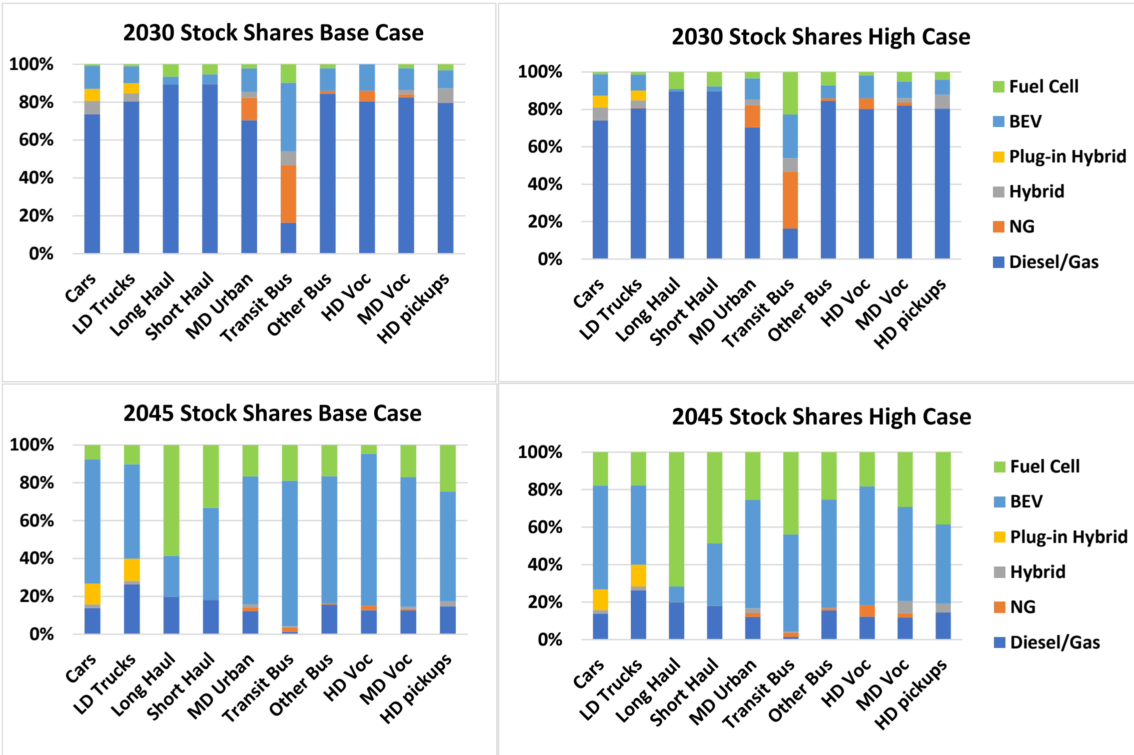


Figure 18. Stock shares by vehicle type and technology, 2030 and 2045, Base and High FCEV case (Note: LH= long-haul truck; SH=short-haul or regional/drayage truck; MD=medium duty; HD=heavy duty; Voc=vocational)

The resulting stock growth from these scenarios (based on sales shares and stock turnover, coupled with the total ZEV sales growth over time) is shown in Figure 19, with all LDVs and major truck/bus types shown in the top two figures for Base and High Case, and a detailed breakout of truck and bus stocks on the bottom.

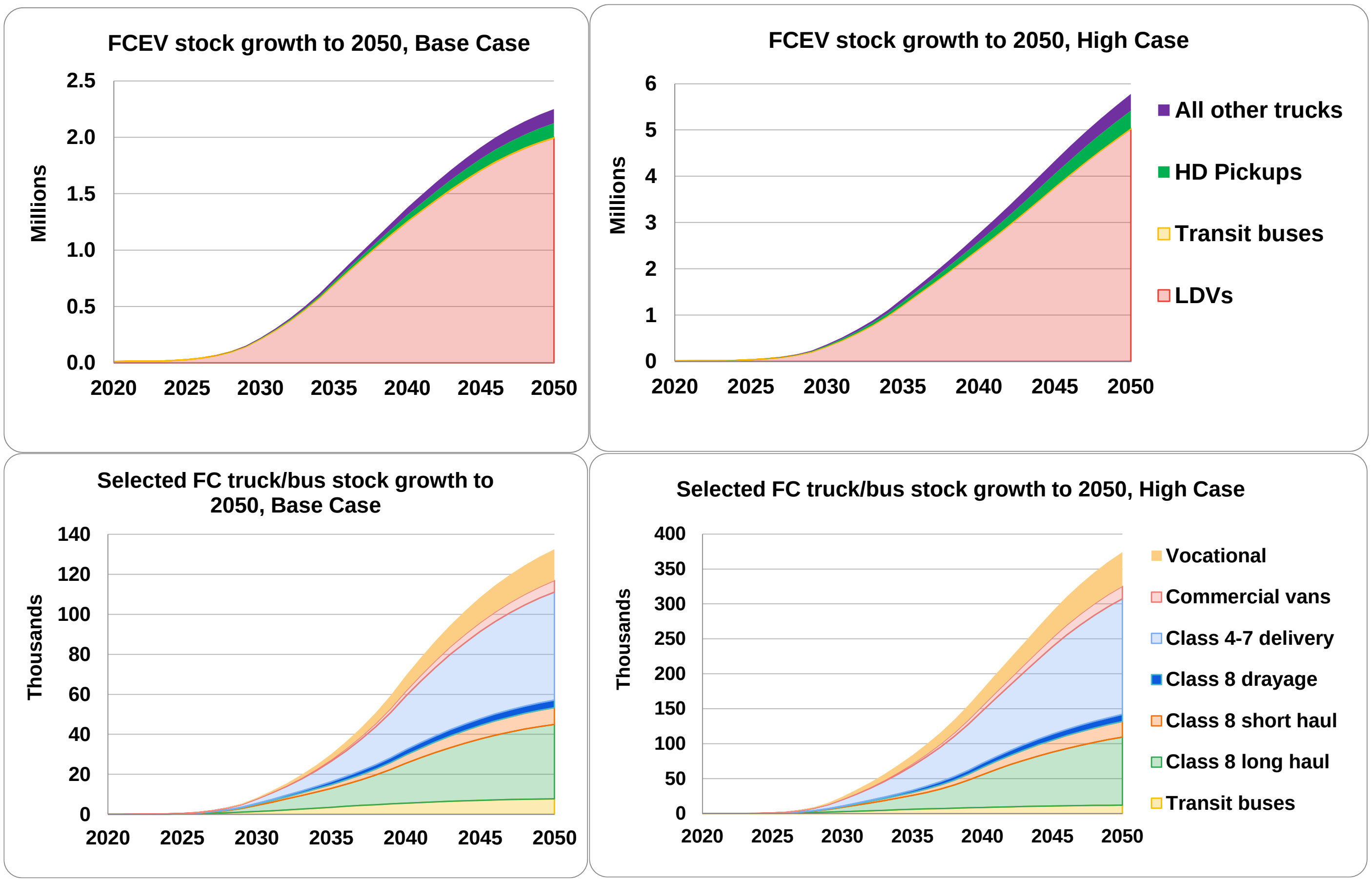


Figure 19. FCEV stock growth to 2050 by case (Note that the y-axis scales differ in each panel)

Figure 20 shows the resulting fuel use by all road vehicle types; Figure 22 puts this into context with all road vehicle fuels. Hydrogen use increases as total fuel demand decreases dramatically across road vehicle categories, due mainly to the efficiency benefits of both fuel cell and electric vehicles (since VMT does not decrease significantly over time). Hydrogen demand in the Base Case reaches 1.3 bil gallons gasoline equivalent in 2045 (about 1.3 million tons/year or 3600 tons/day) and 2.1 bil gallons in the High case (2.1 million tons/year, 5800 tons/day). By 2045, hydrogen holds the biggest share of California road fuels in the High Case.

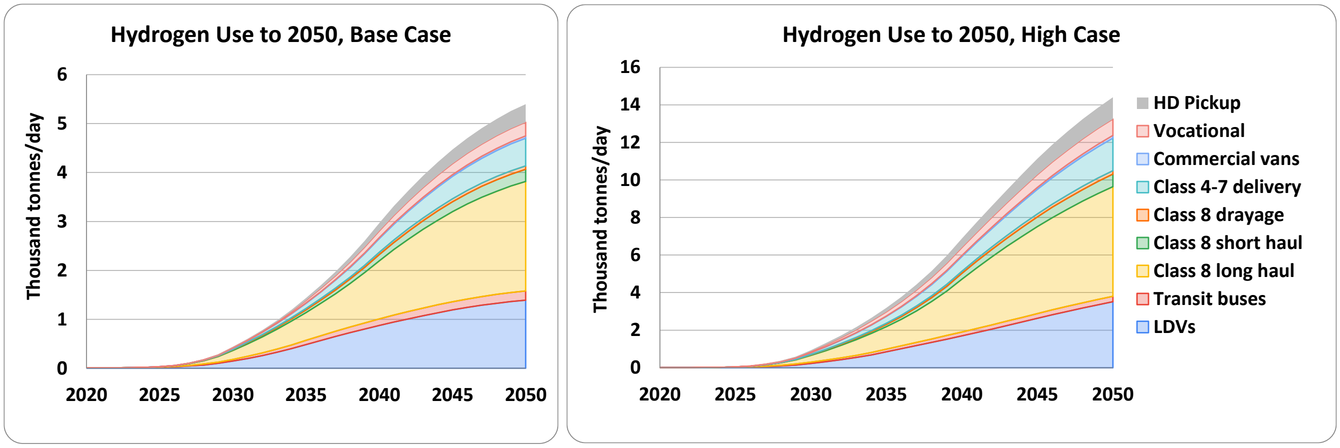


Figure 20. Hydrogen fuel use for all vehicle types, Base and High case (Note that the y-axis scales differ)

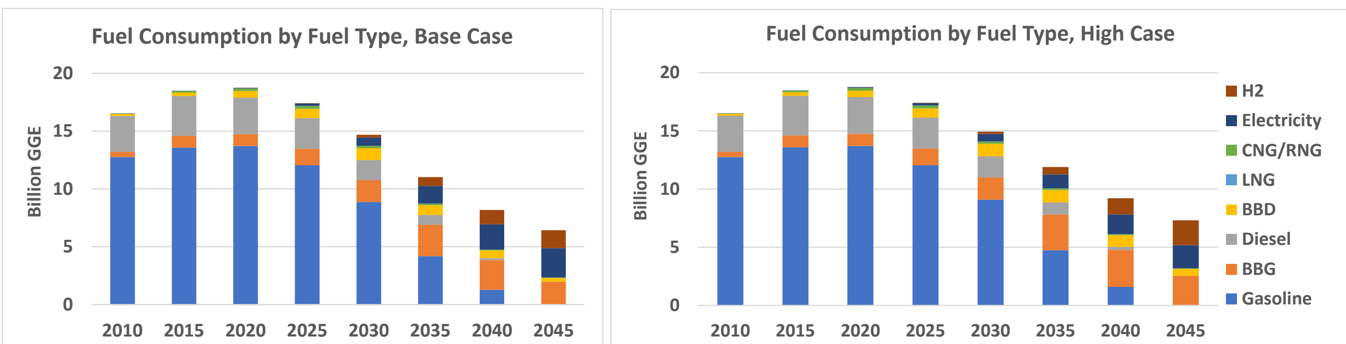


Figure 21. Fuel consumption by fuel type, Base and High case

4.2 Spatial Hydrogen Demand and Refueling Station Analysis with STIEVE Model

The vehicle sales and stock projections, along with typical vehicle travel patterns, are used to calibrate the STIEVE spatial transportation model. The total stock of light duty vehicles, trucks, and buses is projected based on the CSTDM model and its projections, along with that model's sets of origins and destinations for various types of vehicle trips. STIEVE uses data on trip origins and destinations to create full trip routes across a sample of vehicles and scales those up to estimate the total travel of different types of vehicles along different routes within California (Acharya et al, 2021). Using a system of constraints about where vehicles are willing to refuel (how far from the main road and their primary route), along with constraints on where hydrogen stations may be built, stations are placed in different zones to fulfill demand, tracking the increase in demand as more FCEVs enter service. A view of the state map with the daily capacity and number of stations is shown in Figure 22. A marker is placed at the centroid of each of the transportation analysis zone (TAZ); the marker's color and size represent the number of stations in the TAZ, while the shape represents the daily capacity in kilograms per day.

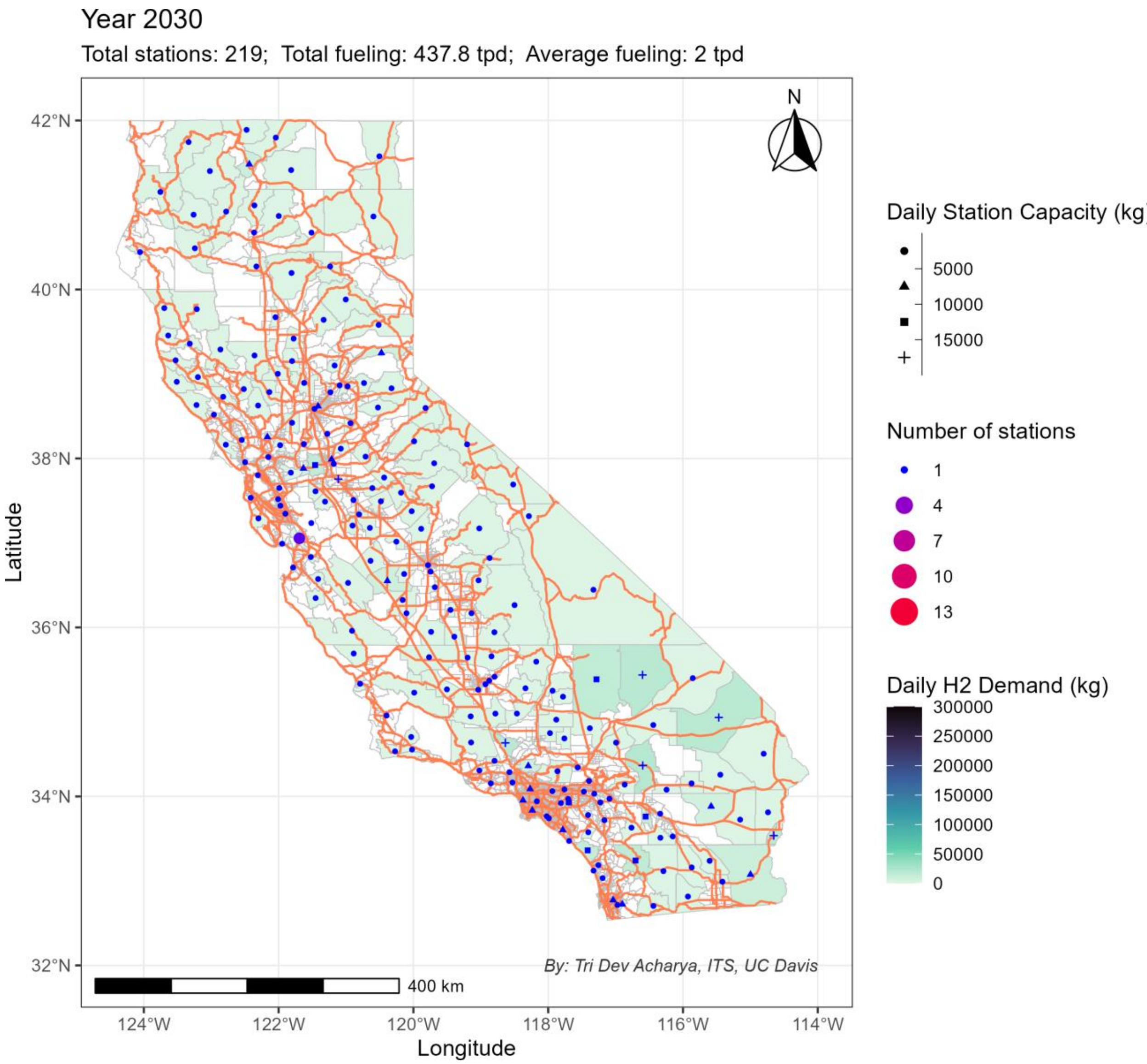


Figure 22. Scenario demand for hydrogen and station sizing by TAZ in California, 2030 Base case.

If fuel demand at public stations by both cars and trucks is included in the model, a large number of stations are needed early on to meet spatial travel/refueling demands (so that vehicles can refuel anywhere in the state, at least where there is significant travel). The resulting count of stations by size is shown for all years, for Base and High demand cases, in Figure 23 below. Smaller stations (between 0.5 and 1.5 tonnes per day) dominate the initial years in both cases, with a similar number in 2025 (around 175). Since stations can be expanded in these scenarios, this occurs regularly over time, with the number of 500 kg/day stations declining as larger stations grow; much of this is simply station expansion. Many stations grow up to the size of 15–20 tonnes per day by 2050.

Figure 23. Station counts by station size (i.e., capacity) in the Base and High Scenarios for different years. The y-axis scales differ between scenarios.

As of the early 2020s, LDV station developers generally have been building 1 tonne/day or larger stations, perhaps in part because of the LCFS credit system that provides capacity credits up to 1.5 tonnes/day. Our STIEVE modeling suggests that more small (e.g., 0.5 tonnes/day) stations would be better than fewer large (e.g., 1.5 tonnes/day) stations to meet the anticipated station location needs of drivers. As of early 2023, there are about 55 operating stations in the state rather than the 200 shown here as optimal in 2025. The California target for the mid 2020s is around 150 (as per the latest CARB AB-8 fuel cell and hydrogen station report). But reaching this number with 1.5 tonne/day average station capacity may mean these stations have low utilization rates (capacity factors) until the number of LDV FCEVs grows toward 100,000 or more. A renewed effort to rapidly grow LDV FCEV purchases should align with the station growth plans.

An important part of the station sizing, siting, and overall numbers needed is the assumption regarding drivers' willingness to depart from their primary routes to search for fuel. This set of scenarios assumes that a driving buffer of up to 5 miles diversion, out of the way of the shortest planned route, is acceptable to drivers. This vastly reduces the number of needed stations. The average diversion is significantly less than 5 miles and many trips can be made on the planned route. A separate paper will explore how the diversion distance relates to the number of needed stations, and the time cost of additional driving vs the cost of additional stations, particularly in the early years, is needed.

As Figure 23 shows, the number of small stations declines over time and the number of large ones increases, in part via an assumption that stations can expand capacity somewhat incrementally. The eventual result is large numbers of 20-ton capacity stations, to meet large demands in many areas, rather than increasing the number of stations beyond about 400 in the Base case in 2050 and 800 in the High case. The larger stations reflect high demand levels in certain areas for light-duty vehicles and medium-/heavy-duty vehicles.

If station capacities were capped at a smaller size, e.g., 5 tons, then more stations would be needed, roughly in proportion to this cap relative to the current results dominated by 20-ton stations. Thus if all 20-ton stations were instead four 5-ton stations, over 1500 stations would be needed in the Base case in 2050 rather than the 400 in this scenario. This would raise the overall system cost considerably. Table 1 below shows additional details of the numbers, sizes, cost and utilization of stations. Only in the initial year 2025 (and likely a few years after that) does the system suffer from low average capacity factors, due to the need for many stations throughout California. By 2030 capacity factors are above 90%. (Note these capacity factors take into account queuing aspects, so a “100%” capacity factor reflects limits to how many vehicles are likely to be able to refuel each day). This suggests that, with the growth in vehicle numbers in these scenarios, stations should be able to achieve positive cash flows within a few years. Initially, revenues appear unlikely to be enough to ensure profitability across stations, though we have not done a detailed profitability analysis. Average fuel demand per station is as low as 0.3 tonnes per day for the Base case in 2025 and grows to an average of 13.8 and 18.2 tonnes per day for Base and High cases, respectively, in 2050.

Table 1. Characteristics of stations by year, Base and High scenario

	Year	Station count	Total Capacity (tonne/ day)	Fueling (tonne/ day)	Capacity per station (tonne/ day)	Fueling per station (tonne/ day)	Avg capacity factor (%)	Total Cost (× 1 million)	Average station cost per kg dispensed
Base case	**2025**	200	127	60	0.6	0.3	47	$ 284	$ 13.0
	2030	219	500	438	2.3	2.0	86	$ 630	$ 3.9
	2035	240	1450	1396	6.0	5.8	96	$ 1,381	$ 2.7
	2040	294	2923	2846	9.9	9.7	97	$ 2,570	$ 2.5
	2045	354	4678	4458	13.2	12.6	95	$ 3,966	$ 2.4
	2050	419	6147	5797	14.7	13.8	94	$ 5,161	$ 2.4
High case	**2025**	207	147	86	0.7	0.4	58	$ 311	$ 9.9
	2030	257	1025	990	4.0	3.8	96	$ 1,071	$ 3.0
	2035	325	3811	3555	11.7	10.9	93	$ 3,322	$ 2.6
	2040	556	7690	7572	13.8	13.6	98	$ 6,500	$ 2.4
	2045	680	11,955	11,593	17.6	17.1	97	$ 9,862	$ 2.3
	2050	800	14,700	14,588	18.4	18.2	99	$ 12,058	$ 2.3

4.3 Station Siting and Land Suitability Analysis

The siting of stations in STIEVE is based on hydrogen demand by geographic location, which in turn is based on the number of FCEVs and where they travel. However, the suitability of land for locating hydrogen stations is a potentially important constraint on this selection process. The project has spent considerable attention on this question and has undertaken a detailed suitability analysis that is separate from the STIEVE model runs but feeds into them.

The number of hydrogen refueling stations on a TAZ level of detail is shown for Base and High demand cases in Figure 24 and Figure 25. Stations are located throughout the state, but some areas have more stations and greater capacity than others do. There is high refueling demand in some areas, such as near the California-Nevada border, due to highway refueling stops being located there, and providing large quantities of fuel to both cars and trucks. More detailed versions of these maps, focused on specific areas, are available upon request.

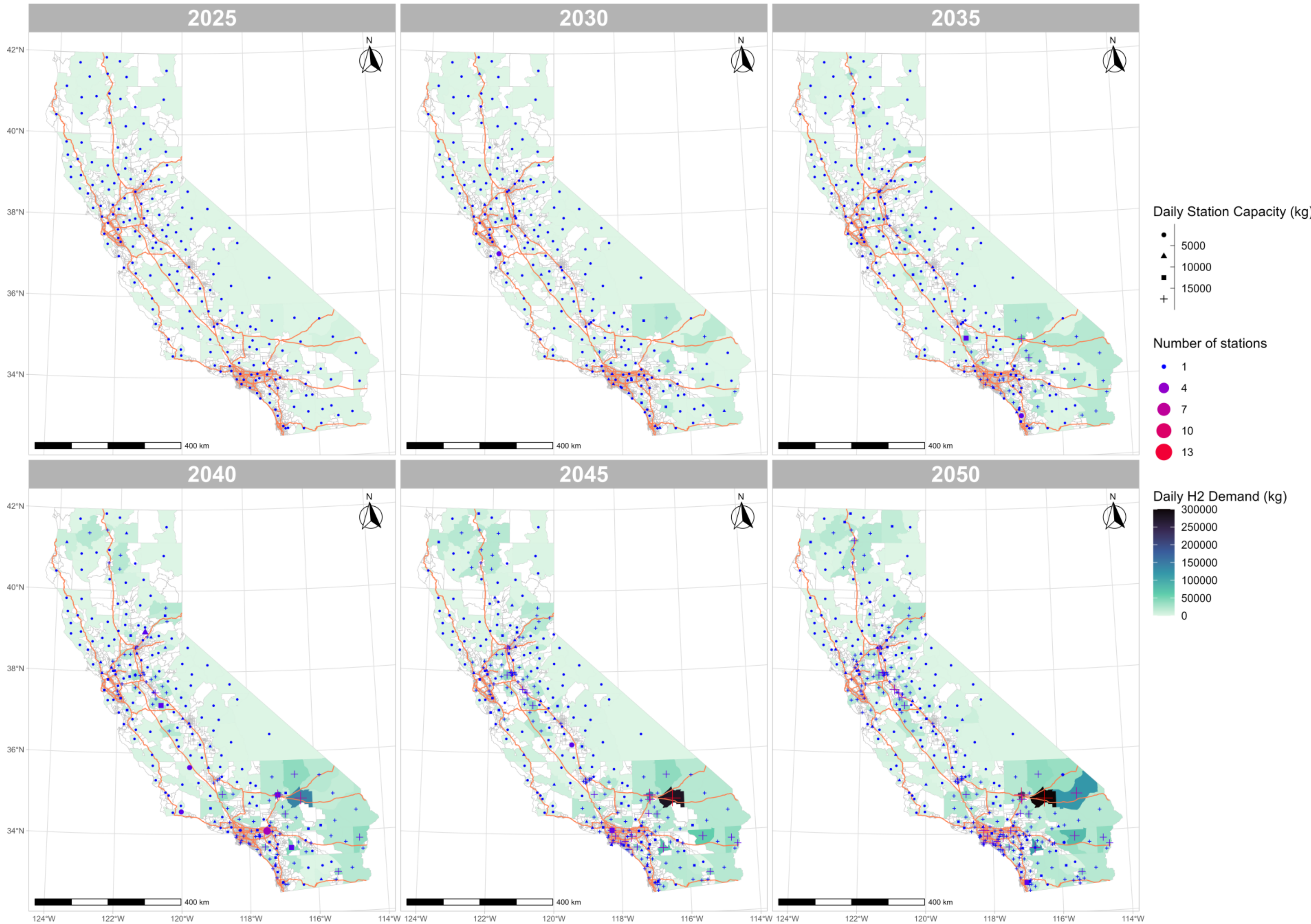


Figure 24. Number and daily capacity of stations, and refueling demand, by TAZ in Base case

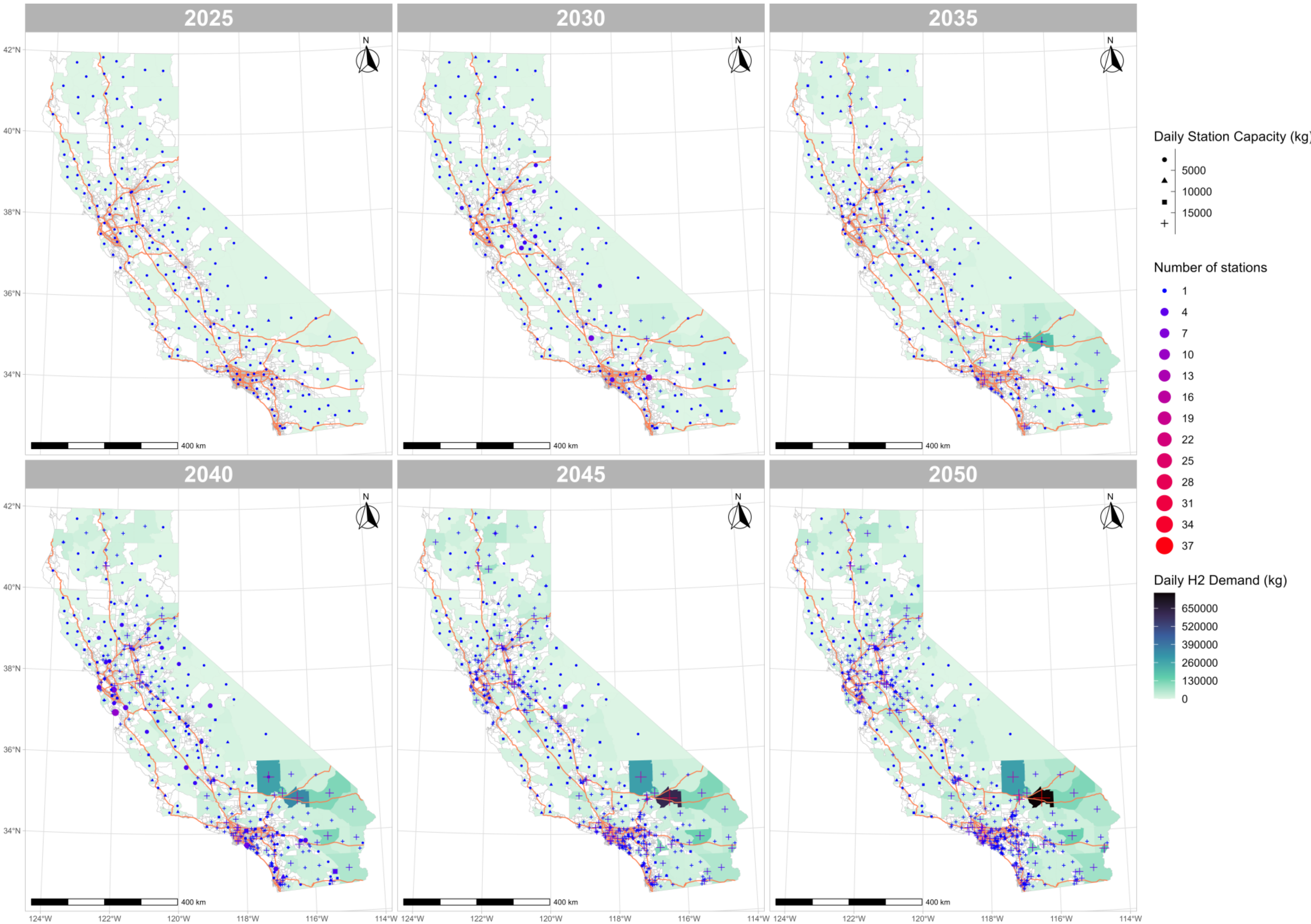


Figure 25. Number and daily capacity of stations, and refueling demand, by TAZ in High case

4.3.1 Station Suitability Analysis

To test the viability of existing gasoline stations and other land parcels for the possible development of hydrogen stations, the numbers and sizes of parcels were investigated. In the ArcGIS environment, random samples of 15,000 non-gas station points were generated and merged with the existing 9601 gas station points. For these data, land cover, land use, slope, distance from all roads, and distance from primary and secondary roads were extracted. Using the extracted full dataset, a decision tree as shown in Figure 26 was established. The decision tree shows the major criteria for the new parcel selection for the hydrogen refueling stations. Parcels that have either a large existing building footprint and lack available space, or are within residential or water-dominated areas, etc. were removed to select suitable open land parcels. To remove small, elongated, and irregularly shaped open land parcels, further filtering was done based on parcel shape and size. For example, parcels were excluded if they had e.g., (i) an area less than 500 m^2; (ii) a perimeter less than 120 m, and an area less than 1000 m^2; or (iii) an area less than 1500 m^2, perimeter greater than 150 m, and a circularity less than 0.30 .

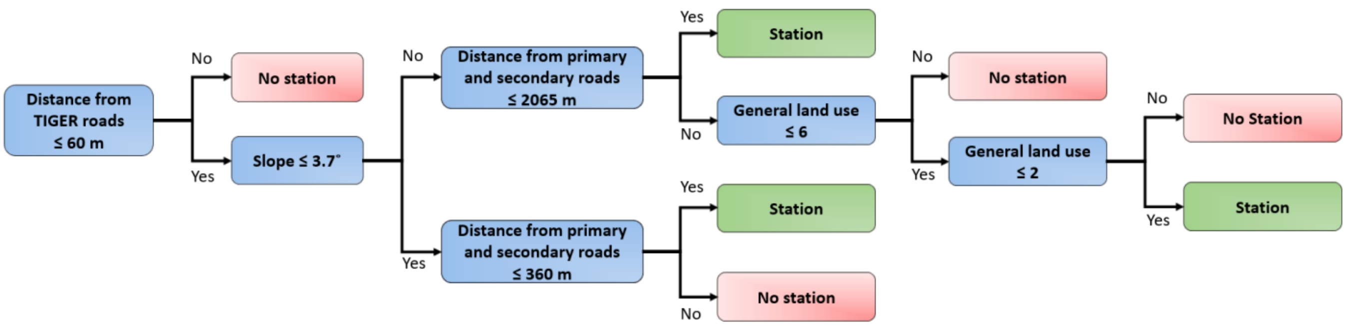


Figure 26. Logic used to determine whether land parcels can accommodate stations

Once the parcels of existing and new possible sites were selected, the final selection could be made based on the minimum area requirement for various types of hydrogen refueling stations. Based on the H2FIRST specifications (Hecht and Pratt, 2017) and on-site PEMs as shown in Figure 10, we derived the minimum area requirement for the hydrogen refueling stations as shown in Table 1. As refueling capacity and the number of refueling dispensers increase, so does the land required for the station. The smallest stations, refueling only LDVs with one-line dispenser islands, can be placed on parcels of about 1609 m^2. For larger stations (up to 18,000-20,000 kg/day capacity), parcels need to be at least 5707 m^2 and as high as 7128 m^2. This depends on the number of dispensers and whether they are intended to serve trucks as well as (or instead of) LDVs.

For gaseous cylinder (or tube trailer) storage at stations, the area requirements are the same initially but become greater than electrolyzers as the latter can be stacked to save space. For pipeline delivery-based stations, a station still needs minimum on-site storage and a compressor and/or units to maintain the temperature. So, a minimum area for storage of 2 tonnes per day is enough for small stations that will not have any production capacity.

Table 2. Area required for different sizes and types of hydrogen stations and percentage of existing 9061 fossil-fuel stations that meets the area required

Station designed for	H2 dispensing capacity (kg/day)	One-line dispenser (4 to 8)		Two-line dispenser (8 to 16)	
		Min. area (m^2)	No. of stations above min. area	Min. area (m^2)	No. of stations above min. area
Light duty vehicles	500–2000	1609	6848 (76%)	2037	5169 (57%)
	2000–4000	1976	5378 (59%)	2501	3896 (43%)
	4000–6000	2343	4194 (46%)	2965	3207 (35%)
	6000–8000	2710	3583 (40%)	3430	2726 (30%)
	8000–10,000	3077	3082 (34%)	3894	2303 (25%)
	10,000–12,000	3444	2712 (30%)	4358	1944 (21%)
	12,000–14,000	3810	2373 (26%)	4822	1675 (18%)
	14,000–16,000	4177	2072 (23%)	5287	1481 (16%)
	16,000–18,000	4544	1836 (20%)	5751	1342 (15%)
	18,000–20,000	4911	1633 (18%)	6215	1243 (14%)
Heavy duty vehicles	500–2000	2186	4578 (51%)	2731	3539 (39%)
	2000–4000	2578	3775 (42%)	3219	2942 (32%)
	4000–6000	2969	3204 (35%)	3708	2476 (27%)
	6000–8000	3360	2796 (31%)	4197	2051 (23%)
	8000–10,000	3751	2432 (27%)	4685	1756 (19%)
	10,000–12,000	4142	2102 (23%)	5174	1517 (17%)
	12,000–14,000	4533	1843 (20%)	5662	1362 (15%)
	14,000–16,000	4925	1628 (18%)	6151	1258 (14%)
	16,000–18,000	5316	1472 (16%)	6640	1168 (13%)
	18,000–20,000	5707	1349 (15%)	7128	1092 (12%)

The distribution of the areas of land parcels for the existing refueling stations can be seen in Figure 27. Very few stations have parcel areas of less than 1000 m^2, and the median area is around 2100 m^2. Industrial and open/public land use have larger median land parcel areas of 2900 m^2 and 2600 m^2, respectively, whereas urban re-serves and medium and high-density commercial areas have a median area below 2000 m^2.

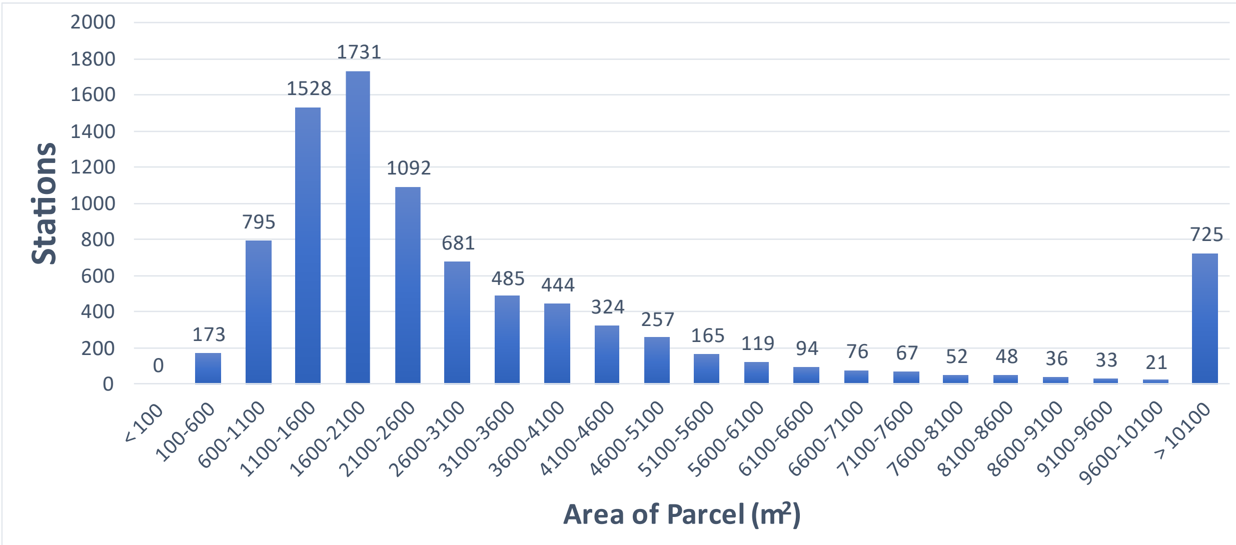


Figure 27. Distribution of the area of refueling stations in California.

Based on the minimum area requirement, existing gas station parcels were evaluated to see if they can be completely removed and accommodated for hydrogen refueling stations or not. Table 4 above shows the number and percentage of existing 9061 refueling stations that can accommodate different types of hydrogen refueling stations. As the size of hydrogen refueling stations increases, fewer existing stations can accommodate them. Given the minimum area requirement for a single island dispenser (Table 2), around 76% of existing station parcels can accommodate LDV and around 50% can accommodate HDV refueling (Table 2). Similarly, for very large stations of double dispenser islands and 20 tonnes per day capacity for HDV refueling, around 12% of stations can be converted.

4.3.2 Implications of Transportation Spatial Analysis

- With strong growth in fuel cell vehicle sales (either car or truck, but especially with both), hydrogen demand could reach several hundred thousand tonnes per year (up to 1000 tons/day) by 2030, and an order of magnitude higher by 2045. To serve this demand with required spatial distribution around the state, rapid growth to approximately 200 hydrogen stations would be needed by 2030, and additional growth to many thousand stations would be needed by 2045. However, a move to much larger stations would be attractive to reduce costs and would result in less than 1000 stations needed overall even in the High case.
- With more and more stations, the sizing and siting of these stations are likely to become more complex, with possible land constraints preventing sizing from what would otherwise be optimal, particularly after 2030 when many hundreds of stations are needed. More research is needed in this area.
- It will be important that stations are built with the possibility of expansion over time. For example, doubling storage and refueling locations (and thus doubling station size) would help cut costs early on and increase the number of stations as the market grows. This in turn means that a long-term perspective (of decades) is important even for near-term (5–10-year) station planning.
- Building dedicated hydrogen refueling stations will require parcels of land that meet a number of criteria, and such parcels appear limited within California. Our screening effort suggests that

once large numbers of stations are required (e.g., over 200), and if larger station sizes are important, locating suitable parcels that align with where demand is may become more challenging.

- Liquid-hydrogen vehicle and station systems have some advantages over gaseous systems, especially with vehicles that also store liquids. However, these systems may be more expensive, in some cases, the number of vehicles that will be equipped to store liquid H2 remains unclear, with light-duty vehicles very unlikely to store liquids and trucks varying with the application.

4.4 Industrial and Other Stationary Demand Analysis

In addition to potential hydrogen demand from the road transportation sector, the project considers other possible types of demand, that we collectively term “stationary demand.” This may include various industrial types of demand (refining, chemicals, manufacturing, etc.), transportation-oriented facilities (airports, ports), large buildings (institutions such as hospitals and schools), and other possibly dense areas of demand.

While a more detailed analysis of potential hydrogen demand from different stationary sectors will be published separately, here we provide some rough estimates of what could be a low and high demand level for various sectors, based on sector size and potential for adoption of hydrogen. This follows work such as that undertaken by UC Irvine (2019) and in many cases aligns with their estimates. No attempt is made here to explain these estimates, but simply share them and show the assumptions that are then used in some scenarios including both transportation and stationary hydrogen demands.

As shown in Figure 30, we considered 9 sectors apart from light-duty vehicles and trucks (shown in the figure for comparison purposes). Sectors include aviation, “other transport” (most importantly, ports), production of biofuels and synthetic fuels, refineries, bio and synthetic natural gas, cement, ammonia, other industrial, and residential/commercial. The figure shows the estimated hydrogen demand by sector in 2045 for the Base and High cases.

As can be seen, in the High hydrogen case, some of these sectors have a projected demand that is similar to the Base demand case for transport, while none is anywhere near the level for the High transportation demand case. Though taken together, these sectors do achieve such levels.

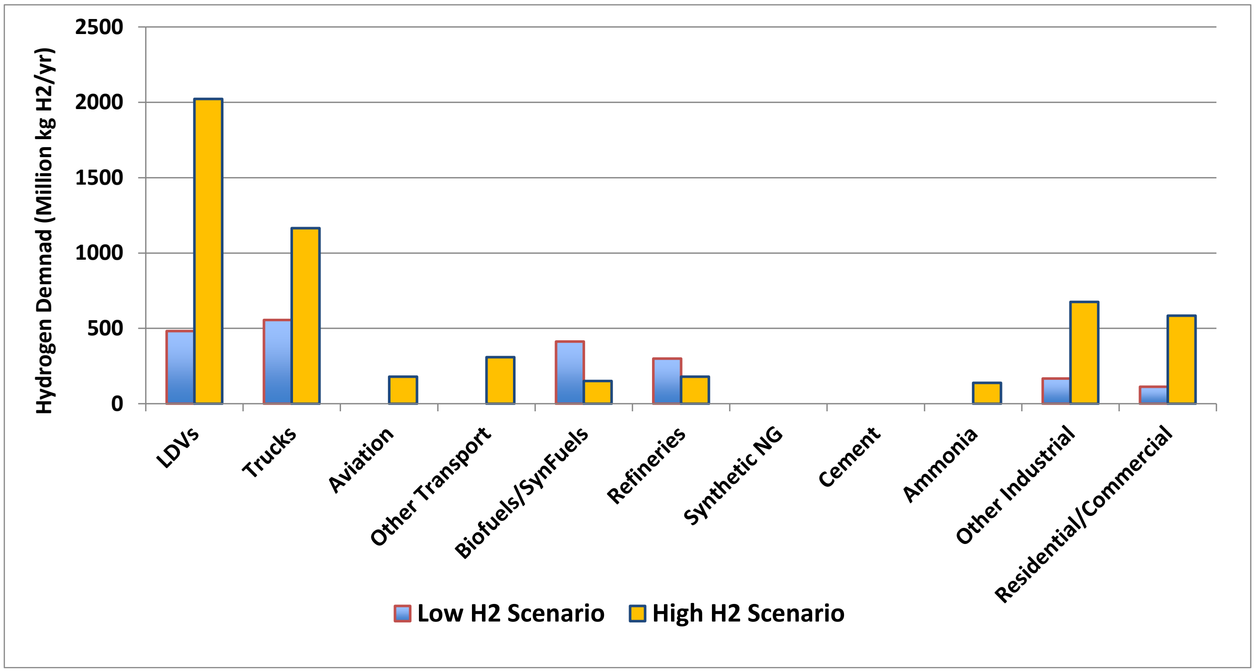
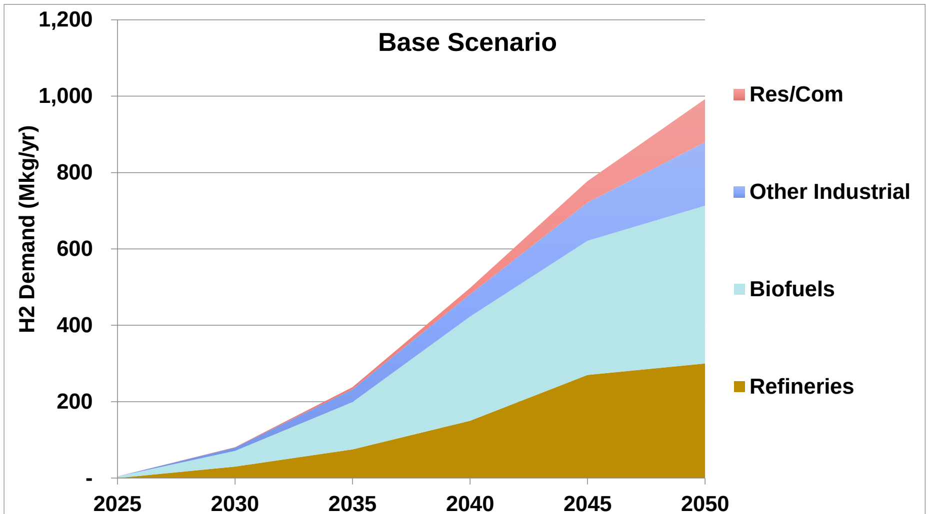


Figure 28. Hydrogen demand in 2045 by end-use sector in Base and High demand cases

Figure 31 shows these scenarios from 2025 to 2050 for the Base and High scenarios. It shows rapid growth in the High case, but still within a range based on the potential demand for hydrogen from different sectors. Hydrogen demand reaches 2000 million kilograms (or two million tonnes) per year, with the "other industrial" and residential/commercial sectors having the greatest demand at that point.

In the Base scenario, overall demand in 2050 is half that in the High scenario, and biofuels and refining are the most important sectors out to 2050. The demands from these two sectors are actually higher in the Base scenario than the High scenario, since the High scenario is associated with rapid decarbonization and movement away from oil use in the state, as well as more hydrogen and electricity use for vehicles, which leads to lower oil use and lower biofuels production than in the Base case. In the nearer term, the 2030 demand is about 80,000 tons/year (250 tons/day) in the Base case and 150,000 tons/year (450 tons/day) in the High case.



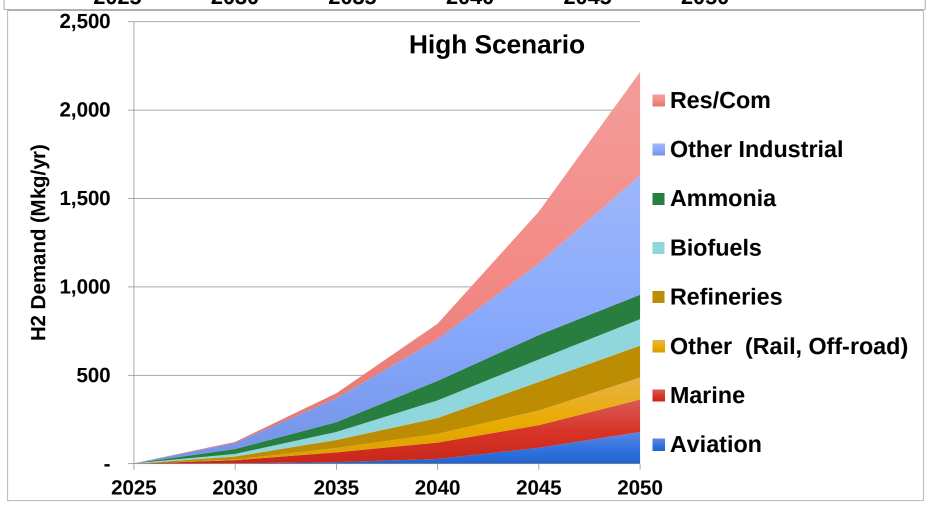
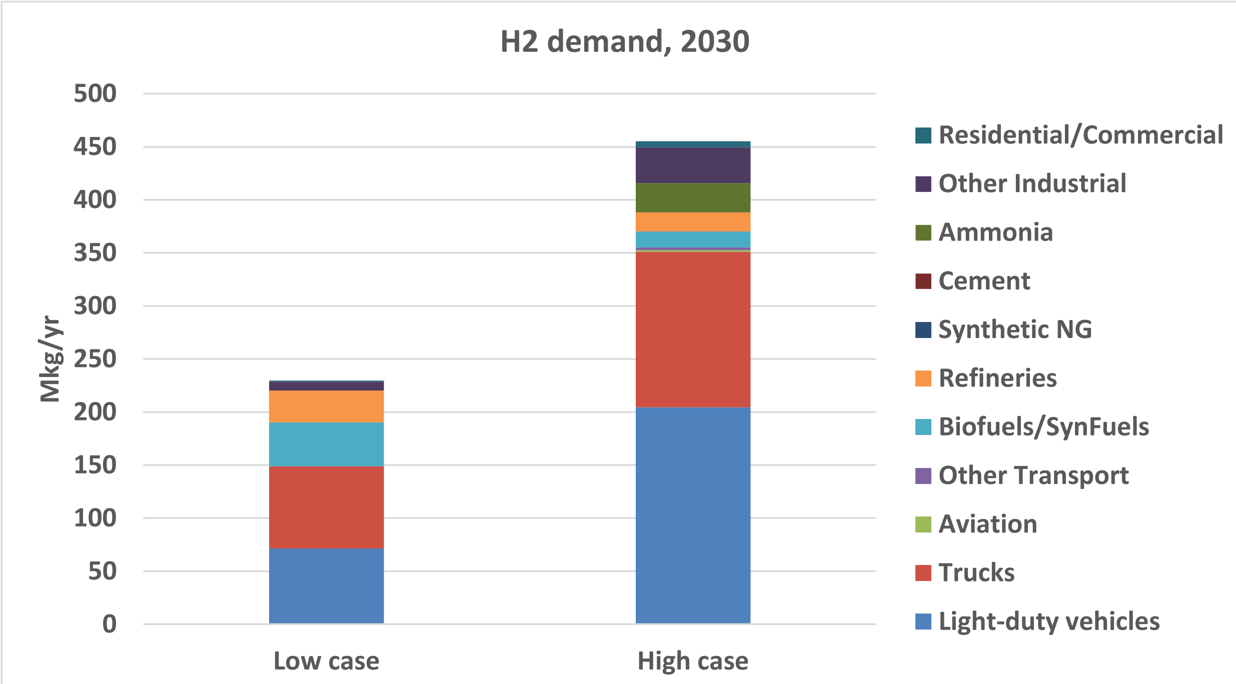


Figure 29. Growth in stationary hydrogen demand by end-use sector, Base and High scenarios (thousand tonnes/year). (Note: The y-axis scales are different.)

When combining the High stationary demand with High transportation demand, and Base with Base, the results are as shown in Figure 32 for 2030 and 2045. Remembering that at this point in the research, only about half of the potential stationary demand sectors have been mapped onto a spatial basis and included in the analysis, stationary demand represents about as much as transportation demand in the Base case, and about half as much in the High case, though with a rising share over time. Overall demand in 2045 reaches 2 million tonnes in the Base case and 5 million in the High case; this compares to about one million tonnes used in refining today and perhaps only a few thousand tonnes across all other commercial end uses.



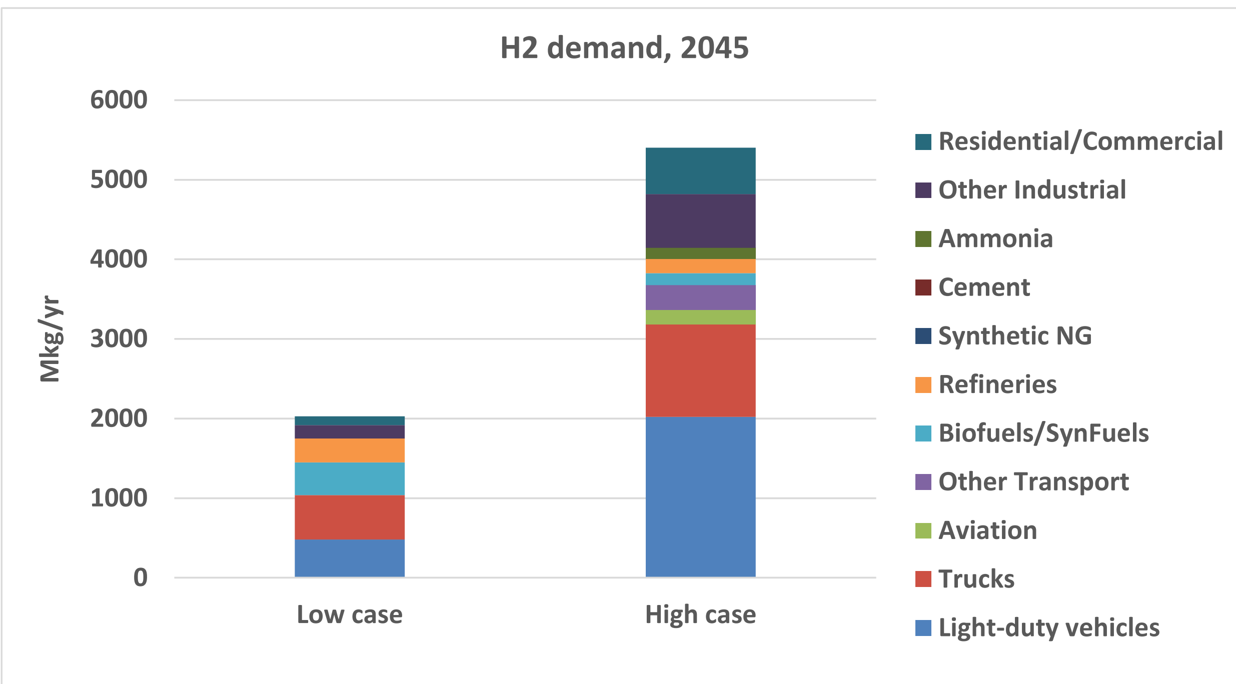


Figure 30. Transportation and stationary hydrogen demand in the Base and High scenarios, 2030 and 2050 (thousand tonnes/year) (Note: The y-axis scales are different.)

Spatializing the stationary demands produces the demand maps shown in Figure 33. These show 2030 and 2050 for the High case, and indicate the vast majority of stationary demand is concentrated in the LA and San Francisco regions. From this, the analysis grouped these into hubs that could receive large quantities of hydrogen for final distribution to each facility. This is discussed in the section on supply chain (SERA) modeling.

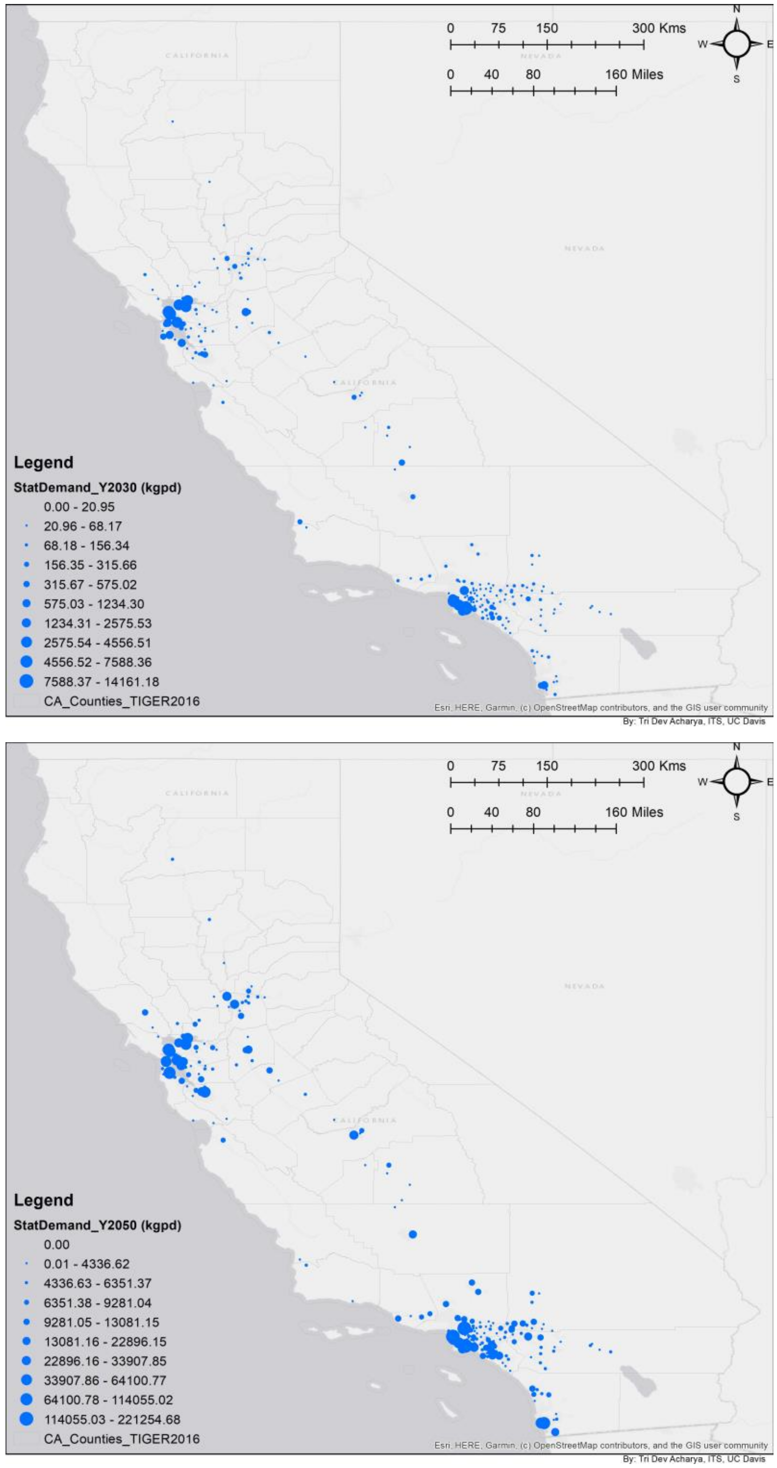


Figure 31. California stationary hydrogen demand locations in 2030 (top) and 2050 (bottom)

5 Electric Sector Modeling with GOOD Model

As described in the model overview section above, the GOOD model is used as a stand-alone model of the electric sector in this analysis, though "soft linked" to both the STIEVE model and SERA model. It received transportation hydrogen demands from STIEVE, on a spatial basis (though somewhat aggregated from STIEVE's highly disaggregated structure), and stationary hydrogen demands from our separate analysis described in the previous section.

GOOD produces projections of the entire electricity demand from all sources in California in 5 year intervals to 2050, drawing on electricity capacity and grid connections throughout the Western Interconnection (managed by WECC). For this analysis, we have run this model for a range of scenarios to investigate how hydrogen demand would be met by the electric sector (if all hydrogen demand were met this way, via electrolysis), and what impacts this might have on power capacity expansion, generation, and generating cost (and thus electricity prices used in SERA for the price of hydrogen passed on to consumers).

We start by presenting key inputs to GOOD that vary by scenario, and then present various outputs. There is far more detail available on these aspects than can be included here; separate reports are in preparation to explore the analysis in more detail.

5.1 GOOD Model Inputs

The model uses a wide range of inputs and these are being documented separately (and have to some degree been documented in previous reports):

Financing: discount rate: 10%

Capacity costs:

- Solar (30-year lifetime): $800/kW, not including transmission
- Wind (30-year lifetime): $1300/kW, not including transmission
- H2 Storage: $2/kg
- PEM Electrolyzer: $300/kW

The targeted level of renewables by state and year is shown in Table 3, based on announced state plans. It is also possible that the US will create a national level renewable portfolio standard (RPS) or clean energy standard (CES) for a future year, such as 2050, but at this time no such standard is in development and is not modeled in this study.

Table 3. State targets for renewables as a percentage of generation and target year

State	RPS or CES Target	Target Year
California	100%	2045
Colorado	100%	2050
Nevada	100%	2050
New Mexico	100%	2045
Oregon	100%	2040
Washington	100%	2045

RPS, renewable portfolio standard; CES, clean energy standard

A more detailed report on GOOD modeling assumptions and results is in development.

5.2 GOOD Electricity Model Scenarios

Currently, we have developed 12 different scenarios as separate runs of the GOOD model. These scenarios are based around several combinations of parameters of interest including:

- FCEV stocks and hydrogen demand in the transportation sector [Base, High; 2 options]
- Electric vehicle stocks and their electricity demand (excluded, medium, high; 3 options. The EV stock scenarios are inverse to the FCEV stock scenarios)
- Cost of hydrogen infrastructure (storage and PEM electrolyzers) [Low, Medium, High; 3 options]
- Cost of renewable generation capacity (solar and wind) [Baseline, High; 2 options]
- Renewable Portfolio Standards [Baseline, Aggressive, All 100%; 3 options]
- Renewable curtailment options [Baseline, No Curtailment Allowed; 2 options]

The four vehicle and hydrogen related scenarios are further detailed in Table 4, and the ZEV stocks in the three main vehicle scenarios are shown in Figure 34. The FCEV-Only Fleet (or stock) scenario provides an initial look at how the growth in FCEVs could affect the grid, and it can be compared to one with both FCEVs and BEVs. The FCEV-Only Fleet scenario has fewer overall ZEVs (and electricity demand) than the mixed fleet. A comparison to a PEV-Only Fleet (no FCEVs) is made in the third vehicle scenario, where PEVs are all plug-in vehicles, including pure electric (BEVs) and plug-in hybrid electric vehicles (PHEVs). The FCEVs reach about 1 million by 2050, consistent with the High case, though the low case was also run.

Table 4. Vehicle/hydrogen Scenario Breakdowns

Fleet Scenarios	Heavy-duty vehicles	Light-duty vehicles	Hydrogen infrastructure & storage
FCEV only	FCEVs	FCEVs	Yes
Mixed ZEV	50% FCEVs + 50% PEVs	FCEVs + PEVs	Yes
PEV only	BEVs	PEVs	Yes
PEV only	BEVs	PEVs	No

PEVs, plug-in electric vehicles: battery electric vehicles and plug-in hybrid electric vehicles

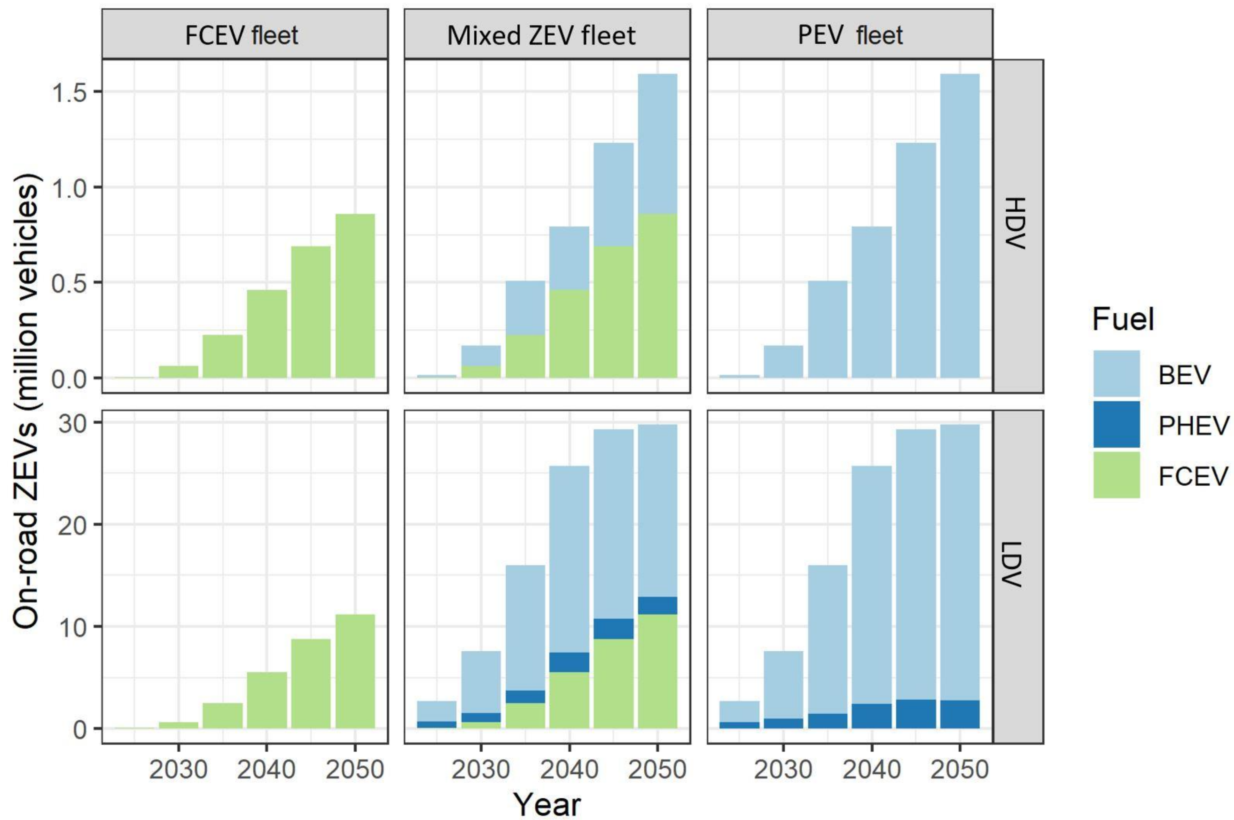


Figure 32. HDV (top) and LDV (bottom) fuel-cell and electric vehicle stocks in different scenarios

Taking into account the possible electricity scenarios, the combination across all possible parameters leads to a total of 144 possible scenarios, though we do not report all the combinations of parameter inputs. A curated selection of scenarios allows our model to simulate a set of representative future scenarios of the H2 system and reveal nuances of integrating the electricity grid into the that system. In the following section, we provide an overview of some of the primary findings from the model runs.

The Baseline scenario is currently specified using our high hydrogen demand growth in the transportation and industrial sectors along with medium costs for developing hydrogen infrastructure, Baseline options for RPS in different states (and thus high in California and the Northwest, modest elsewhere), renewable generation capacity costs, and Base curtailment options.

5.2.1 GOOD Modeling Results - Baseline Scenario

Figure 33 shows a range of key capacity-related outputs from our modeling, with the three transportation technology scenarios and the PEV scenario with and without hydrogen storage. Capacity evolution by generating region (across 8 WECC regions) is shown for hydrogen storage, hydrogen production from electrolysis, and wind and solar power. The co-evolution of the electricity grid toward much greater use of renewable power and hydrogen production and storage capacities are shown across the figures. The importance of hydrogen storage in moderating the need for renewable capacity is also evident. Specific findings include:

- Hydrogen storage is not important before 2035, but by 2040 it is substantial and typically doubles again to 2045. Further, a "PEV" rather than "ZEV" fleet (i.e. with plug-in vehicles only, no FCEVs) requires nearly twice the H2 storage capacity as a mixed fleet to meet the temporal charging demand. This is because hydrogen FCEVs "absorb" much of the excess renewables and much more grid management is possible with lower levels of storage than in a PEV-only scenario.

- H2 production capacity is the highest in the mixed fleet scenario because the PEM capacity is built to meet both transport H2 demand and electric generation storage needs.
- If no hydrogen storage is available, combined wind and solar capacity rises and shifts from solar to wind, reflecting the needs for greater overall power generation and for a better temporal mix of available capacity to reduce peaks and troughs in availability. The wind power is somewhat more expensive on average than solar but provides grid balancing benefits around the WECC system.

These results are not surprising, as the near 100% renewable generation requirement from the RPS in California and some other regions by 2045 requires either substantial variable renewable capacity to provide sufficient reliability or substantial storage to reduce that capacity and maintain the feasibility of operation within the electricity grid. Storage available at $2/kg of hydrogen would provide a cost-effective alternative to further build-out of the renewables system. In the PEV-only scenario, the amount of hydrogen storage in 2050 is about 1.2 million tonnes, compared to 700k tons in the mixed system. This additional storage in the former displaces about 50 GW of renewable capacity.

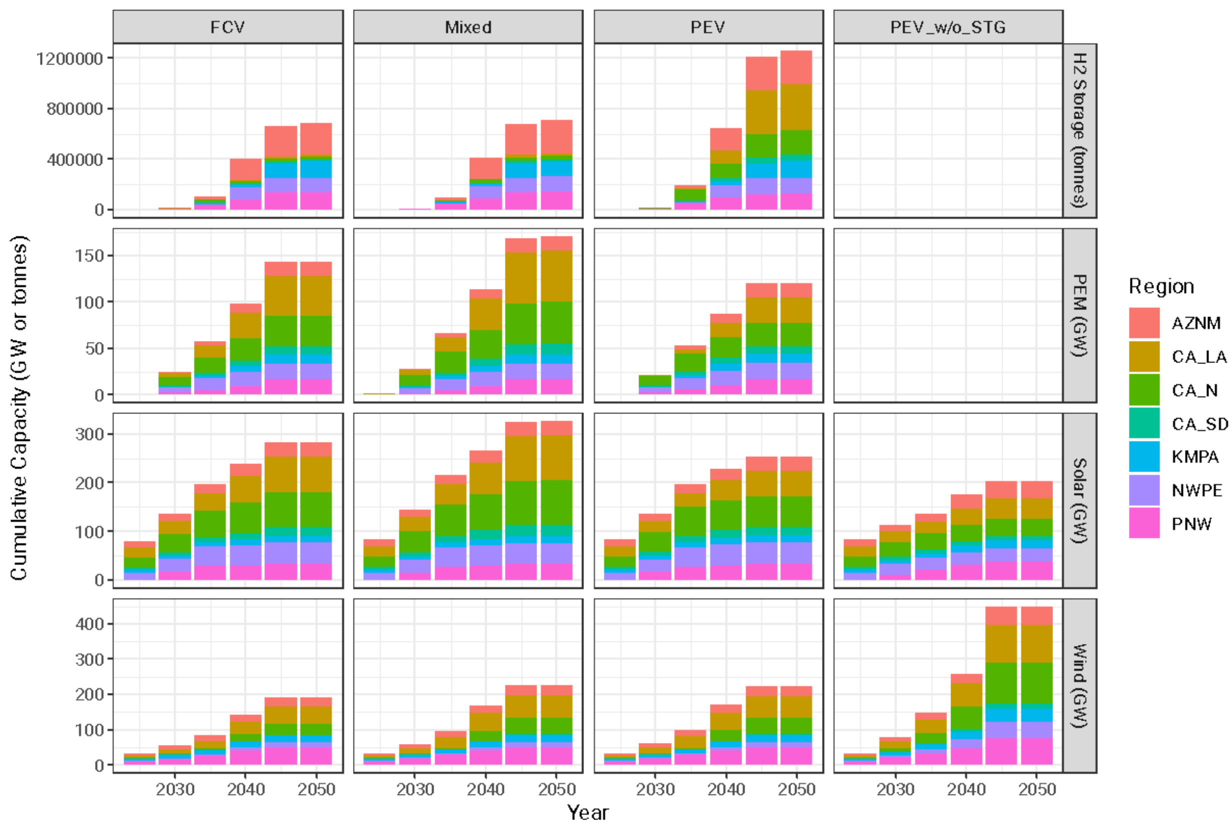


Figure 33. Cumulative capacity growth of hydrogen infrastructure and renewable generation through 2050 (*three transportation scenarios and a no-storage scenario*) (STG=hydrogen storage)

The generation mix by fuel type and region for the Baseline scenario is shown in Figure 34. This varies considerably by region and reflects different expected policies regionally, with only California requiring a high share of renewable generation by 2050. California regions are dominated by wind and solar power after about 2030, while some other regions still operate coal plants in 2050. The Pacific Northwest, like California also transitions to nearly 100% renewables over the projection period.

We observe steady growth of renewable generation resources in all regions with existing RPS targets. In California, by 2050 the total capacity of renewable energy is around 210 GW—nearly a tripling of current generation capacity. This capacity of renewables is mainly used to meet RPS requirements and are only mildly influenced by hydrogen system demand.

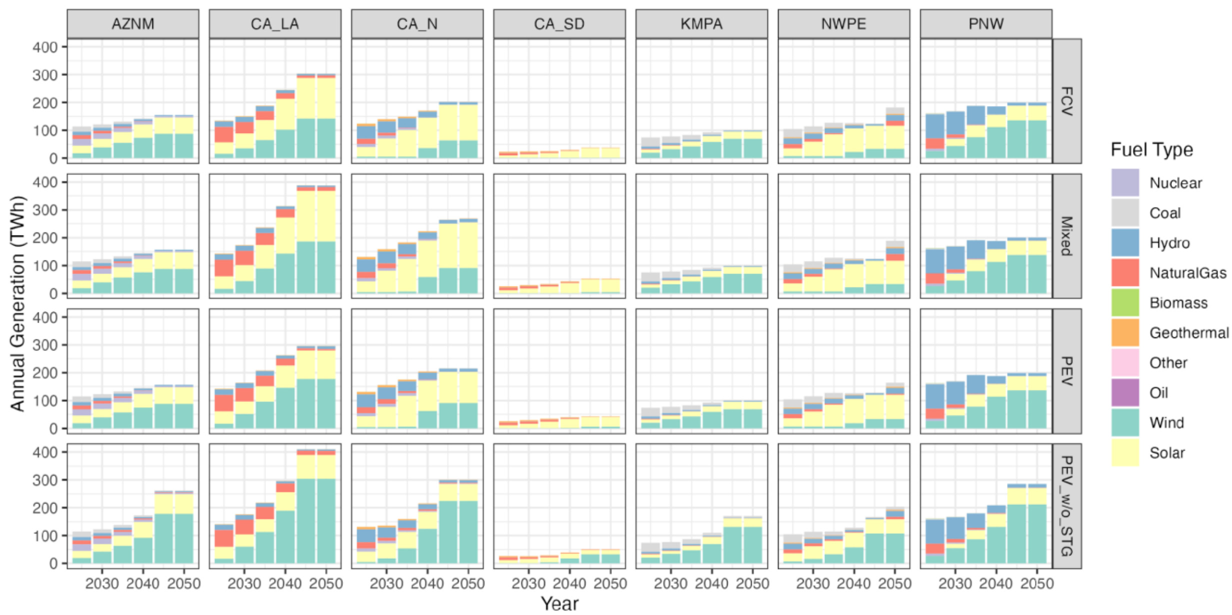


Figure 34. Generation mix by fuel type (*Baseline Scenario*) (STG=hydrogen storage)

Figure 35 and Figure 36 below showcase the high resolution of the GOOD simulation model. In the first figure, we observe the response of aggregated generators by fuel type to shifting demand patterns over the course of 11 days. In California regions, rich with solar resources, there is a substantial ramp down of natural gas resources during the day, though some imports are necessary to fill in troughs of renewable generation and ramping events corresponding to the "duck" curve. Most of the transmission into California can be seen coming from excess wind generation from the Pacific Northwest during this time period. Lastly, there is very little hydrogen production in 2025, barely observable in any of the dispatch curves within California.

However, these results stand in stark contrast to Figure 37 below which shows dispatch results corresponding to an aggressive RPS requirement for all states in 2050. Over identical summer months, we observe a very different mix of generators providing the totality of electricity to each of the regions in our analysis. Notably the stringent requirements of the renewable portfolio standards (RPS) lead to electricity generation predominantly from solar and wind resources. There is substantial import of wind resources to help balance load in the San Diego region of California, though in the remaining regions, supply of electricity is fairly well balanced with the demand over this time period. Regarding hydrogen production, a notable feature of these dispatch curves is that most fuel is produced by large amounts of "excess" solar (excess with regards to electricity demand) that would otherwise be curtailed. While some curtailment still occurs (see peak corresponding to the third day within the CA_N region), it is clear that the system is doing a good job in taking advantage of the installed capacity to fulfill both the immediate electricity demands and the hydrogen production necessary for end-use and/or electricity generation.

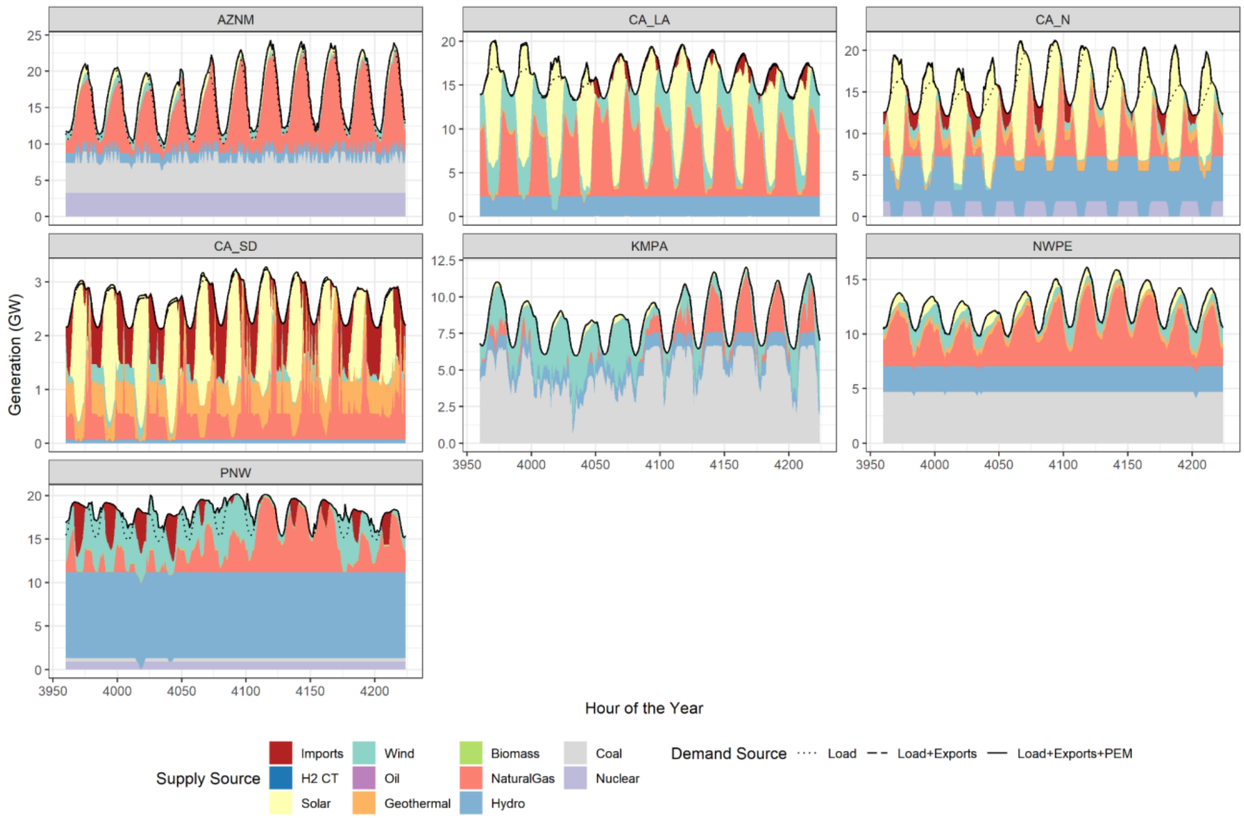


Figure 35. Example of 11 days of dispatch during the summer of 2025 (*Baseline scenario*)

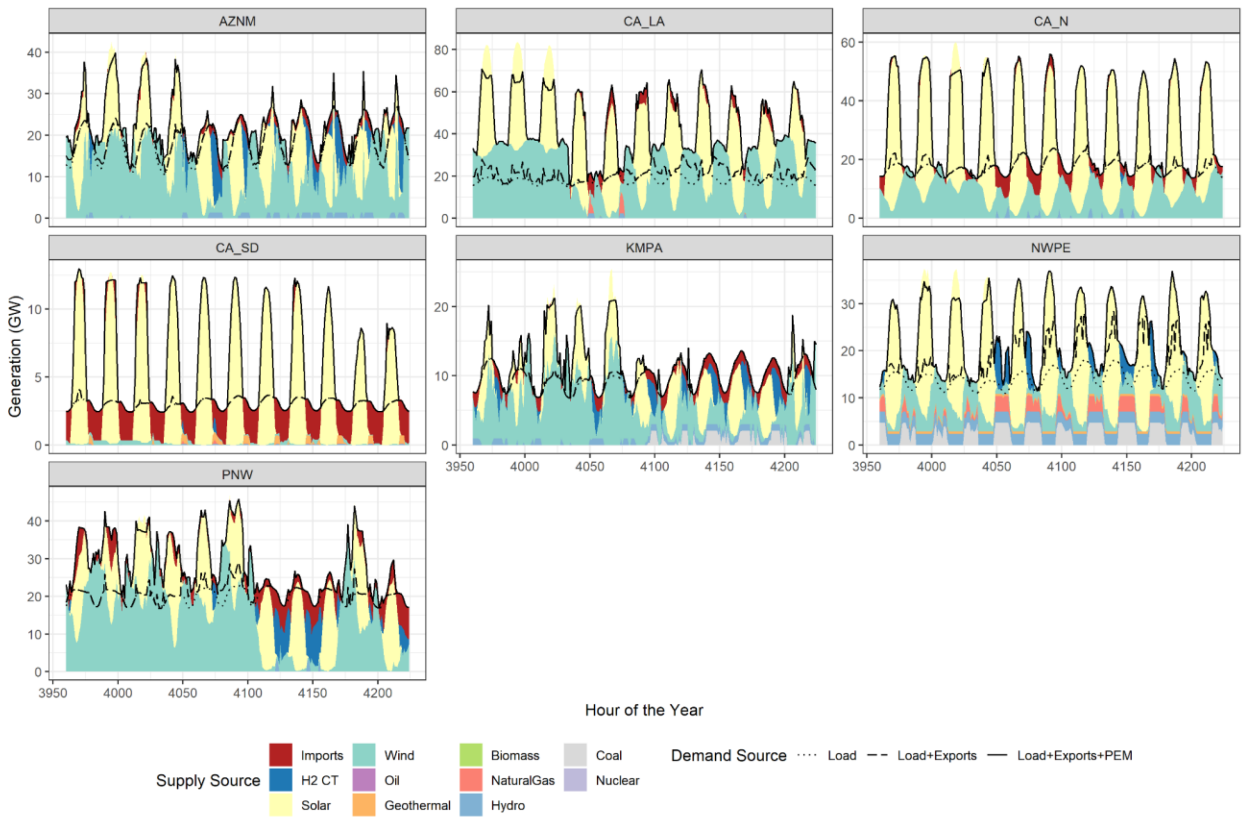


Figure 36. Example of 11 days of dispatch during the summer of 2050 (*Aggressive RPS scenario*)

Although hydrogen can be used for a variety of services, in the Baseline scenario most hydrogen ends up being used for the transportation sector (Figure 37). As the figures show, while hydrogen storage and re-generation of electricity is projected for all regions, we only consider end-use hydrogen demand in California. Other regional demands may be added at a later date, but would likely be much smaller than for California, at least across the Western WECC states. Even for California, our projected demands for some sectors, notably buildings and industry, are still evolving as we do more analysis of those end uses.

Our results to date show that industrial (and some other stationary) demands are a relatively small proportion of the end-use in our Baseline scenario, though there is substantial growth of hydrogen fuel combusted to produce electricity in later years. This generation could evolve to use fuel cells over time, though for this round of analysis we assumed it is all combustion with some blending and eventually dedicated hydrogen turbines. In the most aggressive RPS scenarios across all states, hydrogen combustion begins to rival the demand of the fuel in the transportation sector. However, most of the scenarios we investigated did not lead to this outcome.

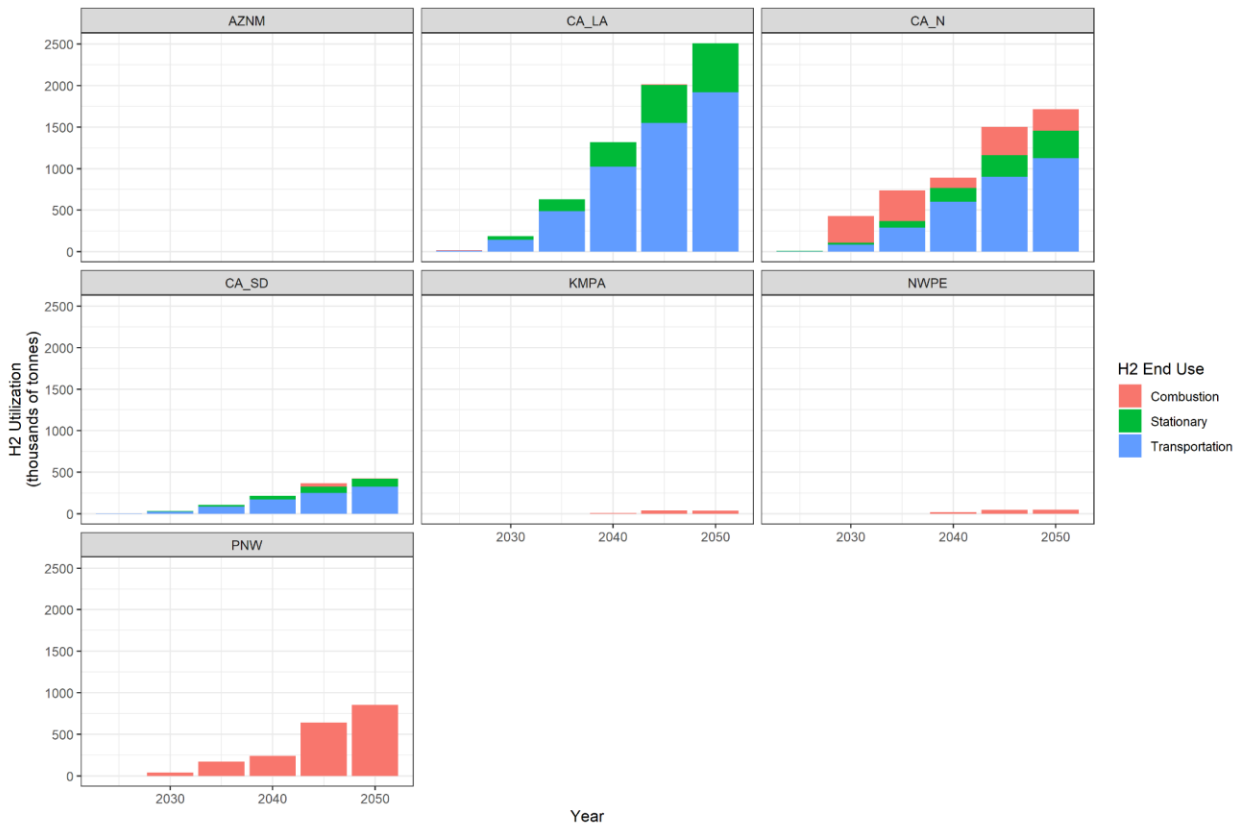


Figure 37. End-use volumes of hydrogen for industrial and other stationary uses, the transportation sector, and for electricity generation through combustion (*Baseline scenario*)

One interesting aspect of the modeling is the ability to observe the transition of turbine resources away from natural gas towards hydrogen combustion. The combination of RPS requirements and hydrogen demands both increasing over time allows for the system to begin taking advantage of these growth synergies. As shown in Figure 38 below, in 2035, before RPS and hydrogen infrastructure fully "take over" the combustion turbine resources, there is still abundant use of gas turbines with both fuels. Natural gas effectively differs from hydrogen: natural gas is a purely new dispatchable capacity of electricity, while hydrogen is effectively acting as the output of storage and hence the net electricity generation is actually negative (but fairly close to zero).

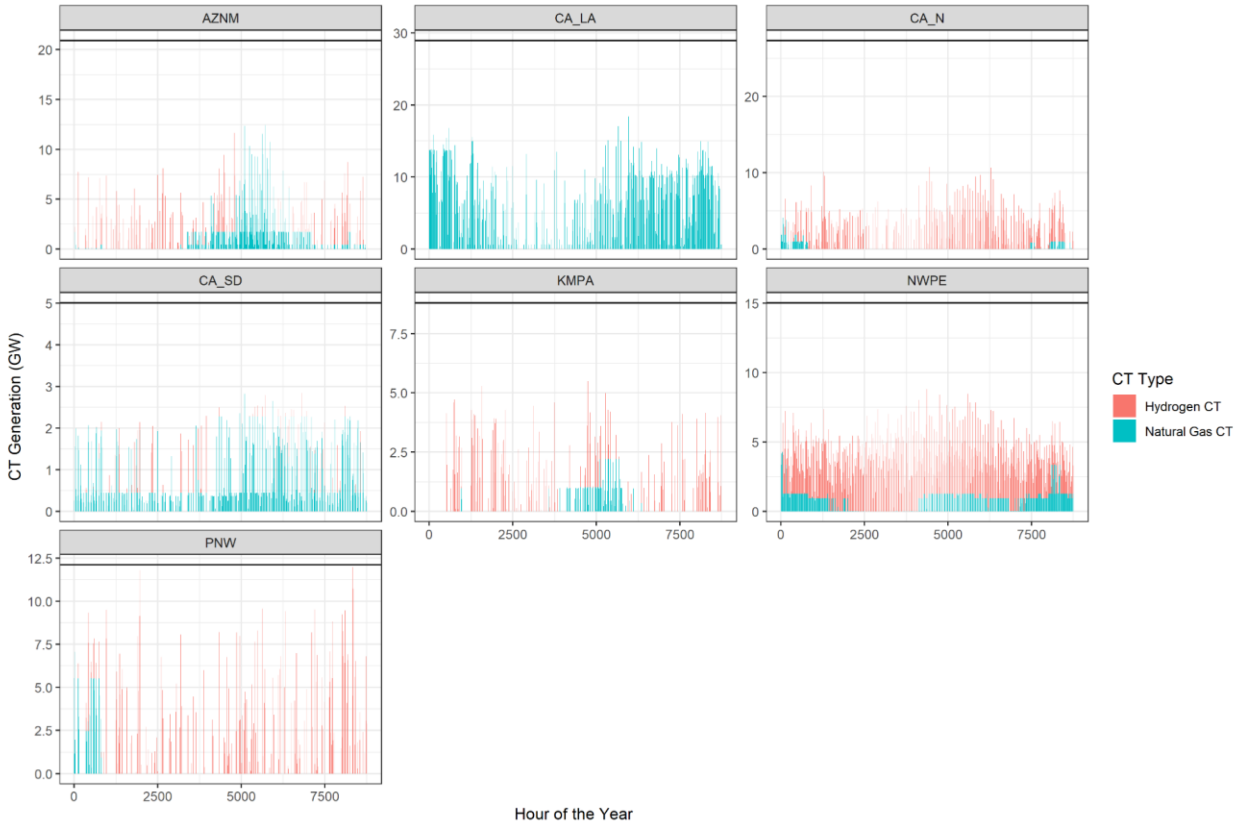


Figure 38. Mix of natural gas versus hydrogen fuel for electricity generation out of gas turbines throughout WECC in 2035 for an aggressive RPS scenario for all states.

The seasonal variation in resource availability of renewable solar and wind consistently lead to higher utilization of storage in later years of our analysis. As seen in Figure 39, the storage is fairly seasonal to deal with the seasonal variation, with stored capacity reaching as high as 125 million kg of hydrogen. Our results reveal that hydrogen is import in helping to (i) balance the grid; (ii) economically meet RPS requirements; and (iii) allow for greater expansion of renewable energy capacity. In other scenarios, these advantages could be even greater than in the Baseline scenario.

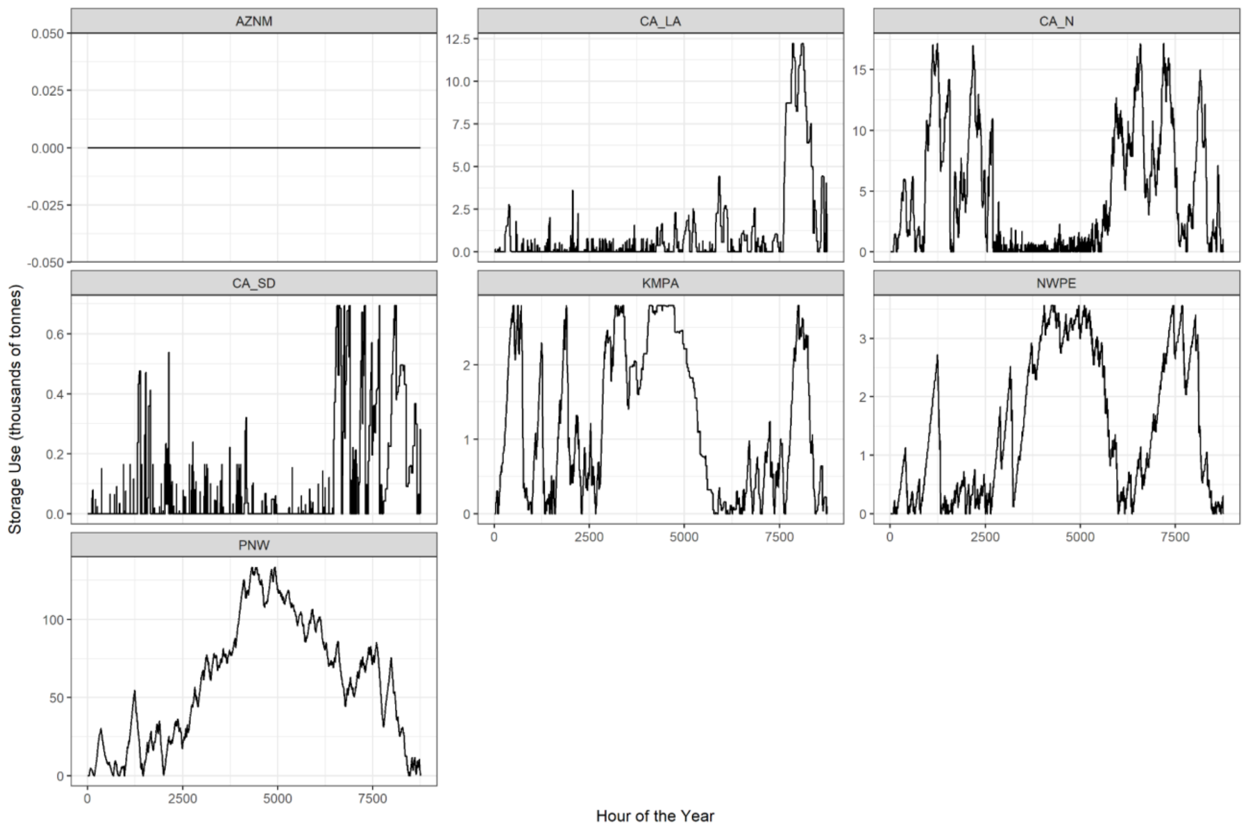


Figure 39. Hydrogen storage use over a period of a year (8760 hours) in 2050 (*Baseline scenario*) by region

5.2.2 Other GOOD Model Scenarios and Sensitivity Cases

As described in the section above, we ran a wide range of sensitivity cases relative to the Baseline Scenario. Here we focus on two: the High Renewables Cost/Low Hydrogen Production Cost Scenario, and the High RPS Across All Regions Scenario. These are shown in Figure 40 and Figure 41, respectively. There are many things that can be compared to the Baseline Scenario, but visually this can be difficult, so a few numbers and points are pulled out for discussion.

Many of these scenario results are intuitive: In the scenarios where we investigated relatively lower and higher costs of renewable capacity, there is a corresponding expected decrease and increase in installed capacity of renewable resources. For example, the total capacity of newly installed renewables (wind and solar) in California in 2025 is 50 GW, and it increases, in 2050, to 230 GW in the Base Case but only to 180 GW when renewables cost 50% more (Figure 40). Clearly the RPS requirements are still leading to relatively large amounts of renewables even with higher costs. In addition, the installation of renewables tends towards wind generation at higher costs.

Across scenarios of low to high hydrogen infrastructure costs, we find that the capacity of hydrogen storage and PEM electrolyzers sensibly scale to these changing costs. At 50% lower hydrogen infrastructure costs, the installed capacity of electrolyzers increases from about 95 GW up to 120 GW. In this scenario, the end-use demand does not increase and therefore the increased electrolyzer capacity is being used to serve electricity demand through hydrogen combustion turbines. Storage capacity increases by over 50% in this scenario as well. If hydrogen infrastructure costs are 50% higher than in the Base Scenario, both electrolyzer and storage capacity decrease.

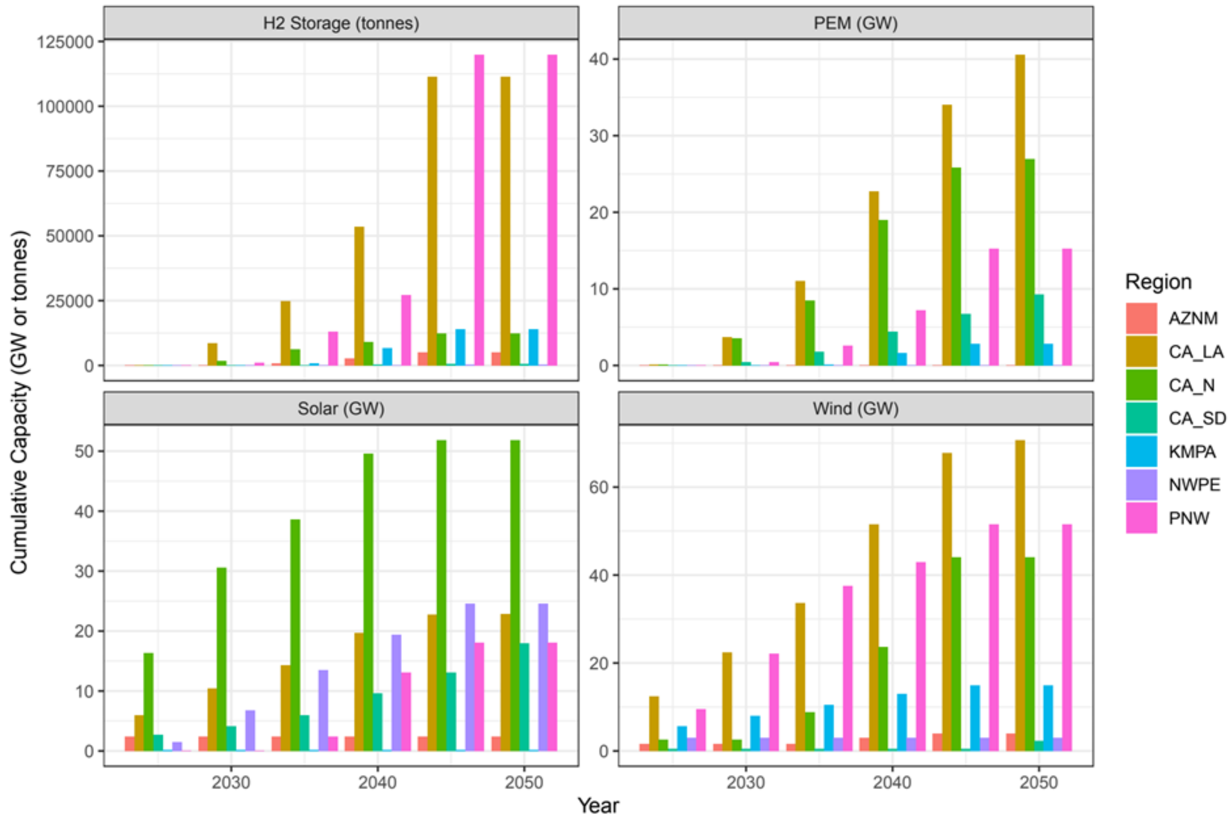


Figure 40. Model outputs for the High Renewable Cost/Low H2 Production Cost Scenario

Figure 41 shows the results of assuming all WECC regions reach a high share of renewable generation by 2050, basically an RPS in all regions (not currently legislated but possible, or reflective of a national RPS policy). This assumption dramatically affect the total amount of renewables in non-CA regions, the capacity of PEM in these regions, and the total amount of stored hydrogen. PEM in non-CA regions rises to 70 GW by 2050 compared to 15 in the Baseline Scenario. The effect on non-CA storage is to increase it to 700,000 tonnes of capacity in 2050, compared to 150,000 in the Baseline Scenario.

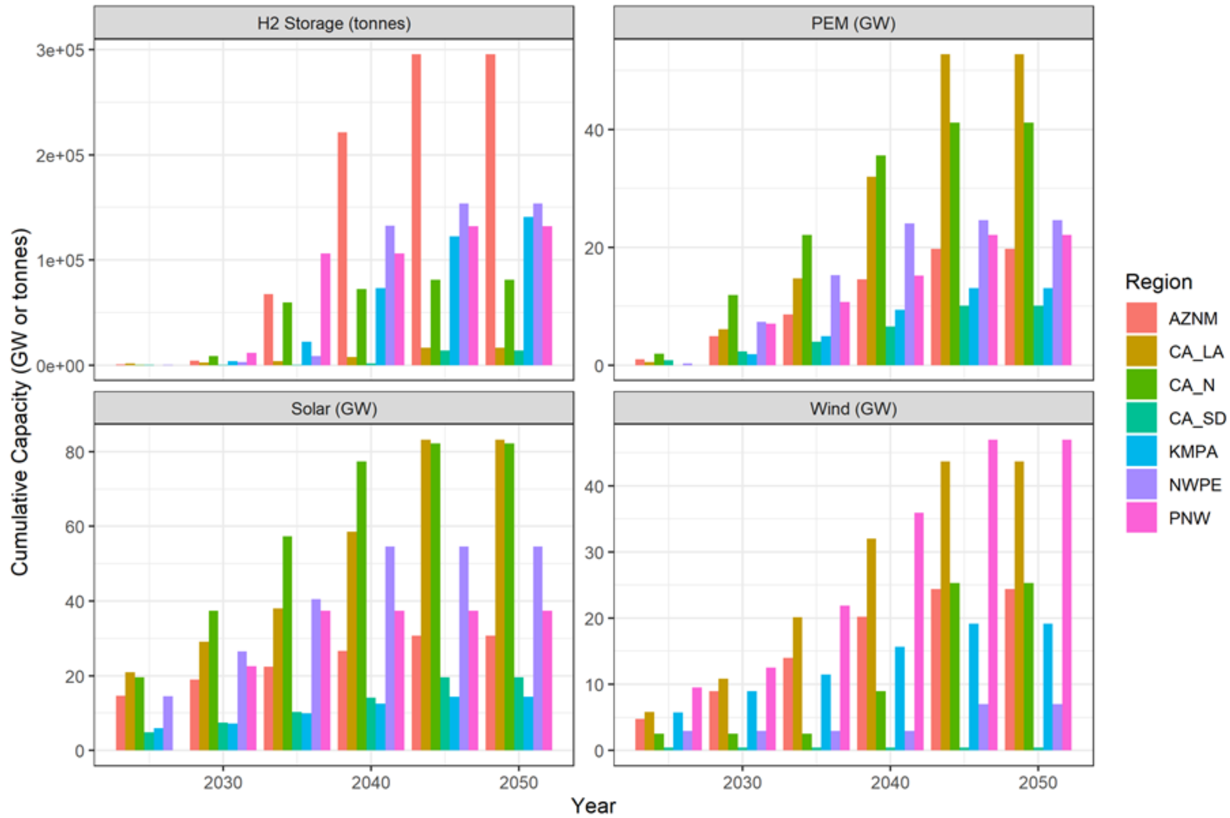


Figure 41. Model Outputs for High RPS Across All Regions Scenario

Hydrogen storage is explored across more scenarios in Figure 42. Storage in 2050 in the Baseline mainly occurs outside California, and reaches a modest overall capacity of near 200,000 tonnes per year. In scenarios with either higher renewable cost (reducing the tendency to overbuild and accept curtailment) or lower hydrogen costs (including production and other infrastructure), storage rises, particularly in California. But the High RPS in All Regions case stands out for needing a far higher level of storage. This reflects very high renewables use around the WECC, and an accompanying need for high levels of hydrogen storage to manage variability and minimize curtailment.

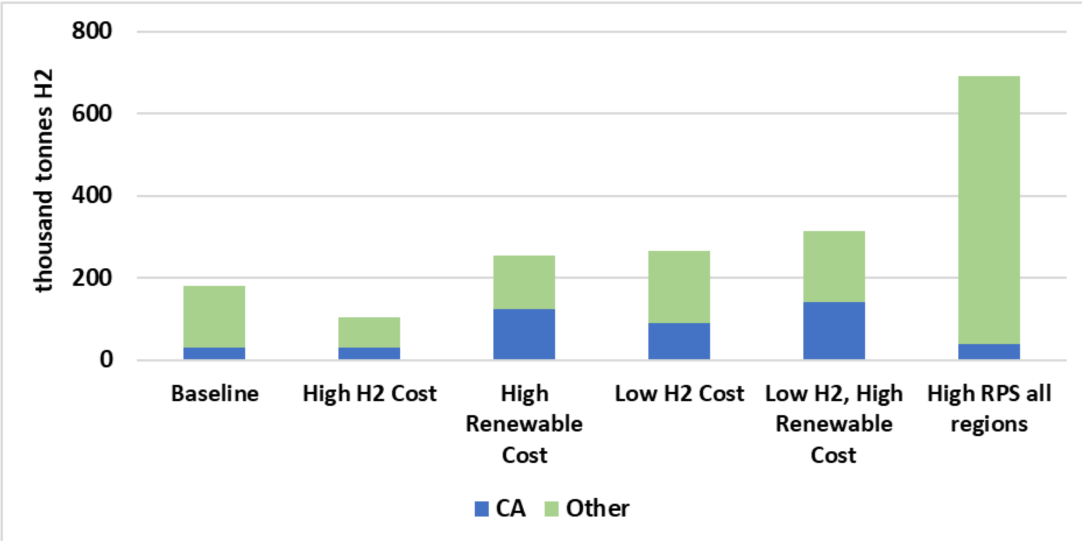


Figure 42. Hydrogen storage requirements in 2050 by scenario

Figure 43 shows the use of the hydrogen storage capacity in each of the seven WECC regions in 2050, in the High RPS All Regions case (the one with by far the highest storage requirements). Some regions clearly provide seasonal storage: storing hydrogen in a steadily increasing fashion through part of the year, then decreasing back to zero. Others use it either on a more weekly or even daily basis (reflected by the frequency of spikes and drops). It is those regions tending to store hydrogen seasonally that need the largest capacity, since they are continually adding to storage rather than having many up-down cycles.

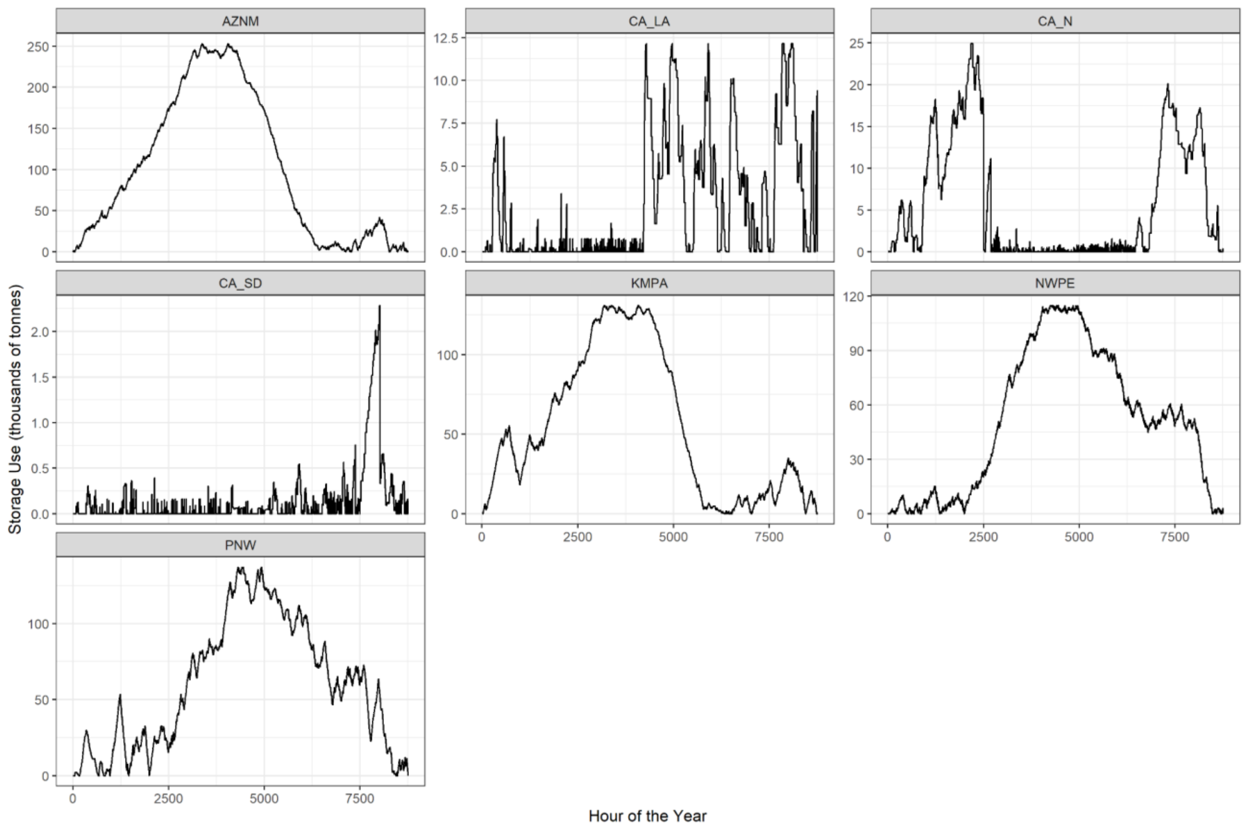


Figure 43. Hydrogen storage use over a year (8760 hours) in 2050, *High RPS All Regions Case*, by region

Additional sensitivity cases will be provided in a forthcoming appendix to this report. Additional comparisons will also be prepared as the report evolves. Particular comparisons can be prepared upon request.

6 Supply Chain Analysis with SERA Model

The supply chain analysis with SERA covers a range of scenarios and sensitivity cases, some of which are still in development and all subject to review and revision. Here we focus on main findings to date. We present main inputs and assumptions, then a series of outputs and interpretations. The scenarios and sensitivity cases overall are shown below.

Main Scenarios

- Explore hydrogen supply chain buildout to meet road transportation demand in California
- Understand the impacts of sector coupling of hydrogen demand types (transportation, stationary) and the electricity grid
- Consider the impacts of renewable hydrogen mandates on hydrogen supply sources

Sensitivity cases

- Explore the impact of foresighted planning : 5 vs 10 vs 25 years
- Consider demand uncertainty cases: Base vs High
- Forecourt production (i.e., at the refueling station) versus central production
- Central PEM only versus all types of production

6.1 Key Inputs to SERA modeling in These Scenarios

Here we show that among a wide range of inputs used in SERA, some of the most important include: cost assumptions for hydrogen production, transportation, and refueling. These are the components of the supply chain that have the biggest impact on what types of systems make sense under different circumstances.

6.1.1 Hydrogen Production Costs

Figure 44 shows the estimated cost of producing hydrogen given particular assumptions (Table 5) regarding capital and operating costs, including the prices of electricity and natural gas as two energy source options. Particular examples are shown for the near term (e.g., 2025) at modest volumes and relatively high electricity costs that could be grid industrial prices, with technology development levels estimated for this time frame. In the longer term (e.g., 2030-35), after considerable system build-out, cost reductions are achieved via scale and learning, and with much lower electricity prices based on generation from low-cost renewables. These costs are based on runs of various cost models that inform SERA.

As shown in Figure 44, costs of hydrogen production are especially a function of operating costs, including energy costs. The cost of electricity or natural gas are important components in the overall cost of hydrogen production. Capital costs per unit production are relatively low, at least in a case where there is high utilization of the equipment (over 80% assumed here). New SMR plants using natural gas and CCS after 2025 are assumed to be large scale and sited so as to enable CCS. With rising natural gas prices over time, and opportunities to use cheap electricity likely to become widespread, electrolysis becomes cheaper than gas-based SMR. “Forecourt” electrolysis (produced at refueling stations) remains more expensive than large-scale, remotely sited facilities, though the costs of hydrogen transportation can offset some of these savings, as shown in the full cost scenario in the Executive Summary. In any case, all hydrogen produced with large scale production after perhaps 2030 is below \$4/kg. Uncertainties in the levelized costs are primarily driven by energy prices, plant sizes, and capacity factors.

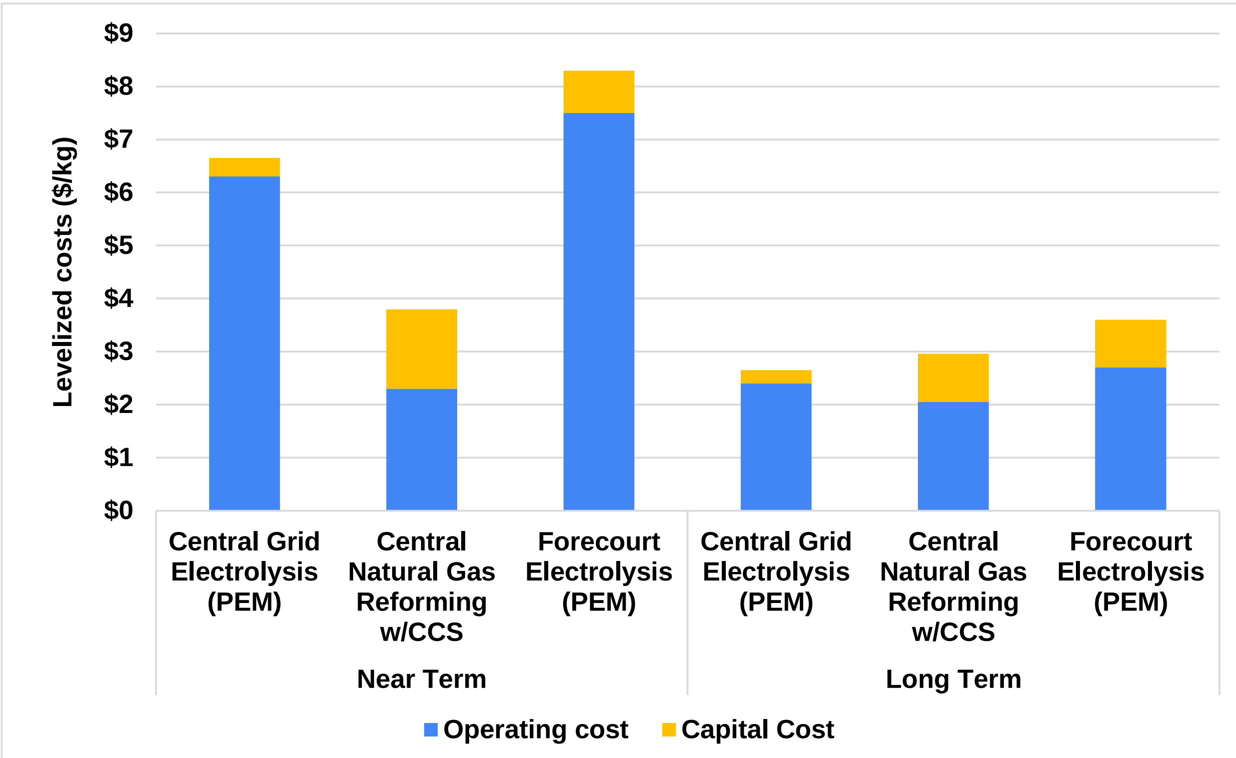


Figure 44. Levelized costs for hydrogen production by technology, near and longer term

Table 5. Assumptions used in hydrogen production cost analysis

Variable	Value
Discount rate (%)	8.00
Lifetime (years)	40
Central Plant size (tonne/day)	55
Onsite/forecourt plant size (tonne/day)	1.5
Industrial elec. price, \$/kWh (near, long term)	0.12, 0.04
Industrial NG. price \$/MMBtu (near, long term)	4, 5.5
Avg. Capacity factor	> 80 %

6.1.2 Cost of Transporting and Delivering Hydrogen

Three methods of transporting and delivering hydrogen to stations are considered: gas “tube-trailer” trucks, cryogenic liquid carrying trucks, and pipelines. There are many details about how stations must be configured if receiving hydrogen from these three approaches, and the differences in station costs are considered below. Many new technologies are reducing the costs of liquid-based hydrogen systems. Costs also depend on volumes and distance moved. Table **6** shows the cheapest options for a wide range of system sizes and distances of movement, from different perspectives. The number in each cell indicates the lowest cost for a given system capacity (in tonnes/day, shown on the horizontal axis of the table) over a given distance (in kilometers, shown on the vertical axis of the table). The cells are colored to indicate which mode of hydrogen transmission (gas truck, liquid truck, or pipeline) would provide the lowest cost for each combination of system capacity and distance. The different tables (a–e) show the results for different station types and different pipeline utilization rates. The smaller tables (b–e) are intended to emphasize the overall color patterns, showing the cheapest transmission mode, rather than the numerical cost in each cell.

As can be seen in Table **6**a, tube trailers moving gaseous H2 are the cheapest option almost regardless of the distance, when capacities are low. Even for well-utilized pipelines, narrow diameter pipeline systems moving small amounts of hydrogen are typically not cost-effective. However, due to non-linearities in costs, there are some situations where pipelines are the cheapest even for smaller capacities, such as very short distances up to 30 km. Pipelines dominate the lowest cost of delivery for all systems above about 50 tonnes/day, though they still must overcome high capital costs and possibly early stage low utilization to reach these low “equilibrium” cost numbers. Liquid hydrogen tanker (LH2) trucks become slightly less expensive than pipelines for certain capacities for very long distance travel, though may be impractical at such distances.

The situation changes with lower pipeline utilization and when station costs are included—linked to the type of fuel provided and infrastructure needed at the stations to support that fuel type. It also changes with station size. In a nutshell, liquid tanker trucks become increasingly cost effective with lower pipeline utilization, when station costs are included, and with larger stations. The extreme case with all three of these is shown in Table **6**e, where tanker trucks are the cheapest option in well over half the volume/distance combinations, generally at longer distances and higher volumes. Pipelines are relatively non-cost effective with larger stations (due to higher station compression and storage costs) and low utilization, though they can still be the best option for long-distance transmission.

Table 6. Levelized cost of hydrogen transportation by mode (showing lowest-cost mode by color), by system capacity and total hydrogen distribution distance (sub-tables a-e show different situations).

Legend		
Lowest Cost Transmission Mode		
Gaseous H2 Truck	**Liquid H2 Truck**	**H2 Pipeline**

Table 6a. Delivery costs without station costs, 0.5 tons/day stations, pipelines operating at 100% utilization.

H2 Flow (tonnes/day)

Dist (km)	0.5	1	1.5	2	3	5	7.5	10	15	20	25	30	35	40	45	50	75	100	125	150	175	200	225	250	275	300	350	400	450	500
10	3.30	1.70	1.17	0.90	0.63	0.41	0.32	0.27	0.21	0.18	0.17	0.15	0.14	0.14	0.13	0.13	0.11	0.10	0.10	0.10	0.09	0.09	0.09	0.09	0.09	0.09	0.08	0.08	0.08	0.08
20	6.34	3.22	2.18	1.66	1.14	0.72	0.54	0.44	0.33	0.28	0.25	0.22	0.21	0.19	0.18	0.17	0.15	0.13	0.12	0.12	0.11	0.11	0.10	0.10	0.10	0.10	0.10	0.09	0.09	0.09
30	9.37	4.74	3.19	2.42	1.64	1.02	0.75	0.61	0.46	0.38	0.32	0.29	0.27	0.25	0.23	0.22	0.18	0.16	0.15	0.14	0.13	0.13	0.12	0.12	0.11	0.11	0.11	0.10	0.10	0.10
40	###	6.18	4.18	3.18	2.15	1.32	0.97	0.77	0.58	0.47	0.40	0.36	0.33	0.30	0.28	0.27	0.21	0.19	0.17	0.16	0.15	0.14	0.14	0.13	0.13	0.12	0.12	0.11	0.11	0.11
50	###	6.19	4.19	3.20	2.23	1.63	1.19	0.94	0.70	0.57	0.48	0.43	0.39	0.36	0.33	0.31	0.25	0.21	0.19	0.18	0.17	0.16	0.15	0.15	0.14	0.14	0.13	0.13	0.12	0.12
60	###	6.20	4.21	3.21	2.24	1.93	1.40	1.11	0.82	0.66	0.56	0.50	0.45	0.41	0.38	0.36	0.28	0.24	0.22	0.20	0.19	0.18	0.17	0.16	0.15	0.15	0.14	0.14	0.13	0.13
80	###	6.23	4.23	3.23	2.26	1.96	1.80	1.45	1.06	0.85	0.72	0.63	0.57	0.52	0.48	0.45	0.35	0.30	0.27	0.24	0.22	0.21	0.20	0.19	0.18	0.18	0.17	0.16	0.15	0.15
100	###	6.25	4.25	3.25	2.28	1.99	1.82	1.73	1.30	1.04	0.88	0.77	0.69	0.63	0.59	0.55	0.42	0.35	0.31	0.28	0.26	0.24	0.23	0.22	0.21	0.20	0.19	0.18	0.17	0.16
120	###	6.28	4.27	3.27	2.30	2.01	1.84	1.75	1.55	1.24	1.04	0.91	0.82	0.74	0.69	0.64	0.49	0.41	0.36	0.33	0.30	0.28	0.26	0.25	0.24	0.23	0.21	0.20	0.19	0.18
140	###	6.30	4.30	3.29	2.32	2.03	1.87	1.78	1.70	1.43	1.20	1.05	0.94	0.85	0.79	0.73	0.56	0.46	0.41	0.37	0.34	0.31	0.29	0.28	0.26	0.25	0.24	0.22	0.21	0.20
160	###	6.33	4.32	3.32	2.34	2.05	1.89	1.80	1.72	1.62	1.36	1.18	1.06	0.96	0.89	0.82	0.62	0.52	0.45	0.41	0.37	0.35	0.33	0.31	0.29	0.28	0.26	0.24	0.23	0.22
180	###	6.36	4.34	3.34	2.36	2.07	1.91	1.82	1.74	1.69	1.52	1.32	1.18	1.07	0.99	0.92	0.69	0.57	0.50	0.45	0.41	0.38	0.36	0.34	0.32	0.31	0.28	0.27	0.25	0.24
200	###	6.38	4.37	3.36	2.38	2.09	1.93	1.84	1.77	1.71	1.68	1.46	1.30	1.18	1.09	1.01	0.76	0.63	0.55	0.49	0.45	0.42	0.39	0.37	0.35	0.33	0.31	0.29	0.27	0.26
250	###	6.45	4.42	3.41	2.43	2.15	1.99	1.90	1.82	1.77	1.73	1.71	1.61	1.46	1.34	1.24	0.93	0.77	0.67	0.60	0.54	0.50	0.47	0.44	0.42	0.40	0.37	0.34	0.32	0.31
300	###	6.51	4.48	3.47	2.48	2.20	2.04	1.96	1.88	1.83	1.79	1.76	1.75	1.74	1.59	1.48	1.10	0.91	0.79	0.70	0.64	0.59	0.55	0.51	0.48	0.46	0.42	0.40	0.37	0.35
350	###	6.57	4.54	3.52	2.53	2.25	2.10	2.01	1.94	1.89	1.85	1.82	1.81	1.80	1.80	1.71	1.27	1.04	0.90	0.81	0.73	0.67	0.63	0.59	0.55	0.53	0.48	0.45	0.42	0.40
400	###	6.64	4.60	3.57	2.58	2.31	2.15	2.07	1.99	1.94	1.91	1.88	1.87	1.86	1.85	1.85	1.44	1.18	1.02	0.91	0.82	0.76	0.70	0.66	0.62	0.59	0.54	0.50	0.47	0.45
450	###	6.70	4.65	3.63	2.63	2.36	2.21	2.12	2.05	2.00	1.96	1.94	1.93	1.92	1.91	1.91	1.61	1.32	1.14	1.01	0.92	0.84	0.78	0.73	0.69	0.66	0.60	0.56	0.52	0.49
500	###	6.77	4.71	3.68	2.69	2.41	2.26	2.18	2.11	2.06	2.02	2.00	1.99	1.98	1.97	1.96	1.78	1.46	1.26	1.12	1.01	0.93	0.86	0.81	0.76	0.72	0.66	0.61	0.57	0.54
600	###	6.89	4.82	3.79	2.79	2.52	2.37	2.29	2.22	2.17	2.14	2.11	2.10	2.09	2.09	2.08	2.06	1.73	1.50	1.33	1.20	1.10	1.02	0.95	0.90	0.85	0.78	0.72	0.67	0.63
700	###	7.02	4.94	3.90	2.89	2.63	2.48	2.40	2.33	2.28	2.25	2.23	2.22	2.21	2.20	2.20	2.17	2.01	1.73	1.54	1.39	1.27	1.18	1.10	1.03	0.98	0.90	0.83	0.77	0.73
800	###	7.15	5.05	4.01	2.99	2.73	2.59	2.51	2.44	2.40	2.36	2.34	2.33	2.32	2.32	2.31	2.29	2.20	1.97	1.74	1.58	1.44	1.34	1.25	1.17	1.11	1.01	0.94	0.87	0.82
###	###	7.41	5.28	4.22	3.19	2.95	2.81	2.74	2.67	2.63	2.59	2.57	2.56	2.56	2.55	2.52	2.35	2.25	2.22	2.16	1.95	1.79	1.65	1.54	1.45	1.37	1.25	1.15	1.08	1.01
###	###	7.67	5.51	4.44	3.39	3.16	3.03	2.96	2.90	2.85	2.82	2.80	2.73	2.67	2.62	2.57	2.41	2.31	2.28	2.25	2.23	2.13	1.97	1.83	1.72	1.63	1.49	1.37	1.28	1.20
###	###	8.05	5.86	4.76	3.69	3.48	3.36	3.30	3.23	3.13	2.99	2.88	2.81	2.75	2.70	2.66	2.49	2.40	2.36	2.33	2.31	2.29	2.27	2.26	2.13	2.02	1.84	1.70	1.58	1.48

Table 6b. Same as 6a except with only 25% pipeline utilization

Legend: GH2 Truck | LH2 Truck | Pipeline

H2 Flow (tonnes/day)

Dist (km)	0.5	1	1.5	2	3	5	7.5	10	15	20	25	30	35	40	45	50	75	100	125	150	175	200	225	250	275	300	350	400	450	500
10	12.10	6.14	4.15	3.15	2.15	1.32	0.97	0.77	0.58	0.47	0.40	0.36	0.33	0.30	0.28	0.27	0.21	0.19	0.17	0.16	0.15	0.14	0.14	0.13	0.13	0.12	0.12	0.11	0.11	0.11
20	12.12	6.15	4.16	3.16	2.20	1.90	1.74	1.45	1.06	0.85	0.72	0.63	0.57	0.52	0.48	0.45	0.35	0.30	0.27	0.24	0.22	0.21	0.20	0.19	0.18	0.18	0.17	0.16	0.15	0.15
30	12.14	6.16	4.17	3.18	2.21	1.91	1.75	1.65	1.55	1.24	1.04	0.91	0.82	0.74	0.69	0.64	0.49	0.41	0.36	0.33	0.30	0.28	0.26	0.25	0.24	0.23	0.21	0.20	0.19	0.18
40	12.15	6.18	4.18	3.19	2.22	1.92	1.76	1.67	1.59	1.53	1.36	1.18	1.06	0.96	0.89	0.82	0.62	0.52	0.45	0.41	0.37	0.35	0.33	0.31	0.29	0.28	0.26	0.24	0.23	0.22
50	12.17	6.19	4.19	3.20	2.23	1.93	1.77	1.68	1.60	1.54	1.50	1.46	1.30	1.18	1.09	1.01	0.76	0.63	0.55	0.49	0.45	0.42	0.39	0.37	0.35	0.33	0.31	0.29	0.27	0.26
60	12.19	6.20	4.21	3.21	2.24	1.94	1.78	1.69	1.61	1.56	1.52	1.49	1.48	1.41	1.29	1.20	0.90	0.74	0.64	0.58	0.52	0.48	0.45	0.42	0.40	0.38	0.35	0.33	0.31	0.30
80	12.22	6.23	4.23	3.23	2.26	1.96	1.80	1.71	1.63	1.58	1.54	1.51	1.50	1.49	1.48	1.48	1.17	0.96	0.83	0.74	0.67	0.62	0.58	0.54	0.51	0.49	0.45	0.42	0.39	0.37
100	12.26	6.25	4.25	3.25	2.28	1.99	1.82	1.73	1.65	1.60	1.56	1.53	1.52	1.51	1.51	1.50	1.44	1.18	1.02	0.91	0.82	0.76	0.70	0.66	0.62	0.59	0.54	0.50	0.47	0.45
120	12.29	6.28	4.27	3.27	2.30	2.01	1.84	1.75	1.68	1.62	1.58	1.56	1.55	1.54	1.53	1.52	1.50	1.40	1.21	1.08	0.98	0.90	0.83	0.78	0.73	0.70	0.64	0.59	0.55	0.52
140	12.32	6.30	4.30	3.29	2.32	2.03	1.87	1.78	1.70	1.65	1.61	1.58	1.57	1.56	1.55	1.55	1.52	1.50	1.40	1.24	1.13	1.03	0.96	0.89	0.84	0.80	0.73	0.68	0.63	0.60
160	12.36	6.33	4.32	3.32	2.34	2.05	1.89	1.80	1.72	1.67	1.63	1.60	1.59	1.58	1.58	1.57	1.54	1.53	1.52	1.41	1.28	1.17	1.08	1.01	0.95	0.90	0.83	0.76	0.71	0.67
180	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
200	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
250	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
300	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
350	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
400	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
450	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
600	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
700	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
800	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1200	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1500	14.63	8.05	5.86	4.76	3.69	3.48	3.36	3.30	3.23	3.13	2.99	2.88	2.81	2.75	2.70	2.66	2.49	2.40	2.36	2.33	2.31	2.29	2.27	2.26	2.25	2.23	2.22	2.21	2.21	2.20

Table 6c. Including station costs for 1.5 tons/day stations, with 100% pipeline utilization

Legend: GH2 Truck | LH2 Truck | Pipeline

H2 Flow (tonnes/day)

Dist (km)	0.5	1	1.5	2	3	5	7.5	10	15	20	25	30	35	40	45	50	75	100	125	150	175	200	225	250	275	300	350	400	450	500
10	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
20	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
30	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
40	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
50	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
60	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
80	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
100	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
120	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
140	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
160	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
180	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
200	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
250	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
300	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
350	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
400	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
450	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
500	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
600	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
700	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
800	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1000	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1200	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
1500	16.11	9.53	7.34	6.24	5.17	4.96	4.84	4.68	4.38	4.19	4.05	3.94	3.87	3.81	3.76	3.71	3.55	3.45	3.42	3.39	3.37	3.35	3.33	3.32	3.30	3.29	3.28	3.27	3.26	3.26

Table 6d. With 5 tons/day stations, 100% pipeline utilization

Legend: GH2 Truck | LH2 Truck | Pipeline

H2 Flow (tonnes/day)

Dist (km)	0.5	1	1.5	2	3	5	7.5	10	15	20	25	30	35	40	45	50	75	100	125	150	175	200	225	250	275	300	350	400	450	500
10	5.40	3.80	3.27	3.00	2.73	2.51	2.42	2.37	2.31	2.28	2.27	2.25	2.24	2.24	2.23	2.23	2.21	2.20	2.20	2.20	2.19	2.19	2.19	2.19	2.19	2.18	2.18	2.18	2.18	2.18
20	8.44	5.32	4.28	3.76	3.24	2.82	2.64	2.54	2.43	2.38	2.34	2.32	2.30	2.29	2.28	2.27	2.25	2.23	2.22	2.22	2.21	2.21	2.20	2.20	2.20	2.20	2.19	2.19	2.19	2.19
30	11.47	6.84	5.29	4.52	3.69	3.12	2.85	2.70	2.55	2.47	2.42	2.39	2.37	2.35	2.33	2.32	2.28	2.26	2.25	2.24	2.23	2.22	2.22	2.22	2.21	2.21	2.21	2.20	2.20	2.20
40	13.63	7.65	5.66	4.66	3.70	3.40	3.07	2.87	2.68	2.57	2.50	2.46	2.43	2.40	2.38	2.37	2.31	2.29	2.27	2.26	2.25	2.24	2.24	2.23	2.23	2.22	2.22	2.21	2.21	2.21
50	13.65	7.67	5.67	4.68	3.71	3.41	3.25	3.04	2.80	2.67	2.58	2.53	2.49	2.46	2.43	2.41	2.35	2.31	2.29	2.28	2.27	2.26	2.25	2.25	2.24	2.24	2.23	2.22	2.22	2.22
60	13.67	7.68	5.68	4.69	3.72	3.42	3.26	3.17	2.92	2.76	2.66	2.60	2.55	2.51	2.48	2.46	2.38	2.34	2.32	2.30	2.29	2.28	2.27	2.26	2.25	2.25	2.24	2.24	2.23	2.23
80	13.70	7.71	5.71	4.71	3.74	3.44	3.28	3.19	3.11	2.95	2.82	2.73	2.67	2.62	2.58	2.55	2.45	2.40	2.36	2.34	2.32	2.31	2.30	2.29	2.28	2.28	2.27	2.26	2.25	2.24
100	13.73	7.73	5.73	4.73	3.76	3.46	3.30	3.21	3.13	3.08	2.98	2.87	2.79	2.73	2.68	2.65	2.52	2.45	2.41	2.38	2.36	2.34	2.33	2.32	2.31	2.30	2.29	2.28	2.27	2.26
120	13.77	7.76	5.75	4.75	3.78	3.49	3.32	3.23	3.15	3.10	3.06	3.01	2.92	2.84	2.79	2.74	2.59	2.51	2.46	2.42	2.40	2.38	2.36	2.35	2.34	2.33	2.31	2.30	2.29	2.28
140	13.80	7.78	5.78	4.77	3.80	3.51	3.35	3.26	3.18	3.12	3.09	3.06	3.04	2.95	2.89	2.83	2.66	2.56	2.51	2.47	2.44	2.41	2.39	2.38	2.36	2.35	2.34	2.32	2.31	2.30
160	13.84	7.81	5.80	4.79	3.82	3.53	3.37	3.28	3.20	3.15	3.11	3.08	3.07	3.06	2.99	2.92	2.72	2.62	2.55	2.51	2.47	2.45	2.43	2.41	2.39	2.38	2.36	2.34	2.33	2.32
180	13.87	7.83	5.82	4.82	3.84	3.55	3.39	3.30	3.22	3.17	3.13	3.10	3.09	3.07	3.01	2.97	2.79	2.67	2.60	2.55	2.51	2.48	2.46	2.44	2.42	2.41	2.38	2.37	2.35	2.34
200	13.90	7.86	5.84	4.84	3.86	3.57	3.41	3.32	3.24	3.19	3.16	3.13	3.12	3.07	3.02	2.97	2.81	2.71	2.65	2.59	2.55	2.52	2.49	2.47	2.45	2.43	2.41	2.39	2.37	2.36
250	13.99	7.92	5.90	4.89	3.91	3.62	3.47	3.38	3.30	3.25	3.21	3.19	3.15	3.09	3.03	2.99	2.82	2.73	2.69	2.66	2.64	2.60	2.57	2.54	2.52	2.50	2.47	2.44	2.42	2.40
300	14.07	7.99	5.96	4.94	3.96	3.68	3.52	3.43	3.36	3.31	3.27	3.23	3.16	3.10	3.05	3.00	2.84	2.74	2.71	2.68	2.65	2.64	2.62	2.60	2.58	2.56	2.52	2.50	2.47	2.45
350	14.16	8.05	6.02	5.00	4.01	3.73	3.58	3.49	3.41	3.36	3.33	3.25	3.17	3.11	3.06	3.02	2.85	2.75	2.72	2.69	2.67	2.65	2.63	2.62	2.60	2.59	2.58	2.55	2.52	2.50
400	14.24	8.12	6.07	5.05	4.06	3.78	3.63	3.55	3.47	3.42	3.37	3.26	3.19	3.13	3.08	3.03	2.87	2.77	2.73	2.71	2.68	2.66	2.65	2.63	2.62	2.61	2.60	2.59	2.57	2.55
450	14.33	8.18	6.13	5.11	4.11	3.84	3.69	3.60	3.53	3.48	3.38	3.28	3.20	3.14	3.09	3.04	2.88	2.78	2.75	2.72	2.70	2.68	2.66	2.65	2.63	2.62	2.61	2.60	2.59	2.59
500	14.41	8.24	6.19	5.16	4.16	3.89	3.74	3.66	3.58	3.54	3.40	3.29	3.22	3.16	3.10	3.06	2.89	2.80	2.76	2.73	2.71	2.69	2.67	2.66	2.65	2.63	2.62	2.61	2.61	2.60
600	14.58	8.37	6.30	5.27	4.26	4.00	3.85	3.77	3.70	3.56	3.42	3.32	3.24	3.18	3.13	3.09	2.92	2.82	2.79	2.76	2.74	2.72	2.70	2.69	2.67	2.66	2.65	2.64	2.64	2.63
700	14.75	8.50	6.42	5.38	4.37	4.10	3.96	3.88	3.79	3.59	3.45	3.35	3.27	3.21	3.16	3.11	2.95	2.85	2.82	2.79	2.77	2.75	2.73	2.72	2.70	2.69	2.68	2.67	2.66	2.66
800	14.92	8.63	6.53	5.48	4.47	4.21	4.07	3.99	3.81	3.62	3.48	3.37	3.30	3.24	3.19	3.14	2.98	2.88	2.85	2.82	2.80	2.78	2.76	2.74	2.73	2.72	2.71	2.70	2.69	2.69
1000	15.26	8.89	6.76	5.70	4.67	4.42	4.29	4.17	3.87	3.68	3.54	3.43	3.36	3.30	3.24	3.20	3.03	2.94	2.90	2.88	2.85	2.83	2.82	2.80	2.79	2.78	2.77	2.76	2.75	2.74
1200	15.60	9.14	6.99	5.92	4.87	4.64	4.51	4.23	3.92	3.73	3.59	3.48	3.41	3.35	3.30	3.25	3.09	2.99	2.96	2.93	2.91	2.89	2.87	2.86	2.84	2.83	2.82	2.81	2.81	2.80
1500	16.11	9.53	7.34	6.24	5.17	4.96	4.59	4.31	4.01	3.81	3.67	3.57	3.50	3.44	3.38	3.34	3.18	3.08	3.04	3.02	2.99	2.97	2.96	2.94	2.93	2.92	2.91	2.90	2.89	2.88

Table 6e. With 5 tons/day stations, 25% pipeline utilization

Legend: GH2 Truck | LH2 Truck | Pipeline

H2 Flow (tonnes/day)

Dist (km)	0.5	1	1.5	2	3	5	7.5	10	15	20	25	30	35	40	45	50	75	100	125	150	175	200	225	250	275	300	350	400	450	500
10	13.58	7.62	5.63	4.63	3.67	3.37	3.07	2.87	2.68	2.57	2.50	2.46	2.43	2.40	2.38	2.37	2.31	2.29	2.27	2.26	2.25	2.24	2.24	2.23	2.23	2.22	2.22	2.21	2.21	2.21
20	13.60	7.63	5.64	4.64	3.68	3.38	3.21	3.12	3.04	2.95	2.82	2.73	2.67	2.62	2.58	2.55	2.45	2.40	2.36	2.34	2.32	2.31	2.30	2.29	2.28	2.28	2.27	2.26	2.25	2.24
30	13.62	7.64	5.65	4.65	3.69	3.39	3.22	3.13	3.05	3.00	2.96	2.93	2.92	2.84	2.79	2.74	2.59	2.51	2.46	2.42	2.40	2.38	2.36	2.35	2.34	2.33	2.31	2.30	2.29	2.28
40	13.63	7.65	5.66	4.66	3.70	3.40	3.24	3.14	3.06	3.01	2.97	2.94	2.93	2.92	2.92	2.91	2.72	2.62	2.55	2.51	2.47	2.45	2.43	2.41	2.39	2.38	2.36	2.34	2.33	2.32
50	13.65	7.67	5.67	4.68	3.71	3.41	3.25	3.15	3.08	3.02	2.98	2.95	2.94	2.93	2.93	2.92	2.77	2.67	2.63	2.59	2.55	2.52	2.49	2.47	2.45	2.43	2.41	2.39	2.37	2.36
60	13.67	7.68	5.68	4.69	3.72	3.42	3.26	3.17	3.09	3.03	2.99	2.97	2.96	2.95	2.94	2.93	2.77	2.67	2.64	2.61	2.59	2.57	2.55	2.52	2.50	2.48	2.45	2.43	2.41	2.40
80	13.70	7.71	5.71	4.71	3.74	3.44	3.28	3.19	3.11	3.06	3.02	2.99	2.98	2.97	2.96	2.94	2.78	2.68	2.64	2.62	2.59	2.57	2.56	2.54	2.53	2.52	2.50	2.50	2.49	2.47
100	13.73	7.73	5.73	4.73	3.76	3.46	3.30	3.21	3.13	3.08	3.04	3.01	3.00	2.99	2.98	2.95	2.78	2.68	2.65	2.62	2.60	2.58	2.56	2.55	2.53	2.52	2.51	2.50	2.49	2.49
120	13.77	7.76	5.75	4.75	3.78	3.49	3.32	3.23	3.15	3.10	3.06	3.04	3.02	3.02	3.00	2.95	2.79	2.69	2.65	2.63	2.60	2.58	2.57	2.55	2.54	2.53	2.52	2.51	2.50	2.49
140	13.80	7.78	5.78	4.77	3.80	3.51	3.35	3.26	3.18	3.12	3.09	3.06	3.05	3.04	3.00	2.96	2.79	2.69	2.66	2.63	2.61	2.59	2.57	2.56	2.54	2.53	2.52	2.51	2.51	2.50
160	13.84	7.81	5.80	4.79	3.82	3.53	3.37	3.28	3.20	3.15	3.11	3.08	3.07	3.06	3.01	2.96	2.80	2.70	2.67	2.64	2.62	2.60	2.58	2.56	2.55	2.54	2.53	2.52	2.51	2.50
180	13.87	7.83	5.82	4.82	3.84	3.55	3.39	3.30	3.22	3.17	3.13	3.10	3.09	3.07	3.01	2.97	2.80	2.71	2.67	2.64	2.62	2.60	2.58	2.57	2.56	2.54	2.53	2.52	2.52	2.51
200	13.90	7.86	5.84	4.84	3.86	3.57	3.41	3.32	3.24	3.19	3.16	3.13	3.12	3.07	3.02	2.97	2.81	2.71	2.68	2.65	2.63	2.61	2.59	2.57	2.56	2.55	2.54	2.53	2.52	2.52
250	13.99	7.92	5.90	4.89	3.91	3.62	3.47	3.38	3.30	3.25	3.21	3.19	3.15	3.09	3.03	2.99	2.82	2.73	2.69	2.66	2.64	2.62	2.60	2.59	2.58	2.56	2.55	2.54	2.54	2.53
300	14.07	7.99	5.96	4.94	3.96	3.68	3.52	3.43	3.36	3.31	3.27	3.23	3.16	3.10	3.05	3.00	2.84	2.74	2.71	2.68	2.65	2.64	2.62	2.60	2.59	2.58	2.57	2.56	2.55	2.54
350	14.16	8.05	6.02	5.00	4.01	3.73	3.58	3.49	3.41	3.36	3.33	3.25	3.17	3.11	3.06	3.02	2.85	2.75	2.72	2.69	2.67	2.65	2.63	2.62	2.60	2.59	2.58	2.57	2.56	2.56
400	14.24	8.12	6.07	5.05	4.06	3.78	3.63	3.55	3.47	3.42	3.37	3.26	3.19	3.13	3.08	3.03	2.87	2.77	2.73	2.71	2.68	2.66	2.65	2.63	2.62	2.61	2.60	2.59	2.58	2.57
450	14.33	8.18	6.13	5.11	4.11	3.84	3.69	3.60	3.53	3.48	3.38	3.28	3.20	3.14	3.09	3.04	2.88	2.78	2.75	2.72	2.70	2.68	2.66	2.65	2.63	2.62	2.61	2.60	2.59	2.59
500	14.41	8.24	6.19	5.16	4.16	3.89	3.74	3.66	3.58	3.54	3.40	3.29	3.22	3.16	3.10	3.06	2.89	2.80	2.76	2.73	2.71	2.69	2.67	2.66	2.65	2.63	2.62	2.61	2.61	2.60
600	14.58	8.37	6.30	5.27	4.26	4.00	3.85	3.77	3.70	3.56	3.42	3.32	3.24	3.18	3.13	3.09	2.92	2.82	2.79	2.76	2.74	2.72	2.70	2.69	2.67	2.66	2.65	2.64	2.64	2.63
700	14.75	8.50	6.42	5.38	4.37	4.10	3.96	3.88	3.79	3.59	3.45	3.35	3.27	3.21	3.16	3.11	2.95	2.85	2.82	2.79	2.77	2.75	2.73	2.72	2.70	2.69	2.68	2.67	2.66	2.66
800	14.92	8.63	6.53	5.48	4.47	4.21	4.07	3.99	3.81	3.62	3.48	3.37	3.30	3.24	3.19	3.14	2.98	2.88	2.85	2.82	2.80	2.78	2.76	2.74	2.73	2.72	2.71	2.70	2.69	2.69
1000	15.26	8.89	6.76	5.70	4.67	4.42	4.29	4.17	3.87	3.68	3.54	3.43	3.36	3.30	3.24	3.20	3.03	2.94	2.90	2.88	2.85	2.83	2.82	2.80	2.79	2.78	2.77	2.76	2.75	2.74
1200	15.60	9.14	6.99	5.92	4.87	4.64	4.51	4.23	3.92	3.73	3.59	3.48	3.41	3.35	3.30	3.25	3.09	2.99	2.96	2.93	2.91	2.89	2.87	2.86	2.84	2.83	2.82	2.81	2.81	2.80
1500	16.11	9.53	7.34	6.24	5.17	4.96	4.59	4.31	4.01	3.81	3.67	3.57	3.50	3.44	3.38	3.34	3.18	3.08	3.04	3.02	2.99	2.97	2.96	2.94	2.93	2.92	2.91	2.90	2.89	2.88

6.1.3 Station Costs

Costs for constructing and operating hydrogen refueling stations are based on operating station models such as HDSAM (ANL, 2022) for light-duty (smaller capacity) and truck-oriented (larger capacity) stations (HDRSAM, also by ANL). We use a range of assumptions around station size, technology components, and delivery system (such as liquid vs. gaseous handling and storage of hydrogen). Results are shown in Figure 45. These include station size (less or greater than 1.5 tonnes/day of hydrogen capacity), station types, and near term vs. longer term.

The lowest cost station type is typically a liquid-storing type, particularly for larger size stations. We estimate that in the long run, this station could reach levelized costs on the order of $1-2 per kg of H2 dispensed. Refueling station costs are primarily driven by size, station utilization (affecting operating costs), and capital costs. Reductions in capital costs over time (due to both scale and technology learning) have large effects on cost per kg of hydrogen produced. Coupling these cost estimates with hydrogen transportation costs (and relatively low costs of cryogenic liquid trucks), suggests that the supply chain for LH2 can be cost effective in many circumstances. GH2 truck–compatible stations are only considered for small stations, as the practicality of serving large stations with GH2 trucks is questionable, given the trucks typically have small delivery capacity.

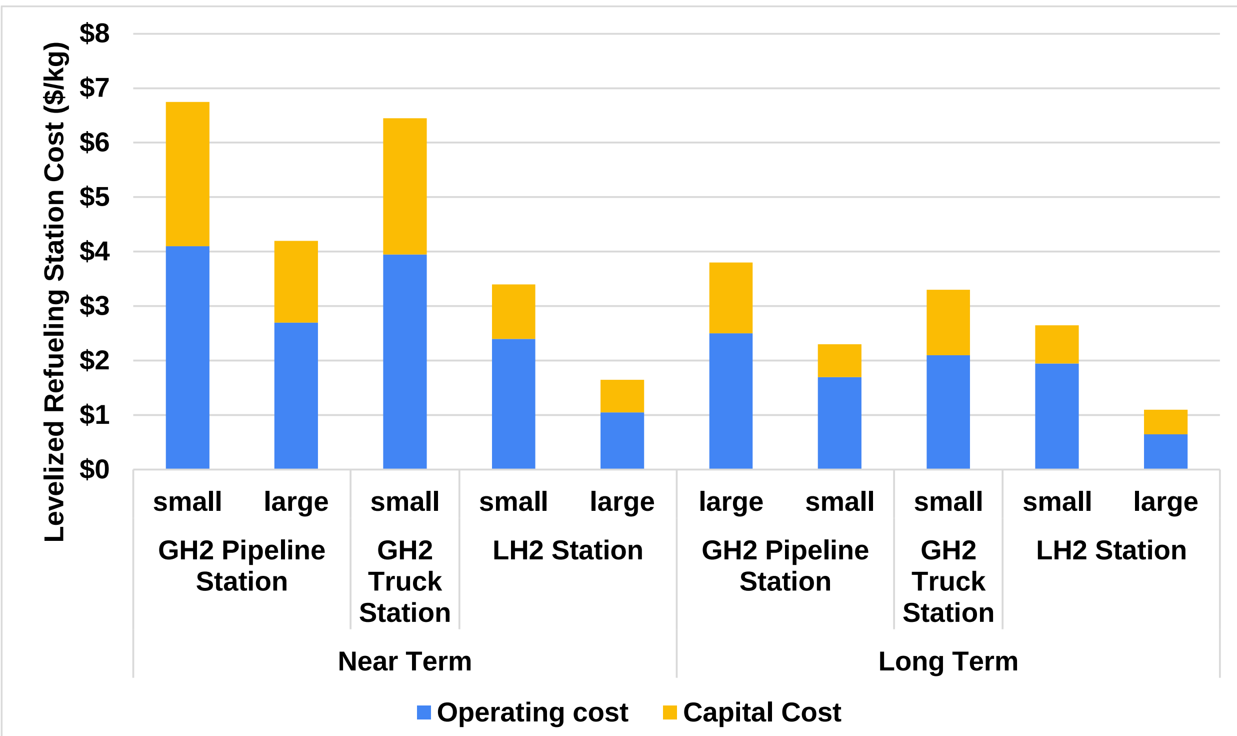


Figure 45. Hydrogen refueling station costs by technology and delivery system, near and long term

6.1.4 Feedstock Prices

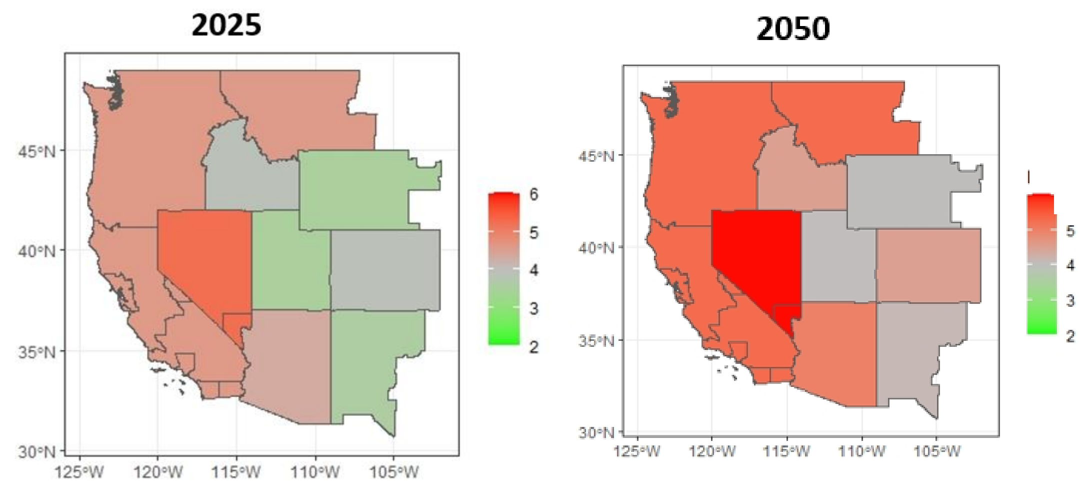
The underlying price of electricity and other feedstocks (notably natural gas) are important parameters and drivers of overall system costs. We rely on EIA projections of natural gas prices but generate industrial electricity prices using our GOOD model. The basic story is as follows:

- Industrial gases price are expected to increase over time

- Electricity prices are expected to drop with cheaper renewables around WECC, but these are offset by other factors affecting costs, such as transmission. The overall effect is a decline, though not by not very much.
- California sees much higher electricity prices than neighboring regions (more than 2x in some instances), in part due to high transmission and distribution costs that we try to reflect in our cost/price estimates.

The electricity and gas prices by state, in 2025 and 2050, are shown in **Figure 46**. As shown, electricity prices generally decline over time while gas prices rise.

Natural gas rates ($/mmBtu)



Electricity rates ($/kWh)

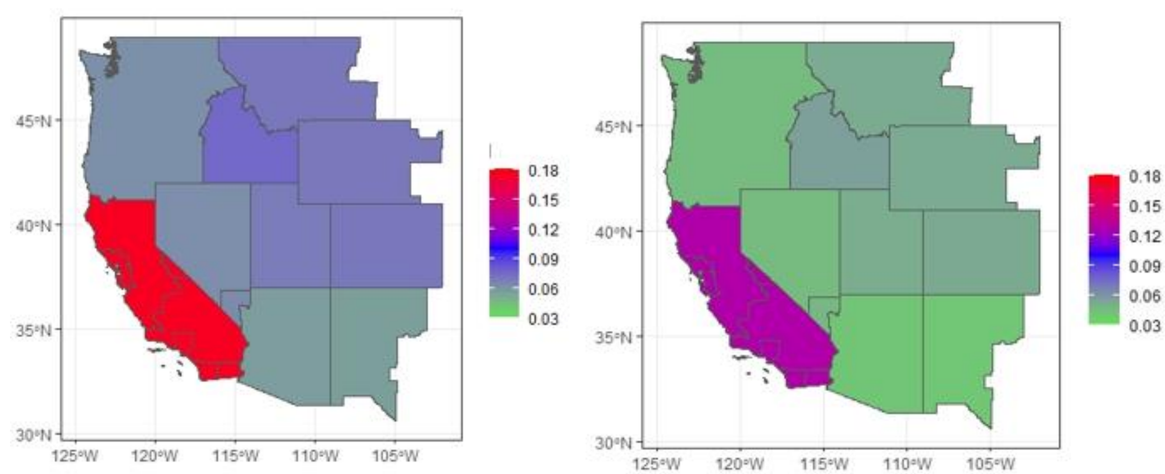


Figure 46. Industrial natural gas and electricity rates by state

6.2 SERA Modeling Scenarios and Findings

Here we present a range of results, starting with a Base case then comparing to several other scenarios where certain assumptions are changed. Comparisons to the Base case then reveal certain findings

6.2.1 Base Case (On Road Transport Demand Only)

The Base case considered here includes a number of assumptions beyond the inputs described above. Additional or different assumptions are presented in the scenario analysis that follows the presentation of this Base case. It includes:

- High demand scenario for hydrogen from transportation and stationary sectors
- Two potential methods to produce hydrogen:
    - central plant SMR with CCS
    - central plant PEM electrolysis(grid connected)
- Three methods to transport and distribute hydrogen
    - pipelines, gas tube trailer and liquid tanker
    - salt caverns and line packed storage available
- 5-year planning horizon, starting in 2025 and extending to 2050; cost optimal choices are based on a 5-year return consideration.
- Constraints:
    - policy levers like SB 1505 (33% renewable hydrogen requirement)
    - locational and production/transmission capacity constraints

6.2.2 SERA Base Case Results

Given the rapid demand growth for hydrogen in California in the High demand case (assumed in this Base case), SERA meets this rising demand almost exclusively via growth in electrolysis. As shown in Figure 47, the annual production of hydrogen rises from about 100 million kg in 2025 to 10 times more by 2035 (1 billion kg) and finally to 3.5 billion kg by 2050. SMR grows as well for the first 5 years (and maintains about a 40% market share of production to 2030) but then stops growing and never exceeds about 100 million kg. By 2050 it accounts for only about 3% of total production. This relates to two main factors: a) SMR is relatively expensive in small sizes but large sizes require a longer planning horizon than 5 years so are not built into this scenario, and b) the cost of natural gas rises over time while the cost of electricity and electrolyzers drop, so they have an increasing advantage over time. This tends to suggest that a 33% requirement for renewable hydrogen is not binding, though not all electrolytic hydrogen is renewable in 2025 or even 2030, and this is just one scenario; others can have much higher SMR production growth.

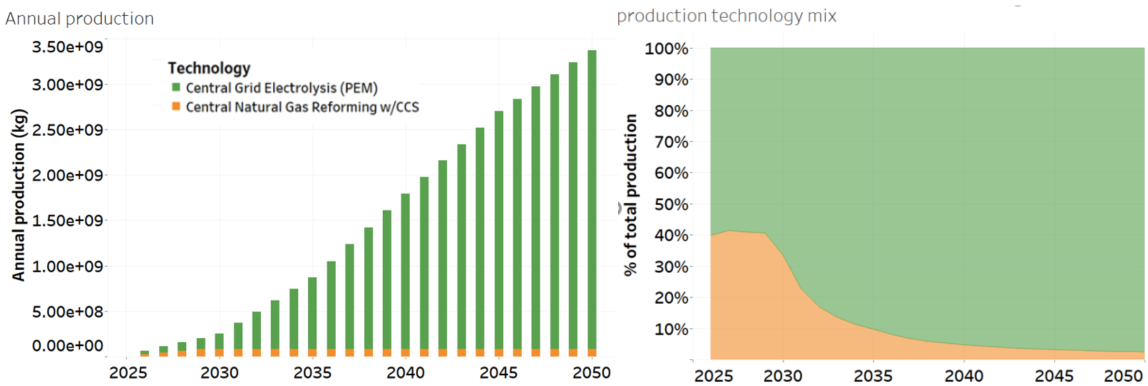


Figure 47. Hydrogen production from SMR with CCS and from PEM electrolysis over time.

Figure 48 shows where this hydrogen is produced, in terms of capacity (in 2050, left figure) and production growth to 2050 inside and outside California (right figure). Growth occurs both within and outside CA, but after 2035 it is much faster in-state than out-of-state.

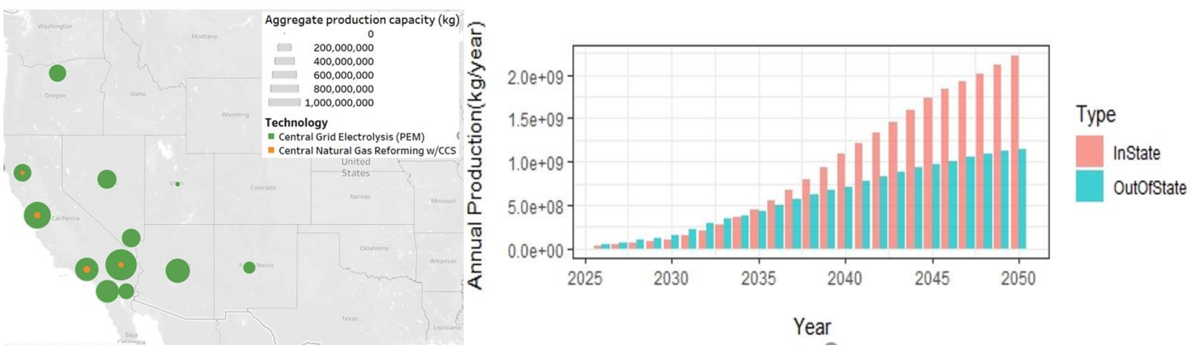


Figure 48. Production capacity in 2050 and annual production to 2050, by location

Figure 49 shows the share of total hydrogen flow from production to consumption sites and indicates that early on trucks dominate distribution, but over time pipelines are developed and eventually carry about 40% of hydrogen. Gaseous fuel trucks decline from about 35% of distribution in 2025 to 20% by 2050.

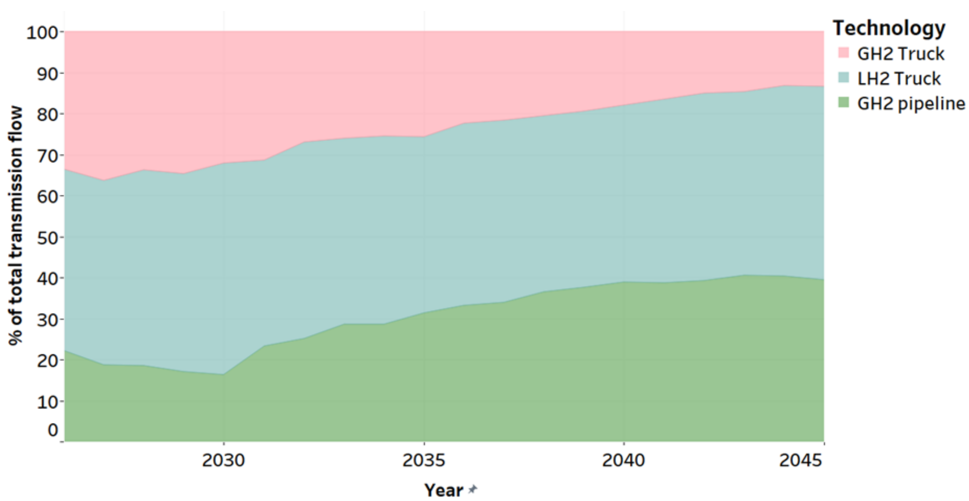


Figure 49. Hydrogen distribution by technology and over time

The distribution systems for each of the three types of distribution are shown in Figure 50, as the cumulative use of these approaches over the time frame 2025 to 2050. Both pipelines and LH2 trucks are used in some cases to carry hydrogen long distances, while CH2 trucks are typically used for shorter distances. The relative choices between when and where to use LH2 trucks vs pipelines are based on the time frame and rate of growth of production, and expected future growth, where a fairly large system must be anticipated relatively soon to justify building a pipeline.

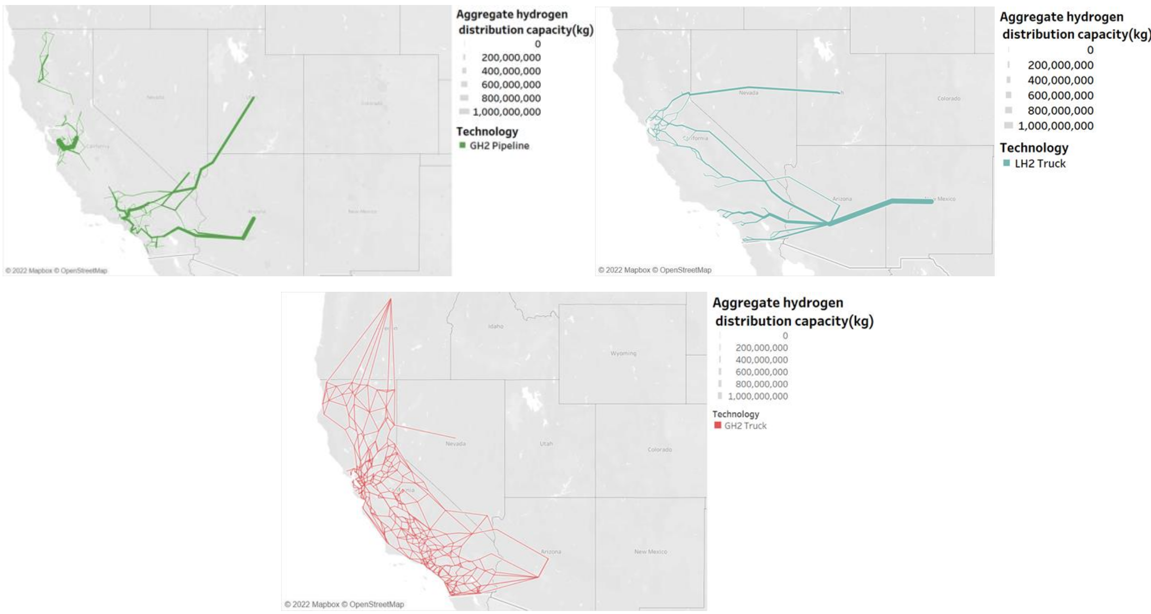


Figure 50. "Footprint" of different types of hydrogen transportation across 25 years from 2025 to 2050

The average cost of hydrogen ($/kg) at the point of use, including all production, distribution, storage, and final fueling costs, are shown in Figure 51 for 2025 and 2050. These costs vary by county but are generally on the order of $5–10/kg in 2025, while they are typically $4-6/kg by 2050. In the early years, while the system is still building out, there is more capital expenditure (capex) which is substantial and adds to the cost for every additional kilogram of hydrogen consumed. But as the system buildout progresses, the marginal costs drop as less new capacity is added. Most of the expenses in a fully built out system are operational costs; hence, we see lower marginal costs in most counties by 2050. In the real world, this could translate to lower retail prices for hydrogen by 2050, as the system matures and when there is high demand.

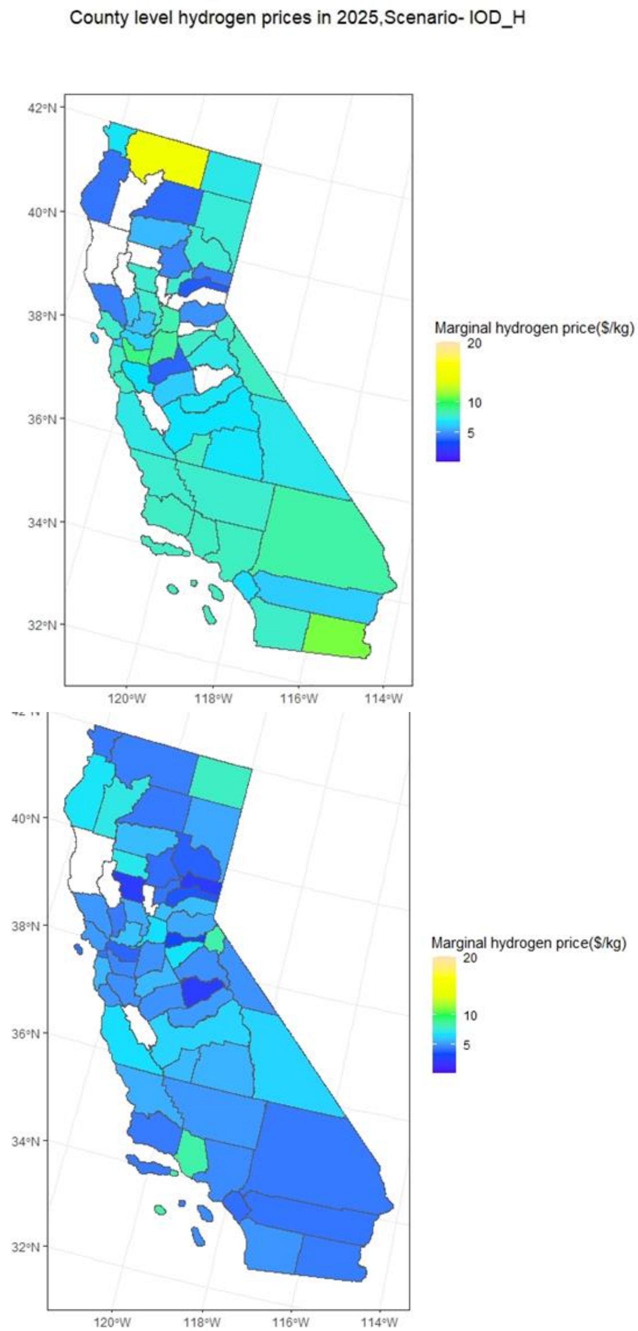


Figure 51. California delivered hydrogen prices by county, 2025 and 2050

6.2.3 Scenario: 20-year Foresight of Hydrogen Demand

One scenario was run with all assumptions similar to the Base case except using a 20-year foresight horizon for planning investments within SERA rather than the 5-year horizon used in the Base case. The longer time frame tends to make investments that don't pay off in 5 or 10 years, but that are low cost over a longer horizon such as 20 years, more competitive. This is more aligned with a societal approach to making investments, but may also require societal support to pay for investments that do not provide a strong near-term return.

A principal effect of this change in assumption is shown in Figure 52. Longer foresight actually leads to more investment in natural gas SMR production of hydrogen. This is because these plants have better economies of scale than PEM electrolyzers and are more competitive, especially within California.

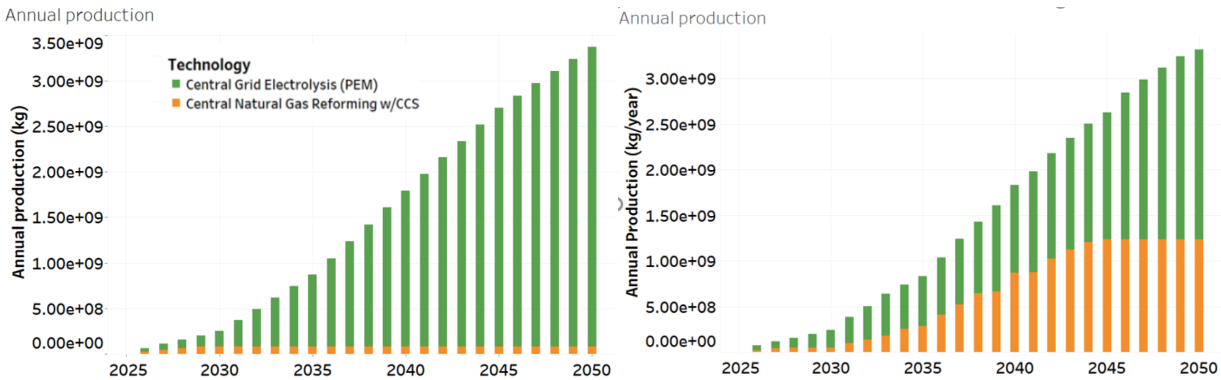


Figure 52. Hydrogen production by technology and year in the Base Case (left) and 20-year foresight case (right).

The breakout of production by technology and location (Figure 53) shows that within California, a much higher share of hydrogen production is by natural gas reforming with CCS than with PEM electrolysis, while nearly all production of hydrogen outside California is with PEM. The share of total hydrogen from out-of-state also rises after 2025 (Figure 54), matching or exceeding growth in-state throughout the projection period. This relates to out-of-state PEM rising in competitiveness even relative to in-state SMR rising in competitiveness. In-state PEM is the technology that fares worst in a longer-term horizon scenario.

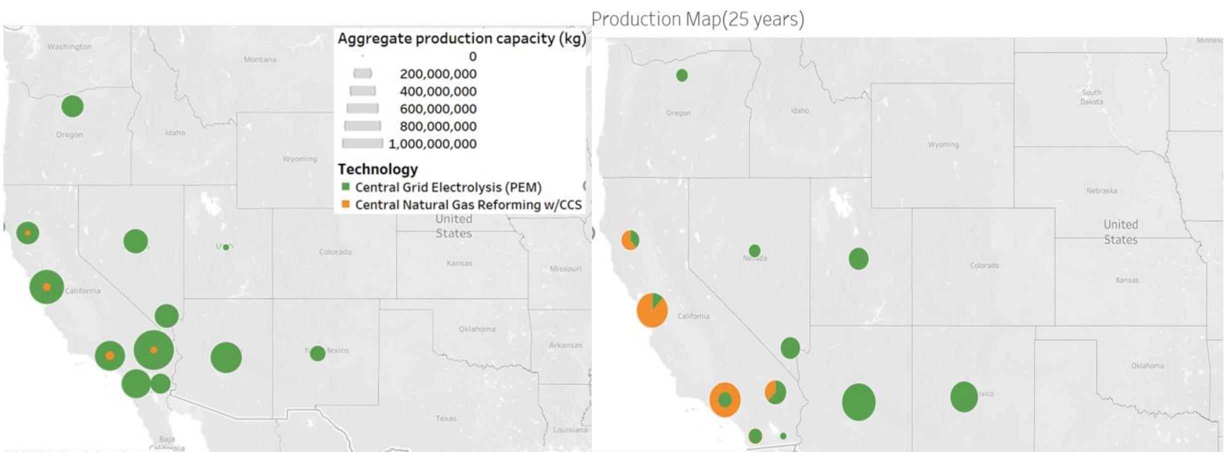


Figure 53. Hydrogen production by technology and approximate location (Base case left, 20-year horizon case right)

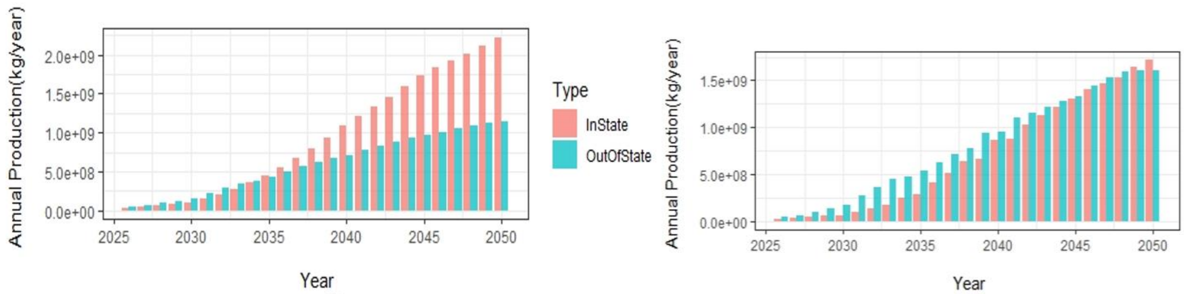


Figure 54. Hydrogen production in and out-of-state over time

6.2.4 Scenario: Industrial Demand Hubs Only

Another scenario considers only "stationary" demand, based on a few selected industries and also a general demand for buildings in medium and large cities in California. This scenario needs further development in terms of which types of industries and buildings, in which locations, are likely to be early or later adopters of hydrogen—and that work is ongoing. Here we simply show what demand could look like if it grew rapidly—and were organized into hubs based on a clustering algorithm.

The analysis includes three types of industries and the potential demand for 190 cities:

- Aviation (13 airports)
- Marine (9 ports)
- Refineries (14)
- Residential/Commercial (190 cities, population > 50k)

Other estimates are ongoing, for example: demand for other types of transport (rail, other off-road), biofuels and ammonia plants, and various chemical plants and other industries with combustion processes. The hydrogen price at which different potential users are likely to make a move toward hydrogen is an ongoing aspect of the analysis.

The location of the various facilities and cities included in this round of analysis are shown in Figure 55. These point-demand "off-takers" are then aggregated into clusters using an algorithm to generate a certain size demand within a certain distance (Figure 56), taking into account the presence of a port, airport, refineries, and numbers of cities (Table 7). The hubs could represent a particular hydrogen storage facility where hydrogen is shipped, e.g. by pipeline, then sent to final demand nodes by truck.

This clustering analysis is preliminary and meant to be indicative; work on better identifying suitable locations for hubs based on potential demand is on-going.

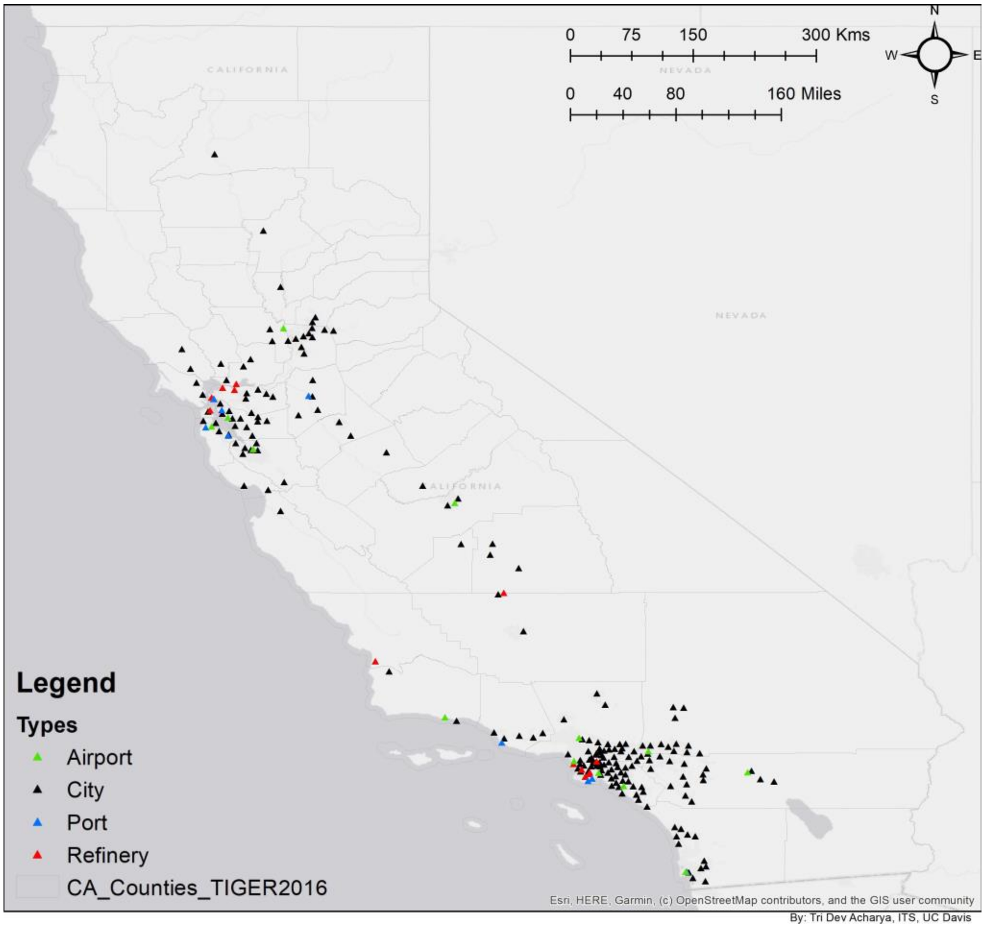


Figure 55. California Stationary Demand locations by 2050, current scenario.

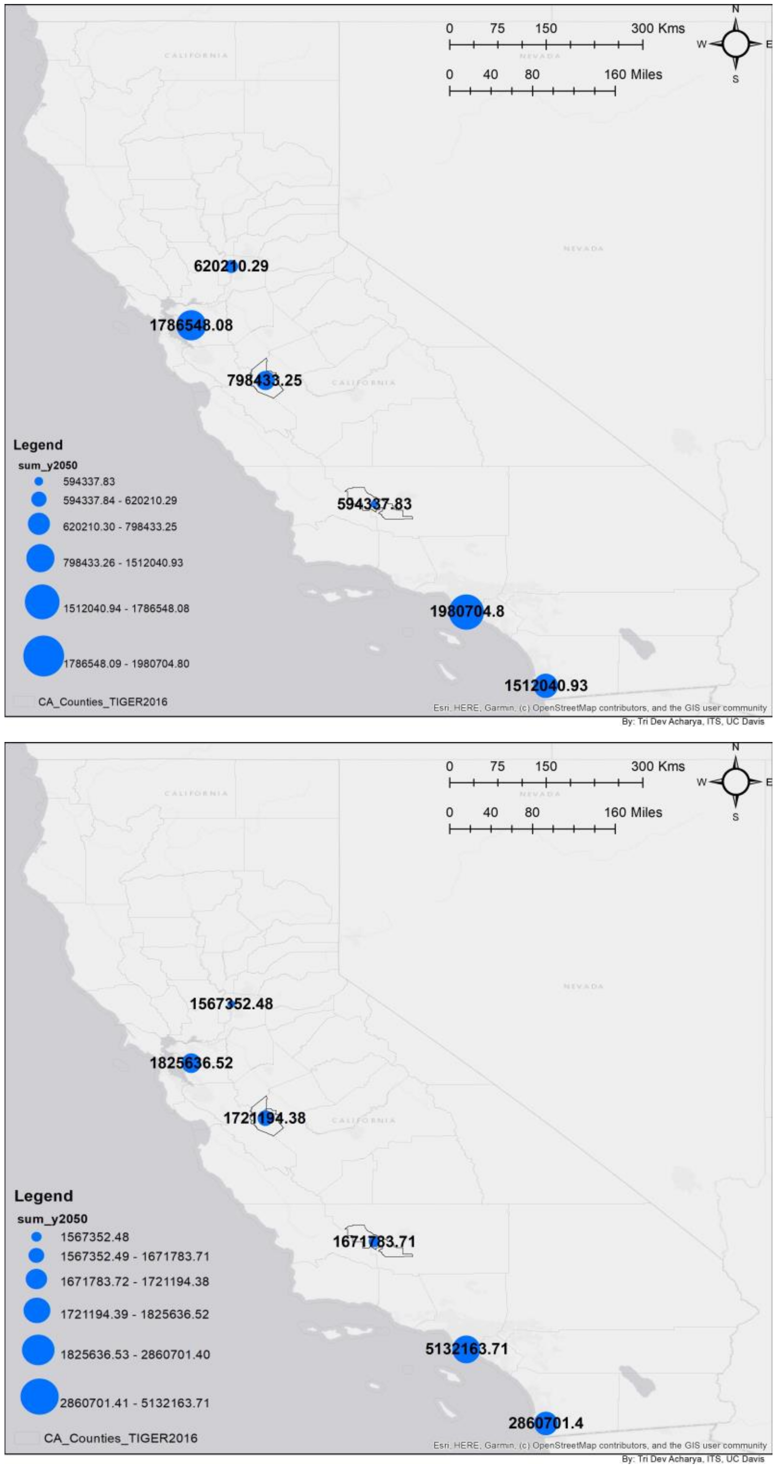


Figure 56. Stationary hydrogen demand in each of 6 hubs, Low (top) and High (below) case, 2050 (tonnes)

Table 7. Locations and features of six hubs developed in analysis

TAZ #	Region	Types of demands				
531	Sacramento	Airport	City	Others	Port	
1408	San Leandro (Alameda / Contra Costa)	Airport	City	Others	Port	Refinery
2312	Los Banos (Merced)	Airport	City	Others		
2947	Bakersfield	Airport	City	Others		Refinery
4619	Los Angeles	Airports	City	Others	Port	Refinery
6424	San Diego	Airport	City	Others	Port	

Providing hydrogen to these six demand hubs (and to no other destinations), changes the pattern of the supply and distribution system compared to our other scenarios. The resulting SERA scenario projections of production types and locations to serve these hubs is shown in Figure 57. Due to the large scale of demand from a few locations and the lack of a need to move hydrogen to many other smaller end uses, the location of hydrogen production is best suited to be near these hubs and dedicated to them. A nearby scale is achieved that is more important than the cost savings of placing production farther away and shipping longer distances. There are some production nodes outside California, but it is less than 10% of overall production by 2050.

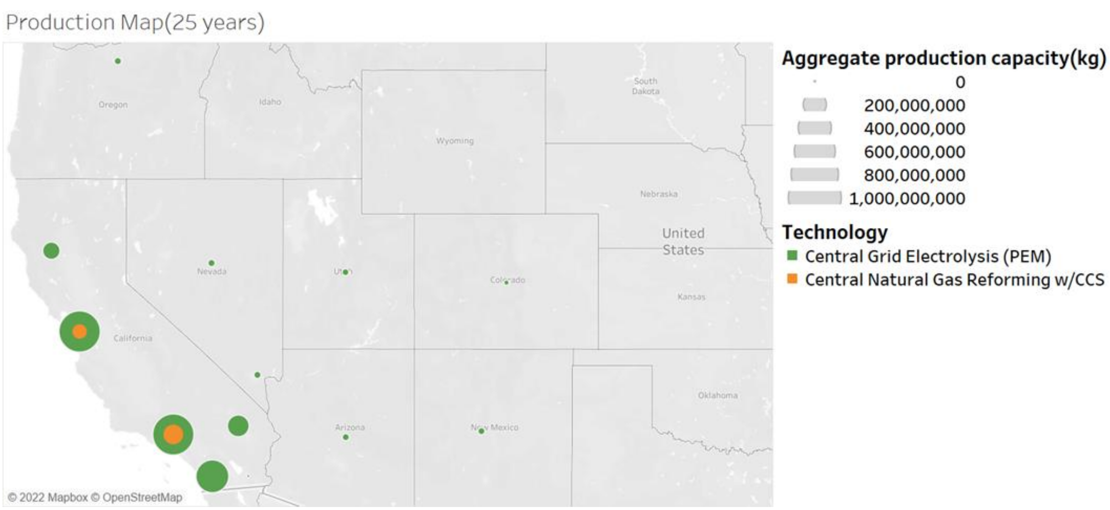


Figure 57. Hydrogen production locations in hubs scenario, 2050

There are some pipeline connections established by 2050 to connect the 5 major “production hubs” with the 6 “demand hubs”, shown in Figure 58. The resilience and energy balancing provided by these pipelines helps the system work with so few nodes. The few small production sites outside California are connected to end uses by truck rather than pipeline, given their scale.

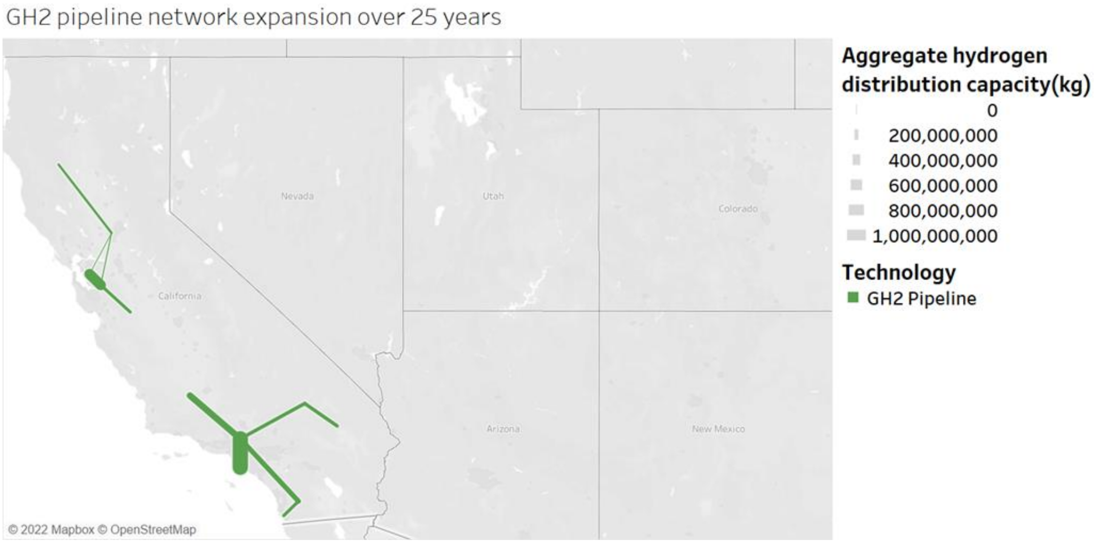


Figure 58. Pipelines developed to serve hubs by 2050

These results are indicative and could change with additional work on model specification and underlying assumptions. Additional scenarios, sensitivity analysis and various comparisons will be added in an on-going fashion as this report is further developed.

7 Future Analysis

The project has explored many aspects of hydrogen systems, and many of our modeling findings are presented in this report. However, there are a range of priority topics to cover in greater detail than has been possible here. A number of stand-alone papers are in planned for publication in 2023. Related on-going analysis will include:

- A deeper analysis of the costs and benefits of building out a hydrogen system, with some analysis of how these benefits accrue to different groups and different regions within California.
- On-going work to refine our hydrogen demand scenarios, taking into account hydrogen market prices and other factors that could affect the speed and ultimate level of demand from different sectors.
- Particular attention to hydrogen refueling station economics and cost recovery under different scenarios. Consideration of a hydrogen system buildout, including demand. Covering the entire Western half of the US. Demand could include car and truck travel and highway fueling stops, and some stationary demands in specific areas. This can all be linked to our electric sector and supply chain modeling work.
- Improving our characterization of hydrogen storage potential and cost (such as a proto-supply curve suitable for our analysis, based on the cost of various types of deep storage in different locations, as well as constructed storage).
- Creating more detailed, complete examples of hydrogen systems with supply from different locations and optimized distribution systems to reach specific demand nodes.
- Better representation and inclusion of renewable natural gas and biomass gasification as a complement to electrolysis.

8 Bibliography

The following are major studies referenced in the review section of this report. Other specific references are provided in our tech briefs and other accompanying documentation.

Acharya, T., Jenn, A. T, Miller, M. R, & Fulton, L. M. (2021). Spatial Modeling of Future Light- and Heavy-Duty Vehicle Travel and Refueling Patterns in California. *UC Office of the President: University of California Institute of Transportation Studies*. http://dx.doi.org/10.7922/G2J67F7H Retrieved from https://escholarship.org/uc/item/1mf9r7g1

ANL (2022), HDSAM (Hydrogen Delivery Station Analysis Model) and related stations models, contents and model versions drawn in mid-2022, https://hdsam.es.anl.gov/index.php?content=hdsam,

CARB (2021), Hydrogen Station Network Self-Sufficiency Analysis per Assembly Bill 8, October 2021, https://ww2.arb.ca.gov/sites/default/files/2021-10/hydrogen_self_sufficiency_report.pdf

CARB (2022), *Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development* (Report Pursuant to Assembly Bill 8; Perea, Chapter 401, Statutes of 2013), https://ww2.arb.ca.gov/sites/default/files/2022-09/AB-8-Report-2022-Final.pdf

CARB (2022), Scoping Plan Documents, including *Final 2022 Scoping Plan Update and Appendices* https://ww2.arb.ca.gov/our-work/programs/ab-32-climate-change-scoping-plan/2022-scoping-plan-documents

CEC, CARB (2022), *Joint Agency Staff Report on Assembly Bill 8: 2022 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California*, California Energy Commission and Air Resources Board https://www.energy.ca.gov/sites/default/files/2022-12/CEC-600-2022-064.pdf

E3 (2020) *Achieving Carbon Neutrality in California: Pathways Scenarios Developed for the California Air Resources Board,* Energy and Environmental Economics, October 2020. https://ww2.arb.ca.gov/sites/default/files/2020-10/e3_cn_final_report_oct2020_0.pdf

FCHEA (2020), *Road Map to a US Hydrogen Economy, Reducing Emissions and Driving Growth Across the Nation,* (20+ authoring organizations under the Fuel Cell & Hydrogen Energy Association umbrella), https://static1.squarespace.com/static/53ab1feee4b0bef0179a1563/t/5e7ca9d6c8fb3629d399fe0c/1585228263363/Road+Map+to+a+US+Hydrogen+Economy+Full+Report.pdf.

Hecht, E.; Pratt, J. *Comparison of Conventional vs. Modular Hydrogen Refueling Stations, and On-Site Production vs. Delivery; Sandia National Laboratories: Albuquerque, NM, USA; Livermore, CA, USA, 2017.* https://h2tools.org/sites/default/files/Reference-Station-Phase-2-1.pdf

Hydrogen Council (2021), *Hydrogen Insights,* Feb 2021, https://hydrogencouncil.com/wp-content/uploads/2021/02/Hydrogen-Insights-2021.pdf

Hydrogen Council (2020), *Path to hydrogen competitiveness: A cost perspective*. Prepared for the Hydrogen Council by McKinsey. Available online: https://hydrogencouncil.com/en/path-to-hydrogen-competitiveness-a-cost-perspective.

IEA (2022), Global Hydrogen Review, International Energy Agency, Paris. https://www.iea.org/reports/global-hydrogen-review-2022

IEA (2019), *The Future of Hydrogen: Seizing Today's Opportunities*, Report prepared by the IEA for the G20, Japan. International Energy Agency, OECD Paris. https://www.iea.org/reports/the-future-of-hydrogen

IRENA (2019), *Hydrogen: A Renewable Energy Perspective*, Report prepared for the 2nd Hydrogen Energy Ministerial Meeting in Tokyo, Japan, by International Renewable Energy Agency, Abu Dhabi.

LA100 (2021), *The Los Angeles 100% Renewable Energy Study*, Executive Summary, Authors Jaquelin Cochran et al, https://www.nrel.gov/analysis/los-angeles-100-percent-renewable-study.html

LLNL (2020), Sarah E. Baker, Joshuah K. Stolaroff, George Peridas, Simon H. Pang, Hannah M. Goldstein, Felicia R. Lucci, Wenqin Li, Eric W. Slessarev, Jennifer Pett-Ridge, Frederick J. Ryerson, Jeff L. Wagoner, Whitney Kirkendall, Roger D. Aines, Daniel L. Sanchez, Bodie Cabiyo, Joffre Baker, Sean McCoy, Sam Uden, Ron Runnebaum, Jennifer Wilcox, Peter C. Psarras, Hélène Pilorgé, Noah McQueen, Daniel Maynard, Colin McCormick, *Getting to Neutral: Options for Negative Carbon Emissions in California*, January (2020), Lawrence Livermore National Laboratory, LLNL-TR-796100 https://www-gs.llnl.gov/content/assets/docs/energy/Getting_to_Neutral.pdf

NREL (2019), SERA Scenario Evaluation and Regionalization Analysis Model, model home page and links to specific reports (reference date used here based on date of most recent report), https://www.nrel.gov/hydrogen/sera-model.html

Ruth *et al* (2020), Mark Ruth, Paige Jadun, Nicholas Gilroy, Elizabeth Connelly, Richard Boardman, A.J. Simon, Amgad Elgowainy, and Jarett Zuboy, The Technical and Economic Potential of the H2@Scale Concept within the United States. Golden, CO: National Renewable Energy Laboratory. NREL/TP- 6A20-77610. https://www.nrel.gov/docs/fy21osti/77610.pdf.

UCI (2020), Reed, Jeffrey, Emily Dailey, Brendan Shaffer, Blake Lane, Robert Flores, Amber Fong, G. Scott Samuelsen, *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California.* CEC. Publication Number: CEC-600-2020-002. https://cafcp.org/sites/default/files/Roadmap-for-Deployment-and-Buildout-of-RH2-UCI-CEC-June-2020.pdf

9 Appendices

Appendices are being developed separately and will be posted on the ITS-Davis hydrogen web site as they become available. Analysis and figures presented in this report are also available upon request. https://its.ucdavis.edu/research/uc-davis-hydrogen-fuel-cell-projects/