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California Energy Commission

Clean Transportation Program

FINAL PROJECT REPORT

Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California

Prepared for: California Energy Commission

Prepared by: UC Irvine Advanced Power and Energy Program

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PREFACE

Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) created the Clean Transportation Program, formerly known as the Alternative and Renewable Fuel and Vehicle Technology Program. The statute authorizes the CEC to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change policies. Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) reauthorizes the Clean Transportation Program through January 1, 2024, and specifies that the CEC allocate up to $20 million per year (or up to 20 percent of each fiscal year's funds) in funding for hydrogen station development until at least 100 stations are operational.

The Clean Transportation Program has an annual budget of about $100 million and provides financial support for projects that:

- Reduce California's use and dependence on petroleum transportation fuels and increase the use of alternative and renewable fuels and advanced vehicle technologies.
- Produce sustainable alternative and renewable low-carbon fuels in California.
- Expand alternative fueling infrastructure and fueling stations.
- Improve the efficiency, performance and market viability of alternative light-, medium-, and heavy-duty vehicle technologies.
- Retrofit medium- and heavy-duty on-road and nonroad vehicle fleets to alternative technologies or fuel use.
- Expand the alternative fueling infrastructure available to existing fleets, public transit, and transportation corridors.
- Establish workforce-training programs and conduct public outreach on the benefits of alternative transportation fuels and vehicle technologies.

To be eligible for funding under the Clean Transportation Program, a project must be consistent with the CEC's annual Clean Transportation Program Investment Plan Update. The CEC issued contract number 600-17-008, the Roadmap for the Deployment and Buildout of Renewable Hydrogen Generation Plants Project. Contract 600-17-008 was approved for funding at the CEC Business Meeting May 9, 2018, and finalized on June 29, 2019, by the Department of General Services.

ABSTRACT

This report presents a roadmap for the buildout and deployment of renewable hydrogen production plants in California. The report provides a fact base to support policy decisions and inform stakeholders. The supporting analysis assesses the demand, in the transportation and other sectors, for and cost of renewable hydrogen to serve California. The analysis includes demand projections, forecasts of technology progress, supply chain costs, and temporal and spatial plant siting scenarios. The work places specific focus on lessons from early project activity and projection through 2030, with higher-level forecasts through 2050. The work concludes with research needs and policy recommendations to successfully launch and scale the California renewable hydrogen sector. The conclusion is that, with appropriate policy support, the renewable hydrogen sector can reach self-sustainability (price point at parity with conventional fuel on a fuel-economy adjusted basis) by the mid- to late 2020s.

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EXECUTIVE SUMMARY

Overview

This report documents the analysis, methodology, and results of a one-year, CEC-sponsored study undertaken by the University of California, Irvine, Advanced Power and Energy Program (UCI APEP) to develop a roadmap for the evolution of the renewable hydrogen supply sector necessary to serve the growing demand for renewable hydrogen through 2050. The analysis focuses on 2020 through 2030 with a less detailed assessment of the time frame beyond 2030. The roadmap defines actions needed to support an optimal deployment of renewable hydrogen production plants needed to meet the growing demand for renewable hydrogen. The analysis builds upon insights from early market development and a series of analyses developed for the roadmap on current and future technology costs, feedstock supply and cost, siting and factory buildout, and demand growth.

This roadmap will help guide future state policy and funding decisions to support the successful buildout of a robust renewable hydrogen sector as a key part of California's zero-carbon economy. The roadmap is also a source of information for the public and interested stakeholders. An extended executive summary of the roadmap findings and recommendations can be found in Appendix C of this report.

UCI APEP developed the roadmap through several discrete tasks, as illustrated in Figure 1.

Figure 1: Renewable Hydrogen Roadmap Task Flow
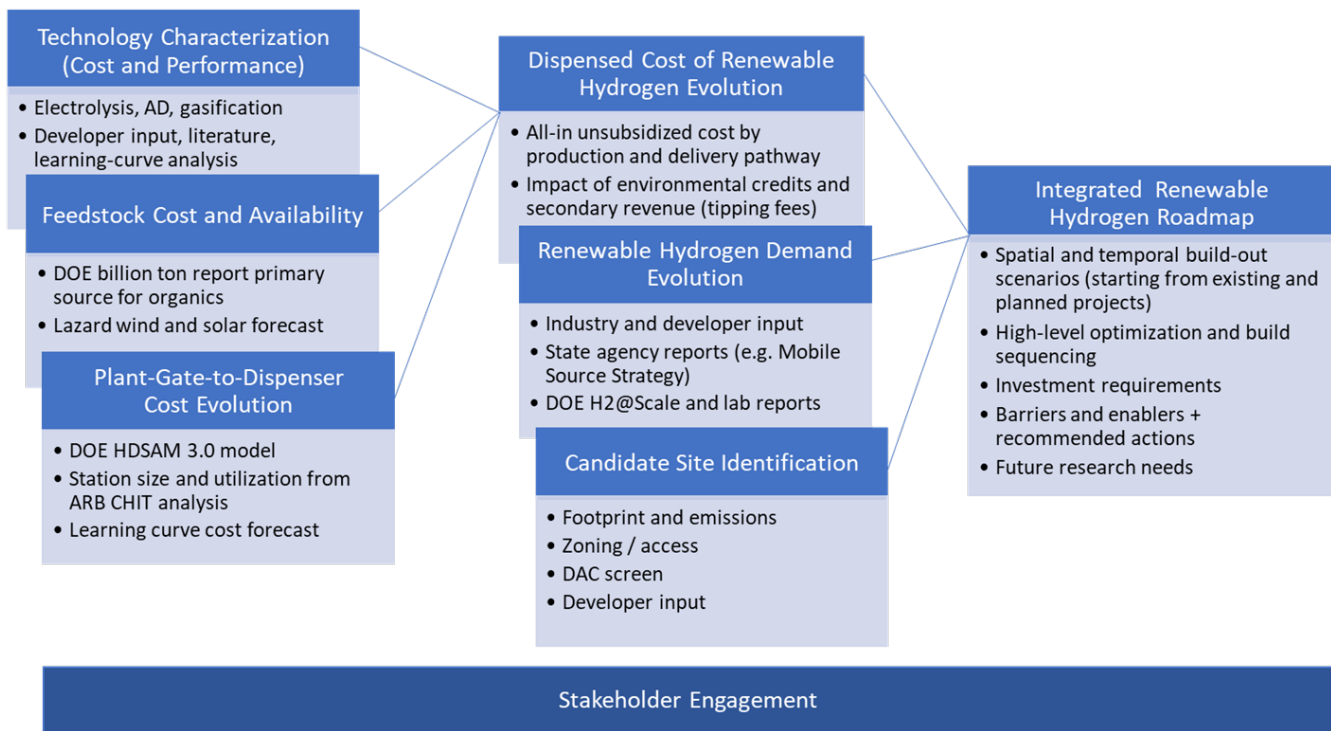
Source: UCI APEP

Stakeholder Input

More than 40 interviews with industry stakeholders supported development of the RH2 Roadmap. In addition, two public webinars were conducted to provide interim results to stakeholders and provide opportunity for public comment. Appendix E summarizes key topics and themes.

Renewable Hydrogen Demand Forecast (Chapter 2)

The roadmap effort developed several scenarios for the growth in renewable hydrogen demand through 2050. Primary sources included hydrogen demand analysis (renewable and nonrenewable) developed for the U.S. Department of Energy (DOE) H2@Scale initiative and several state agency documents projecting decarbonization pathways. Although transportation, depicted in Figure 2, is expected to be the primary source of demand for renewable hydrogen, petroleum refining, power generation and storage, heat, industrial processes, and ammonia production are all additional sources of potential demand. This analysis projects a high-case demand for renewable hydrogen of more than 400 million metric tons per year in 2030 and more than 10 times that amount in 2050. Additional scenarios are detailed in Chapter 2.

Figure 2: Hydrogen in Transportation

Source: UCI APEP, Hyundai, Toyota, Honda

Technology Characterization (Chapter 3)

This task benchmarks the current cost and efficiency of the primary renewable hydrogen production pathways and forecasts the related evolution through 2050. Three classes of hydrogen production technology were assessed: electrolysis, anaerobic digestion, and thermochemical conversion. The analysis employed several methods, and the results are detailed in Chapter 3 and Appendix A. All the technology groups are projected to show significant improvement in cost and performance, with electrolysis showing the greatest reduction potential. The analysis results forecast that the U.S. Department of Energy (DOE) long-term cost target of $2 per kilogram at the plant gate is achievable by the 2030s.

Feedstock Supply and Cost (Chapter 4)

Feedstock supply and cost are important inputs to the delivered cost of hydrogen. The primary feedstocks are biomass for thermochemical conversion and anaerobic digestion and renewable electricity for electrolyzers. The primary source for the organic feedstock analysis was the DOE Billion Ton Report (BTR) and Lazard Levelized Cost of Renewable Electricity 12.0 was the primary source for wind and solar electricity. The analysis projects the potential supply of organic feedstock to be nearly 750 petajoules per year (10^{18} joules or the energy equivalent of 6 billion kilograms of hydrogen) at a cost threshold of $60 per dry ton. The resource potential for wind and solar is more than 70 times current consumption, and the cost of both wind and solar power production will be below 3 cents per kilowatt-hour by 2030. Details of the feedstock analysis can be found in Chapter 4.

Plant-Gate-to-Dispenser Cost Evolution (Chapter 5)

The costs incurred from the production plant through the hydrogen refueling station were analyzed using the HDSAM 3.1 tool developed by Argonne National Laboratory augmented with a learning-curve forecast of cost-reduction potential. The station size and utilization follow the forecast in the 2018 AB 8 report (the annual report to the legislature on progress on hydrogen station construction). The analysis projects plant gate-to-dispenser costs to decline from around $16 per kilogram (excluding subsidies and credits) at present to a midpoint estimate of $6 by 2025, declining to below $5 by 2050 with a low-end estimate of $4 per kilogram. The biggest factor in the cost decline is increased station utilization (fuel dispenses as a fraction of full capacity) with economies of scale and technology progress also contributing. Details can be found in Chapter 5.

Dispensed Cost of Renewable Hydrogen Evolution (Chapter 6)

This task integrates technology, feedstock, and supply chain costs to derive the full dispensed cost of renewable hydrogen forecast ranges. The analysis then adds revenue from environmental credit values and tipping fees for landfill-diverted material to derive a net cost for dispensed hydrogen as a proxy for future pump price. The key findings are that the dispensed price of hydrogen is likely to meet an interim target based on fuel-economy-adjusted price parity with gasoline of $6 to $8.50 per kilogram by 2025. Furthermore, reaching the long-term DOE target of $4 per kilogram is within the forecast band for 2050, but the base forecast is around $5 per kilogram. The cost evolution is shown in Figure 3. Additional detail can be found in Chapter 6.

Figure 3: Net Cost of Dispensed Renewable Hydrogen
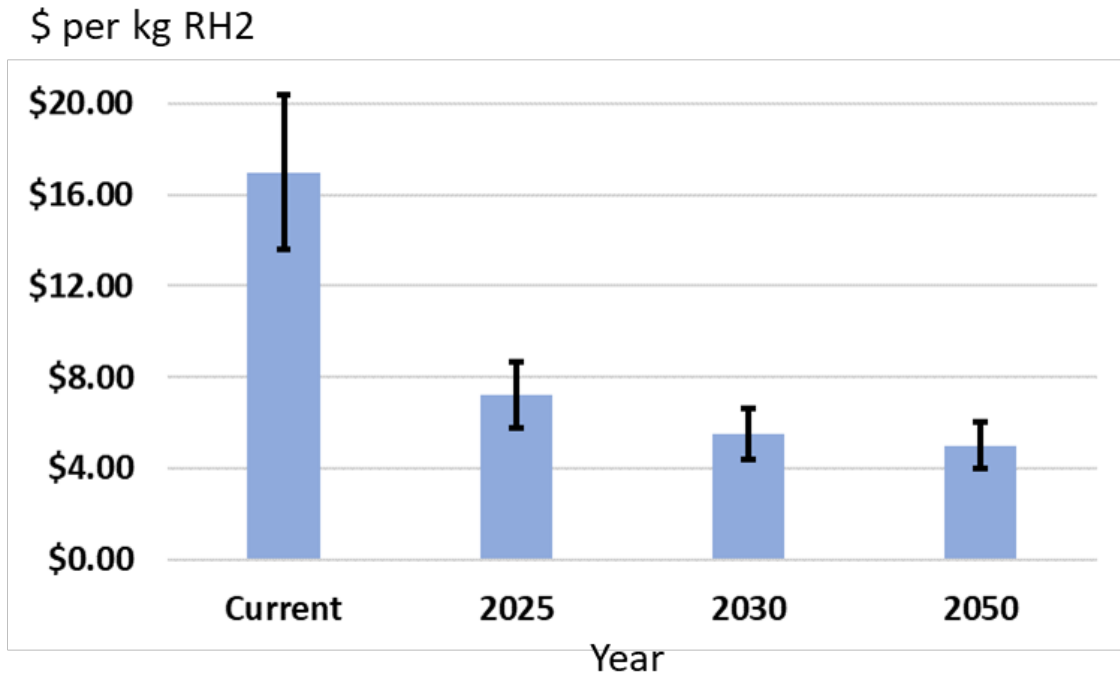
Candidate Site Identification

This analysis assessed locations across the state in a 4-km-by-4-km grid to determine suitability for siting renewable hydrogen production plants based on terrain, land use, and access to necessary infrastructure. The research team selected plant locations in the various buildout scenarios from the resulting set of candidate sites. The analysis shows that proximity to feedstock is the strongest factor in siting. Thermochemical plants are sited in forests and agricultural areas, anaerobic digestion facilities on dairies or refuse routes, and electrolyzers in solar and wind resource areas. Steam methane reformers use pipeline gas as feedstock and are sited near natural gas transmission lines. For outbound transport of produced hydrogen, all facilities are also sited near major highways. Plants that generate smog-causing emissions were excluded from disadvantaged communities in high-pollution areas.

Integrated Buildout Scenarios and Roadmap (Chapters 7 and 8)

The final step was integrating the results from prior tasks to develop time-phased buildout scenarios for renewable hydrogen production plants. Based on a defined set of assumptions and constraints including community impacts, the buildout scenarios minimize the cost of dispensed hydrogen to serve incremental demand in time steps from the present through 2050. Details of the siting analysis and buildout scenarios can be found in Chapter 7 and Appendix B. Recommendations for market support and research, development, and demonstration (RD&D) are summarized below with additional detail provided in Chapter 8 and Appendix D (RD&D needs). Figure 4 shows the base-case facility buildout. The 2050 facility count exceeds 500 across the various technology types.

Figure 4: Base-Case Facility Build 2020 to 2050
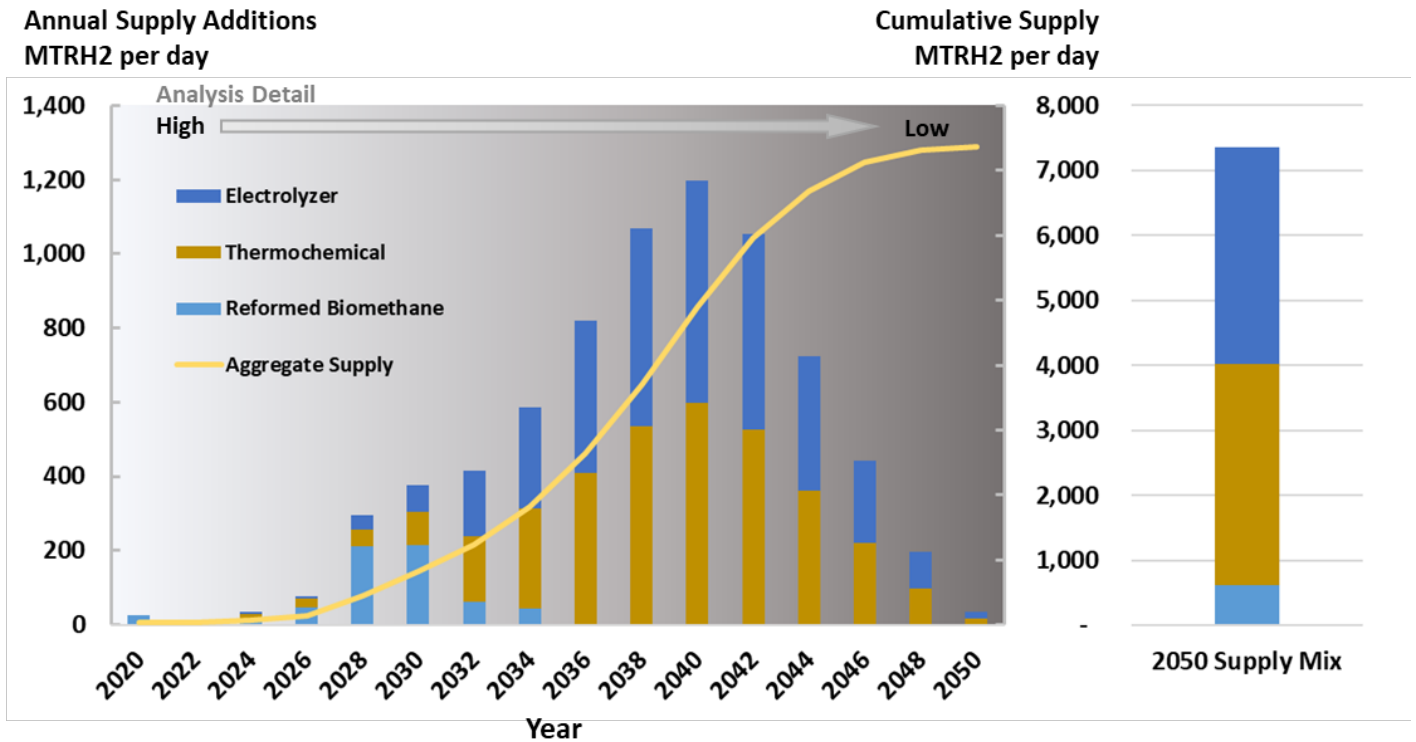
Source: UCI APEP

Recommendations

The roadmap project team developed a set of recommendations for state action based on the roadmap research and analysis, and input from stakeholders. The recommendations are presented in two categories. The first category defines actions to support market development and evolution directly through things such as incentives. The second category recommends research, development, and demonstration (RD&D) activities to refine the findings of the roadmap and support technology advances needed to achieve long-term targets.

Market Development Recommendations

1. Extend hydrogen infrastructure support to the entire supply chain (extend the current program focus on stations to renewable hydrogen production, processing and transport).
2. Focus on forms of support that attract private capital (such as loan guarantees).
3. Take steps to support a smooth expansion of capacity and avoid boom/bust cycles while promoting robust competitive markets by increasing market transparency and targeting incentives.
4. Reduce barriers to development in California: California Environmental Quality Act (CEQA), codes and standards, costs (including taxes), and local issues.

5. Develop electric rate structures specific to transmission-connected renewable fuels facilities (for example, electrolyzers and liquefaction facilities) such as whole power market access + transmission charge.

6. Promote access to the natural gas system for renewable hydrogen transport and storage—establish blending limits and interconnection requirements.

7. Take steps to ensure that a mixed gas/liquid supply chain does not create barriers to market access. For example, provide incentives for development of open access points of entry to the supply chain such as gaseous or liquid terminal facilities.

8. Ensure that renewable hydrogen development advances social justice by maximizing job creation in disadvantaged communities while minimizing negative impacts such as traffic, noise, visual impacts and air emissions.

9. Act to ensure that program eligibility, environmental accounting, and lack of definitions are not barriers to renewable hydrogen development

Future RD&D Recommendations

- Renewable hydrogen production technology and feedstock supply
- Demand, adoption, and impacts analysis
- Supply-chain forecasting and optimization (plant gate to point of use)
- Renewable hydrogen fuel production and electric grid integration

CHAPTER 1:
Introduction and Purpose of the Roadmap

Hydrogen fueling infrastructure development in California is accelerating. The Joint Agency Staff Report on Assembly Bill 8 states, "This year (2019) marked the beginning of the Low Carbon Fuel Standard Hydrogen Refueling Infrastructure credit program. CARB has approved 48 stations to participate in the program thus far. The program encouraged several hydrogen refueling station operators to increase the renewable hydrogen content of their fuel to increase the potential to earn more credits. The CARB 2019 Annual Evaluation of Fuel Cell Electric Vehicle Deployment & Hydrogen Fuel Station Network Development reported that the funded station network will dispense hydrogen with 39 percent renewable content sourcing, based on information available as of June 2019. Since that time, some station operators have secured new hydrogen feedstock sources that will provide 100 percent renewable hydrogen. These new agreements demonstrate that, once station operators are able to secure renewable hydrogen feedstock sources, the percentage of dispensed hydrogen that is renewable can increase nearly instantaneously. Furthermore, this increase in renewable content comes at no additional infrastructure cost to the state. This ability to quickly increase renewable content is one advantage of hydrogen as a transportation fuel, and why the CEC has supported the development of renewable hydrogen plants in California."[1]

To keep pace with the expanding fuel-cell vehicle population and fueling capacity, renewable hydrogen supply must expand rapidly. The renewable hydrogen market is in the very early stage. No fully dedicated renewable hydrogen production plants are operating in California. Reformed biomethane using existing steam methane reformation (SMR) capacity is the dominant supply approach. The renewable hydrogen market has few participants and no transparency on pricing or terms.

This report documents the analysis, method, and results of a one-year CEC-sponsored research effort undertaken by the University of California, Irvine, Advanced Power and Energy Program (UCI APEP) to develop an initial roadmap for the evolution of the renewable hydrogen supply sector necessary to serve the growing demand for renewable hydrogen through 2050. The analysis focuses on the time frame from the present through 2030, with a less detailed assessment of the time frame beyond 2030. The roadmap defines actions needed to support an optimal deployment of renewable hydrogen production facilities needed to meet the growing demand for renewable hydrogen. The analysis builds upon insights from early market development and a series of analyses developed for the roadmap on current and future technology costs, feedstock supply and cost, siting and facility buildout, and demand growth. The roadmap will guide future state policy and funding decisions to support the successful buildout of a robust renewable hydrogen sector as a key part of California's zero-carbon economy. The roadmap also serves as a source of information for the public and interested stakeholders.

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1 Baronas, Jean, Gerhard Achtelik, et al. 2019. Joint Agency Staff Report on Assembly Bill 8: 2019 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California. California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2019-039.

Hydrogen fuel cell electric vehicles (FCEVs) are a cornerstone for (1) achieving the governor's target of 5 million zero-emission vehicles on the road in California by 2030; (2) meeting environmental goals directed toward removing the emissions of carbon and criteria pollutants from the transportation sector, (3) retaining the range, fueling time, and scalability (for example, light-, medium-, and heavy-duty vehicles, locomotives, ships) to which the public is accustomed; and (4) succeeding in achieving fuel independence. While fueling stations are being developed to support the emerging retail market for light-duty FCEVs, the sources of hydrogen are immediately stressed because of existing demands from the industry in general and petroleum refining in particular. The requirement that 33.3 percent of the hydrogen dispensed today (and 40 percent to be eligible for LCFS infrastructure credits)[2] be derived from renewable sources adds even more stress to meeting the daily requirements for the fuel. Given the challenge of building a renewable hydrogen production sector from virtually nonexistent in 2015 to hundreds of millions of kilograms per year by 2030 and billions by 2050, a roadmap for the evolution of resources to generate renewable hydrogen from today to full buildout is prudent and timely to develop.

To meet the immediate stress of renewable hydrogen demand in the early FCEV market, several entities are contemplating new hydrogen production for vehicle use in California. Because of the unique scale and risk associated with the unfolding passenger car market, these various entities are already competing for resources, locations, and future supply contracts. The design, siting, cost, and overall strategy for building and operating the facility represent a powerful first example upon which to establish a roadmap. In addition, the CEC has solicited, under GFO-17-602, the development of renewable hydrogen production plants, providing an additional source of information on near-term cost and performance.

As noted, initial project development has been undertaken to increase the supply of renewable hydrogen in California, but current and announced production will be inadequate to meet supply by the early to mid-2020s. Renewable hydrogen supply shortages could slow or stall the growth in the nascent fuel cell vehicle market and erode consumer confidence. The roadmap provides specific recommendations for state support, and research needs to help ensure a smooth and successful ramping and scaling of a self-sustaining renewable hydrogen supply sector in California.

This research builds upon the extensive body of work that has been developed on optimal hydrogen refueling station network deployment by addressing the supply side of the hydrogen value chain, as well as assessing additional sources of future demand. While the state has invested considerable effort in developing a clear, time-phased buildout strategy for hydrogen refueling stations to meet the anticipated growth in demand for renewable hydrogen for transportation, no comprehensive plan has been developed for the production and supply chain to serve that demand with an increasing supply of cost-effective renewable hydrogen. The roadmap seeks to address this gap.

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2 Section 95486.2. Generating and Calculating Credits for ZEV Fueling Infrastructure Pathways.

CHAPTER 2:
Renewable Hydrogen Demand Scenarios

Introduction

The project began by developing RH_2 demand scenarios to determine the scale of RH_2 production needed over time. The current global demand for hydrogen is 65 million metric ton per year (MMT/yr) where one metric ton is 1000 kilograms. The demand by use is shown in Figure 5. The current U.S. demand for hydrogen is 10 MMT/yr, roughly 15 percent of global demand, and is used mostly for petroleum refining and ammonia production. California demand is roughly 2 MMT/yr and is used predominantly for refining. The renewable or zero-carbon fraction of the hydrogen supply in California is insignificant.

Figure 5: Global Hydrogen Demand
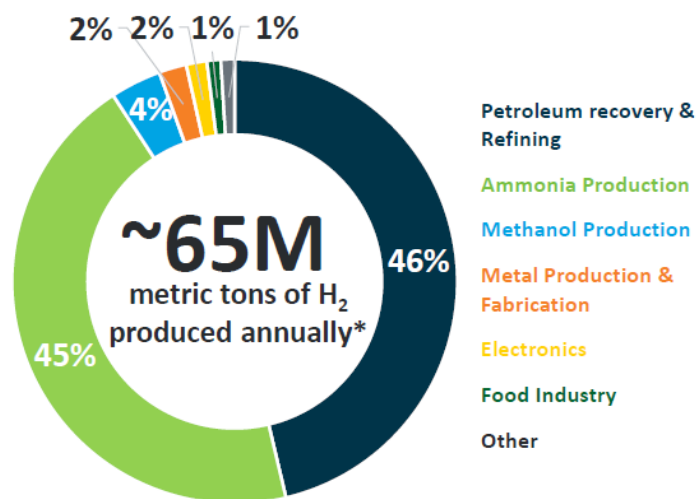
Source: (Satyapal 2017)

California policy calling for an 80 percent reduction in CO_2 emissions from the 1990 level by 2050 will create new demand for zero-carbon hydrogen and necessitate a shift in current demand from fossil-derived hydrogen to zero-carbon hydrogen. Sources of potential demand for renewable hydrogen include:

- Light-duty vehicles (LDVs).
- Medium and heavy-duty (MD/HD) vehicles.
- Off-road transportation (marine vessels, trains, forklifts, and other).
- Petroleum refining.
- Power generation and storage.
- Residential, commercial, and industrial applications (process and heat).
- Ammonia-based fertilizer.
- Export.

The present analysis developed high-, medium-, and low-demand scenarios for renewable

hydrogen. Table 1 summarizes the key assumptions used for each. Additional detail is provided below for each area of potential demand.

Table 1: Renewable Hydrogen Demand Scenario Descriptions

RH$_2$ Application	High	Low	Mid
Light-duty Vehicles	1 million FCEVs by 2030 50% penetration by 2050	250,000 FCEVs by 2030 20% penetration by 2050	500,000 FCEVs by 2030 35% penetration by 2030
Medium-Duty, Heavy-Duty, and Other	Hydrogen serves 50% of MD/HD renewable diesel demand in Vision 2.1 and 20% of "other" non-LDV	Mobile Source Strategy Clean Vehicles and Fuels Scenario in Vision 2.1	Midpoint between high and low
Petroleum Refining	100% decarbonized H$_2$ by 2050 on linear ramp beginning 2025	No RH$_2$ demand in low case	50% of high case
Power Generation and Storage	Geothermal and storage hold half of resources	No RH$_2$ demand in low case	50% of high case
Process and Heat	10% of current natural gas (NG) demand in 2050 with H$_2$ blending beginning in 2025	No RH$_2$ demand in low case	50% of high case
Ammonia Production	100% decarbonized H$_2$ by 2030	No RH$_2$ demand in low case	15% of high case

Source: UCI APEP

Light-Duty Vehicles

At the time of this report, roughly 7,000 fuel cell electric vehicles (FCEVs) are operating in California. The light-duty FCEV population is projected to grow to between 250,000 and 1 million vehicles by 2030 (California_Air_Resources_Board 2018). The 2012 California Vision for Clean Air (California Air Resources Board 2012) projects that more than 50 percent of passenger vehicles in the South Coast Air District will be FCEVs (Figure 6), while the California Air Resources Board (CARB) Mobile Source Strategy projects around 20 percent of total vehicle population to be FCEV by 2050 (Figure 7) (California Air Resources Board 2016).

This analysis assumes 50 percent penetration for passenger vehicles and light trucks by 2050, roughly 17.5 million vehicles, for the high or optimistic demand forecast, and the low case assumes penetration of 20 percent of vehicle population in 2050. The average fuel economy for the FCEV population was assumed to improve from 65 miles per gallon equivalent (mpg$_e$) in 2018 to 115 mpg$_e$ by 2050 [approximate average for passenger vehicles and light trucks in 2050 from (Mahone et al. 2018)]). The renewable fraction of total hydrogen demand is

another important element of the renewable hydrogen demand scenarios. The Hydrogen Council and the California Hydrogen Business Council have endorsed a goal of achieving 100 percent carbon-free hydrogen supply by 2030 (CHBC 2019). However, concern also exists about increasing the mandated renewable fraction too rapidly, given the current high price of dispensed hydrogen (in the range of $15/kg or gasoline gallon equivalent). The scenario assumption here is that the renewable fraction will be maintained at the currently mandated level of 33.3 percent[3] through 2025, after which it ramps to 100 percent by 2050. The resultant renewable hydrogen demand scenarios for LDVs are shown in Figure 8.

Marine, rail, and off-road applications, such as forklifts and construction equipment, are also significant consumers of fuel, accounting for nearly 20 percent of total fuel use in California[4]. Hydrogen solutions are being developed for these applications with rail, oceangoing vessel, and ferry applications at the pilot stage and hydrogen fuel cell forklifts already showing significant penetration. A hydrogen ferry will enter operation in California in 2019, and initial designs are being developed for oceangoing vessels. Aviation is also a high consumer of fuel, but the use of hydrogen as an aviation fuel is at the concept stage and is not considered a source of demand in this analysis.

Figure 6: Vision for Clean Air South Coast AQMD Passenger Vehicle Scenario
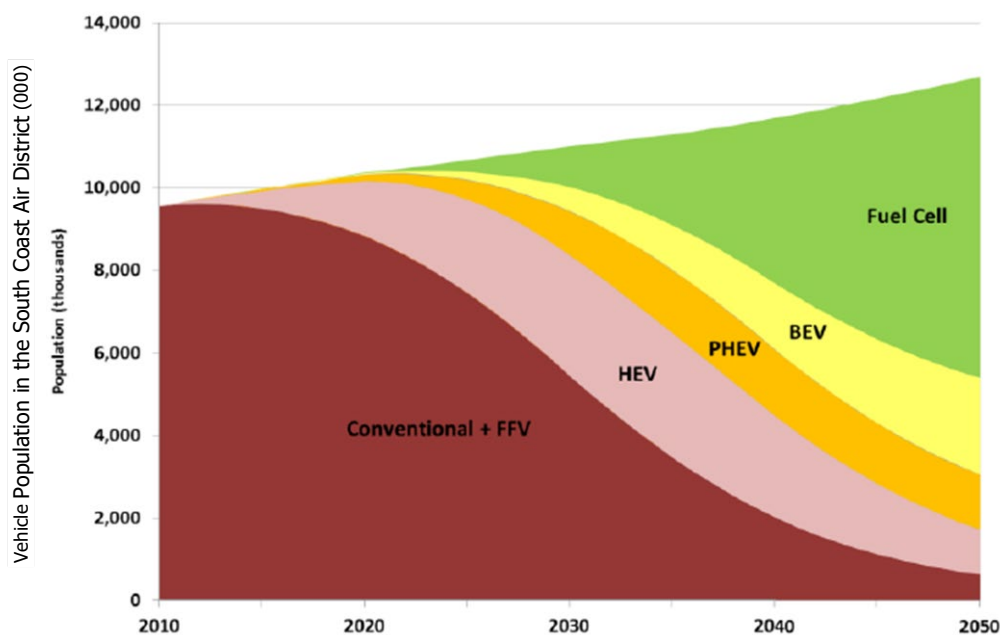
Source: California Air Resources Board 2012

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3 The recently approved (mid-2019) Low Carbon Fuel Standard (LCFS) Hydrogen Refueling Infrastructure (HRI) credits program, which provides credits both for dispensed hydrogen and remaining station capacity, requires a minimum of 40 percent renewable hydrogen. This provision was approved after the development of the present scenarios, so the renewable fraction may increase slightly more rapidly than reflected in the scenarios presented here as use of the HRI credit program expands.

4 (California Air Resources Board 2016, 2017)

Figure 7: Vehicle Count in Mobile Source Strategy LDV Scenario
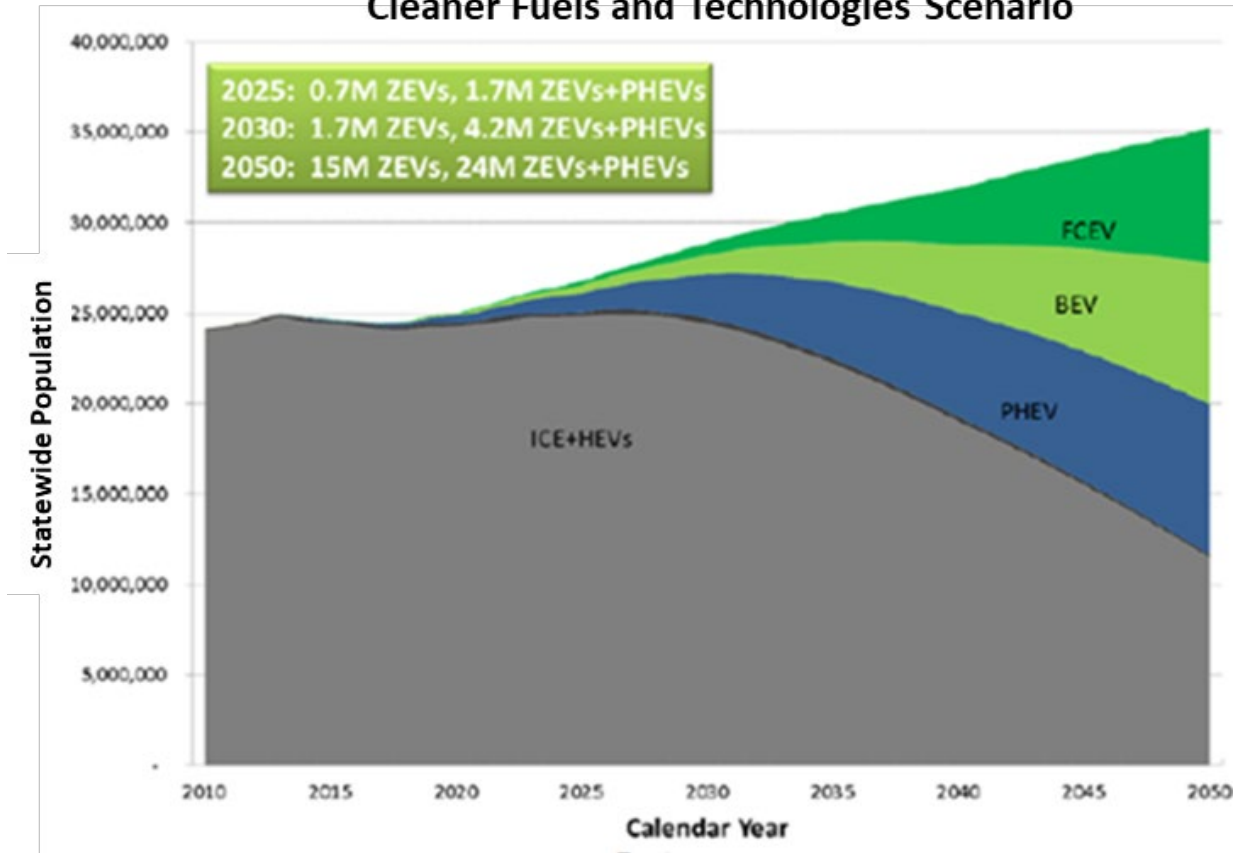
Source: California Air Resources Board 2016

Figure 8: Light-Duty Vehicle Renewable Hydrogen Demand Scenarios
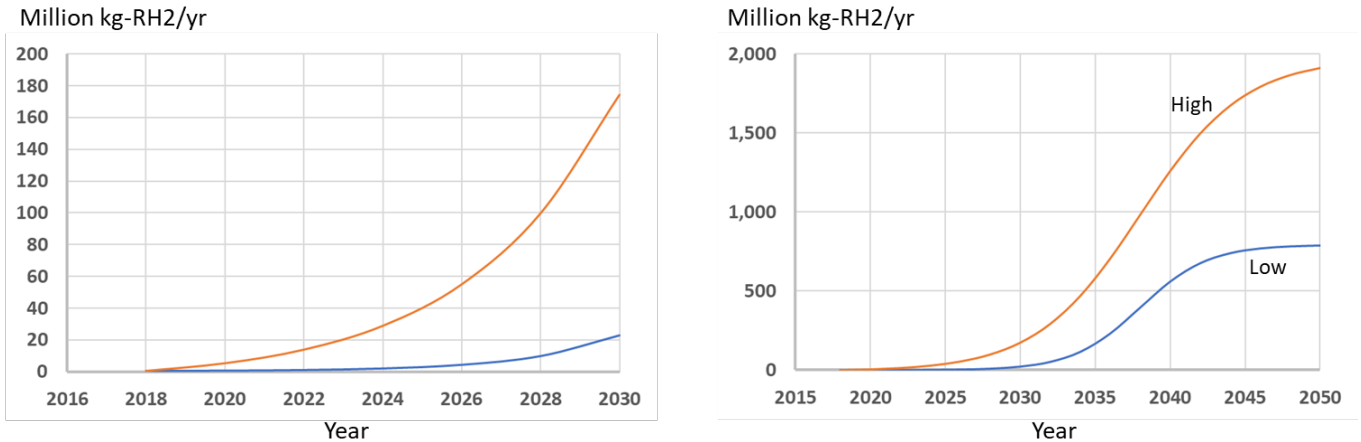
Demand Scenarios through 2030 and through 2050   Source: UCI APEP analysis

Medium-Duty, Heavy-Duty, and Other Transportation Applications

Decarbonizing the medium- and heavy-duty elements of the transportation sector is a challenge. Battery-electric vehicles are being developed for a range of applications, including urban delivery, transit, drayage, and other applications. However, the required battery storage on board presents a challenge, and, to date, electrification has been considered infeasible for long-haul trucking. Although at the pilot and early-deployment stages, FCEVs are under development for the full range of medium- and heavy-duty applications and are expected to show significant share of these applications, particularly for higher-mileage and heavier-vehicle applications.

The Mobile Source Strategy (MSS) assumes that liquid fuels, transitioning to liquid renewable fuels over time, serve most demand for transportation fuel outside the light-duty sector, as shown in Figure 9. Figure 10 shows the non-LDV fuel demand by application in 2030 and 2050. As an alternative to the MSS scenario, this assessment assumes that half of the assumed demand for renewable diesel will be served by hydrogen solutions with a renewable fraction that tracks with that for LDVs.

For this analysis, the MSS cleaner fuels and technologies forecast will be taken as the base case. The high case will assume that half of the 2050 diesel demand for MD/HD is met by hydrogen, and 20 percent of the remaining demand—which includes oceangoing vessels (OGV), locomotives, and other off-road vehicles—is met by hydrogen. Both high and base cases will use the MSS 2030 demand from the cleaner fuels and technologies scenario. A fuel economy ratio of 1.5 will be used for all non-LDV applications and cases (1 kg of hydrogen replaces 1.5 gallons of conventional fuel). The renewable fraction of hydrogen fuel will be assumed to be 33 percent in 2025 and ramp to 100 percent by 2050. The resultant renewable hydrogen demand growth is shown in Figure 11.

Refining

The demand for hydrogen for refining in the western United States is roughly 1.4 MMT per year, excluding by-product hydrogen generated by refining operations and consumed internally, of which roughly 65 percent is consumed in California (Elgowainy et al. 2019; EIA 2018a). An LCFS pathway has been certified for the generation of credits using renewable hydrogen in refining. However, the use of renewable hydrogen for refining is insignificant. One electrolytic hydrogen project for refining is under development in Germany (ITM_Power 2018). Given California's policy goal to reduce GHG emissions by 80 percent by 2050 and the expectation of declining costs for production of renewable hydrogen, decarbonization of hydrogen used for refining can be expected over time. For this analysis, it is assumed that hydrogen used for refining reaches 100 percent renewable fraction by 2050, beginning with a 1 percent fraction in 2025. This analysis assumes that overall demand for petroleum refinery hydrogen tracks downward with petroleum use to 20 percent of current demand by 2050. The resultant hydrogen demand is shown in Figure 12.

Figure 9: Mobile Source Strategy Non-LDV Transportation Fuel Demand

Million DGE
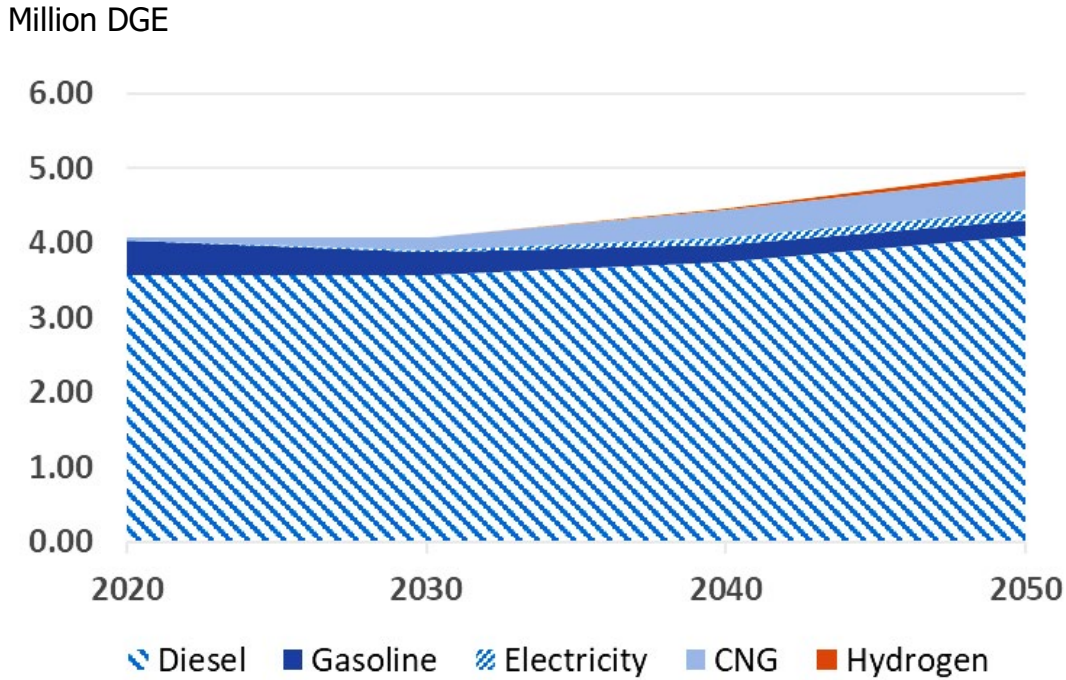
Note: One DGE (diesel gallon equivalent) is roughly equal to 1 kg of hydrogen.

Source: Cleaner Technologies and Fuels Scenario from VISION 2.1 Model

Figure 10. Gasoline and Diesel Fuel Demand for Non-LDV Transportation
Million Gallons
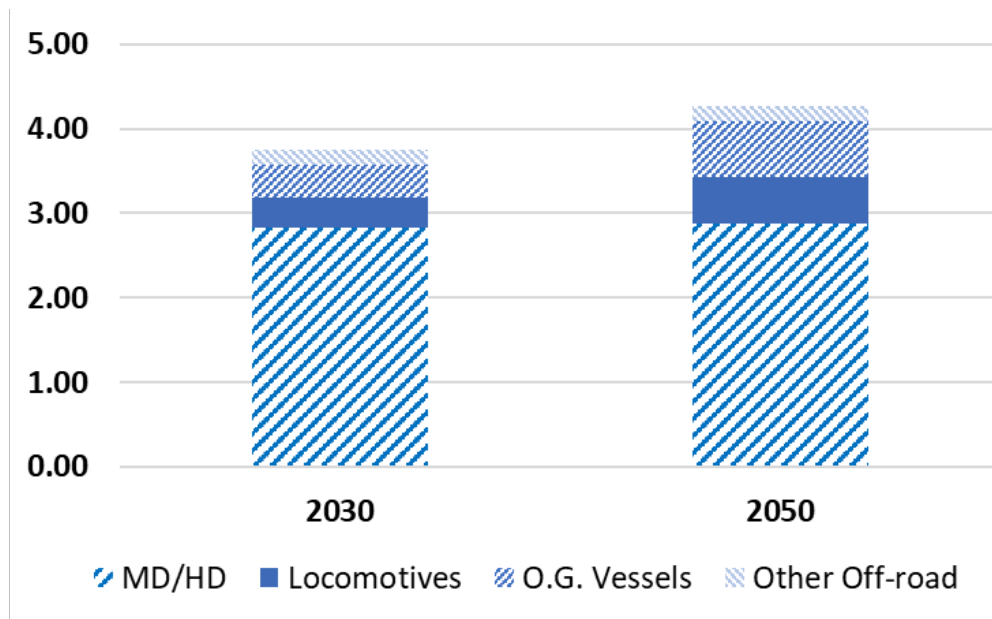
Source: Cleaner Technologies and Fuels Scenario From VISION 2.1 Model

Figure 11: Non-LDV Transportation Renewable Hydrogen Demand Scenarios

Million kg-RH2/yr
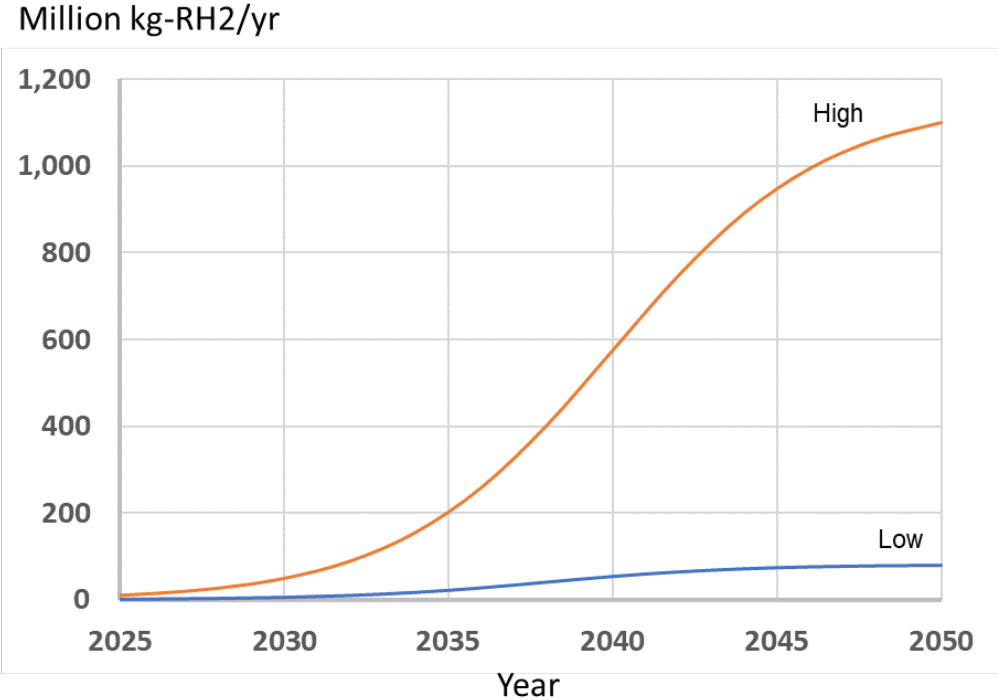
Source: UCI APEP analysis

Figure 12: Renewable Hydrogen Demand for Petroleum Refining

Million kg-RH2/yr
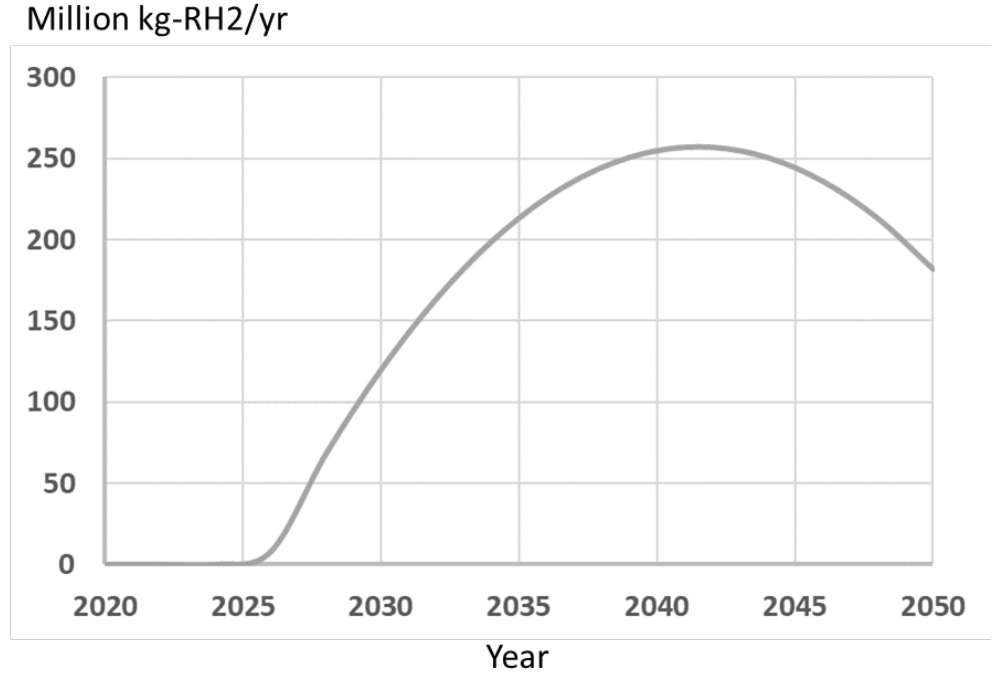
Source: UCI APEP analysis

Power Generation and Hydrogen Energy Storage

Although curtailment of intermittent renewable electric power resources is infrequent, the frequency and duration of curtailment are increasing. By the late 2020s, the need for long-duration storage and dispatchable, rapid-load-following resources will begin to increase rapidly. If hydrogen technology cost and performance advance sufficiently, hydrogen may become a least-cost resource for serving these functions in micro- and macrogrids.

The RESOLVE resource planning model (CPUC 2018) is an optimization model that dispatches existing resources and adds new resources over time to serve load at least cost. The model includes changes in electricity demand over time for things like transportation electrification and building efficiency. RESOLVE is the model adopted by the California Public Utility Commission for electric resource planning. The model shows that, beginning in the mid-2020s, there will be the need for new storage and dispatchable renewable generation to serve load during times of low wind and solar production. Table 2 below shows the resource additions forecast by RESOLVE for 60 percent renewable fraction (anticipated in the 2030 time frame) and 80 percent renewable fraction (anticipated in the 2045 time frame). Note that RESOLVE does not include hydrogen as a renewable fuel source in these scenarios and does not currently feature hydrogen energy storage (HES) as a resource option.

This analysis uses the electricity storage and firm renewable generation resource additions shown in Table 2 to reflect the demand for those functions. As an alternative to adding geothermal resources, batteries and pumped hydro electric storage hydrogen via power-to-gas-to-power or by biomass-to-hydrogen-to-power pathways could serve the same resource needs. Depending on the progression of technology costs among the alternative technologies, scenarios that employ hydrogen pathways as alternatives to the base case are possible, particularly if the cost ratio of electrolyzers to batteries and of hydrogen generation versus geothermal are more favorable to hydrogen than the base assumptions in RESOLVE.

To reflect this potential, the present demand scenario assumes that 50 percent of base-case storage discharge capacity addition is replaced with electrolyzers. Furthermore, 50 percent of the forecast 2 GW of new geothermal capacity addition through 2045 is served by hydrogen power generation via fuel cells or advanced hydrogen turbines (central resources or on microgrids) with an assumed 70 percent efficiency. The difference in roundtrip efficiency between electrolyzers and alternative storage resources would have a secondary impact on the overall system wide energy balance, which is not considered here. The incremental projected hydrogen demand is shown in Figure 13.

Commercial, Industrial, and Residential Uses (Process and Heat)

A variety of industrial processes such as material manufacturing and steelmaking use hydrogen. These sources of demand are not likely to be substantial in California. However, should prices for pipeline injected renewable hydrogen fall below $15 per million British thermal units (MMBtu), hydrogen blending or localized gas-system conversion to pure hydrogen could become a significant element of the decarbonization strategy for applications currently served by natural gas such as process heat, water and space heating and cooking. Pilot projects are already commencing in Europe that will shift complete districts from natural

gas to pure hydrogen. Additionally, hydrogen as a blendstock for conventional and renewable methane is being explored globally. The initial pure-hydrogen distribution system conversions are targeted for full implementation in the late 2020s. For this analysis, it is assumed that, beginning in 2030, localized transition to dedicated hydrogen distribution networks grows to 10 percent of current California residential and commercial natural gas demand of 670 billion cubic feet (Bcf) (or 5.85 billion kg of hydrogen), which gives a hydrogen demand of 585 million kg per year in 2050 (EIA 2018b). The renewable fraction is assumed to begin at 50 percent in 2030 and reach 100 percent by 2050. The buildout will likely occur via discrete projects, but, given timing uncertainty and project size, a smooth curve is used for this scenario, as shown in Figure 14. The mid-case and low-case demand scenarios do not include residential and commercial demand for hydrogen.

Table 2: RESOLVE Model Results for 60 Percent and 80 Percent Renewable Scenarios

Renewable Scenarios	60% Renewable Fraction (2030)	80% Renewable Fraction (2045)
Battery Storage Additions	2.6 GW	5.8 GW
Pumped Hydro Additions	--	1.4 GW
Geothermal Additions	--	2.0 GW
Gas-Fired Generation	50,000 GWh	16,600 GWh

Source: UCI APEP analysis

Figure 13: Potential Incremental Hydrogen Demand for Electric Generation

Million kg-RH2/yr

Year
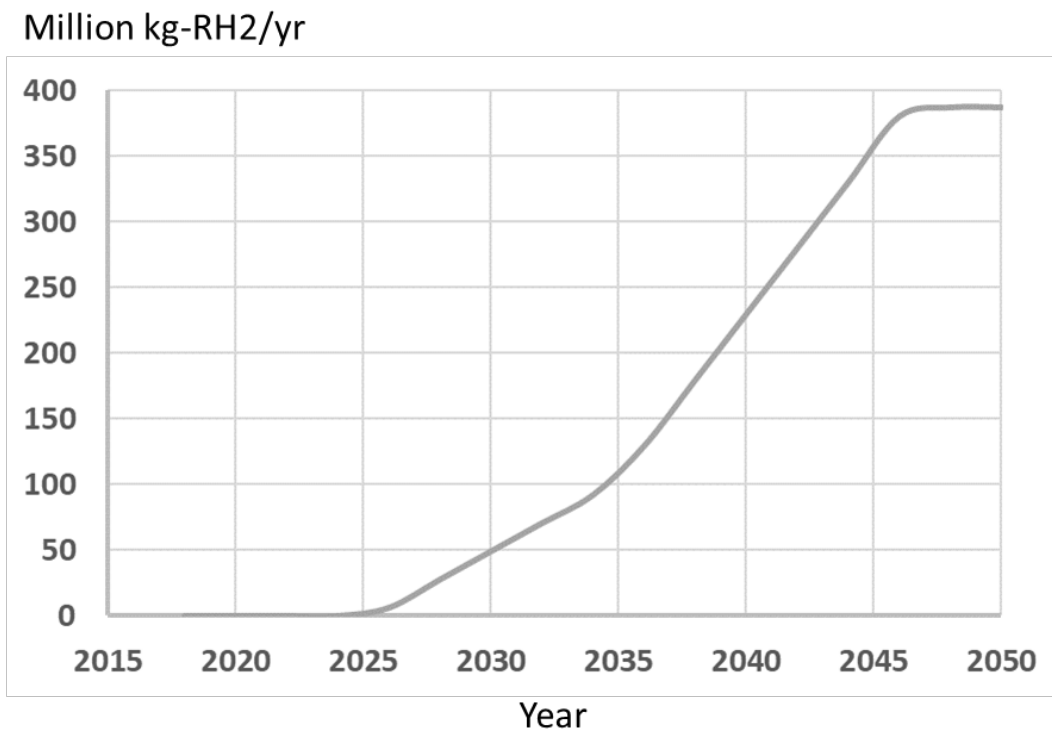
Source: UCI APEP analysis

Figure 14: Potential Commercial and Residential Hydrogen Demand Scenario

Million kg-RH2/yr
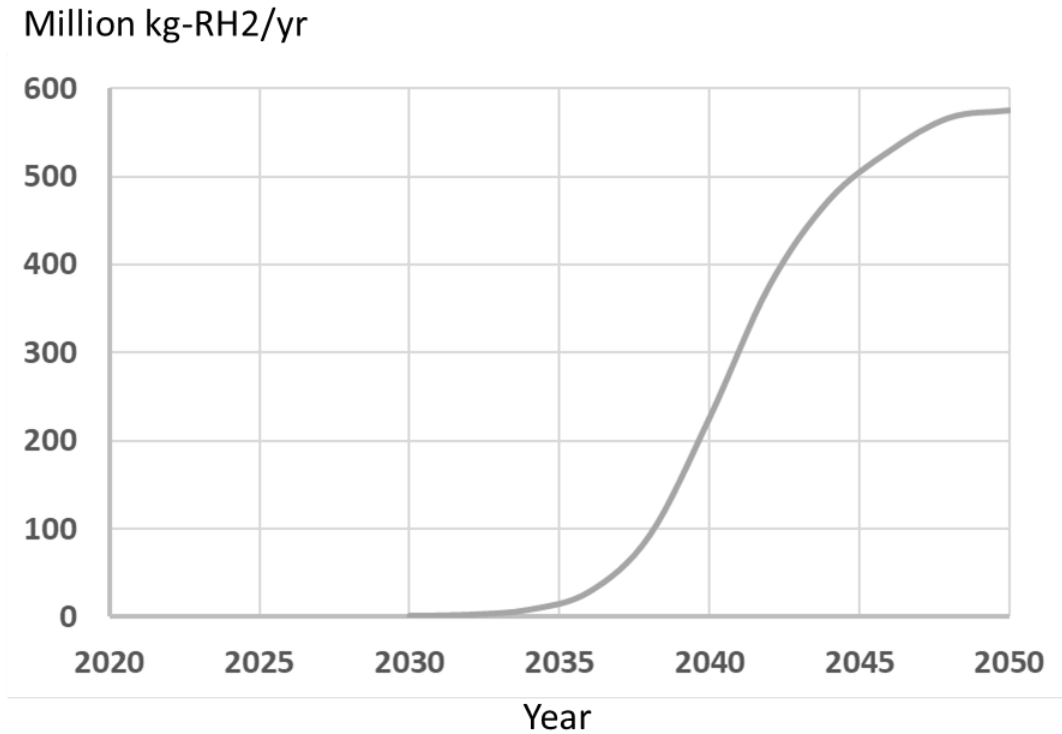
Source: UCI APEP analysis

Ammonia Fertilizer

U.S. demand for hydrogen for ammonia production is currently estimated to be 2.5 MMT, of which 88 percent is used for fertilizer according to (Elgowainy et al. 2019). That number is forecast to increase to 3.3 MMT and remain flat thereafter. The California share of U.S. agricultural product is 13 percent, which scales to 0.286 MMT (286 million kg) of hydrogen. A UC Davis assessment of nitrogen fertilizer use in California estimated nitrogen for fertilizer in the range of 650,000 to 950,000 tons in the early 2000s on a trend line to nearly 1 million tons at present (Tomich 2014). If all of this were used for ammonia, the hydrogen requirement would be about 0.190 MMT (190 million kg). Data from the U.S. Department of Agriculture show that roughly 15 percent of ammonia for fertilizer is used in the form of anhydrous NH_3, with the remainder in the form of fertilizers, such as urea, that are manufactured from ammonia (USDA 2018). Using the midpoint of the two estimates above, anhydrous ammonia demand in California would be estimated at 36 million kg of hydrogen equivalent demand. This amount is consistent with anhydrous ammonia demand of 200,000 tons stated by California ammonia collaborative, CALAMCO (Hildebrand 2017). 200,000 tons of anhydrous ammonia is equivalent to 37 million kg of hydrogen equivalent demand.

A recent report argues that it is feasible to transition to zero-carbon-ammonia pathways at reasonable cost by midcentury (Energy Transitions Commission 2018). Potential cost reductions for renewable hydrogen production support this perspective. This analysis assumes that beginning in 2025, the in-state production of renewable ammonia grows to serve the entire anhydrous ammonia demand and half of the ammonia-based fertilizer demand. These

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demands total roughly 135 million kg per year and are assumed to remain constant. The increase in renewable ammonia fraction will likely show step changes as facilities are added, but, because of uncertainty in facility size and deployment timing, a linear ramp was used for the present demand scenario. The resultant demand scenario is shown in Figure 15.

Figure 15: Potential Demand for Renewable Hydrogen for Ammonia Production

Million kg-RH2/yr
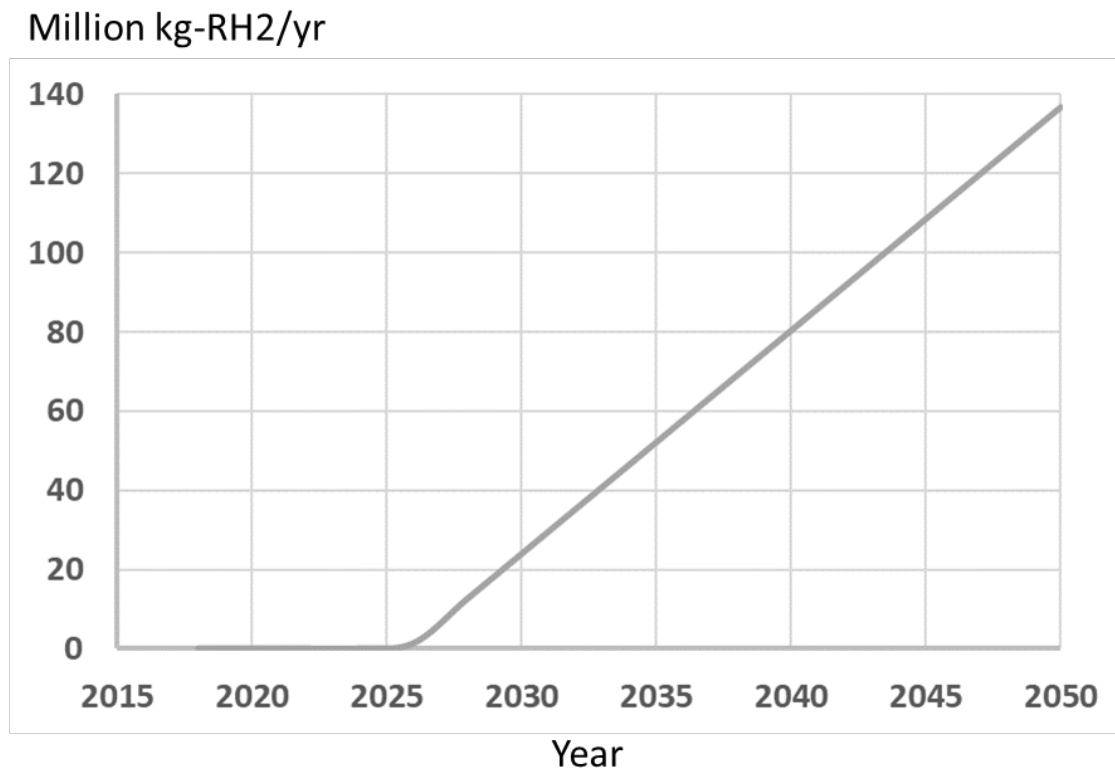
Source: UCI APEP analysis.

Import and Export

Renewable hydrogen imports and exports will affect the necessary plant buildout in California. Today, California produces most of its own hydrogen. However, in the future, hydrogen import via rail, ship, and truck is expected. The recently announced Air Liquide hydrogen production plant will be out of state, and other project development is underway in neighboring areas targeting California as an import market via rail or truck. Several international efforts are underway to develop liquid hydrogen and liquid-hydrogen carrier oceangoing tankers, and California is a candidate to access the emerging seaborne renewable hydrogen market. Similarly, export markets are a potential source of demand for renewable hydrogen production plants in California. Given the cost of operating in California and the limited supply of low-cost biomass, California is likely to be a net importer of renewable hydrogen. However, the buildout scenarios do not make specific assumptions about import or export but rather add in-state facilities to serve renewable hydrogen demand. Imports would represent a reduction in demand for in-state production, so the lower demand cases can be taken as a proxy for imports.

Integrated Demand Scenarios

Figure 16 shows the aggregate demand potential for the various application areas discussed above through 2030 and through 2050. This demand potential represents the high-demand case and assumes that all demand areas see significant renewable hydrogen penetration. Figure 17 adds low- and midcase scenarios for overall California renewable hydrogen demand. The low case assumes that light-duty fuel cell vehicle population reaches 250,000 by 2030 and grows to 7 million by 2050 (25 percent LDV penetration), medium- and heavy-duty trucking demand as forecast in the Mobile Source Strategy cleaner vehicles and fuels scenario (which assumes most MD and HD are renewable diesel and renewable CNG), 100 percent refinery and ammonia decarbonization, and no renewable hydrogen demand for power generation, residential, or commercial applications. The mid case assumes LDV population of 500,000 in 2030 and 12 million in 2050, half of the high case potential for non-LDV transportation, for power generation and storage, and for residential and commercial, and 100 percent decarbonization of refining and ammonia production.

The relative likelihood of the three scenarios depends strongly on the cost of renewable hydrogen as a decarbonization solution relative to others. In most applications, the relevant cost goes beyond the fuel-to-fuel cost comparison and includes potential new infrastructure, end-use equipment cost, and relative system efficiency (relative quantity of hydrogen consumed). Some general benchmarks in Table 3 indicate the price range direction of renewable hydrogen for significant penetration to occur in the relevant applications.

Figure 16: High-Case Renewable Hydrogen Demand Scenario Breakdown Through 2030 and 2050

Million kg-RH2/yr
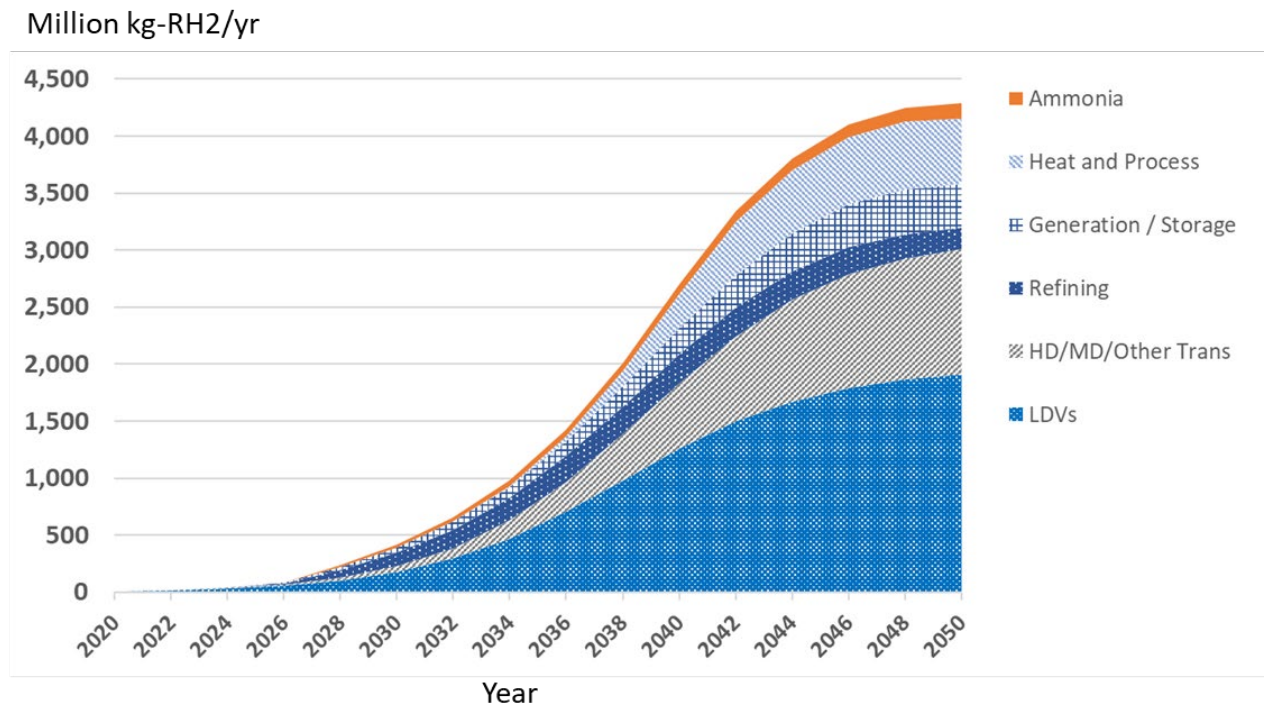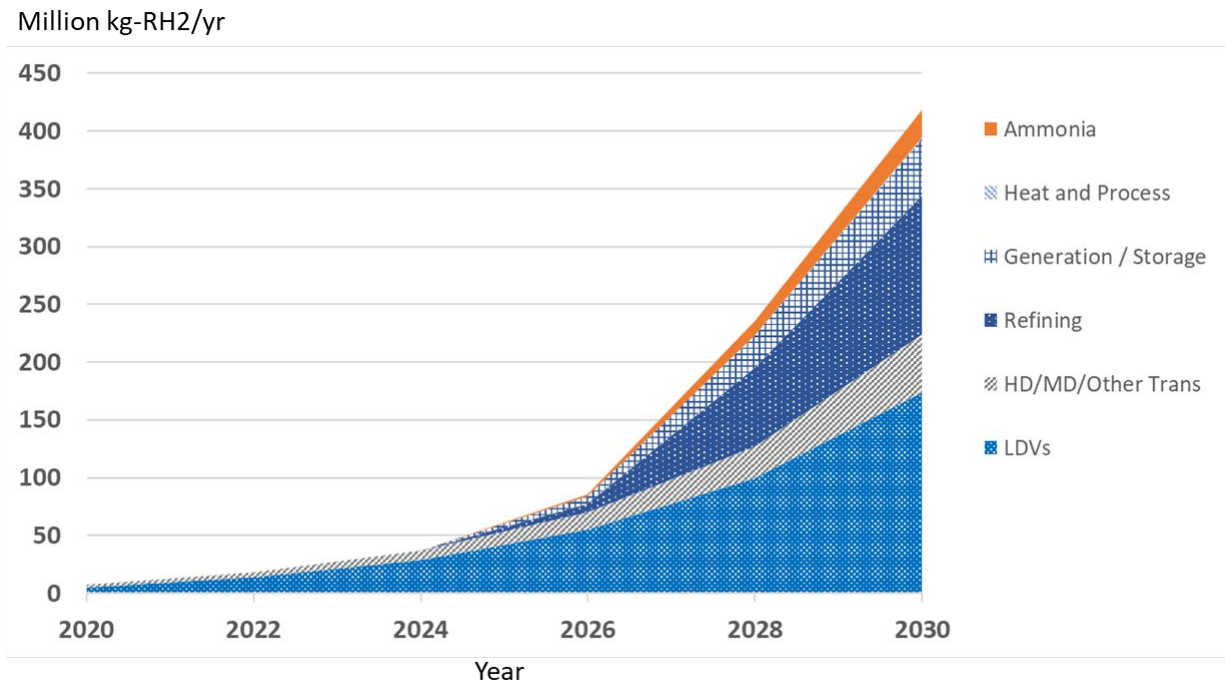
Million kg-RH2/yr

Source: UCI APEP analysis

Figure 17: California Renewable Hydrogen Demand Scenarios
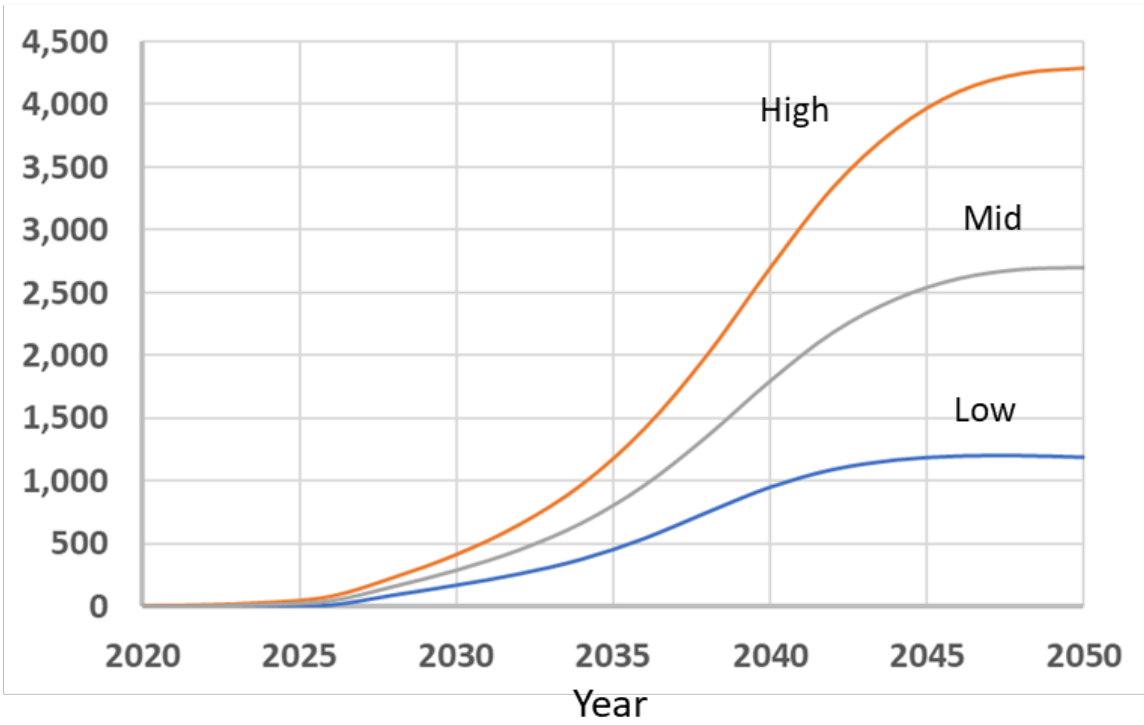
Million kg-RH2/yr

Million kg-RH2/yr
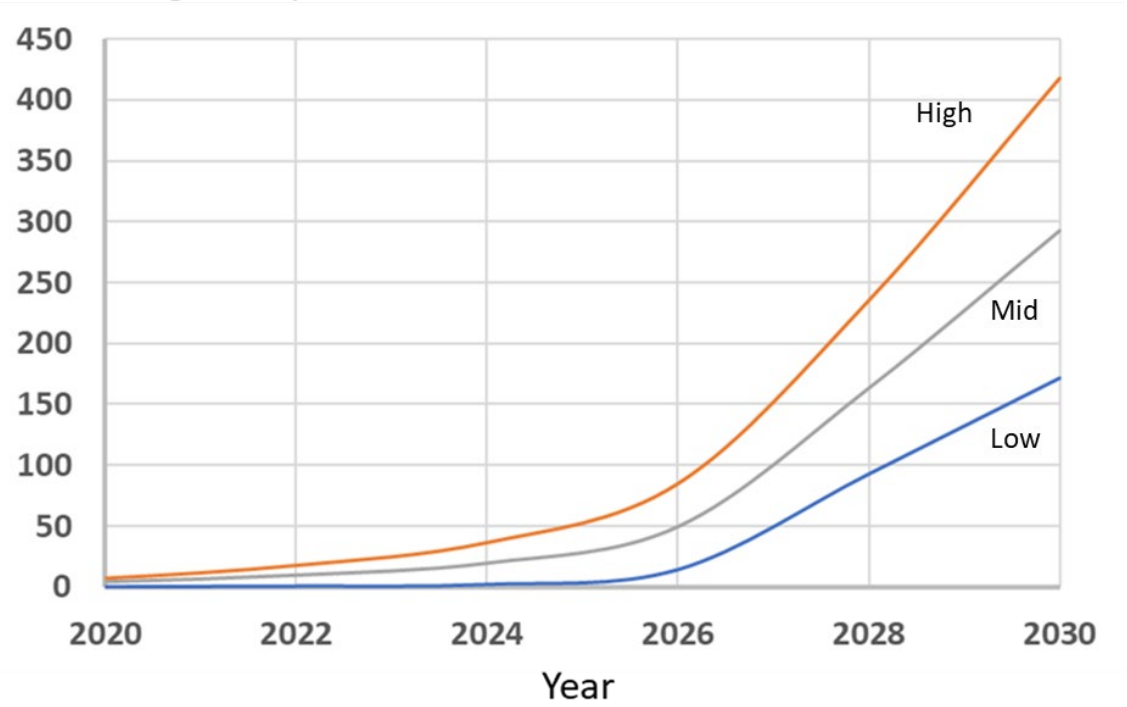
Source: UCI APEP analysis

Table 3: Representative Costs for RH$_2$ Substitutes

Use	Substitute	RH$_2$ Target Range	Comments
Light-Duty Vehicles	Gasoline or Diesel	$2-$4/kg	Based on dispensed price target of $6-$8.5/kg (also DOE target for production cost)
Medium- and Heavy-Duty Vehicles	Gasoline or Diesel	$2-$4/kg	Same as above
Refining	Fossil Hydrogen + CO2 Price	$2.20 - $3.40/kg	SMR CI of 125 gCO2e/MJ and carbon price of $20 - $100 MT
Fertilizer	Fossil Hydrogen + CO2 Price	$2.20 - $3.40/kg	SMR CI of 125 gCO2e/MJ and carbon price of $20 - $100 MT
Generation/ Storage	Other Firm Renewables (e.g. biomethane, geothermal)	$2-$3/kg	Assumes $15 - $25/MMBtu delivered for biomethane as the alternative resource
Industrial, Commercial, and Residential Thermal and Process	Renewable Electricity Renewable Natural Gas	$3-$6/kg	Electricity delivered at $140 - $200/MWh equivalent assuming Biomethane $15 - $25/MMBtu Assumes $10/MMBtu gas system T&D for RH2 and RNG

Source: UCI APEP

CHAPTER 3:
Renewable Hydrogen Production Technology Characterization and Forecasts

Introduction

The evolution of technology cost and performance is a critical determinant of the pace at which renewable hydrogen will be adopted as a fuel and the ultimate role in the decarbonized energy and transportation sectors. To support the RH$_2$ Roadmap development, a comprehensive analysis of the state of the relevant renewable hydrogen production technologies and forecast of potential improvement were undertaken. The details of the work can be found in Appendix A, including technology descriptions and method. The method and principal results are summarized below.

Scope and Approach

The research team assessed three primary pathways for renewable hydrogen:

- Electrolysis (use of electrical energy to split water into hydrogen and oxygen)

- Anaerobic digestion with reformation (decomposition of organic material through a series of anaerobic reaction to create methane and CO$_2$, followed by reformation of methane to yield hydrogen)

- Thermochemical conversion (use of temperature and, in some cases, pressure to create hydrogen-rich gas from biomass). The team used gasification as a proxy for this class of technology. (See Appendix A for further discussion of gasification technology.)

The selected technology groups are in development (electrolysis and anaerobic digestion) or predevelopment (gasification) in California (Table 4). These are the technology groups that are expected to be commercially available from the present through 2030. These groups do not rule out the possibility that new technologies or technology variants may emerge. The cost and performance ranges developed in this task are broad enough to serve as a proxy for other renewable hydrogen production pathways.

A variety of methods are employed to forecast technology cost and performance. The primary methods used in the analysis reported here were:

- Expert elicitation (researchers, equipment vendors).

- Progress or learning rate analysis/trend analysis.

- Bottom-up analyses based on design, bill of materials, and production scale.

- Analogy or proxy analysis.

For current cost benchmarking, vendor bids and "as-built" data were also used where available. More than 40 stakeholder interviews were conducted to augment published sources of information and learning-curve analysis.

Table 4: Renewable Hydrogen Production Technology Summary

Technology Group	Subgroups	Description	Deployment Status
Electrolysis	Alkaline Polymer Electrolyte Membrane (PEM) Solid Oxide	Uses applied voltage to drive a catalyzed electrochemical reaction completed via an electrolyte to evolve hydrogen and oxygen	Commercial
Anaerobic Digestion	High vs. low solids Batch vs. continuous Note: Tier 1 covered lagoon for dairy and complete mix continuous flow for MSW assumed for this study	Decomposition of organic material via anaerobic reaction to form methane, CO_2 and minor constituents	Commercial
Thermochemical	Gasification (several types) Pyrolysis Hydrothermal Note: Gasification using circulating-fluidized bed assumed for this study	Use of heat and/or pressure to extract volatile material from biomass producing syngas (mostly hydrogen and carbon-monoxide) which is further reacted and purified to hydrogen or methane	Commercial Prototype

Source: UCI APEP. See glossary and Appendix A for further detail.

Depending on the availability of recent published reports and studies, this analysis employed different methods for different technologies. Learning rate (or progress curve) analysis was a primary method and was applied to all technology groups. Learning-rate forecasts can use either time (Moore's Law) or cumulative production (Wright's Law) as the independent variable for cost forecasting. Wright's Law has been shown to be somewhat more accurate (Nagy et al. 2012), so this study uses that approach.

Figure 18 shows the probability distribution of learning rates for various industrial technologies collected from 108 studies (Ferioli, Schoots, and van der Zwaan 2009). The data show that most technologies show a significant learning effect with most technologies above exhibiting learning rates above 10 percent. Technologies with negative learning rate are rare, but this

result can occur when long-term upward pressures impact cost because of factors such as regulation as seen with nuclear power plants. Learning rates generally decline as technologies reach full maturity. Lead-acid batteries are an example of a technology that has reached a low learning rate.

Figure 18: Learning Rates From 22 Industrial Sectors
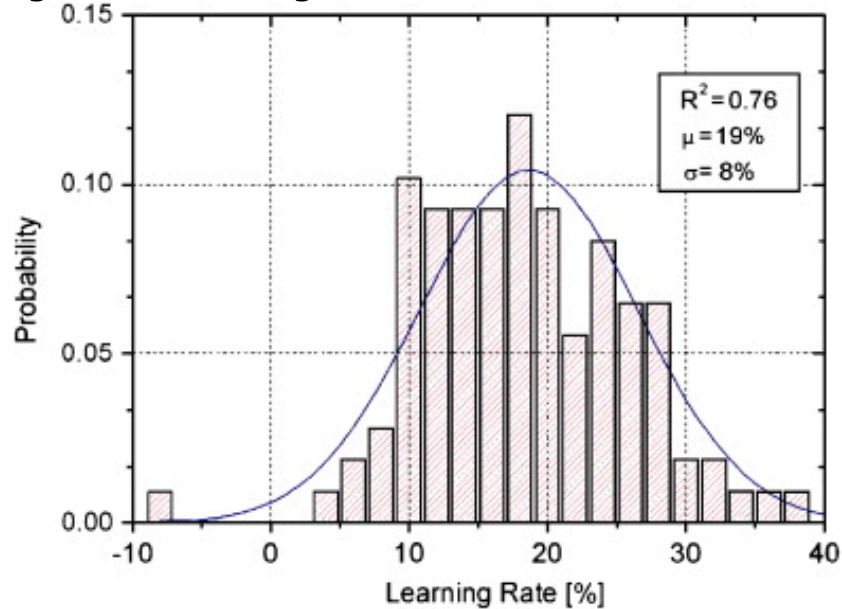
Source: (Ferioli, Schoots, and van der Zwaan 2009)

When applying Wright's Law (cost reduction based on cumulative global production) two primary factors must be established: the forward-looking growth in cumulative production and the learning rate. Figure 19 illustrates the effect of variation in learning rate and growth in cumulative production on cost progression.

All costs in this study were normalized to constant 2018 dollars ($2018). There was substantial spread in cost data even for current costs. Some degree of variance relates to fundamental variation in project-to-project costs at a given point due to unique site characteristics, and local differences in cost factors. Uncertainty also exists from a variety of factors, including differences in scope of equipment included in reported costs, normalization of plant scale, differing currency mixes (and fluctuations in exchange rate), and uncertainty in cost indexation (inflationary adjustment). Figure 20 illustrates the range of potential effects of the various indexation factors. As shown in Figure 21, the renewable hydrogen production pathways considered in this study also show significant scale dependence, although electrolysis shows lower scale sensitivity than gasification and anaerobic digestions. Differences in plant size must be normalized to accurately compare costs. Overall, the uncertainty in current cost benchmarks is in the range of +/- 25 percent.

Figure 19: Illustration of Learning Rate (LR) Sensitivities
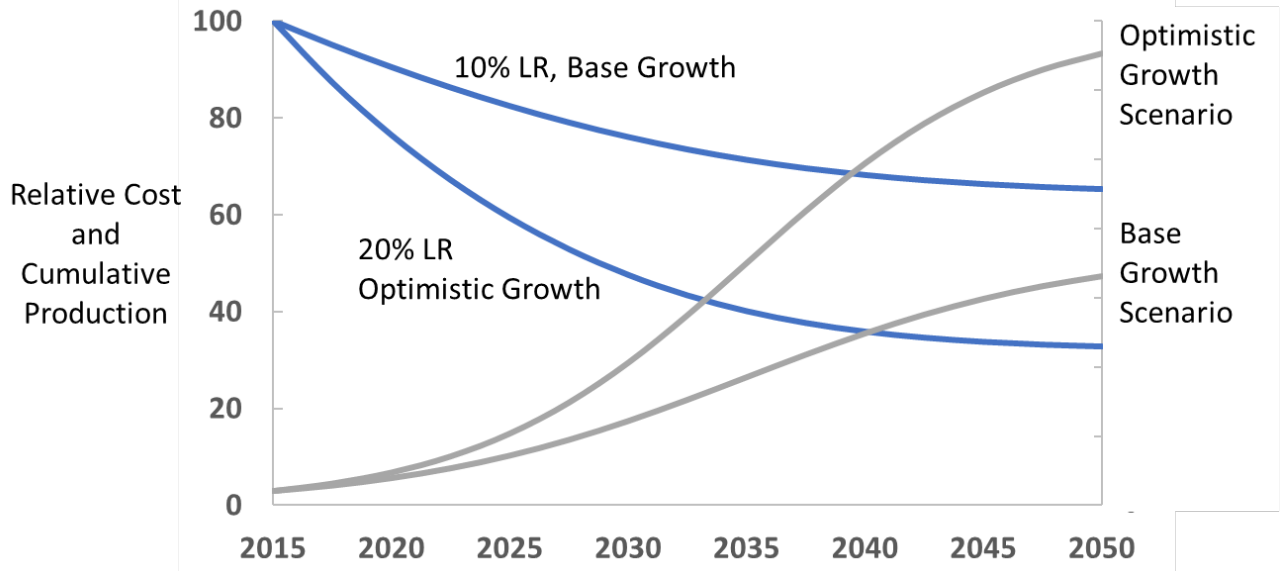
Source: UCI APEP

Figure 20: Normalizing Indices Used in This Study
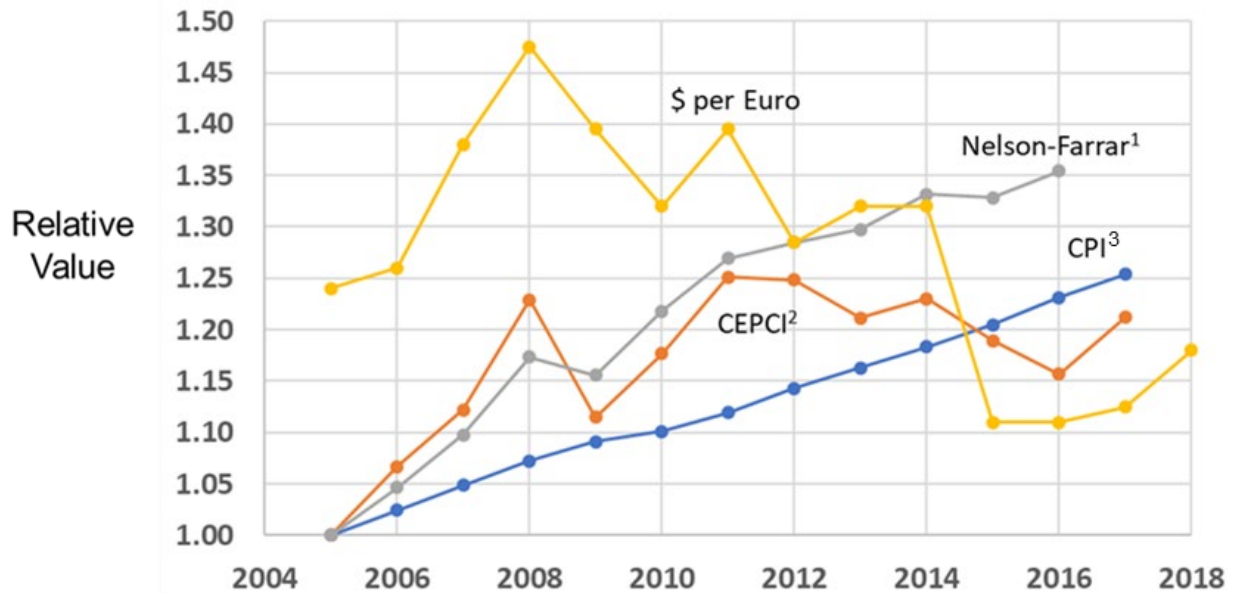
1 Refinery cost escalation index

2 Chemical Engineering Plant Cost Index

3 Consumer Price Index

Source: UCI APEP

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Figure 21: Scale Dependency of Hydrogen Production System Capital Cost
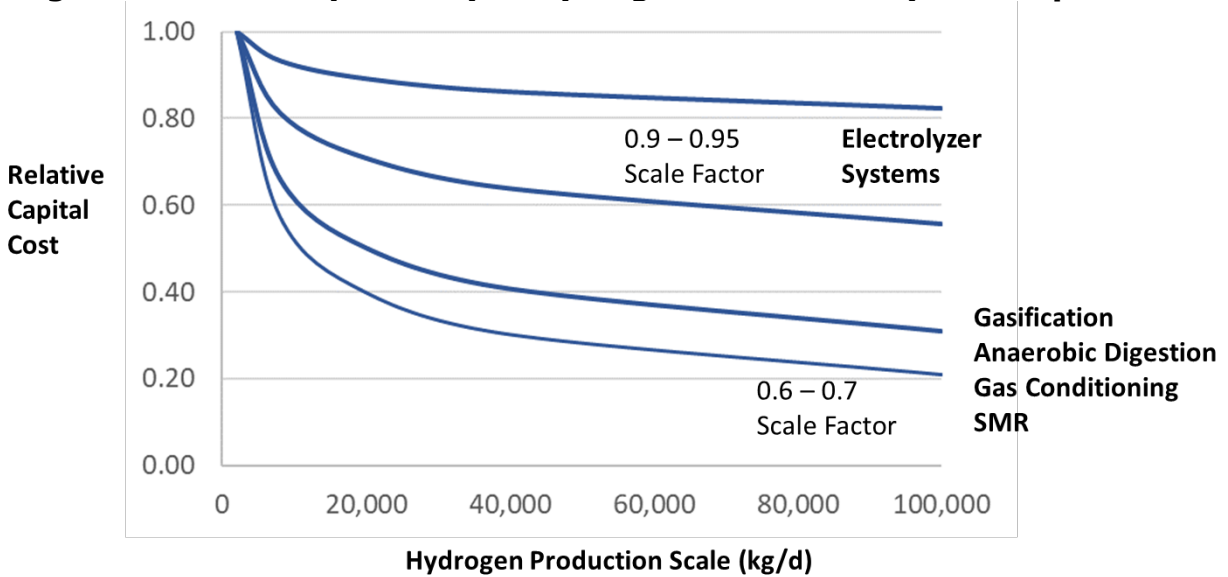
Source: UCI APEP

Technology Characterization Results

Figure 22 shows the results of the capital cost assessment for the three technology groups at representative plant sizes. As large-scale chemical processing systems using mostly mature component technology, the improvement trajectories for gasification and anaerobic digestion are less substantial than that for electrolysis. However, the uncertainty bands are such that, when feedstock costs and carbon credit values are included, any of these technologies may be the low-cost solution under certain circumstances in the future. All technologies will likely be represented in the future resource mix.

In addition to capital cost, the production cost of hydrogen depends on conversion efficiency (amount of hydrogen produced per unit of feedstock energy or mass) and operation and maintenance (O&M) costs, as well as feedstock costs. Tables 5 through 7 present the forecasts for those parameters. Feedstock costs are addressed elsewhere in this report. Figure 23 presents the nonfeedstock hydrogen production costs (feedstock conversion costs) for the various pathways forecast through 2050. Supporting detail can be found in Appendix A.

Figure 22: Capital Cost per Unit of Renewable Hydrogen Production Capacity

Capital Cost per kilogram per day
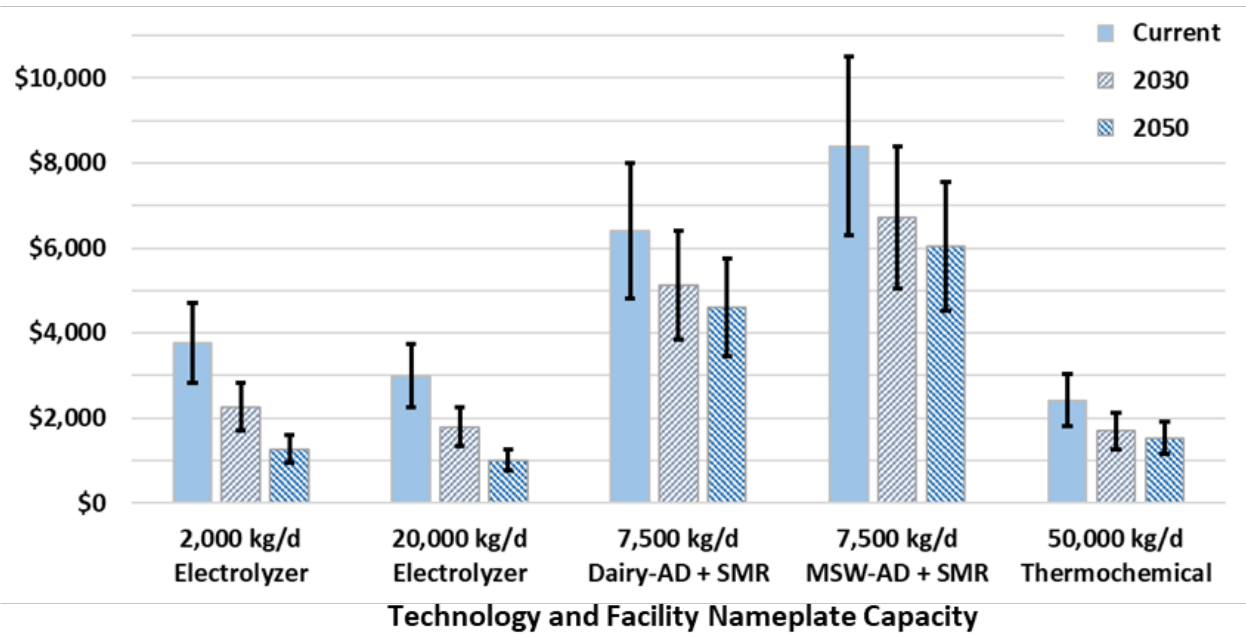
AD = Anaerobic Digester, SMR = Steam Methane Reformation, MSW = Municipal Solid Waste Source: UCI APEP

Table 5: Electrolyzer Operating Parameters and Operating Cost

Cost Type	Current	2030
Stack Electricity Use	49.2 kWh/kg	46.7 kWh/kg
Total System Electricity Use	54.6 kWh/kg	50.2 kWh/kg
Stack Life/Replacement Cost	60,000 hours 15% of Total Capex	85,000 hours 15% of Total Capex
Operation and Maintenance Expense	3% of Capex (3 MW) 1.75% of Capex (30 MW) 7-year stack life (15% of new system direct cost)	Pro-rate with Capex 9-year stack life
Water Usage	4.76 gallons/kg	3.98 gallons/kg

Source: UCI APEP based on sources in Table A-2

Table 6: Anaerobic Digestion Conversion Efficiency and Operating Costs

Cost Type	Covered Lagoon Current	Covered Lagoon 2030	Above-Ground Continuous Current	Above-Ground Continuous 2030
Conversion Efficiency (LHV)	38%	42%	50%	55%
Annual Fixed Maintenance O&M	4% of Capex	4% of Capex	4% of Capex	4% of Capex
Variable O&M ($/MMBtu)	1.25	1.25	2.50	2.50

Source: UCI APEP based on sources in Appendix A

Table 7: Gasifier Conversion Efficiency and Operating Costs

Cost Type	Hydrogen Current	Hydrogen 2030	Methane Current	Methane 2030
Conversion Efficiency (LHV)	54%	62%	67%	72%
Fixed Maintenance O&M $/kW-yr.	40	26	59	39
Variable O&M $/kW	6	4	13	8

Source: UCI APEP based on sources Appendix A

Figure 23: Nonfeedstock Renewable Hydrogen Production Costs
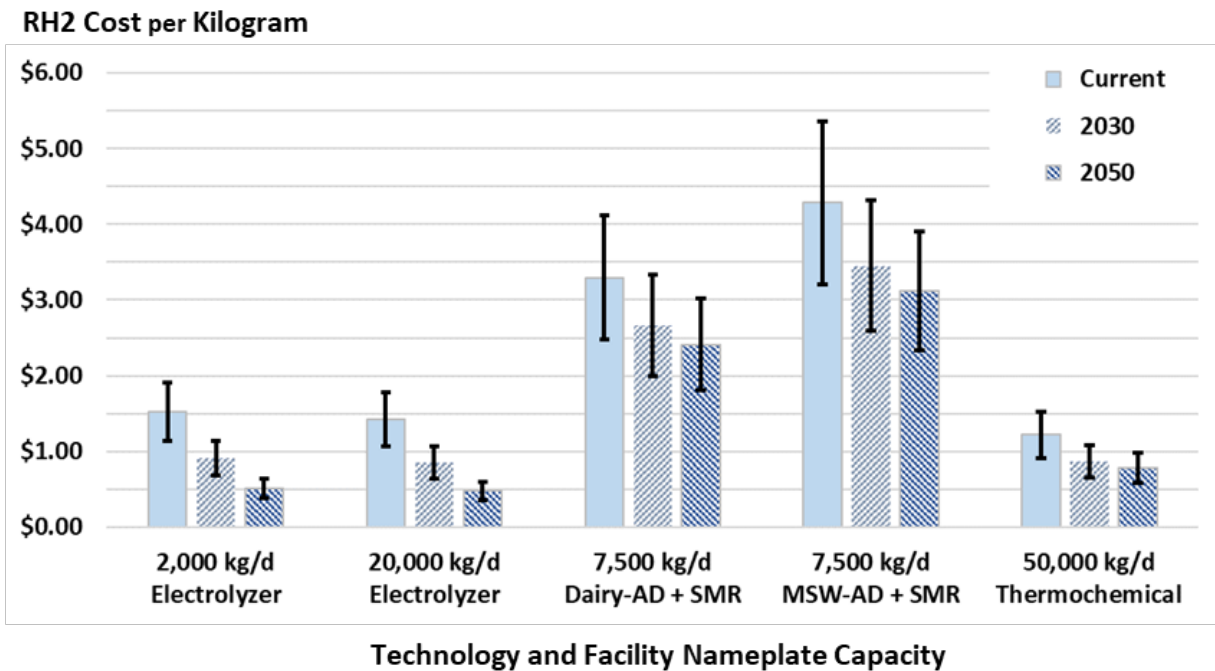
Source: UCI APEP. AD = Anaerobic Digester, SMR = Steam Methane Reformation, MSW = Municipal Solid Waste

CHAPTER 4:
Renewable Hydrogen Feedstock Supply and Cost

Introduction

The available supply and cost of feedstock for the various renewable hydrogen production pathways are a key input to the final delivered cost and the ultimate quantities that can be produced for the various renewable hydrogen pathways. Two primary categories of feedstock are used in renewable hydrogen production: organic material (biomass) and renewable electricity. The primary source for estimating potential supply and cost of plant-based organic material used for this study was the U.S. Department of Energy *Billion Tons Report* (BTR) (U.S._Department_of_Energy 2016). In addition, California-specific studies were used for dairy and landfill-diverted, high-moisture-content organic waste (CA_Air_Resources_Board 2016). Prices for wind and solar electricity were forecast using a recent study by Lazard (Lazard 2018) and the CPUC RESOLVE model (CPUC 2018).

Organic Feedstock Supply and Cost

The BTR estimates biomass availability as a function of the cost of harvesting or recovering the resource from a farm, forest, or other source location and transporting it to a roadside location for further transport to the point of use. The study developed resource potential estimates for seven biomass categories: (1) agriculture residues, (2) energy crops, (3) food waste, (4) forest residue, (5) manure, (6) municipal solid waste (MSW), and (7) trees. Figure 24 shows California agricultural and forest biomass densities from the BTR in dry tons per year at cost thresholds of $30 and $100/dry ton for recovery of the resource. Figure 25 shows the primary types of vegetation across the state.

Table 8 shows the in-state quantities estimated in the BTR for plant-based biomass at $30, $60, and $100 per dry ton cost thresholds in 2030 (cost to harvest or collect and transport the feedstock to a roadside location for transport). Municipal solid waste (MSW) quantities shown are only the organic fraction of MSW. This study excludes plastics, rubber, and leather from the BTR data as these are not renewable feedstocks. Table 9 provides the resource potential for manure based upon the analysis presented in the California Air Resources Board (CARB) Short-Lived Climate Pollutant Strategy and for landfill gas based on a 2016 UC Davis study (Jaffe, Dominguez-faus, and Parker 2016).

Significant variability exists across feedstocks in how sensitive supply quantity is to cost of recovery. Available quantity of woody material has the highest sensitivity to recovery cost with supply increasing more than 10 times, moving from a $30/ton cost threshold to $100/ton. The agricultural waste wood in the valleys is inexpensive, and the mountain forest slopes are expensive to harvest. A consulting study by The Beck Group (Beck_Group 2017) estimates that harvesting dead trees for fire prevention could create 1 million dry tons per year of biomass for energy production. That quantity is included within the resource estimate in the BTR. The priority on managing dead trees might affect the timing of harvesting those dead tree resources in contrast to other resources The quantity of energy crop supply (assumed commercial in the mid- to late 2020s) also increases with cost threshold (price) as higher prices provide incentives for additional energy crop cultivation and expand the acreage that

can be farmed economically. However, energy crops will not have a material effect on renewable hydrogen production before 2030.

A detailed economic allocation of biomass resources among the primary alternative uses (biomethane, liquid fuel, hydrogen) is beyond the scope of this study. Such an analysis would be a valuable addition in future work. This analysis instead caps the maximum share of each biomass feedstock used to produce renewable hydrogen. Chapter 7 describes the resource allocations used and rationale for the various buildout scenarios. The base-case allocation of resources to hydrogen production is capped at 50 percent for anaerobic digestion pathways and 65 percent for thermochemical pathways (which are inherently more amenable to hydrogen production). The actual feedstock used may be less than the cap, depending on the demand for renewable hydrogen.

Renewable Electricity Supply and Cost

The potential supply of renewable electricity (assumed to be from wind and solar) from in-state resources is determined by the average wind speed and insolation across the state. Figures 26 and 27 depict the high wind and solar resource areas suitable for development in California. The resource potential is more than adequate to serve the energy demand of the state, and no upper limit on supply was imposed for this analysis (Lopez et al. 2012). However, the development of the required wind and solar facilities will require construction of a large set of new wind and solar facilities as described in Chapter 7. Figure 28 shows the cost forecast ranges for new wind and solar power generation facilities developed using the Lazard twelfth annual levelized cost of electricity report (Lazard 2018) and the resource definitions in the CPUC RESOLVE model (CPUC 2018).

Figure 24: Biomass Density Map for California

a) Agricultural Residue at $30 and $100 per Dry Ton
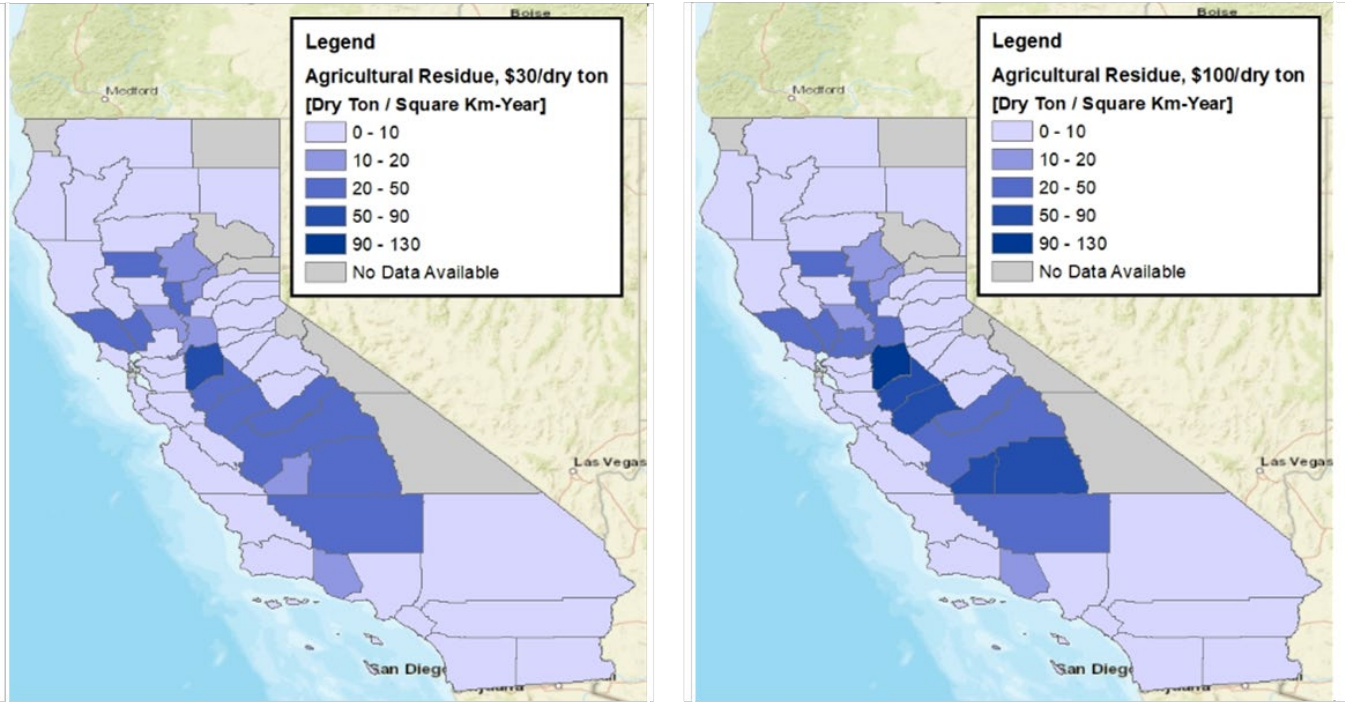
b) Forest Residue at $30 and $100 per Dry Ton
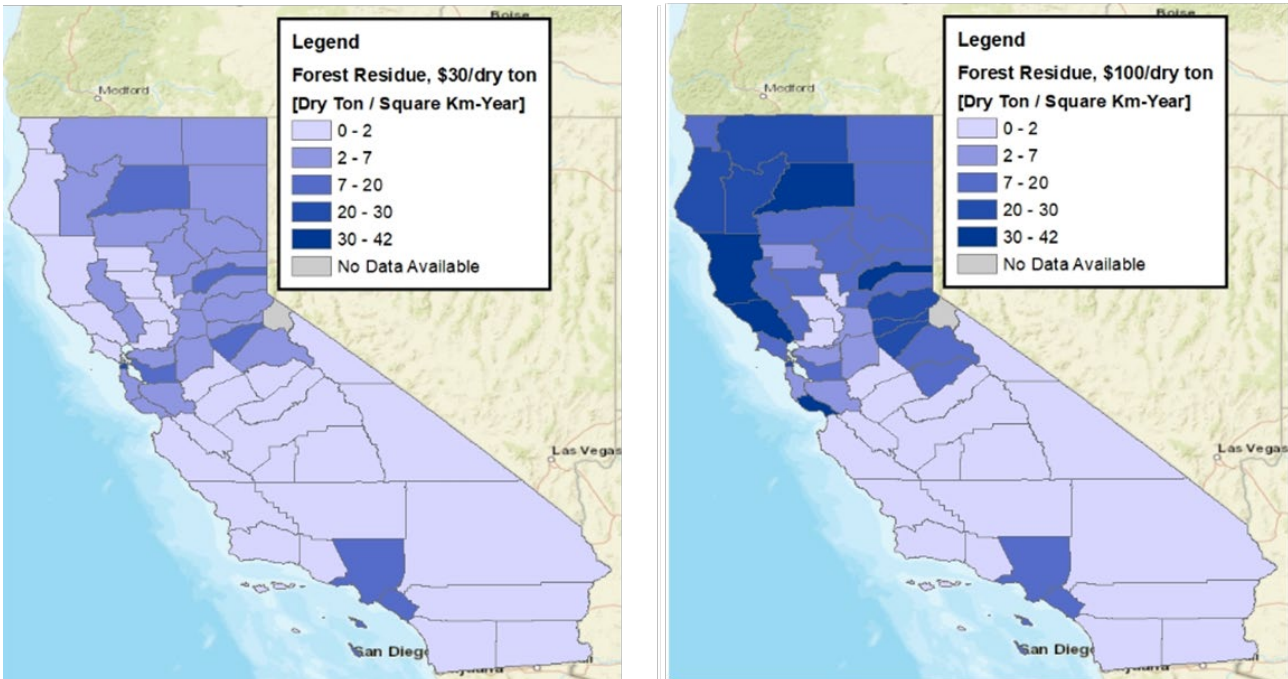
Source: UCI APEP based on Billion Ton Report (U.S._Department_of_Energy 2016)

Figure 25: Vegetation Cover in California
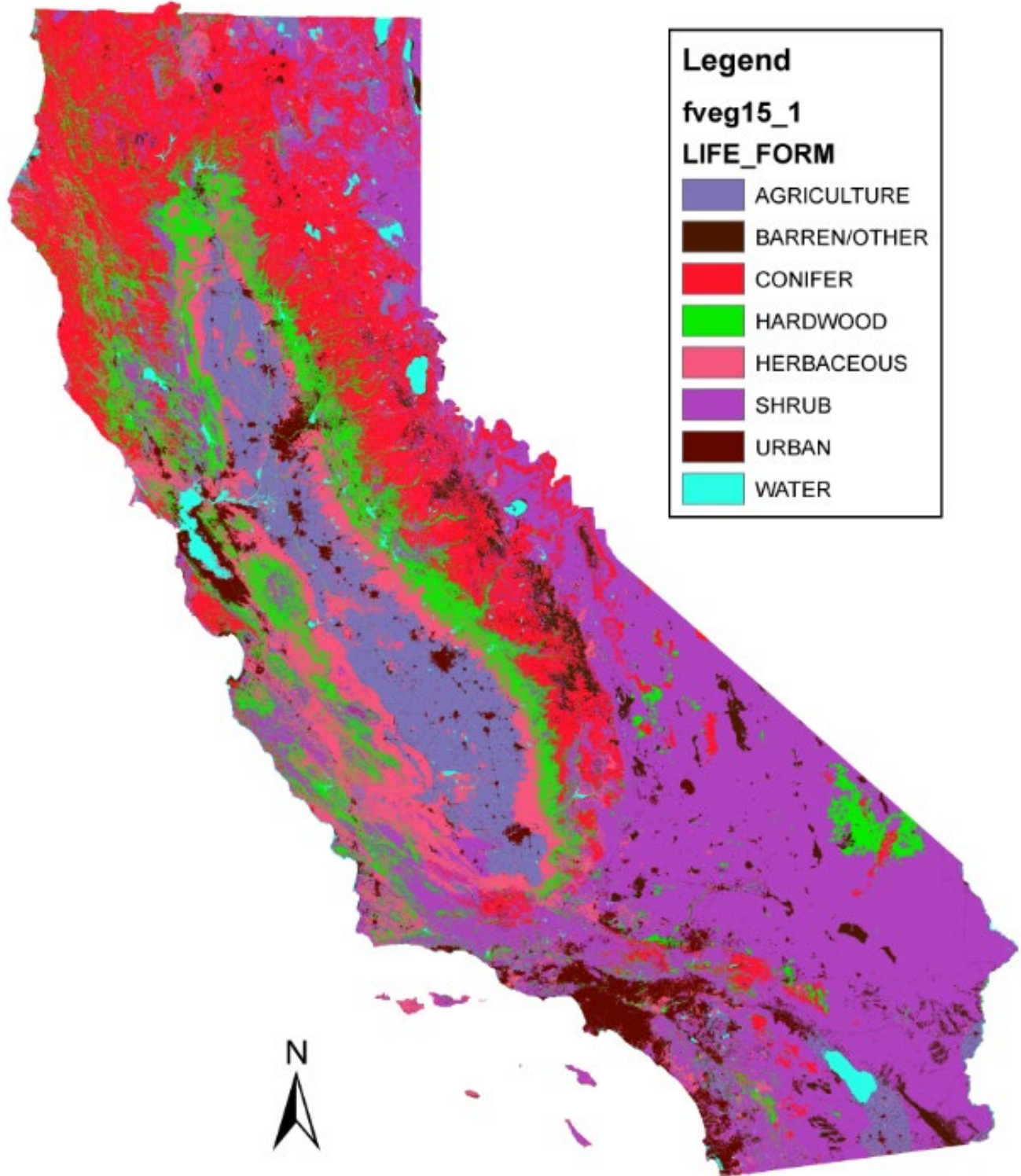
Source: California Department of Fire Protection 2015

Table 8: 2030 Feedstock Quantities (million dry tons/PJ per yr.)

Feedstock	Conversion	$30/ton	$60/ton	$100/ton
Forest, Agricultural Residue, Woody MSW	Thermochemical	12.5/227	37.6/686	63.0/1,160
Energy Crops	Thermochemical	0	0	0.563/10.6
High-Moisture Organic MSW	Anaerobic Digestion	0	0.977/17.7	1.97/35.7
Total Annual Supply	--	12.5/227	38.6/704	65.5/1,200

Source: U.S. DOE *Billion Ton Report* (U.S. Department of Energy 2016), UCI APEP analysis

Table 9: Biomethane Resource Potential Used in This Study

Feedstock	Notes	2030 Quantity (PJ biomethane/y)
Dairy Manure	Manure capture from 1 million milking cows	12
CA Landfill Gas	UC Davis assessment of active and closed landfills receiving organic waste in California	43

Sources: Dairy (CA_Air_Resources_Board 2016); Landfill (Jaffe, Dominguez-faus, and Parker 2016)

Figure 26: California Solar Resource Potential
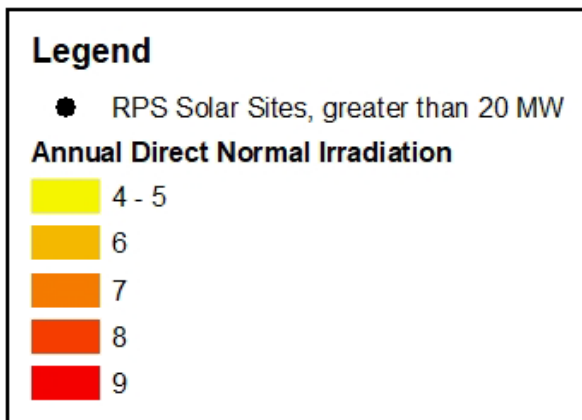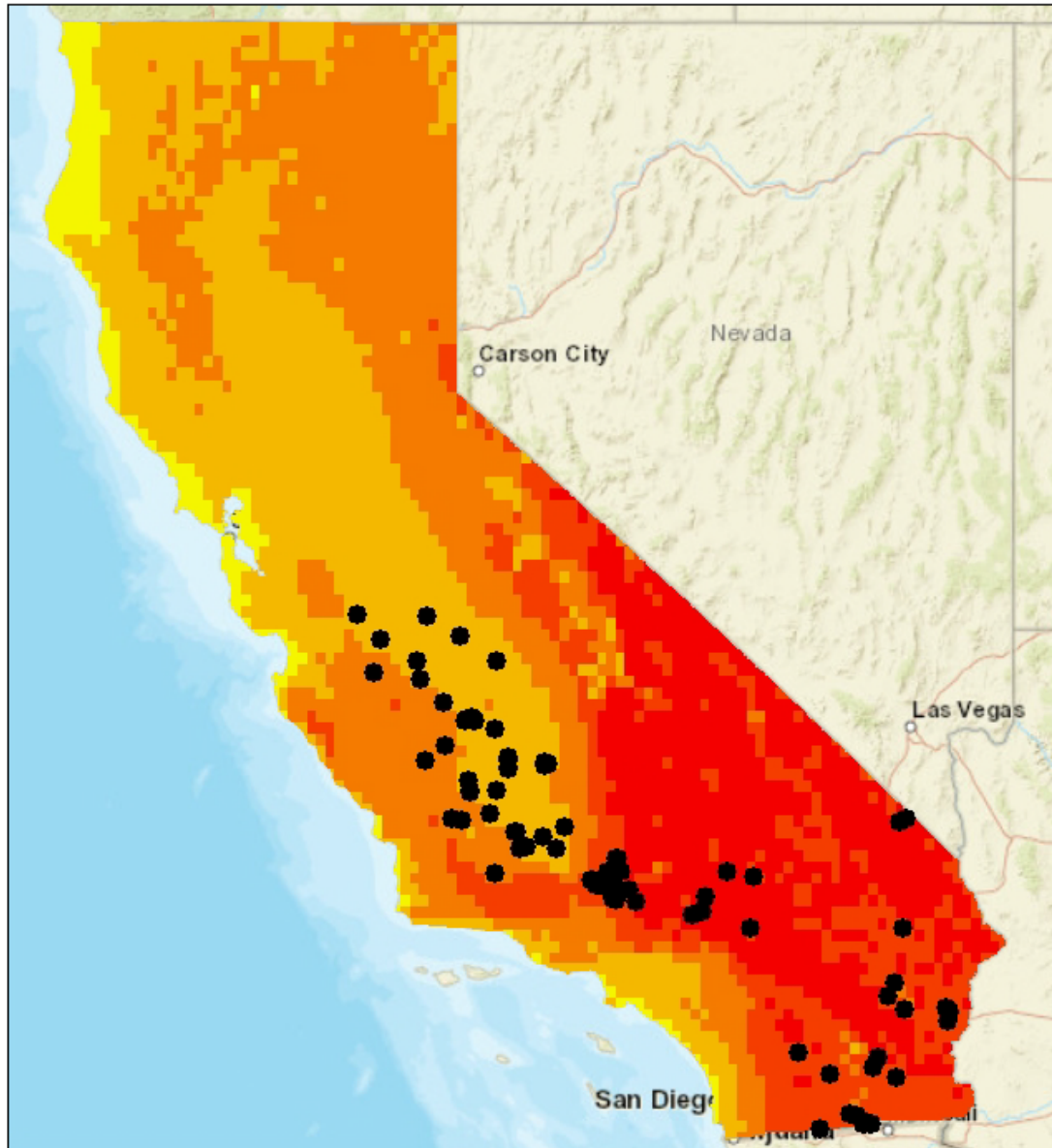
Legend

● RPS Solar Sites, greater than 20 MW

Annual Direct Normal Irradiation

- 4 - 5
- 6
- 7
- 8
- 9

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: National Renewable Energy Laboratory (b)

Figure 27: California Wind Resource Potential

Source: National Renewable Energy Laboratory (a)

Figure 28: Wind and Solar Cost Forecast Scenarios
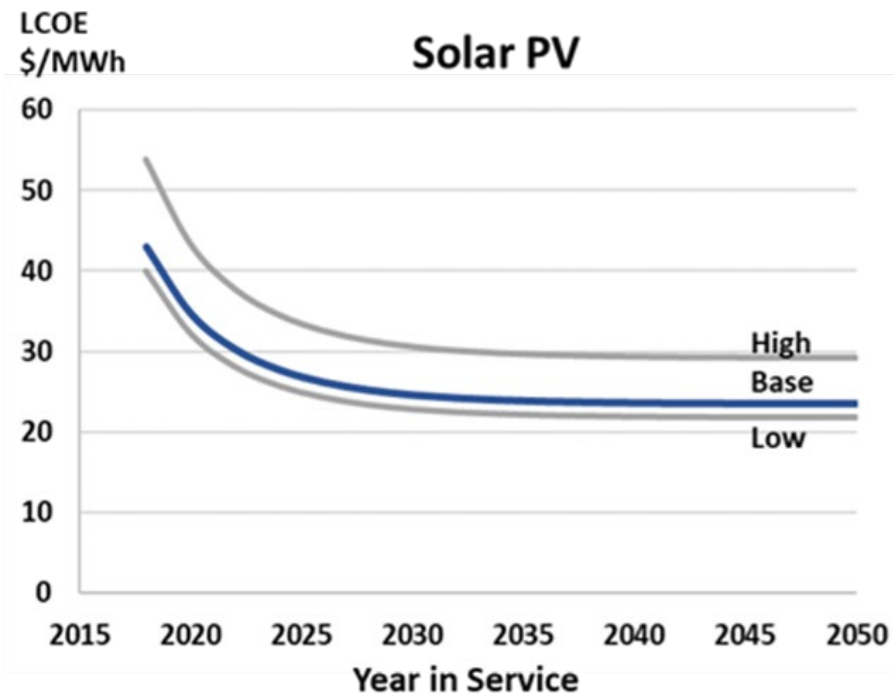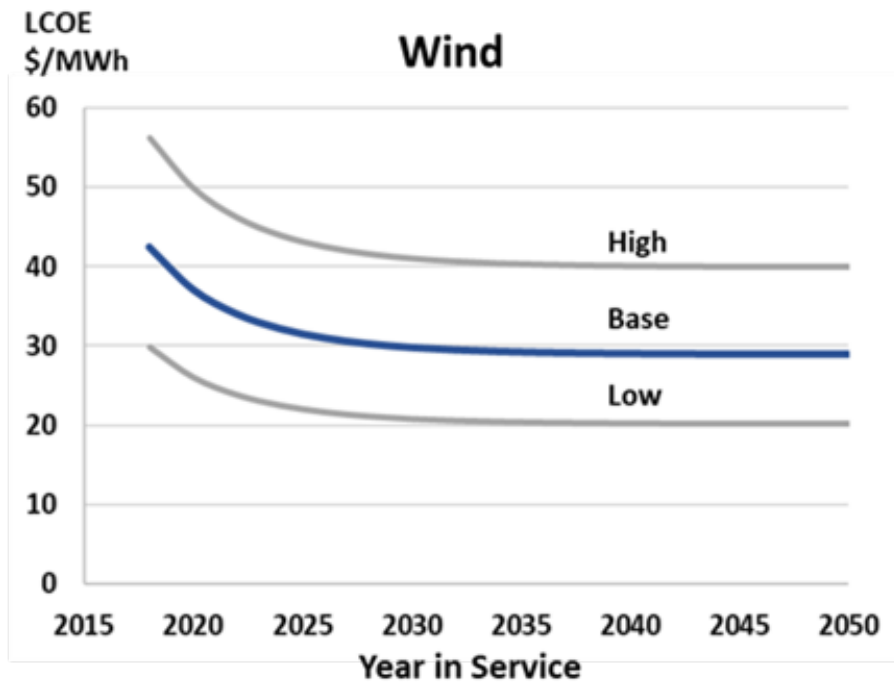
Levelized cost of electricity (LCOE) in 2018 dollars from Lazard and CPUC RESOLVE. Source: UCI APEP

CHAPTER 5:
Supply Chain Configuration and Cost Evolution

Purpose, Scope and Approach

Although the present study focuses on renewable hydrogen production, costs incurred from the production "plant gate" through the point of use constitute a significant portion of the dispensed cost of hydrogen. This chapter forecasts the cost of the hydrogen delivery chain from the production point to the hydrogen refueling station as an input to the analysis of the full dispensed cost of renewable hydrogen presented in the next chapter of this report.

This analysis focuses on the supply chain configurations relevant to the California hydrogen market through 2030, adding a high-level assessment through 2050. Accordingly, the analysis assumes ground delivery of compressed or liquefied hydrogen via truck, as illustrated in Figure 29. Terminal operations are the set of facilities and activities to store and load processed (compressed or liquefied) hydrogen onto trucks for transport. The analysis assumes that production, processing, and terminal operations are collocated.

Figure 29: Hydrogen Delivery Chains Included in This Analysis
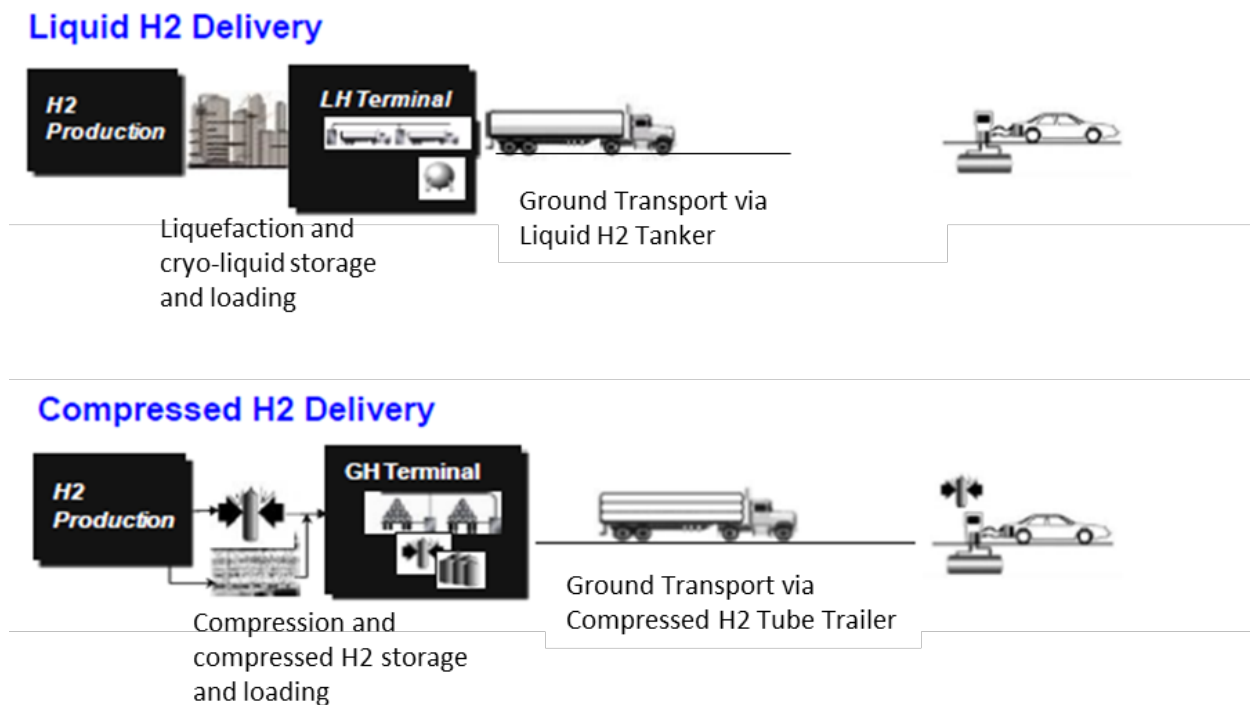
Source: Adapted from (Elgowainy et al. 2015)

The analysis does not consider long-distance hydrogen pipelines delivering hydrogen from out of state. Moreover, it does not analyze the potential role of in-state dedicated hydrogen pipelines that might be developed beyond 2030, at which time hydrogen demand may justify the construction of such facilities. The small existing network of dedicated hydrogen pipeline serving Southern California refineries may be used to supply hydrogen refueling stations in the area but will not have a material effect on the overall buildout of the network.

Forecourt production of hydrogen (production of hydrogen at the refueling station using on-site reformation or electrolysis) is technically possible but not currently economically viable. Electrolyzers show only a small cost penalty at forecourt scale but need access to low-cost renewable grid electricity, so transmission-level connection and real-time rates or direct access will be a precondition to significant deployment where grid energy is needed. Reformer systems are scale-sensitive, leading to a significant cost penalty at forecourt scale, and produce oxides of nitrogen (NO_x) emissions, so technology advances are needed, and siting may be limited in nonattainment areas. The need for additional space at the station may also limit this approach to MD/HD size stations and locations in less dense areas. Forecourt RH_2 production could have a net benefit of between 10 and 15 percent on dispensed cost if the above constraints are addressed. However, timing is also a consideration. Aggressive station construction to reach 1,000 stations by 2030 may outpace the evolution of forecourt solutions and either limit deployment or require retrofit approaches.

The tool used for this analysis is the HDSAM model developed by Argonne National Laboratory (Elgowainy et al. 2015). The modeling assumptions and results are further described below.

Gaseous Versus Liquid Supply Chain

As discussed above and as shown in Figure 29, two types of delivery chain configurations are in use in California. The first transports hydrogen as a compressed gas. In this configuration, terminal operators must compress hydrogen to high pressure and load it onto tube trucks that carry the compressed hydrogen to hydrogen refueling stations, where it is stored on site in gaseous form. Alternatively, the hydrogen is cooled to cryogenic temperature, at which it becomes liquid and is transported as liquid and stored in cryogenic tanks. In both cases, the processing steps of either compression or liquefaction are capital intensive and consume a significant amount of energy. As will be discussed below, the cost of the two modes of transport is similar, with liquefaction carrying higher processing costs but lower transport costs because of the higher energy density of liquid hydrogen relative to compressed hydrogen gas and the resultant higher fuel quantity per truckload. Station footprint and delivery logistics (number of tankers per day) favor liquid delivery at station size above 1,000 kilograms per day. The stakeholder survey in the 2018 AB 8 report[5] suggest that both configurations will remain in use. Because of the similarity in delivered cost of the two modes, a forecast of relative shares is not necessary for this analysis.

Modeling Assumptions and Results

The HDSAM model calculated the supply-chain cost per kilogram of dispensed hydrogen based on station size, utilization, and supply-chain configuration (for example, gaseous versus liquid hydrogen). Future cost improvement potential was forecast using the HDSAM market volume factor set for low volume in the current market, medium volume in 2025, and high volume by 2030. The improvement factors for the medium- and high-volume cases were determined by

[5] Baronas, Jean, Gerhard Achtelik, et al. 2018. *Joint Agency Staff Report on Assembly Bill 8: 2018 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California.* California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2018-008.

component groups defined in the model and were 20 percent to 50 percent for moving from low volume to medium volume and 25 percent to 60 percent moving from low volume to high volume. This study assumed an additional learning improvement of 20 percent applied to 2050 capital costs. Utilization was a key factor in the unit cost of dispensed hydrogen. This study assumed station utilization increasing from 40 percent (roughly the current system average) to 70 percent in 2025 and to 80 percent in 2030 and beyond. The case parameters used to represent the various time frames are shown in Table 10, and the results are depicted in Figures 30 and 31.

Table 10: HDSAM Parameters for Plant-Gate-to-Dispenser Cost Forecast

Parameter	Current	2025	2030	2050
Station Size (kg/d)	300	600	1200	1500
Utilization	40%	70%	80%	80%
Production Volume	Low	Medium	High	High

Source: UCI APEP

Figure 30: Plant-Gate-to-Dispenser Cost per Kilogram of Hydrogen by Mode and Time Frame
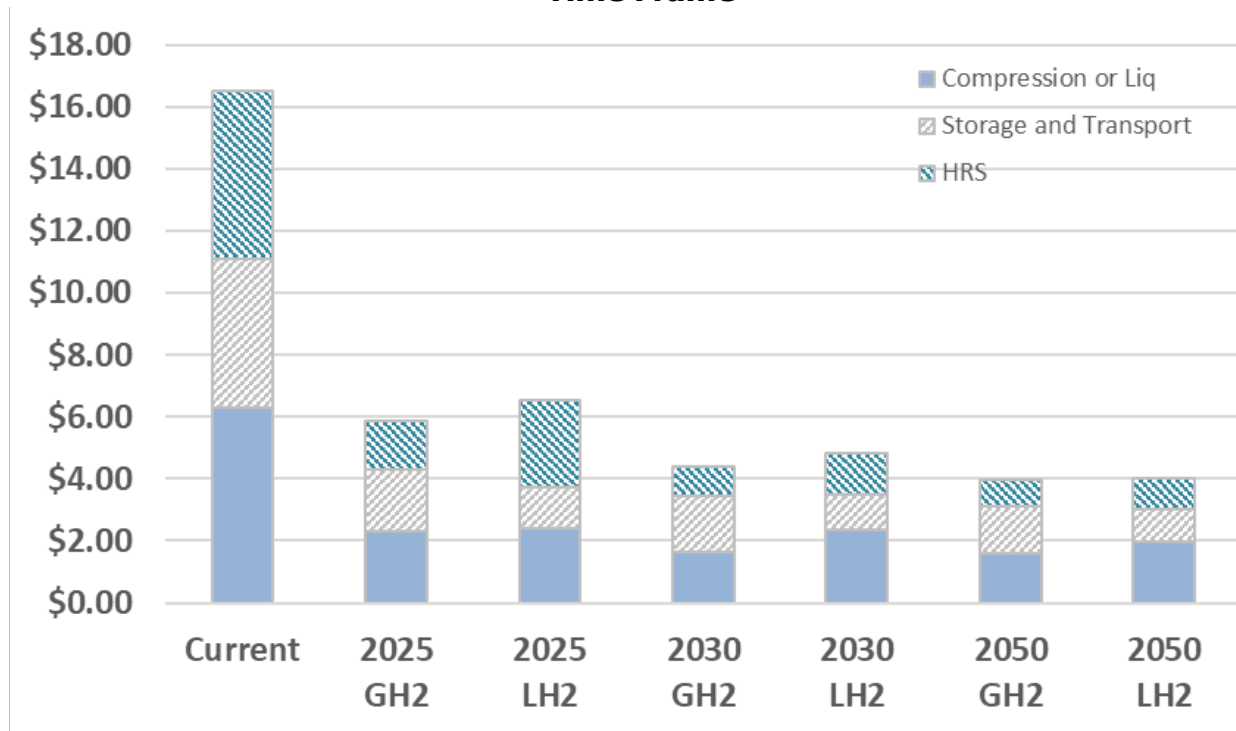
Source: UCI APEP

Figure 31: Plant-Gate-to-Dispenser Cost per Kilogram of Hydrogen Ranges Used for Modeling
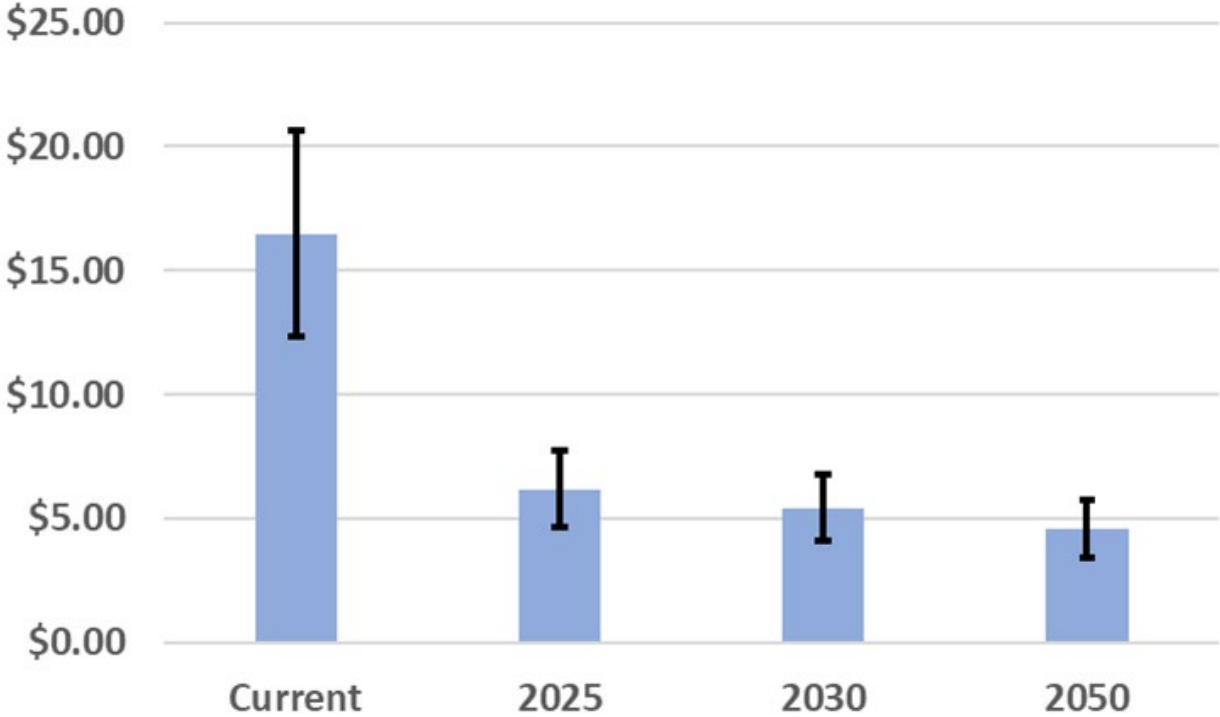
Source: UCI APEP

CHAPTER 6:
Dispensed Cost of Renewable Hydrogen and Path to Self-Sustainability

Introduction

Cost forecasts for all elements in the production, delivery, and dispensing chain for renewable hydrogen have been developed in prior chapters. This chapter integrates those costs into a forecast for the full dispensed cost of renewable hydrogen. The analysis then adds the impact of potential revenues from environmental credits and tipping fees where they are applicable to forecast the dispensed cost of renewable hydrogen net of these revenue sources. This cost, which includes profit to the plant owner, can be taken as a proxy for pump price assuming adequate market competition.

Dispensed Cost Needed for Self-Sustainability

Stakeholders interviewed for this study show a strong consensus that, for the hydrogen transportation sector to be self-sustaining without subsidy, the pump price of hydrogen needs to reach price parity with gasoline on a fuel-economy-adjusted basis. Price points suggested were in the range of $6 to $8 per kilogram, with the view that this price range must be achieved within three to five years.

According to Energy Information Administration data, California gasoline prices have averaged roughly $3.30 per gallon over the past five years. The LCFS energy economy ratio (EER), the ratio of fuel economy for alternative fuel vehicles to conventional vehicles) is 2.5 for fuel cell vehicles. On the other hand, a consumer comparing options may use a ratio closer to 2.0 (assuming a fuel cell sedan mileage of 66 to 69 miles per kilogram and a comparable sedan with a combined mileage rating of 32 to 34 mile per gallon). These mileage ranges and a gasoline price of $3.30 per gallon lead to a hydrogen cost range of $6.60 to $8.25 per kilogram to achieve price parity with gasoline. Longer term, the comparison will be to electric vehicles. A 70-mile-per-kilogram vehicle requires a hydrogen price of about $4 per kilogram to achieve fuel price parity with a 30-kWh-per-100 mile electric vehicle consuming $0.20/kWh electricity. Four dollars per kilogram is the long-term target established by the U. S. Department of Energy and was adopted as the long-term target for this study.

Dispensed Cost of Renewable Hydrogen Evolution

Figure 32 presents the dispensed cost of hydrogen for the various technologies at current and future time points. The results project that by 2025, the low end of the cost forecasts for dispensed hydrogen reaches the upper range of the target band. As will be discussed later, when LCFS credit revenue is added, the net cost comes within the target range. By 2030, the midpoint forecasts for most of the production technologies fall within the target range. In 2050, electrolysis and gasification will be the predominant technologies for in-state production of renewable hydrogen as feedstock supply constraints will limit the role of biomethane by the

Figure 32: Dispensed Cost of Renewable Hydrogen Through 2050 Without Environmental Credits
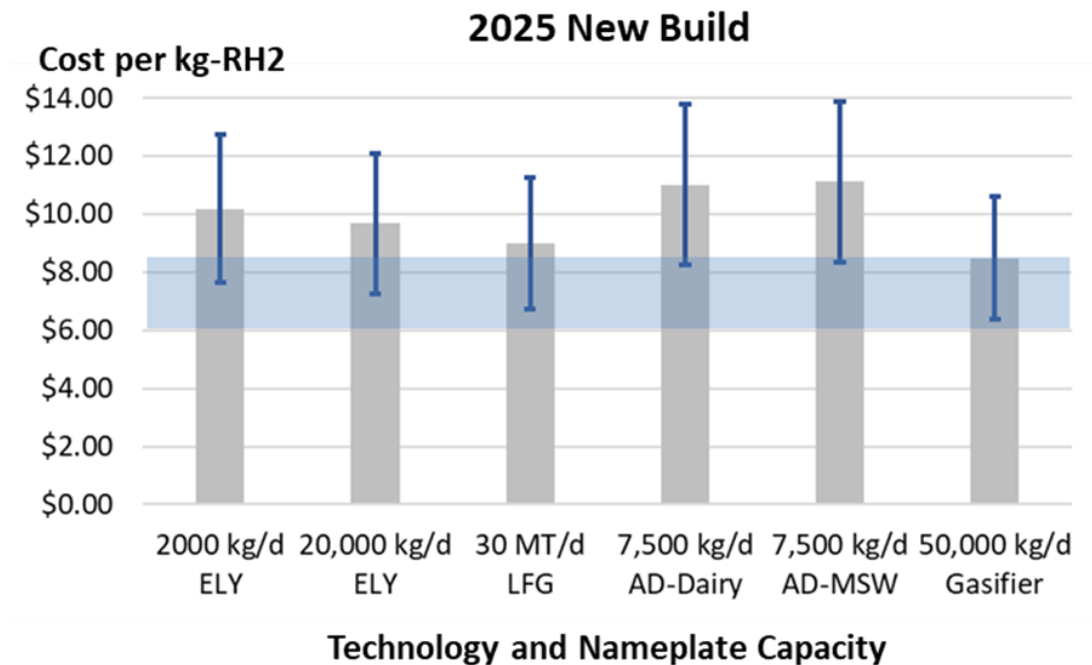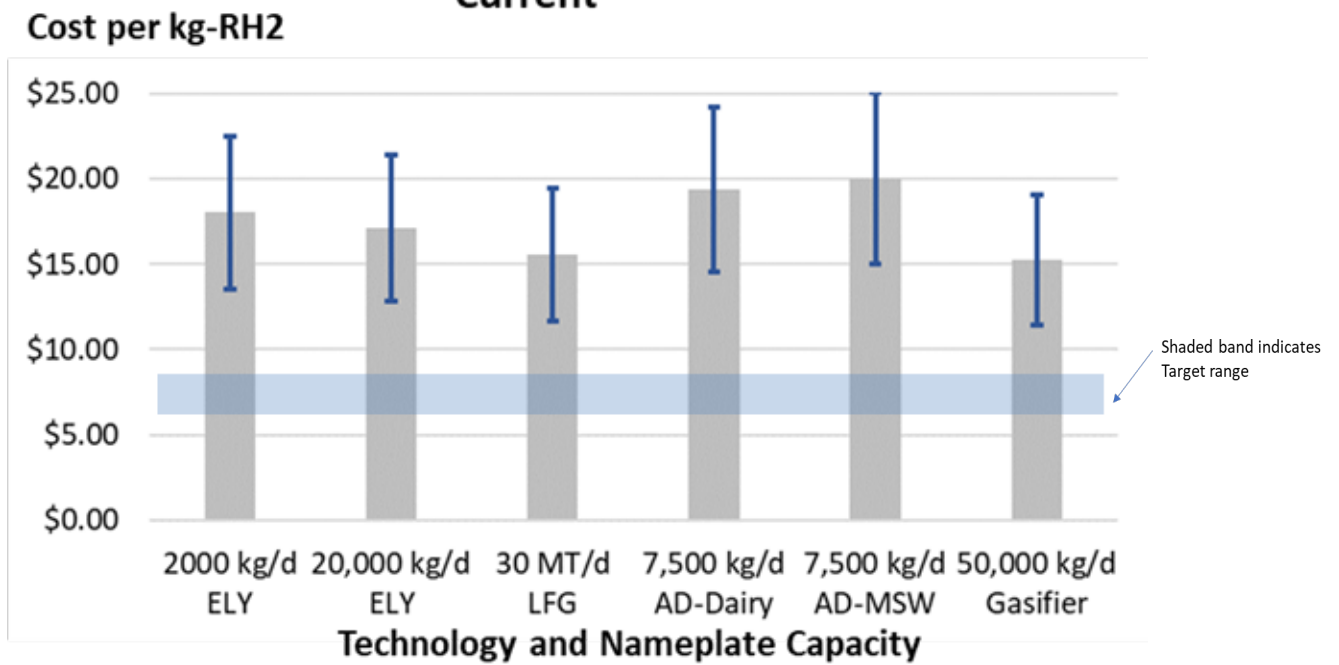
2050 New Build

Cost per kg-RH2
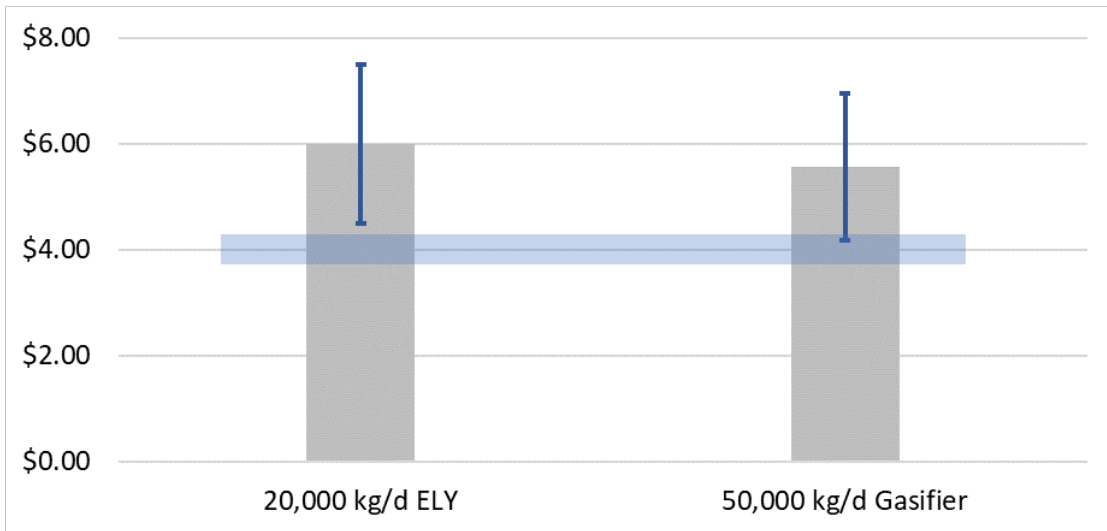
Technology and Nameplate Capacity

2030 New Build

Cost per kg-RH2
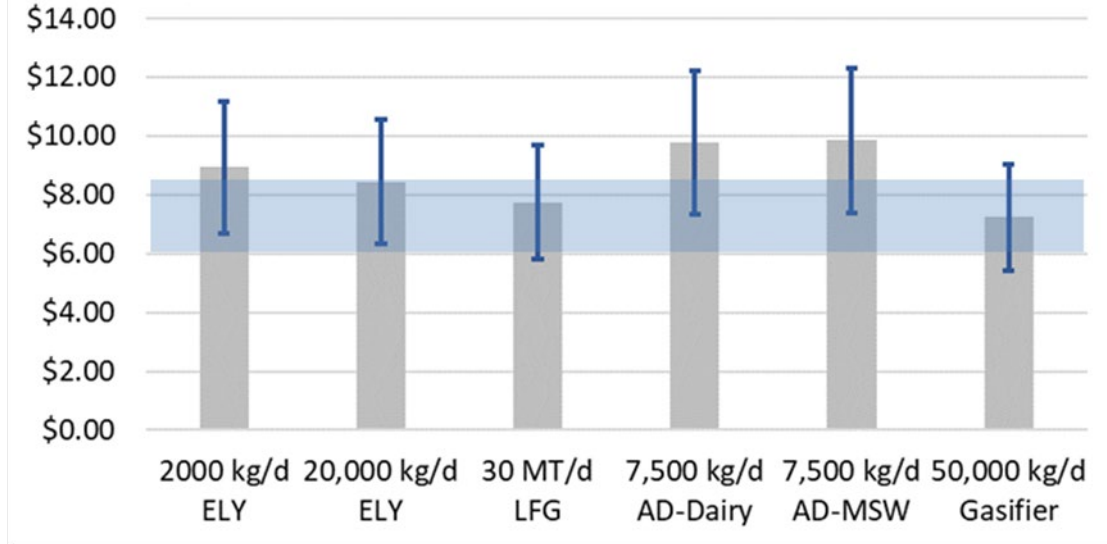
Technology and Nameplate Capacity

Source: UCI APEP

45

2030s. The cost of gasification and electrolysis reaches $5 to $6 per kilogram without carbon-credit revenue, somewhat above the long-term target of $4. Reaching that target requires technology progress on the high end of the range. Advances in early-stage technologies such as artificial photosynthesis and station-scale hydrogen production could also allow the long-term target to be reached.

Role of Environmental Credits in Achieving Self-Sustainability

This section assesses the potential impact of environmental credits on the dispensed cost of renewable hydrogen for transportation applications. This secondary revenue source can reduce the net delivered cost of renewable hydrogen by $2 per kilogram or more. The analysis considers two types of environmental credits, California Low Carbon Fuel Standard (LCFS) credits and federal Renewable Fuel Standard (RFS) renewable identification number (RIN) credits. LCFS credits are based on carbon reduction and are denominated in tons of CO_2 equivalent. RIN credits are denominated in ethanol gallons.

The number of LCFS credits generated per kilogram of renewable hydrogen depends on both primary production pathway and supply chain approach (for example, gaseous versus liquid transport and storage) through the effect of these parameters on the full pathway carbon intensity. Most of the pathways considered in this study do not yet have certified LCFS pathways. Carbon intensities (CI) were estimated based on existing approved pathways. Future carbon intensity values were adjusted to reflect declining carbon intensity of grid electricity, where relevant. The resultant carbon intensities are shown in Table 11. Because of the decarbonization of electricity and transportation over time, all pathways were assigned a CI of zero in 2050. Figure 33 shows historical prices for LCFS credits. The program has instituted a price cap of $200 per credit with the cap escalating at the rate of inflation. The future value of LCFS credits is uncertain, but the recent trend has been upward, and some analysts expect the LCFS value to remain at or near the cap.[6]

RIN credits are generated based on fuel volumes (ethanol gallon equivalents). Five categories of RIN credits are issued by the RFS program representing different classes of fuel with each type trading at a separate price. The RIN categories are:

> D3 – Cellulosic biofuel (category for which landfill biomethane qualifies).

> D4 – Biomass-based diesel.

> D5 – Advanced biofuel (category for which dairy biomethane qualifies).

> D6 – Renewable fuel.

> D7 – Cellulosic diesel.

Currently, no certified RIN pathways for hydrogen are available although several applications are pending. However, both landfill biomethane and dairy biomethane are certified under the

program and qualify for D3 RINs. Figure 34 shows the RIN price history. Because of the uncertainty in program eligibility, this study does not explicitly include RIN value in the dispensed cost forecast. However, future qualification of renewable hydrogen pathways for RINs could have a significant downward impact on renewable hydrogen pump price in the range of $1 per kilogram at current prices.

Figure 35 shows the per kilogram value of LCFS credits as a function of pathway carbon intensity for 2020, 2030, and 2050. The LCFS program is authorized only through 2030. This analysis assumes that the program remains in place through 2050 and that the carbon intensity standard follows a linear decline from the 2030 standard to a standard that is 80 percent lower than the carbon intensity of gasoline (2050 standard of about 20 gCO_{2e}/MJ). For a fuel with a CI of zero and LCFS credit price of $150, the per-kilogram cost impact on renewable hydrogen is about $4 per kilogram in the coming decade, declining to about $1 per kilogram by 2050. The actual impact depends on which fuel pathways are used. Figure 36 shows the dispensed cost of renewable hydrogen, net of LCFS credit value, for the primary renewable hydrogen production pathways in 2030 for credit prices of $50 per credit and $150 per credit. The target range in the figures was set at $5 to $7 per kilogram as an intermediate range between the mid-2020s target and the 2050 target. At these credit prices, the net cost of dispensed renewable hydrogen is within the target range. Figure 37 shows the potential dispensed pump price for renewable hydrogen with a base case of $100 per credit for LCFS credits and assuming that electrolysis and gasification are the price-setting technologies. The price without LCFS credits is also shown for comparison.

Table 11: Pathway Carbon Intensities Used for This Study

Pathway	CI 2030	CI 2050	Basis
Electrolyzer	35	25	Lookup table adjusted for liquid supply chain with 20% in electricity CI in 2025 and 40% in 2030
Landfill Gas	110	95	Lookup table adjusted for 20% improvement in electricity CI in 2025 and 40% in 2030
Dairy Biomethane	-320	-320	Landfill case with fuel CI adjusted to CI of − 283 and improvements in electricity CI and SMR efficiency
Organic MSW Biomethane	-10	-15	Landfill case with fuel CI adjusted to -35
Gasification	85	70	Landfill case with fuel CI adjusted to 5

Source: UCI APEP based on LCFS look-up table and related documents

Figure 33: LCFS Price History
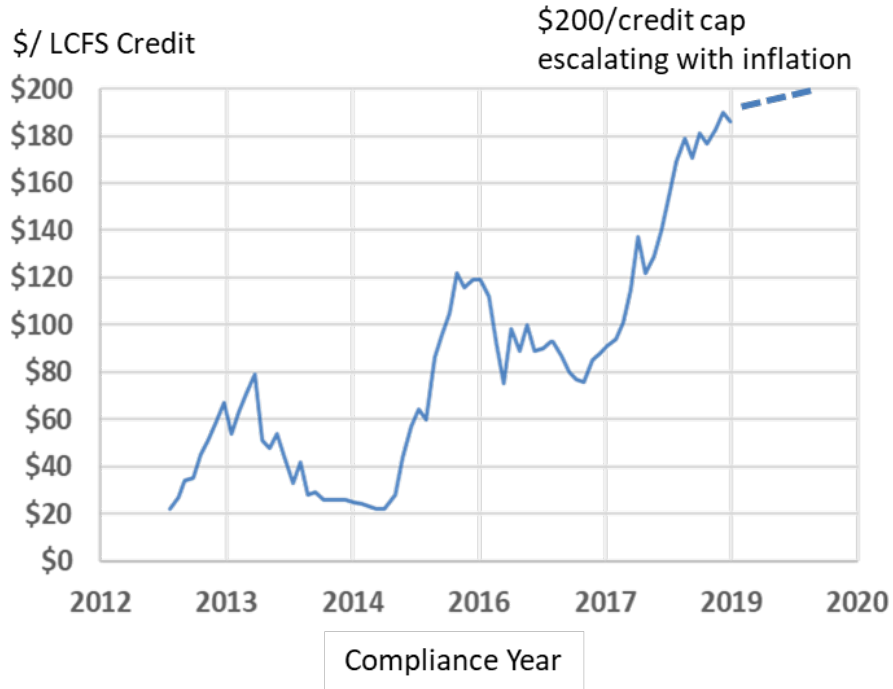
Source: CARB

Figure 34: RIN Price History
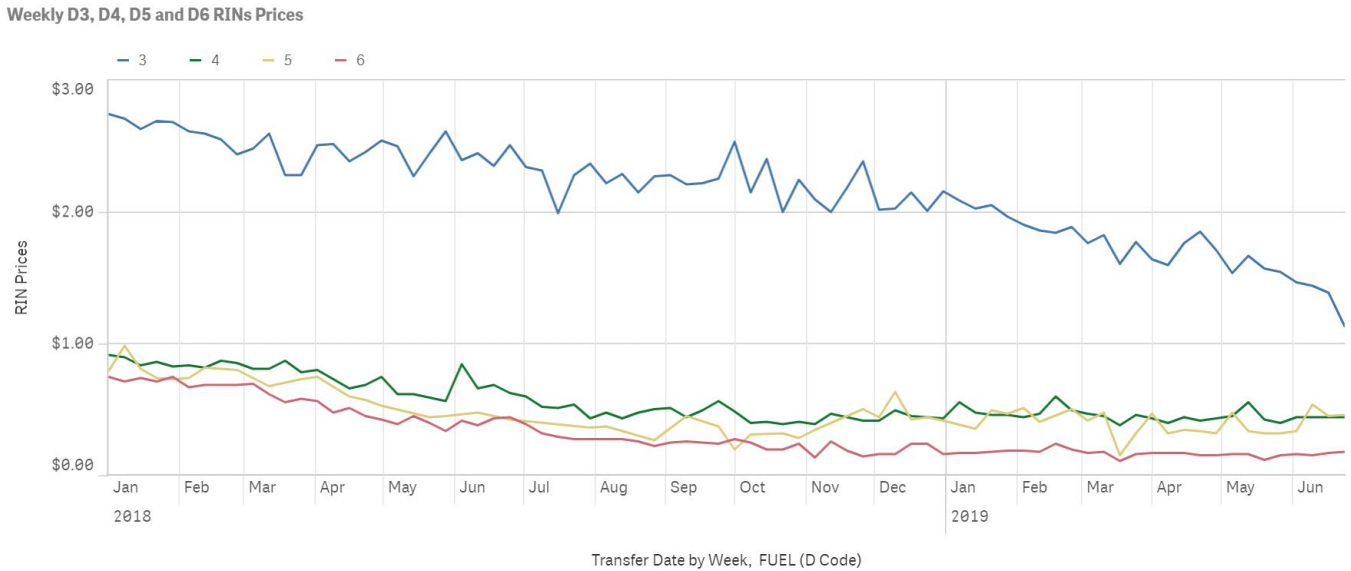
Source: U. S. Environmental Protection Agency

Figure 35: LCFS Credit per Kilogram Value at $150 per Credit

$/kg Value at $150/LCFS-Credit
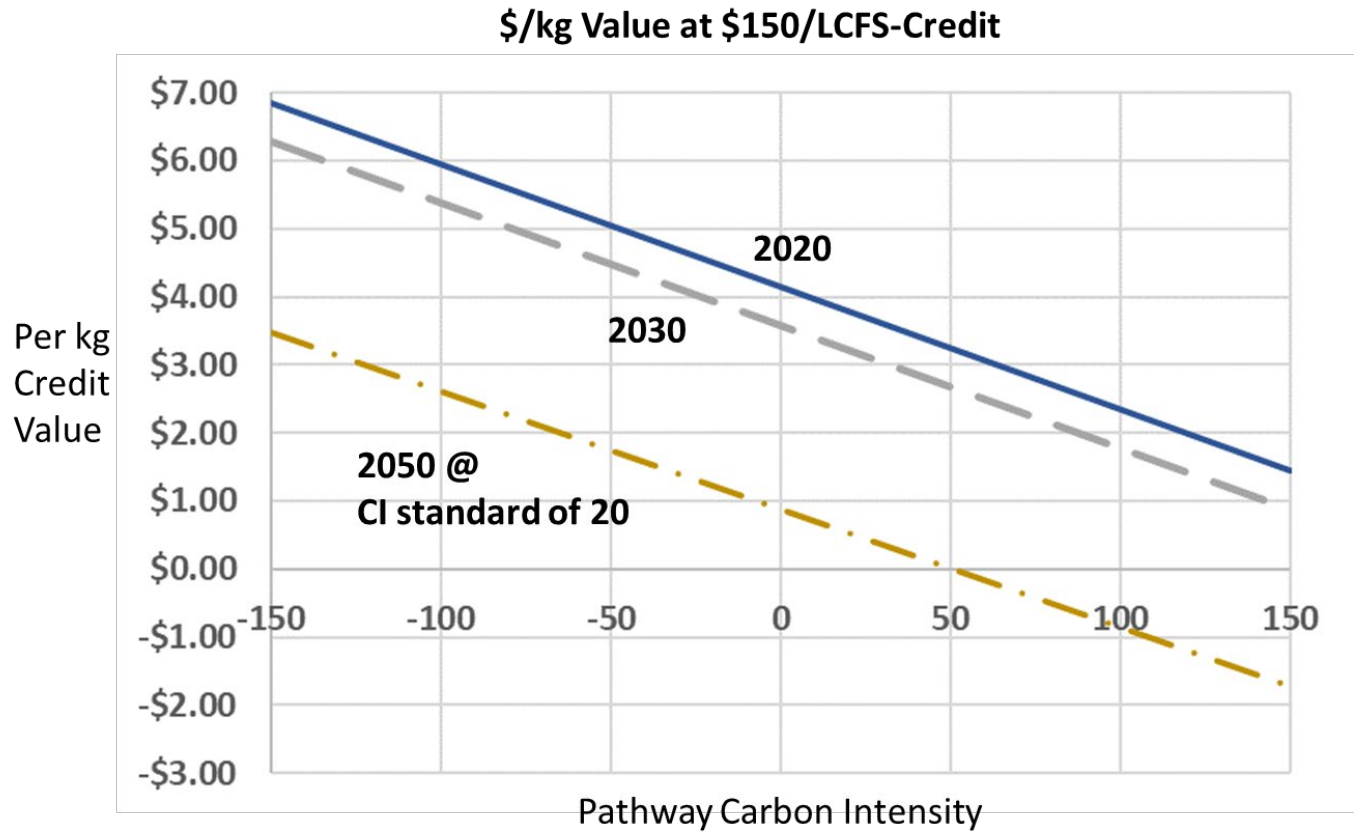
Assuming LCFS Program is extended to 2050.   Source: UCI APEP

Figure 36: 2030 Project Cost Ranges Net of LCFS Credit Value for $50 and $150 Credit Values (No RIN Value Assumed)
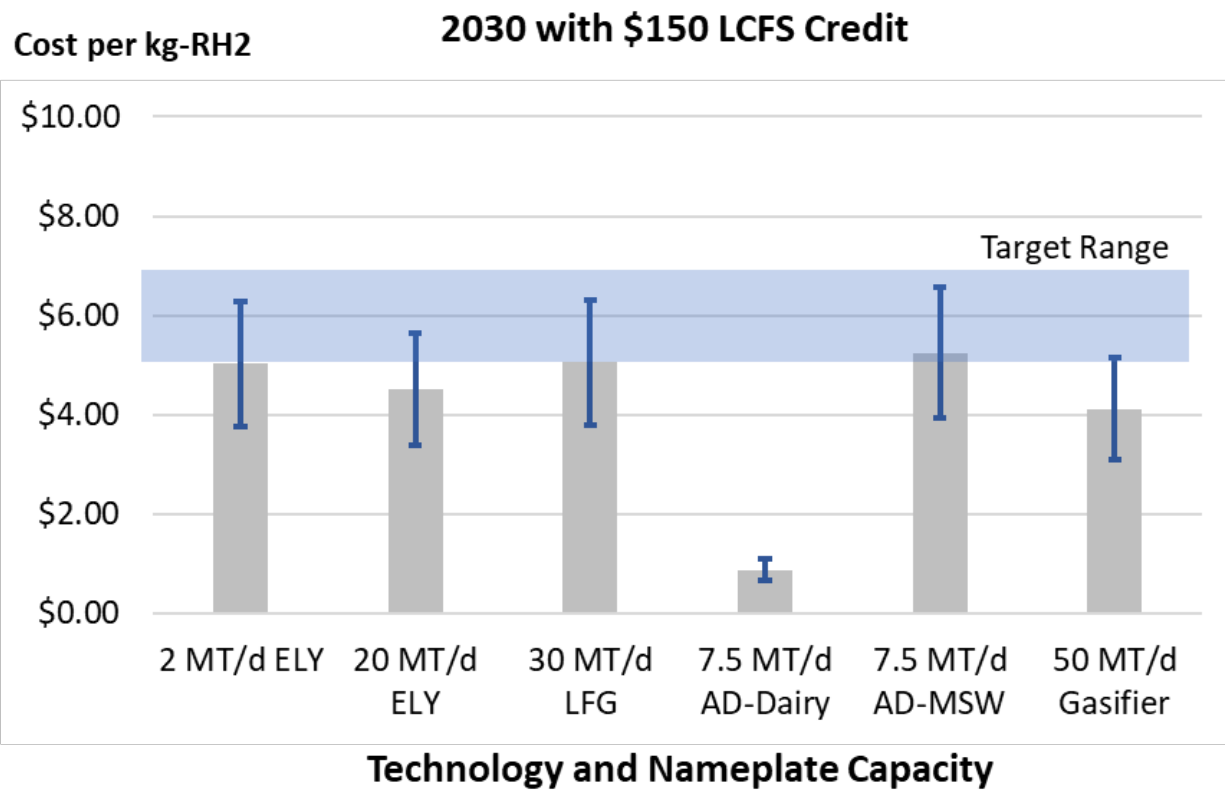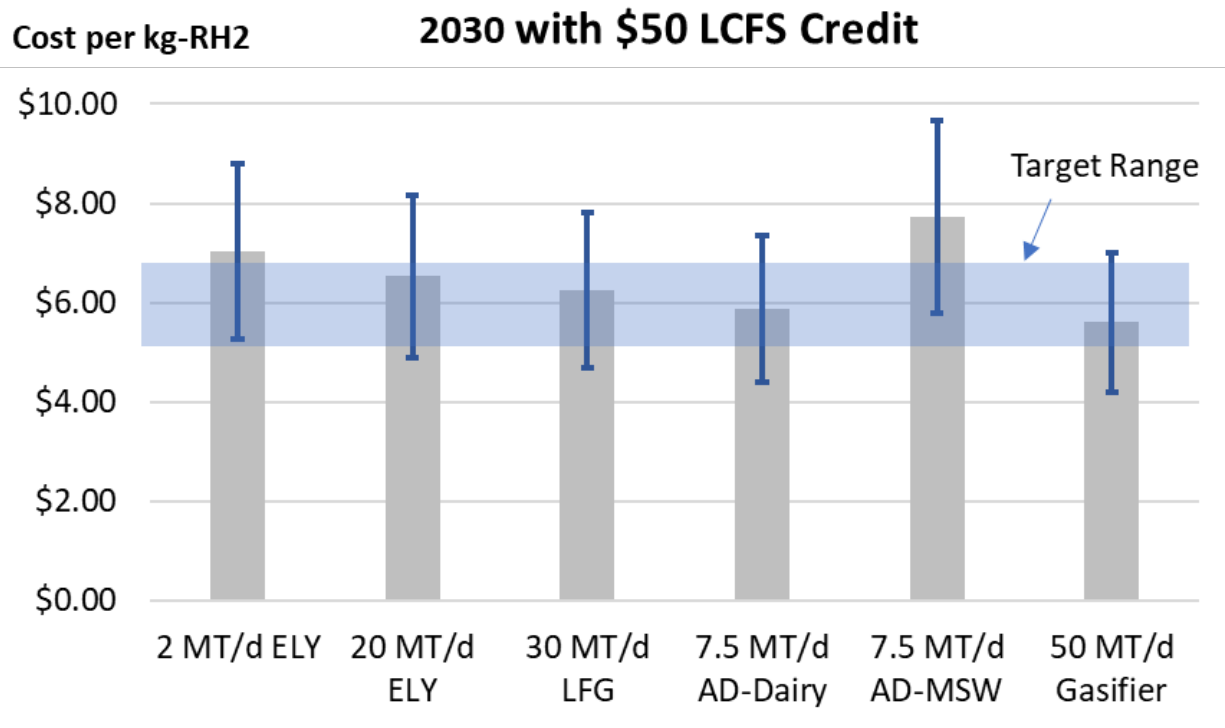
Source: UCI APEP

Figure 37: Dispensed Cost of Hydrogen Forecast With and Without LCFS Credit Revenue
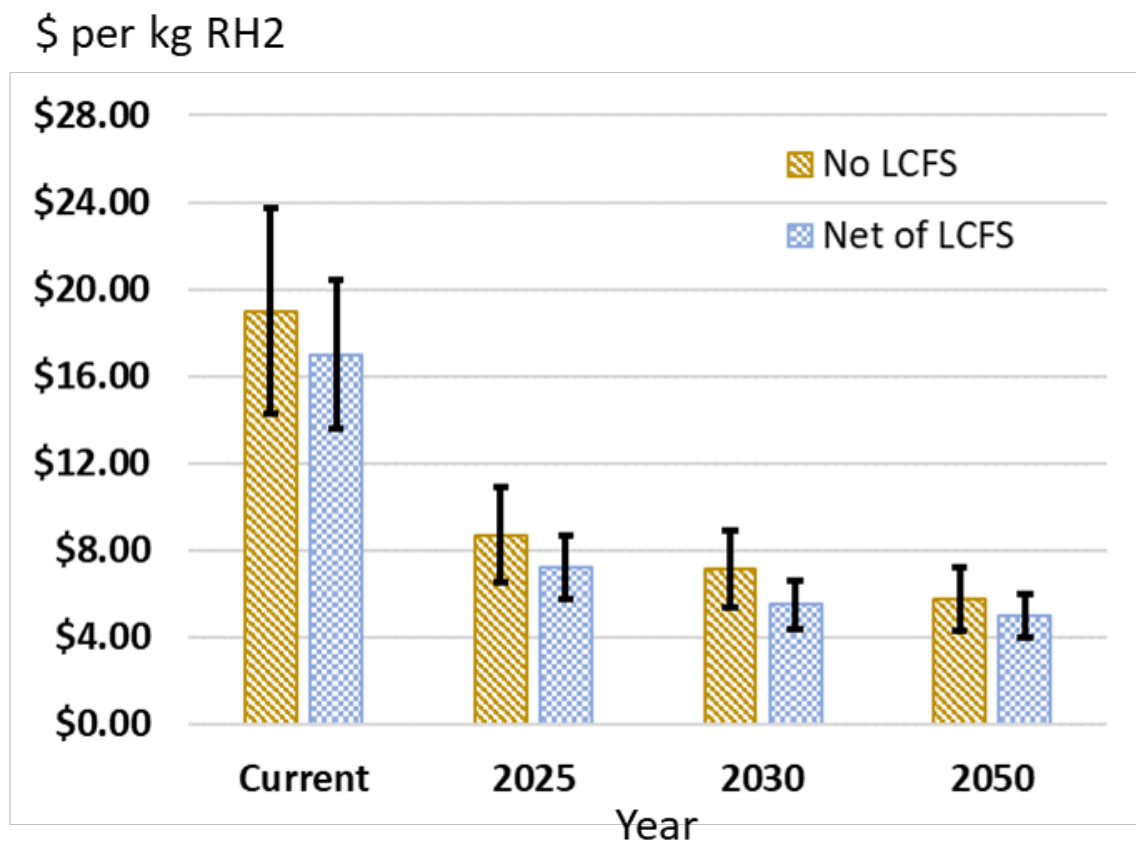
Composite for all technologies with LCFS credit value of $150. Source: UCI APEP

CHAPTER 7:
Renewable Hydrogen Production Siting Analysis and Buildout Scenarios

This chapter summarizes the method and results of the siting analysis and buildout scenarios developed for the renewable hydrogen production roadmap project. Further detail is presented in Appendix B of this report. The siting analysis identifies areas suitable for developing renewable hydrogen production plants and chooses the best locations for adding production capacity to serve renewable hydrogen demand as it grows over time. This method employs commercially available geospatial tools and a UCI-APEP developed cost-minimization model to create plant buildout scenarios consistent with defined constraints and assumptions. The analysis screens locations defined by 4-km-by-4-km cells. (This defines the degree of resolution of candidate locations.) The renewable hydrogen production plant buildout scenarios are intended to be representative rather than precisely predictive of the timing and location of facility construction, which will ultimately be decided by private developers. The analysis scope and method are further described below.

Scope

Three primary hydrogen production facility types were treated in this analysis: electrolysis, thermochemical conversion (gasification is used to represent the thermochemical group), and reformed biomethane produced by anaerobic digestion. Preferred siting areas for central-scale plants were determined based on land availability and zoning, proximity to feedstock, and proximity to and availability of necessary utilities and infrastructure. As described in Chapter 4, this analysis considered the following organic feedstock supplies for thermochemical conversion and anaerobic digestion: forest thinning and waste, agriculture/crop residue, food waste, other organic fraction of municipal solid waste, manure, wastewater, and landfills. For electrolyzer siting, both self-generated renewable energy and grid-supplied energy are considered.

Reformation and liquefaction plants are key, capital-intensive processing facilities that fall between primary production and the hydrogen transport supply chain. Siting for these facilities is also within the scope of the analysis. Liquefaction facilities are assumed to be collocated with central-scale reformation facilities or thermochemical conversion facilities, so they are not separately addressed. Reformation facilities are sited through the same method as primary production plants.

Site-Screening Method

The siting analysis is conducted at a 4-km x 4-km resolution using geographic information system (GIS) layers containing relevant data such as electric transmission line locations, natural gas transmission line locations, land-use classifications, availability and location of biomass feedstock, roadways, rail lines, and population density data. Specific data sets are referenced on individual figures. Figure 38 provides a high-level process flow for the site-screening and ranking process. Table 12 summarizes the key siting criteria for each central-scale plant type.

Table 12: Primary Siting Requirements for Central Renewable Hydrogen Production and Related Facilities

Facility Type	Feasibility Screening Criteria
Electrolyzers	High wind and solar resource areas with transmission access or transmission access within 50 miles of demand
Dairy Anaerobic Digesters	Existing dairy farms in clusters of 5 to 10 with an anchor farm of >5,000 milking cows
Food and High-Moisture Organic Anaerobic Digesters	Along current and historical landfill disposal routes with adequate area for 100,000 MMBtu per year facility size, existing wastewater treatment, and resource recovery facilities
Thermochemical Conversion Facilities	Forest areas and agricultural areas (crop residue) with site suitable for 50,000 kg/d RH2 facility size outside non-attainment areas
SMR Facilities	Outside nonattainment areas, close to natural gas transmission and highway transport
Liquefaction Facilities	Collocated with SMR facilities or production facilities with production capacity of minimum 30 tonnes hydrogen per day

Source: UCI APEP and source noted on feedstock maps below.

Local-scale electrolysis and potentially small-scale reformation may be part of the supply mix beyond 2030 should those technologies progress and supportive policies (such as electric rates) be put in place. For the local production scenario, facilities are assumed collocated with hydrogen refueling stations. Station locations are assumed to be those defined in the future hydrogen refueling station preferred siting analysis developed by the California Air Resources Board using the CARB CHIT and CHAT models[7], and no additional location analysis was performed for this study (California_Air_Resources_Board 2018).

Exclusion Criteria

Some areas are unsuitable for development of large-scale facilities for renewable hydrogen production or processing. Rough terrain areas and inaccessible locations such as military bases and protected lands are excluded (Figure 39). Residential and high-density commercial areas are also not suitable for large-scale plant development.

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[7] CHIT stands for California Hydrogen Infrastructure Tool and CHAT for California Hydrogen Accounting Tool

Figure 38: Siting Analysis Process Flow
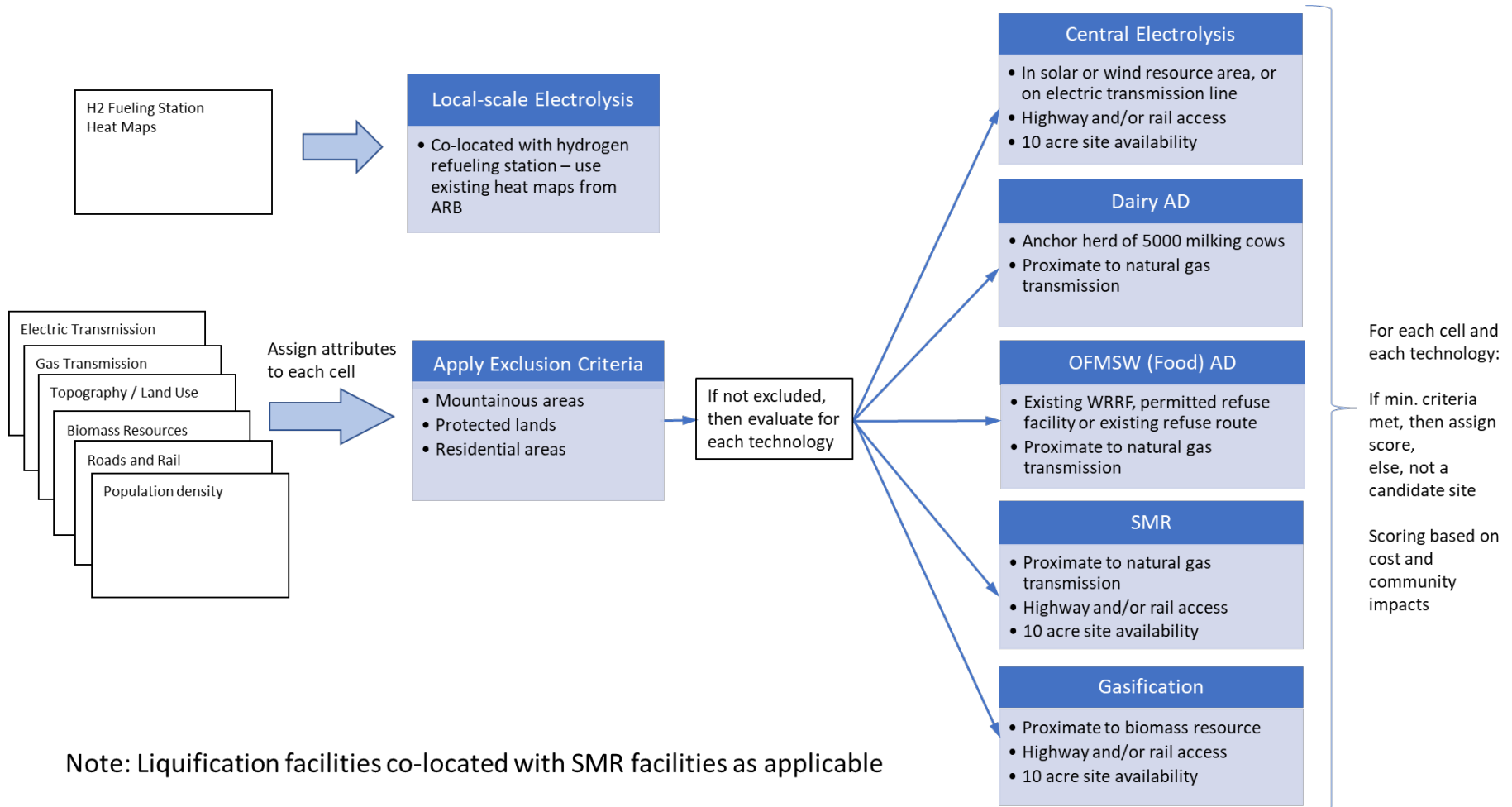
Note: Liquification facilities co-located with SMR facilities as applicable

Source: UCI APEP

Figure 39: California Siting Areas Excluded Because of Terrain

Legend

Excluded Elevation (1000 ft +)

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: U.S. Geological Survey (2016)

Feedstock

Access to feedstock is a primary siting criterion for all production pathways. Proximity to woody or dry biomass is generally the dominant siting criterion for thermochemical systems. Proximity to organic waste hauling routes is similarly critical for organic waste digestion plants, whereas dairy projects are hosted on large farms so that manure does not need to be transported. For electrolyzers, electric transmission and distribution costs are effectively feedstock transport costs and, under current electric rate structures, provide a strong incentive for electrolyzers to be located on the same site as their primary electric feedstock. Figure 40 shows the primary facility siting areas based on feedstock availability. Maps of the feedstock resource areas can be found in Appendix B.

Primary Infrastructure

All the renewable hydrogen production technologies require access to primary electricity, natural gas, transportation and water infrastructure. The relative importance of electricity and gas supply and takeaway capacity varies by technology type and is a primary siting criterion. Primary infrastructure maps can be found in Appendix B.

Optimal Site Selection—Delivered RH2 Cost and Community Impacts

Once all other constraints for facility siting have been met (site is qualified as "feasible"), cost minimization and community impacts define final selection/ranking among otherwise qualified sites. Minimizing transportation costs for hydrogen from production plant to demand points is a key factor in cost minimization. Through 2030, light-duty vehicles will be the dominant source of renewable hydrogen demand. Figure 41 shows the hydrogen refueling station 2030 forecast demand density developed by the CARB as part of the AB 8 implementation program (California_Air_Resources_Board 2018).

Facilities generating significant NOx or PM emissions, or both are excluded from disadvantaged communities, as defined in the CalEnviroScreen 3.0 database, and from all nonattainment areas (Figure 42 and Figure 43). However, although not included in the scenarios here, TC and SMR facilities that meet ultra-low emissions criteria may be sited in disadvantaged communities and nonattainment exclusion areas. (Most legacy biomass projects are sited in these areas.) Community impacts include local air emissions, visual impacts, and traffic (negative factors) and job creation on the positive side. In the absence of a validated weighting of job creation against other factors, this analysis uses NO_x emissions as a community impact factor and excludes reformation and thermochemical conversion plants from siting in nonattainment areas in the disadvantaged communities.

Renewable Hydrogen Production Facility Buildout Scenarios

Serving the evolving demand for renewable hydrogen will require the construction of many new renewable hydrogen production plants and associated facilities such as liquefaction and terminal facilities. The precise number and mix of facilities depend upon many factors, including facility size, relative progress on cost reduction, cost and availability of feedstock, organic waste recovery mandates, and the value of environmental credits, among others. The facility deployment scenarios presented here are intended to represent the general evolution of the renewable hydrogen supply portfolio under assumptions representing the range of likely outcomes and should not be taken as literal predictions of site locations. The actual location of

plants within preferred resource areas involves a variety of factors and details beyond the general considerations used here, for example, the availability and price of land.

The project team developed plant buildout scenarios by calculating the new production capacity needed in each time horizon and determining the optimal mix of new capacity additions to serve the incremental demand. Modest overcapacity is allowed within the first five years of market development to ensure that all facility types gain commercial validation before rapid market growth beginning in the late 2020s.

The following assumptions were employed in developing the deployment scenarios:

- The analysis deals only with renewable hydrogen demand (and does not address nonrenewable hydrogen demand).[8]

- Reference facility sizes are assumed as shown in Table 13.

- Agency-supported commercial pilots for electrolyzer and gasifier projects are specified for all scenarios in the period prior to 2030.

- The buildout of anaerobic digestion plants to process dairy manure and landfill-diverted organics are assumed to follow the scenarios developed for the CARB Short-Lived Climate Pollutant strategy, and the product is assumed to be pipeline-injected biomethane (CA_Air_Resources_Board 2016).

- The demand for new reformation plants to produce renewable hydrogen from pipeline biomethane is based on scenario assumptions on the share of biomethane allocated to hydrogen (as opposed to methane or liquids) with a base-case assumption of 50 percent.

- Mandates for recovery of forest material (for example, to reduce wildfire risk) and agricultural waste are possible in the future, but the base case assumes only economic adoption and assumes that up to 75 percent of feedstock is available for hydrogen production via thermochemical conversion (with the remainder allocated to renewable natural gas and liquid fuel).

- Thermochemical conversion systems are assumed ready for first commercial deployment in 2023 and are constrained to three plants built through 2028.

- Renewable hydrogen to support renewable integration is evenly split between electrolytic hydrogen (power-to-gas) and hydrogen from organic sources power turbines and fuel cells delivering dispatchable renewable electricity.

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8 Some facilities, such as reformation plants and electrolyzers, can produce both renewable and nonrenewable hydrogen depending upon the feedstock composition. The analysis presented here represents only renewable hydrogen demand as described in Chapter 1 of this final report.

Figure 40: Primary Resource Areas for Renewable Hydrogen Production and Conversion
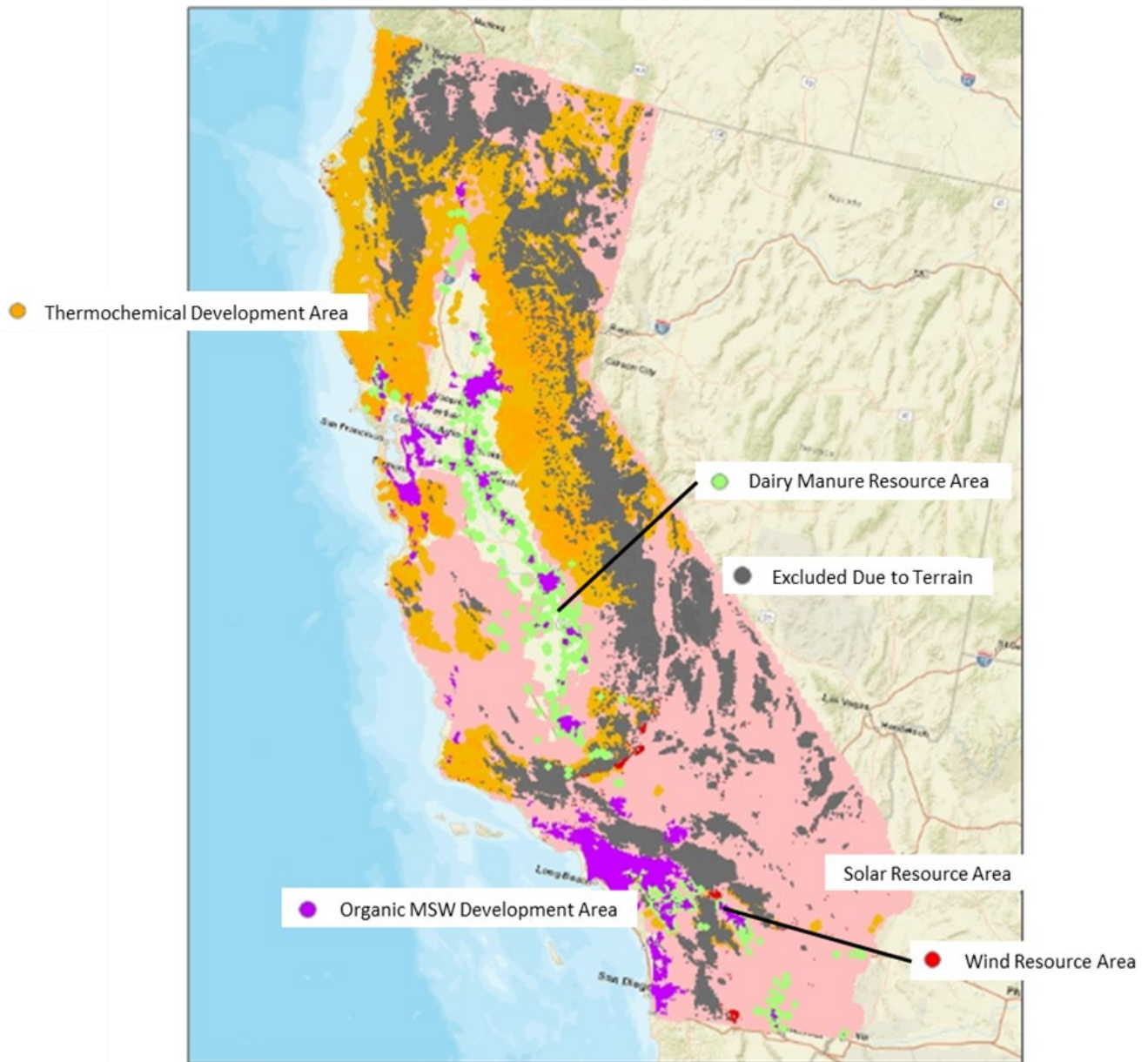
Source: UCI APEP from multiple U.S. EPA, U.S. DOE, and California agency datasets

Figure 41: 2023 Hydrogen Refueling Station Demand Point Evolution

Source: California Air Resources Board (2018)

Figure 42: Clean Air Act Nonattainment Areas
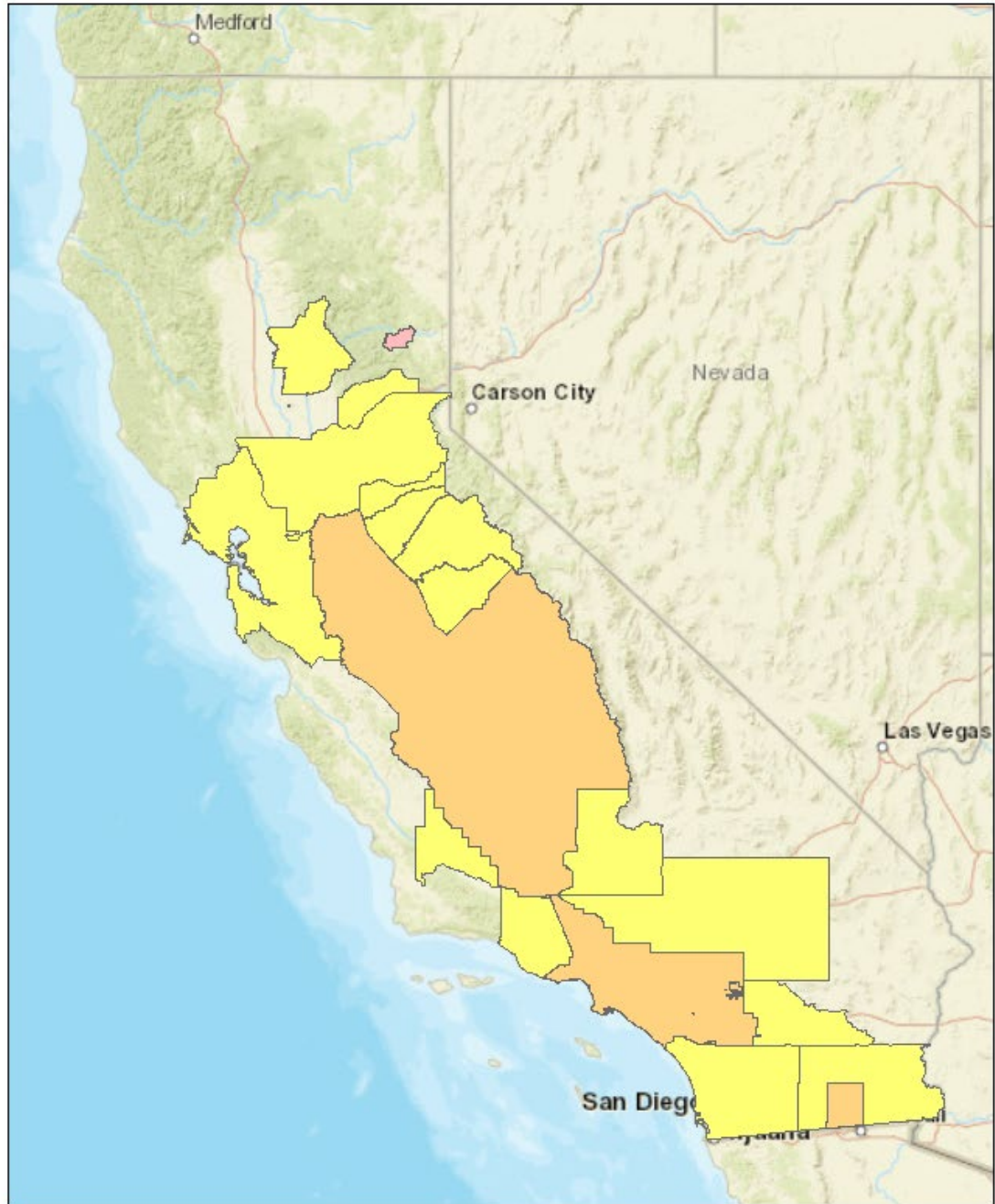
Legend

Ozone and PM 2.5 Non-Attainment Area

PM 2.5 Non-Attainment Area

Ozone 8hr Non-Attainment Area

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: US EPA (2019a)

Figure 43: California Disadvantaged Communities

Legend

Cal EnviroScreen Disadvantaged Communities (DACs)

Cal EnviroScreen DACs in ozone and PM non-attainment areas
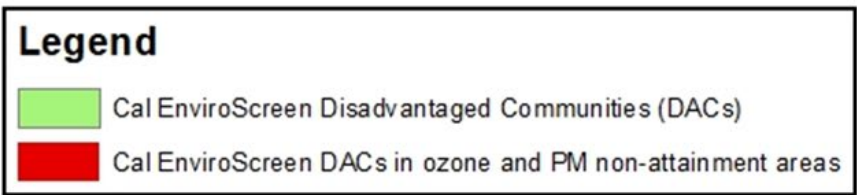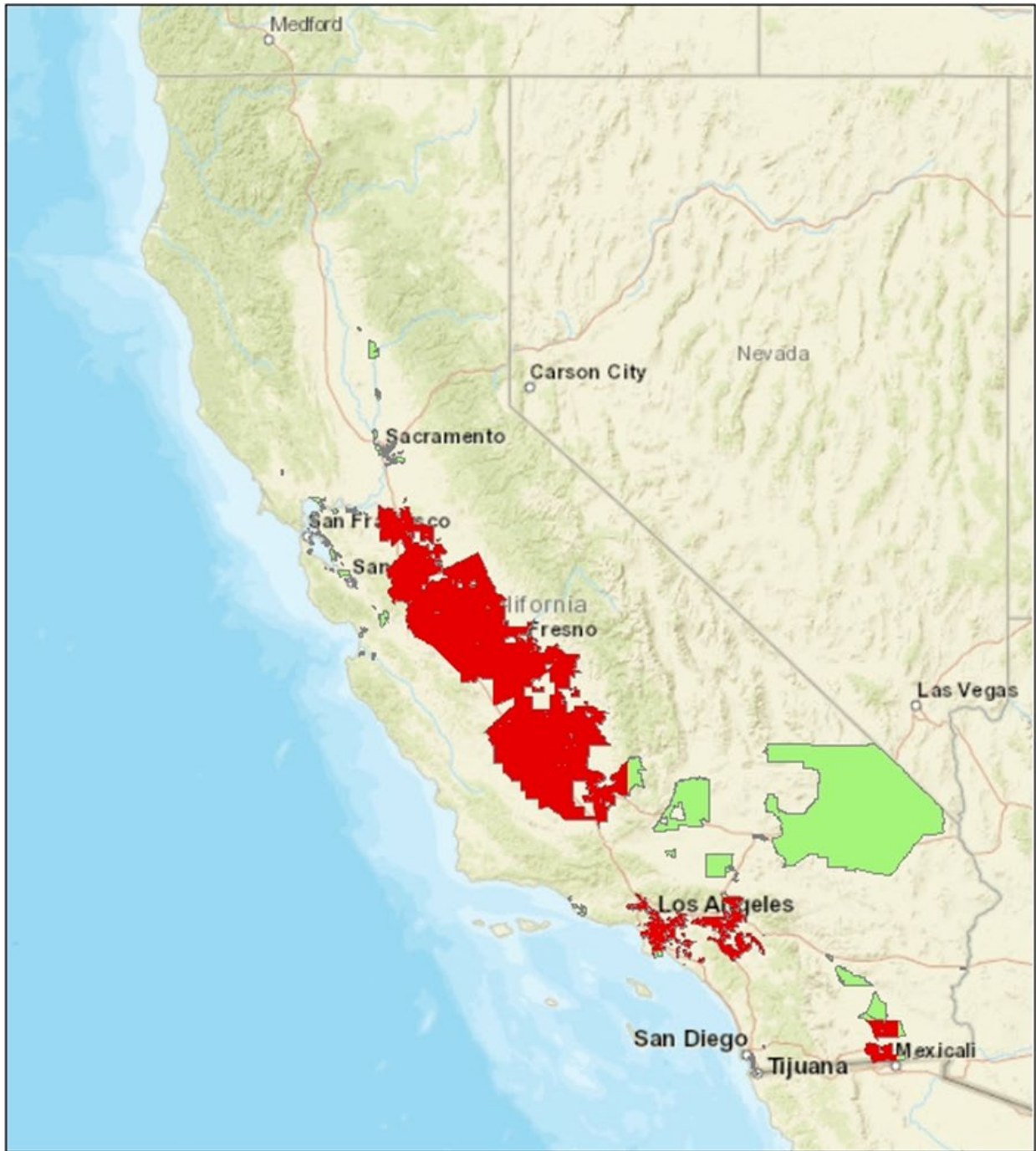
Source: CalEnviroScreen (2018) and US EPA (2019a)

Table 13: Reference Facility Sizes

Technology	Facility Size (Nameplate)	Comment
Thermochemical Conversion	25,000 kg RH_2 per day commercial pilots 50,000 kg per day through 2030 and 150,000 kg per day beyond 2030	Initial projects slightly below efficient scale to minimize initial project cost for agency-sponsored projects with size increasing to efficient scale once full commercial validation is achieved
Anaerobic Digestion	7,500 kg RH_2 per day	Based on current project activity
Reformers (and Associated Liquefaction System)	30,000 kg RH_2 per day	Reformers and liquefier assumed collocated Size matches announced Air Liquide project
Electrolyzer	5,000 kg RH_2 per day for initial pilots growing to 20,000 kg RH_2 per day by 2030 and beyond	Based on manufacturer input on minimum efficient size for central production
Forecourt Systems	N/A	Sized based on the size and demand of host hydrogen refueling stations

Source: UCI APEP

The base-case assumption is that the LCFS program remains in place until 2050, with the reference carbon intensity beyond 2030 (current program and point) ramping down to 20 percent of 2012 level by 2050 and that LCFS credit price stays at the cap ($200 per $MTCO_2e$ escalating with inflation) for the life of the program.

- The spatial demand distribution for all transportation applications is assumed to follow the demand density analysis in the 2018 Joint Report for AB 8.[9] Ammonia production demand is assumed to be in high-agriculture areas, and all other applications are assumed to use the natural gas system for transport and delivery (so the pipeline is the "demand point").

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[9] Baronas, Jean, Gerhard Achtelik, et al. 2018. *Joint Agency Staff Report on Assembly Bill 8: 2018 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California.* California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2018-008. https://ww2.energy.ca.gov/2018publications/CEC-600-2018-008/CEC-600-2018-008.pdf.

- Hydrogen transport costs assume liquid supply chain for thermochemical and biomethane pathways and gaseous for electrolytic hydrogen.

- Roughly 50,000 kg per day of new renewable hydrogen production nameplate capacity has been announced for completion by 2021 in or directly adjacent to California. This new capacity is assumed to be completed for calculating incremental capacity needs.

Subject to the assumptions listed above, buildout scenarios are developed by adding facilities in each period to serve incremental demand. The project team determined the mix of facilities (market share) based on policy-driven construction, feedstock availability, and cost minimization. The primary trade-off variables in the facility selection and siting optimization are presented in Table 14.

Table 14: Primary Site Selection Trade-Offs by Technology

Technology/Pathway	Primary Site Selection Determinant or Trade-Off
Thermochemical Conversion	Feedstock transport cost (a function of feedstock density) versus cost of transport of hydrogen
Anaerobic Digestion	Livestock density and proximity to natural gas pipeline for dairy Refuse route density and proximity to natural gas pipeline for organic MSW
Reformers (and Associated Liquefaction System)	Proximity to demand and access to natural gas and electric transmission
Electrolyzer	Resource collocated systems: wind or solar resource quality versus proximity to demand Grid-supplied systems: proximity to demand

Source: UCI APEP

The research team developed several scenarios to represent potential outcomes for RH2 demand and relative share of different technologies as shown in Table 15. The facility siting analysis assumes central-scale facilities are used. Some portion of production capacity may be provided by forecourt production in the future. Such cases would reduce the number of central facilities built and would instead add capacity at hydrogen refueling locations as shown in Figure C-3.

Table 15: Buildout Scenario Assumptions

Scenario	Demand	Technology Cost
Base-case	Mid-case	Base case for all technologies
High-Demand	High case	Base case for all technologies
Low-Demand	Low case	Base case for all technologies
High-electrolysis	Mid-case	Electrolyzer cost progression favorable relative to others (capital cost, efficiency, input electricity cost)
High-thermochemical	Mid-case	Thermochemical conversion cost progression favorable relative to others (capital cost, efficiency, feedstock)
High-anaerobic-digestion	Mid-case	75% allocation of biomethane to hydrogen production (proxy for hydrogen value chain cost reduction

Source: UCI APEP

Early Market Policy-Supported Facility Additions

A 30,000-kilogram-per-day plant operating at 85 percent capacity produces enough hydrogen to supply 35,000 light-duty vehicles. The roughly 36,000 kilograms per day of capacity under construction to serve the hydrogen transportation market will be adequate to supply the sector until 2023 to 2025. By 2030, at the forecast growth rate, there will be demand for several new facilities per year. However, through the late 2020s, demand growth will not be adequate to allow full utilization of mid (5,000 to 10,000 kg per day) or large (30,000 kilograms per day or larger) production centers within the first year of operation.

The buildout scenarios of the roadmap assume that the state continues to sponsor electrolytic renewable hydrogen production plants and initiates support for gasification facilities to ensure that these technologies are fully proven and established as the market begins to accelerate in the late 2020s and early 2030s. This policy-driven facility construction will require financial support to compensate for reduced facility utilization in the early years of operation. To reduce the required financial support, the assumed facility sizes are below the typical facility sizes assumed for the mature market but large enough to represent full commercial scale. Table 16 shows the policy-driven additions specified for the buildout scenarios. All remaining capacity additions are driven by relative production cost and feedstock availability, as specified for each scenario. To the extent that the policy-driven facility capacity differs from the assumptions in Table 16, any capacity additions needed under the various scenarios would be served by reformed biomethane from landfills or dairies because these are the low-cost, commercially-proven pathways through the 2020s. With these specified additions, the renewable hydrogen production base reaches full utilization by 2022 to 2027 depending on demand scenario, as shown in Figure 44. Figures 45 and 46 show scenario buildout results for the base case. Appendix B provides plots and maps for the other scenarios.

Table 16: Policy-Driven Facility Additions in the Early Market Period

Technology	Demand Case	Period 2022 – 25	Period 2026 - 30	State Support	Subsidy Cost
Gasification	All cases	1 x 25 MT/d	1 x 25 MT/d	50% capital cost grant or loan guarantee valued at 20% of capital cost	$35M - $85M
Electrolysis	High	5 x 5 MT/d	2 x 20 MT/d	50% capital cost grant for first 5 projects; 25% for next 2	~$50M
Electrolysis	Medium and Low	4 x 5 MT/d	1 x 5 MT/d 2 x 20 MT/d	50% capital cost grant for first 5 projects; 25% for next 2	~$50M
				Total State Support	$85 - $135M

Source: UCI APEP

Figure 44: Effect of Policy-Driven Renewable Hydrogen Facility Build on Facility Utilization
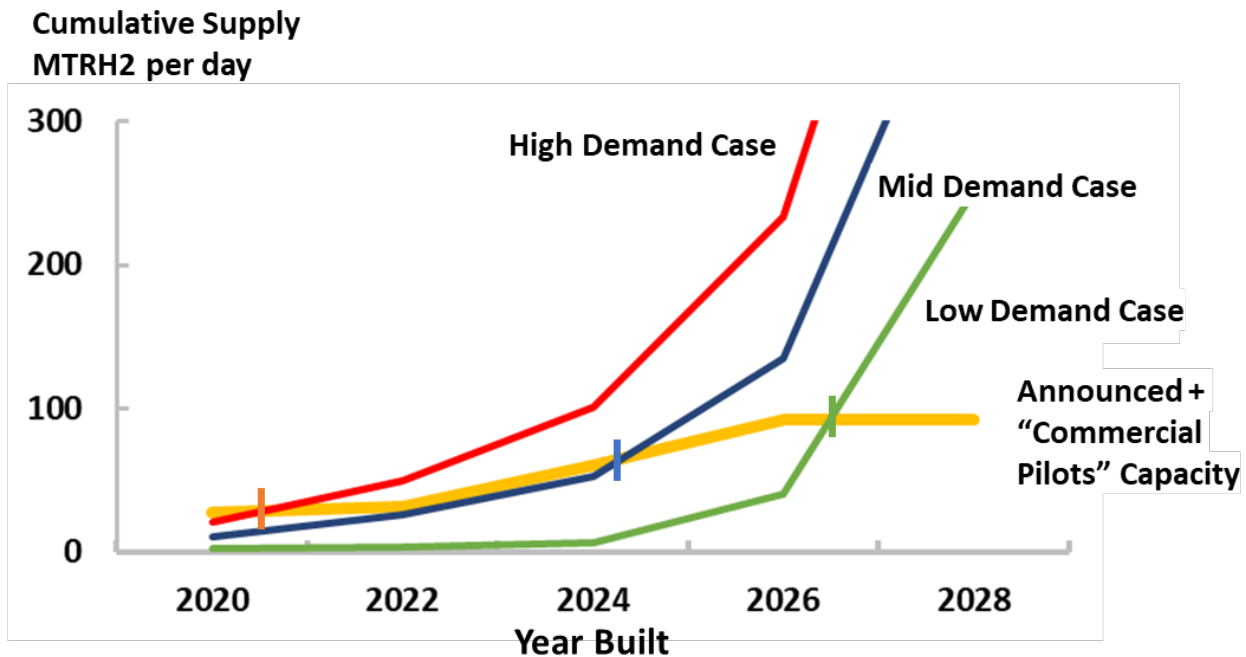
Source: UCI APEP

Figure 45: Base-Case Buildout and 2030 Spatial Detail

Annual Supply Additions
MTRH2 per day

Cumulative Supply
MTRH2 per day

- Electrolyzer
- Thermochemical
- Reformed Biomethane
- Aggregate Supply

Year in Operation

2050 Supply Mix

2030 Spatial Detail

Technology	Count
● Electrolyzer Solar	13
+ Electrolyzer Wind	6
☆ Thermochemical	5
⬠ Dairy	24
▲ Organic MSW	19
☐ SMR	21

Source: UCI APEP

66
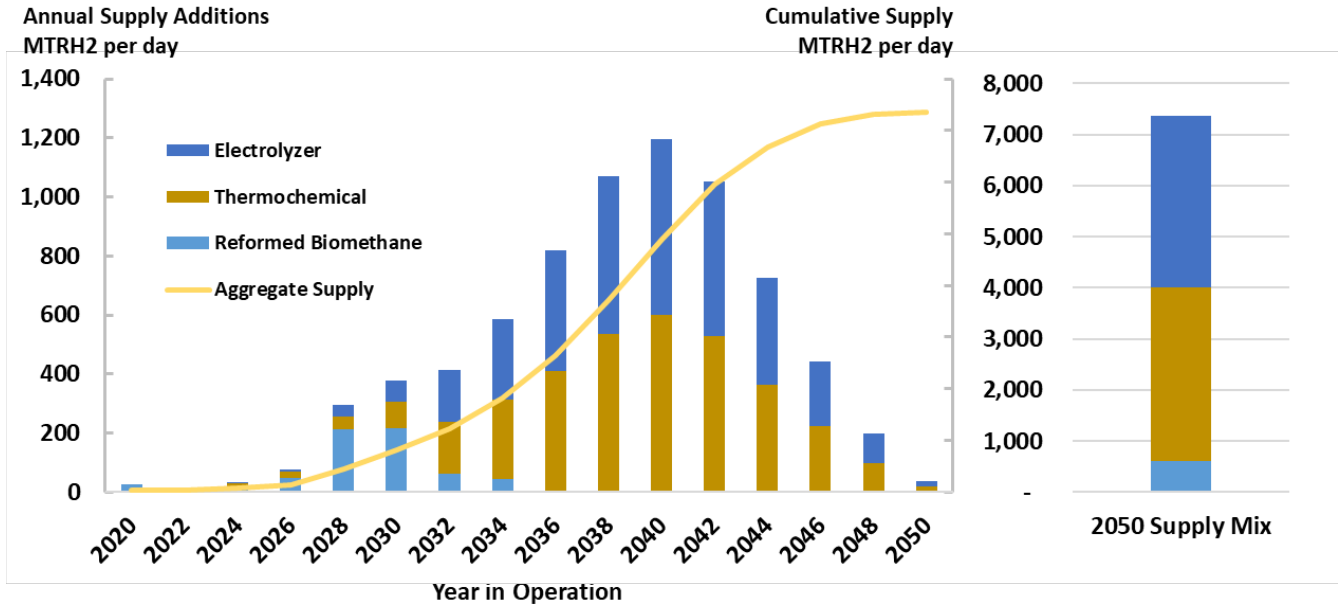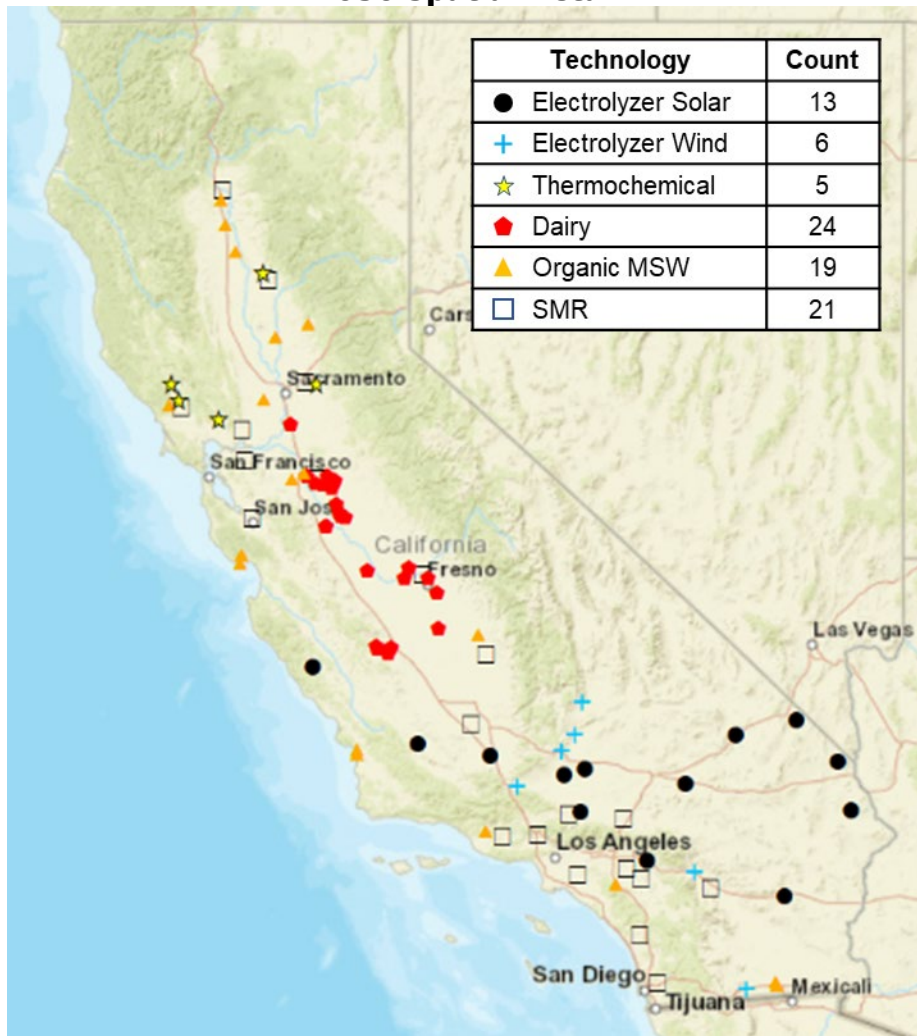
Figure 46: Base-Case Spatial Buildout Progression
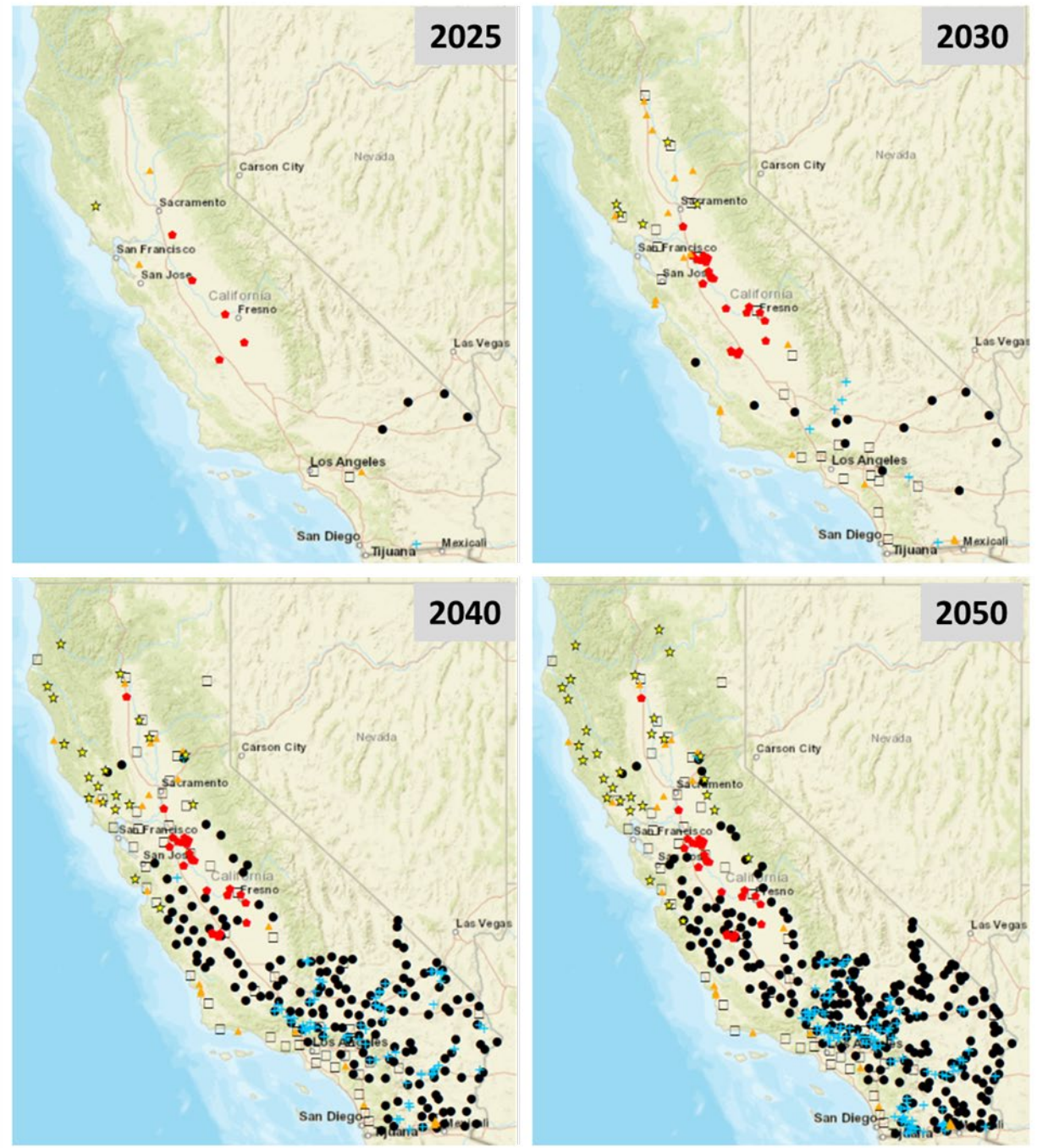
Technology Count by Year	2025	2030	2040	2050
● Electrolyzer Solar	4	13	169	265
+ Electrolyzer Wind	1	6	72	113
☆ Thermochemical	1	5	20	30
⬠ Dairy	5	24	28	28
▲ Organic MSW	3	19	21	21
☐ SMR	2	21	51	51

Source: UCI APEP

Conclusion

The various scenarios developed for renewable hydrogen demand and plants to supply that demand show that hundreds of new renewable hydrogen production plants will be needed over the coming 30 years under all scenarios. While the buildout required may appear daunting, the number of production plants needed is comparable in scale and number to the buildout that will be required to meet the 2045 electricity decarbonization goal. The more than 100 large-scale renewable electricity projects that have been built to date and the rapid scaling of project development activity in the dairy sector provide a degree of confidence that the renewable hydrogen production sector can form and scale to meet the demands of the market. Supportive policies from the involved state agencies can help increase the likelihood that the launch and scaling of the renewable hydrogen production sector goes according to plan.

CHAPTER 8:
Recommendations

Recommendations—Charting the Course

The following sections summarize recommendations developed by the research team to help ensure successful launch and scaling of the renewable hydrogen sector in California.

1 Extend Hydrogen Infrastructure Support to the Entire Supply Chain

The CEC's Clean Transportation Program has funded 64 hydrogen refueling stations.[10] In addition, the CEC has sponsored a substantial amount of research on hydrogen for transportation and has awarded funding for two projects with a total production capacity of 6,000 kg/day of 100 percent renewable hydrogen. However, additional support is needed for commercial, dedicated renewable hydrogen production projects and emerging technologies across the supply chain. In general, dual-purpose facilities such as steam methane reformers, which can serve conventional and renewable hydrogen markets, and biomethane projects, which can serve hydrogen and compressed natural gas (CNG) markets, are financially viable without additional state support. However, as described below, electrolytic hydrogen and gasification have unique features that necessitate additional support, as do emerging technologies across the supply chain such as small-scale reformers and liquid carriers.

Like reformers, electrolyzers can produce either renewable or conventional hydrogen depending on the source of the electricity used in the process. However, electrolytic hydrogen produced from nonrenewable grid electricity is several times more costly than hydrogen produced from natural gas through steam-methane reformation. As a result, investments in electrolyzers dedicated to production of renewable hydrogen for a relatively new and growing market like hydrogen refueling stations represent more of an investment risk than conventional systems that supply hydrogen to established industries. For this reason, incentives may be needed to stimulate investment. Gasification is a very promising renewable

10 Baronas, Jean, Gerhard Achtelik, et al. 2018. *Joint Agency Staff Report on Assembly Bill 8: 2018 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California.* California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2018-008.

hydrogen production technology but requires full-scale commercial demonstration before wide-scale deployment can occur. Next-generation reformation and liquefaction technologies have the potential to significantly reduce the cost of dispensed renewable hydrogen and should receive support. Similarly, programs to support emerging technologies such as liquid carriers should be pursued to the extent those technologies show promise.

The form of financial support for renewable hydrogen production and related plants could take any of several forms, such as Low Carbon Fuel Standard (LCFS) Hydrogen Refueling Infrastructure (HRI) capacity credits (provided that eligible feedstocks and renewable electricity sources are used), capital grants, and loan guarantees. The amount of financial support needed for the renewable hydrogen production sector to reach self-sustainability depends on several factors, including the form of support.

Two scenarios show the magnitude of support required. One uses only capital grants and the other uses loan guarantees for the gasification projects. Both assume that anaerobic digestion projects are commercially viable without incremental support.[11] The first scenario assumes the state provides grants through the market launch phase of 50 percent of capital cost for five electrolyzer projects of 5,000-kilogram-per-day nameplate capacity, stepping down to 25 percent for an additional two projects of 10,000 kilogram per day size and 50 percent grants to two commercial-pilot gasification projects of 25,000-kilogram-per-day nameplate capacity. The project sizes are below optimal scale but large enough to serve as commercial references for future financing. The cost of this program of support would be about $120 million and would ensure adequate renewable hydrogen capacity through the mid-2020s. If the gasification projects were to be supported with loan guarantees rather than grants, the program cost would be reduced to $80 million, estimating the cost of the guarantee at 20 percent of project cost.[12]

2 Take Steps to Support a Smooth Expansion of Production Capacity That Keeps Pace with Demand

The state has created a well-functioning program to support hydrogen station development through AB 8 to carefully plan, offer incentives for, and track station buildout and operating performance. The competitive award of incentives, mandatory reporting, and incorporation of learning has led to a successful public-private partnership. In addition to helping ensure adequate availability of fueling infrastructure to serve the early FCEV market, the program has helped shed light on areas for improvement to promote cost reduction with each generation of stations.

A key collateral feature of the program is that planning transparency and management of incentives have promoted a smooth build cycle for the station sector in which adequate new

11 Landfill gas is the lowest cost resource and is commercially mature. Landfill diversion projects receive tipping fees adequate to make such projects commercially viable. Dairy projects receive support under the California Department of Food and Agriculture grant program as well as subsidies mandated through SB 1383 and generate the most LCFS credits of any pathway.

12 The ability to secure commercial financing via loan guarantees is not certain, but a 20 percent guarantee cost is conservative relative to the loss experience rate and actuarial estimates of default rate for loans to energy project guaranteed under the DOE Loan Guarantee Program (LGP) program. The upper estimate reported in the 2016 General Accounting Office report on the program was a credit subsidy cost of 15 percent of the loan amount. This amount would be 12 percent of project cost for an 80 percent loan.

station capacity is being added without needing a dynamic wherein short supply pushes up prices to attract new capacity. No corresponding program is in place for the renewable hydrogen production and supply chain. Although the ability of renewable hydrogen production plants to use nonrenewable feedstock to serve conventional merchant hydrogen markets mitigates demand risk to some degree, the overall demand risk is substantial and programmatic intervention to facilitate a smooth buildout of supply is likely necessary. Incentives tuned to capacity expansion and technology progress targets can serve this role.

3 Supports That Attract Private Capital and Build Robust Markets

In addition to state support during the launch phase as discussed above, the timely buildout of plants and infrastructure needed to enable wide-scale adoption of hydrogen as an energy and transportation solution will require a steady flow of private capital into the sector. Realizing the necessary capital flow will require that prospective investors foresee the opportunity to achieve an acceptable return on investment while accounting for risk and uncertainty. In addition, transparent and well-functioning markets are critical to the long-term success of the sector for investors and consumers. Factors that facilitate these elements include a broad and diverse array of market participants, low barriers to entry, ready access to market information such as pricing, and an effective mechanism for connecting buyers and sellers across the value chain (such as commodity exchanges and procurement platforms). Although the private sector must play a primary role in achieving these goals, the state can also play an important role.

State policies and programs should be designed to ensure that the renewable hydrogen sector can attract private capital sufficient to meet its capital needs in a well-functioning and established renewable hydrogen market structure by the mid to late 2020s. Financeability requires successful operating history for the relevant technologies, relative certainty of feedstock availability, and relative certainty of a secure stream of revenue from renewable hydrogen sales. The status of the financeability of key renewable hydrogen production technologies is summarized in Table 17.

Table 17: Commercial Financeability of Key Renewable Hydrogen Technologies

Hydrogen Technologies	Commercially Financeable?	Comments
Hydrogen Refueling Station	Close	LCFS price risk is a remaining gap
SMR	Yes	100% financeable. Proven commercial technology with ability to secure revenue through conventional hydrogen production.
Liquefaction Facility	Yes	100% financeable. Proven commercial technology with ability to secure revenue through conventional hydrogen production.
Anaerobic Digester	Close	SB 1383 provides mandates that will make dairy projects suitable for commercial lending including subsidies and LCFS price support. AD projects using landfill diverted feedstock receive contracted tipping fees; LCFS price support mechanism may be needed for full financeability.

Hydrogen Technologies	Commercially Financeable?	Comments
Electrolyzer	No	Capital costs declining but currently above levels required for cost competitiveness.
		Lack of long-term RH2 off-take agreements with firm pricing for LCFS value creates a financing barrier.
Gasifier	No	Technology is not fully commercial, requires high capital investment ($100M+).
		Lack of long-term RH2 off-take agreements with firm pricing for LCFS value creates a financing barrier.

Source: UCI APEP

The renewable electricity and the battery-electric vehicle sectors have addressed the commercial lending gap largely through public-utility-sponsored procurement and investment programs. These programs use the creditworthiness of the host utility through either direct utility financing or long-term revenue contracts to finance investment. Other approaches are needed to serve a similar role in launching and scaling the renewable hydrogen production and supply sector. The Clean Transportation Program hydrogen refueling station program and the recently approved LCFS HRI capacity program support the refueling station part of the supply chain, but additional program elements are needed for renewable hydrogen production and capital-intensive elements of the supply chain.

The renewable hydrogen market is in the very early stage. No fully dedicated renewable hydrogen production facilities are in operation in the state with reformed biomethane using existing SMR capacity as the dominant supply approach. The market has few participants, and transparency on pricing or terms is lacking.

Several elements should be considered in developing programs to support renewable hydrogen supply expansion by addressing the financing gap or otherwise supporting market development or both.

- Transparent and widely communicated information on expected demand growth and planned production and supply capacity additions can help private investors in planning development to match market demand. The demand-forecasting element of the AB 8 program should be continued and expanded to include other sources of demand, particularly for medium- and heavy-duty applications.

- LCFS credits are an important source of value for the entire renewable hydrogen production and supply chain, but uncertainty of future credit value introduces significant investment risk. An LCFS credit price support mechanism was proposed during the most recent legislative session in response to the requirements of SB 1383 (2018, De León).[13] Should such a mechanism be put in place in the future, it is important that it apply to hydrogen and not only dairy biomethane as originally proposed.

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13 SB 1383 "Short-Lived Climate Pollutants (Lara, Chapter 395, Statutes of 2016), https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383.

- The state should also consider developing incentive programs such as grants, capacity credits, or loan guarantees allocated to renewable hydrogen production and related high-capital-cost facilities aggregate funding amounts be tied to optimal buildout strategies. Because loan guarantee programs typically require similar documentation and credit risk assessment to conventional project finance, such programs can provide a smooth evolution to pure commercial financing. In contrast to grant programs, such programs have the potential to return borrowed funds to the sponsor. Examples of such programs include the U.S. DOE loan guarantee program[14] and the green bond program proposed by former California state Treasurer John Chiang.[15]

- Incentive eligibility should continue and extend the selection factors employed in the station program and the initial renewable hydrogen production solicitation (GFO-602), including:

    o Amount of match funding.

    o Strength of the project commercial plan and track record of the applicant.

    o Technology diversity and encouragement of new entrants.

    o Disadvantaged community impacts.

    o Carbon reduction.

- Agencies providing grants or incentives can promote price transparency in the renewable hydrogen market by publishing anonymized pricing and related data on contracts for the purchase or sale of renewable hydrogen from projects receiving state support. The LCFS program and the CTP hydrogen station program already require reporting of key data on costs, quantities, and other operational elements. However, unbundled (separate) price or cost of renewable hydrogen and associated volumes is not among the publicly reported data.

- Operational reporting requirements for funded projects should be developed in consultation with project financing entities to ensure that reported metrics address the information needs of future prospective private lenders.

- State agencies, in collaboration with stakeholders, should systematically identify market barriers in assessing the development of the renewable hydrogen production and supply sector, target programs and incentives to address barriers, and include supplier diversity (number and demographics) in award criteria

- The market for biomass feedstock is not well formed, and secure long-term feedstock agreements will be necessary for commercial viability of projects using biomass. State agencies should convene a stakeholder process to explore approaches to addressing this issue such as establishing an exchange or clearinghouse.

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14 DOE Loan Program Office page https://www.energy.gov/lpo/loan-programs-office; GAO DOE Loan Program Report https://www.gao.gov/assets/680/675595.pdf
15 California Treasurer Green Bond Report https://www.treasurer.ca.gov/greenbonds/publications/reports/green_bond_market_01.pdf

4 Reduce Barriers to Development in California

The development of projects in California can be challenging. Impediments cited by developers include onerous California Environmental Quality Act (CEQA) requirements for some types of projects, prevalence of local opposition to new development often based on misperceptions about impacts of proposed projects, high labor rates, differing requirements across local jurisdictions, high utility rates, and high tax rates. Some of these issues, such as wage rates and general state tax rates, are likely issues that will remain facts of life in California. However, state agencies can act to expedite project development through efforts to harmonize local requirements,[16] streamlining of permitting processes,[17] and approval of program environmental impact reports. In addition, incentives that encourage development in California should continue.

Action in the California diary sector provides a model for the renewable hydrogen sector. Driven by California's Short-Lived Climate Pollutant Reduction Strategy (SLCP Strategy) and industry action, the state has undertaken important steps to streamline permitting for dairy biomethane projects:

- The California Environmental Protection Agency (CalEPA) has spearheaded the establishment of a consolidated permitting process to help project developers navigate the permitting process.

- CalEPA approved a trade group-developed program environmental impact report (PEIR) to relieve much of the burden on individual projects to develop environmental impact reports required under the California Environmental Quality Act (CEQA).

5 Design Programs and Incentives Holistically Across Fuel Types

In designing programs to support renewable hydrogen production, consideration should be given to other programs that may provide support to some pathways. For example, all the organic feedstocks that are candidates for hydrogen production can also be used to produce biomethane (which itself is a primary potential feedstock for renewable hydrogen). Biomethane projects receive support developed in response to Senate Bill 1383 for which electrolytic and thermochemical hydrogen production systems do not currently qualify.

In addition, some primary organic feedstocks are subject to, and others are likely to become subject to, mandates that will affect the price of that feedstock for fuel production. For example, state law directs that regulations be adopted requiring the diversion of 75 percent of the organic material that would otherwise be disposed of in landfill by 2025.[18] Dairies are not currently under mandate to capture methane emissions, but the California Air Resources Board has stated the intent in its short-lived climate pollutant (SLCP) strategy to mandate capture in

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16 The Energy Commission and the California Governor's Office of Business and Economic Development (Go-Biz) have been actively assisting with local permitting issues for stations for several years. This approach should be extended to the entire production and delivery chain.

17 The California EPA has led such an effort for dairy projects. See California EPA Dairy Grant Program page https://calepa.ca.gov/digester/.

18 SB 1383 (Lara, Chapter 395, Statutes of 2016) C Link to bill text https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383

the future.[19] The pressing need for forest management to reduce wildfire risk raises the strong potential for mandates for forest thinning and other measures to gather and remove combustible material from forests.[20] Such organic waste mandates may lead to payments (known as tipping fees, which are disposal payments) by feedstock sources. These payments are the case with landfill-diverted food waste. Potential tipping fee revenue should be considered in any feedstock or technology-differentiated project support programs when assessing the amount of support needed.

In considering appropriate levels of support for hydrogen production infrastructure, policy makers should consider support levels across the full deployment cycle (at least 10 years of deployment) and all sources of effective subsidy.

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19 ARB Short-Lived Climate Pollutant Final Report
https://www.arb.ca.gov/cc/shortlived/meetings/03142017/final_slcp_report.pdf
20 Wildfire Mitigation Report https://www.gov.ca.gov/wp-content/uploads/2018/05/5.10.18-Forest-EO.pdf.

6 Establish Electricity Tariffs for Electrolyzers

Electrolyzers consuming grid electricity currently pay retail rates on tariff schedules that depend on the voltage level at which the electrolyzer interconnects. An electrolyzer receiving service on a standard commercial or industrial rate in California would pay an average of about $0.11 to $0.14 per kilowatt-hour for grid electricity,[21] which has a renewable fraction approaching 35 percent.[22] For electrolyzers interconnected at the transmission level, time-of-use rates would provide a relatively close proxy to wholesale electricity rates but would require the electrolyzer to receive the grid-average blend of renewable and conventional energy and would not convey ownership of renewable energy credits to the electrolyzer operator. In contrast, an electrolyzer using collocated wind or solar energy generation would incur a cost of about $0.03 per kilowatt-hour for 100 percent renewable energy, albeit with much less siting flexibility and a lower capacity factor.

To optimize their revenue generation through LCFS credit strategies, electrolytic hydrogen producers must have the ability to source their own wholesale electricity. Without electric tariffs that provide this capability, electrolytic hydrogen producers must either accept the limitation of current tariff structures or produce their own electricity from dedicated, collocated renewable generation facilities. Such limitations constrain the ability to site electrolyzers optimally in relation to the renewable hydrogen distribution network.

Electrolyzers can also provide grid services such as frequency support, voltage support, and ramping. A knowledge gap exists regarding the future value of such services and the revenue streams that might be available to electrolytic hydrogen production facilities. Additional research or inclusion of value analysis of these functions in the electric utility integrated resource planning process or both would simplify revenue forecasting for electrolyzer project developers.

Utility-sponsored programs such as real-time rates (the rate charged tracks the wholesale market price in real time) with optional renewable-only tariff provisions (an ability for a customer to specifically buy renewable electricity and not the average mix) and dispatchable load tariffs (program allowing the utility to control a load) compensating electrolyzers for providing grid support would create easy access to electricity markets. They would be particularly valuable for smaller projects not positioned to interact directly with wholesale markets. For larger or more sophisticated projects, direct access programs under which electrolyzer owners could procure their own power, pay transmission access charges, and interact directly with the wholesale market for grid services might be most effective. Regulatory proceedings under the authority of the California Public Utilities Commission and, possibly, the California Independent System Operator are needed to address these issues.

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21 EIA Table f Retail Electric Rates;
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a
22 CEC RPS Tracking Report;
https://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf

7 Ease Access to the Natural Gas System for Renewable Hydrogen Transport and Storage

Renewable hydrogen produced through reformation of biomethane generally uses the natural gas system for storage and delivery of the biomethane feedstock to the reformation plant. This is the most common pathway used for renewable hydrogen production under the LCFS program today. State programs instituted under mandates contained in Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) have defined standards for pipeline injection and provided subsidies for interconnection for biomethane producers. No similar programs are currently in place for methane produced from electrolytic hydrogen or for hydrogen directly injected onto the natural gas system as a blendstock. Senate Bill 1369 (Skinner, Chapter 567, Statutes of 2018) directs state agencies, including the California Public Utility Commission (CPUC), to consider uses of green electrolytic hydrogen, but specific action by the CPUC beyond fact-finding workshops has not yet been initiated. Expanding existing programs and tariffs to include electrolytic methane and hydrogen is necessary to ensure a level playing field for electrolytic hydrogen and methane.

Gasifiers generally produce both methane and hydrogen. Clarity on the permissible hydrogen fraction for pipeline-injected biomethane is important for developers of gasification projects wishing to access the natural gas system to design their gas processing and conditioning systems properly.

Although substantial evidence is available suggesting that hydrogen fractions as high as 20 percent can be safely permitted in the natural gas supply,[23] California has yet to establish hydrogen blending limits. Timely action is needed to ensure that renewable hydrogen fuel producers receive the same open access to the common-carrier pipeline system as other fuel types.

8 Take Steps to Ensure That a Mixed Gas/Liquid Supply Chain Does Not Create Barriers to Market Access

The hydrogen supply chain is developing as a mix of gaseous and liquid transport and storage, with 17 stations employing liquid storage and the remainder compressed gas, according to the ARB 2018 AB 8 report. Stakeholders report different perspectives on whether the future supply chain will be dominated by liquid or compressed gaseous transport and storage. It is likely that the future network will include substantial fractions of both cryo-liquid and compressed gas stations. Other transport and storage approaches are also under development, such as liquid organic hydrogen carriers, ammonia, DME, and others that may enter the supply mix in the future. These too would need to be integrated into the production and supply network.

Economic principles suggest that, in a fully mature market, competitive forces will likely be adequate to ensure that the sector evolves to the most cost-effective production and supply chain configurations. However, in the early market, policy interventions may be required to ensure that otherwise promising technologies and business models have appropriate access to the supply chain. For example, one of the benefits of electrolyzer systems is that they are modular and can be implemented at a modest scale without major diseconomies of scale.

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23 See, for example, Oney, F., T.N. Veziroglu, and Z. Dulger, 1994, "Evaluation of Pipeline Transportation of Hydrogen and Natural Gas Mixtures," *International Journal of Hydrogen Energy* 19(10):813–822.

However, integration into the liquid hydrogen supply chain may pose a challenge. Liquefaction facilities show strong economies of scale. As a result, it's generally not cost effective for electrolytic production facilities of modest size (less than 100 MW or so) to install dedicated liquefaction facilities. At the same time, large scale renewable hydrogen liquefaction requires tens of acres of land outside of impacted air districts so they may be distant from electrolytic production facilities. These remote liquefaction facilities will result in high transport costs for hydrogen delivered by truck or rail. In addition, remote liquefaction facilities would generally need to add new receipt points to introduce truck-delivered hydrogen into the inbound supply, which is pipeline delivered. These issues create a potential barrier to accessing the liquid hydrogen supply chain.

Other emerging technologies may face similar barriers. Where barriers exist, state policy makers may wish to consider some form of incentives to ease market access for new entrants and emerging technologies. Potential approaches include additional incentives for projects facing supply-chain access barriers or incentives for critical supply-chain access points (such as liquefaction facilities) to provide capacity to third parties.

9 Ensure That Renewable Hydrogen Development Advances Social Justice

The buildout of the renewable hydrogen sector offers many potential benefits to disadvantaged communities through the creation of high-quality, green-energy jobs and by supporting the transition to zero-emission transportation solutions, displacing fossil fuels that disproportionately impact disadvantaged communities. However, depending on the technology and supply chain model, the buildout may also create additional truck traffic from feedstock supply or outbound trucking of renewable hydrogen or both. Noise and visual impact can also be concerns. The project team recommends that state programs providing support for renewable hydrogen production and related facilities apply a social justice screen with a scoring rubric designed in consultation with stakeholders from the relevant communities. Such a scoring system would assess net community benefits, with local economic development and clean-technology deployment weighed against potential negative impacts such as congestion, noise, and aesthetics.

10 Act to Ensure That Program Eligibility, Environmental Accounting, and Lack of Definitions Are Not Barriers to Renewable Hydrogen Development

As programs are developed to support the transition to clean transportation and clean energy solutions, eligibility requirements relying on specific definitions must be developed. For example, the California Renewables Portfolio Standard relies upon specific definitions for qualifying resources, as does the CPUC storage procurement mandate. The federal renewable fuel standard provides renewable identification number (RIN) credits of varying types (and values) for specific qualifying fuels.[24] Senate Bill 100 (De León, Chapter 312, Statutes of 2018) mandates that California reach 100 percent zero-carbon electricity by 2045. These programs, and other similar current and future programs, ensure environmental integrity and achievement of goals by clearly defined standards and eligibility requirements. However, these provisions can also have the effect of excluding or disadvantaging technologies or use cases

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24 [EPA Renewable Fuel Standard Page](https://www.epa.gov/renewable-fuel-standard-program) ; https://www.epa.gov/renewable-fuel-standard-program.

not envisioned at program inception. As discussed below, these effects can create unnecessary barriers to the evolution of the renewable hydrogen production (and supply) sectors.

Federal RIN credits provide a significant subsidy for eligible fuels. D3 (cellulosic biofuel) RIN credits are trading at roughly $2 per diesel gallon equivalent.[25] Hydrogen derived from renewable feedstocks is not eligible to generate RINs, whereas several biomethane pathways are. Three RIN pathway applications for renewable hydrogen from biomethane are pending but not approved.[26] This difference in eligibility tends to skew biomethane supply toward compressed natural gas as an end fuel, placing renewable hydrogen at a relative disadvantage. It is recommended that interested stakeholders take collective action, for example, through their trade organizations, to secure RIN pathway approval for renewable hydrogen.

Clarity is critical to the buildout and scaling of the renewable hydrogen sector. In current state rulemakings and regulatory proceedings, terms such as "renewable gas," "renewable methane," and "green electrolytic hydrogen" have been used in discussion of the scope and applicability of various programs and regulations. At present, consistent definition of the terms "renewable hydrogen" and "zero-carbon hydrogen" have not been established. To the extent that mandates and/or incentive programs rely on such definitions (which, by necessity, they will), it is critical for fuel producers and purchasers to have clarity on definitions to support investment and purchasing decisions. Some working definitions are provided in Table 18 below. "Low-carbon," "net-zero-carbon," and "zero-carbon" are also terms that have or may appear in legislation or regulation that need to be clearly defined.

Carbon intensity provides a consistent framework that has worked well in the LCFS program. Program eligibility based on feedstock or source, as in the federal Renewable Fuel Standard program, is another viable approach, provided that the addition of new feedstocks is explicitly provided for in program design. Technology-specific or process-specific incentives to support nascent technologies or processes of high potential with defined expiration provisions can play an important role in advancing the sector. However, standards or eligibility or both based on technology or process should be used with great caution, to avoid conveyance of inappropriate market advantages or disadvantages. Renewable hydrogen market participants and trade organizations must act proactively to ensure that statutes and regulations do not directly or indirectly disadvantage renewable hydrogen.

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25 EPA RIN Price and Volumes Page; https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information.
26 EPA Rnewable Fuels Pending Applications; https://www.epa.gov/renewable-fuel-standard-program/pending-petitions-renewable-fuel-pathways.

Table 18: Renewable Fuel Working Definitions

Term	Definition
Biogas (CPUC adopted definition)	Mixture of methane (major constituent) and CO2 (typically 20% to 40% CO2 by volume) and minor constituents derived from bio sources – cannot be introduced onto the common carrier natural gas system without cleanup
Biomethane (CPUC adopted definition)	Biogas that has been conditioned (cleaned and purified) to meet pipeline standards composed primarily of methane with small remaining amounts of CO2
Biosyngas	Hydrogen-rich gas (with high fraction of carbon monoxide, CO) produced through gasification of biomass, from which (near) pure hydrogen or methane (with additional CO2) can be synthesized
Renewable Methane	Methane formed by combining hydrogen (generally from electrolysis) with CO2 – it is renewable if the feedstock for the hydrogen is renewable and if the CO2 is biogenic or captured from the atmosphere or other source of CO2 certified to be climate-neutral
Renewable Natural Gas	While generally used interchangeably with biomethane, includes as well renewable electrolytic methane
Renewable Hydrogen and Green Hydrogen	Hydrogen produced using only renewable feedstock including renewable electricity, biomass or other forms of renewable energy such as solar energy
Renewable Gas	All the above

Source: UCI APEP with stakeholder input

11 Increase State Research, Development and Demonstration (RD&D) Investment in High-Impact Areas and Maximize Leverage of Federal RD&D

Realizing the substantial (40 to 60 percent) cost reduction potential across the renewable hydrogen production and supply chain requires sustained international policy support to achieve global scale and drive learning effects. Also needed are sustained research, development, and demonstration programs to augment scale effects with fundamental improvements.

The United States Department of Energy (U.S. DOE) within its Fuel Cell Technology Office (FCTO) is sponsoring a robust program of research under the hydrogen-at-scale (H2@Scale) cross-lab initiative.[27] As illustrated in Figure 47, the H2@Scale program features focused research at the materials, components, and systems levels in hydrogen production, storage, and systems. California can augment this program of research to address issues of specific priority to California and to bridge U.S. DOE research through technology-to-market activities such as full-scale commercial demonstration programs. Notably, the H2@Scale program through 2019 did not place specific focus on renewable hydrogen production, which amplifies the importance of California RD&D activities specific to renewable hydrogen. Some specific areas of RD&D that are of specific importance to California include:

- Cost and performance tracking and market forecasting of renewable hydrogen production and supply chain infrastructure to guide investor and policy-maker decisions.

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27 DOE H2@Scale Home Page https://www.energy.gov/eere/fuelcells/h2scale.

- Full-scale commercial demonstration of high-impact-potential technologies such as gasification, and novel technologies across the production and supply chain, particularly those supporting production and storage at the station scale.

- Quantification of the value of joint benefits enabled by renewable hydrogen between the transportation, electric, and natural gas systems (sometime referred to as "sector coupling").

- Development of optimal electric and gas rate structures and market designs as they relate to renewable hydrogen.

Appendix D details specific research topics.

Figure 47: Hydrogen and Fuel Cell RD&D Organizing Framework
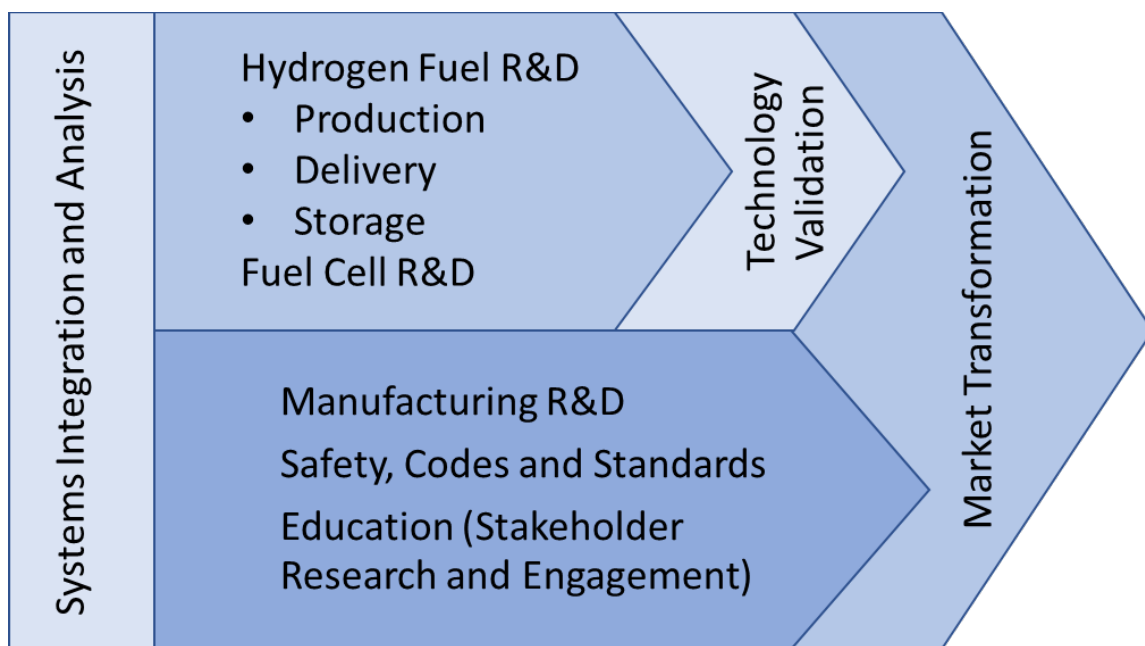
Source: After DOE Fuel Cell Technologies Office

CHAPTER 9:
Conclusions

The renewable hydrogen production roadmap project applied a systematic analytical method to assess and forecast costs and performance of all key elements of the renewable hydrogen production and delivery chain. The work relied on lessons from early project development, the CEC solicitation for renewable hydrogen production projects, and a variety of forecasting methods. The results show that plant-gate cost of renewable hydrogen in the range of $2 to $3 per kilogram can be achieved by 2030, and full dispensed cost net of credits can achieve the near-term target of $6 to $8.50 per kilogram and track toward $4 to $6 per kilogram by 2050. In addition, the effort included a bottom-up analysis to create demand growth scenarios for transportation and other potential sources of demand. This analysis showed that demand for renewable hydrogen could exceed 400 million kilograms per year by 2030 and more than 4,000 million kilograms per year by 2050. The facility buildout and siting analysis shows that several hundred new renewable hydrogen production plants will be needed by 2050, and they will be located throughout the state near feedstock sources.

Market-support recommendations focus on state action to support rapid development of robust competitive markets for renewable hydrogen that are self-sustaining, maintain a level play field across technologies, and advance social justice. Recommended RD&D support targets activities that drive cost reduction, commercialization of high-promise emerging technologies, and enhance market transparency and understanding through data collection and analysis.

Renewable hydrogen has the potential to play a critical role in California's zero-carbon economy. While transportation, particularly in longer-range and high-fuel-consumption applications, will likely be the primary application area, the opportunity for using renewable hydrogen exists across the economy. With continued state policy and program support, the renewable hydrogen production sector can become self-sustaining within the next decade. This new sector of the economy will not only play a key role in decarbonizing transportation and energy but has the potential to create tens of thousands and eventually hundreds of thousands of high-quality green jobs.

GLOSSARY

See the CEC online glossary at https://www.energy.ca.gov/resources/energy-glossary for additional entries.

ArcGIS—A geographic information system for the management, analysis, and display of geographic information. Geographic information is represented by a series of geographic datasets that model geography using simple, generic data structures. ArcGIS includes a set of comprehensive tools for working with the geographic data.[28]

ALKALINE ELECTROLYZER (AECs) – An electrolyzer that uses potassium hydroxide (KOH) as the electrolyte and hydroxide (OH^-) as the charge carrier.

ANAEROBIC DIGESTION – A biological process in which biodegradable organic matters are broken down by bacteria into biogas, which consists of methane (CH_4), carbon dioxide (CO_2), and other trace amount of gases. The biogas can be used to generate heat and electricity.

ANHYDROUS AMMONIA – Ammonia in its pure form that contains no water.[29]

ARTIFICIAL PHOTOSYNTHESIS – Artificial photosynthesis is a composition of chemical systems that converts solar energy into useful forms of energy and materials using the fundamental science of natural photosynthesis.[30]

BATCH DIGESTER – A feedstock loading method for anaerobic digesters where feedstocks are loaded into the digester all at once. Following loading a set period of time is needed for digestion to occur. Following this time period, the digester is manually emptied and reloaded.[31]

BIOMASS - Energy resources derived from organic matter. These include wood, agricultural waste and other living-cell material that can be burned to produce heat energy. They also include algae, sewage and other organic substances that may be used to make energy through chemical processes.

BRITISH THERMAL UNIT (Btu) - The standard measure of heat energy. It takes one Btu to raise the temperature of one pound of water by one degree Fahrenheit at sea level. For example, it takes about 2,000 Btu to make a pot of coffee. One Btu is equivalent to 252 calories, 778 foot-pounds, 1055 joules, and 0.293 watt-hours.

BROWN HYDROGEN – Hydrogen produced from coal may be referred to as brown hydrogen, and from natural gas as blue hydrogen; neither is renewable.[32]

BUILDOUT -- The growth, development, or expansion of something.[33]

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[28] esri web page "What is ArcGIS) ArcGIS
http://downloads.esri.com/support/documentation/ao_/698What_is_ArcGis.pdf

[29] Webster's Dictionary https://www.merriam-webster.com/dictionary/anhydrous%20ammonia

[30] Scribed dot-com https://www.scribd.com/doc/138795090/artificial-photosynthesis-definition

[31] US EPA Digester Page https://www.epa.gov/anaerobic-digestion/types-anaerobic-digesters

[32] Wikipedia Hydrogen https://en.wikipedia.org/wiki/Hydrogen_economy

[33] Lexico dot-com https://www.lexico.com/en/definition/buildout

CAPACITY FACTOR - A percentage that tells how much of a power plant's capacity is used over time. For example, typical plant capacity factors range as high as 80 percent for geothermal and 70 percent for co-generation.

CAPEX – Capital expenditure.[34]

CARBON CAPTURE, UTILIZATION AND STORAGE (CCUS) -- Also referred to as carbon capture, utilization and sequestration, is a process that captures carbon dioxide emissions from sources like coal-fired power plants and either reuses or stores it so it will not enter the atmosphere.[35]

CARBON INTENSITY (CI) -- The amount of carbon by weight emitted per unit of energy consumed. A common measure of carbon intensity is weight of carbon per British thermal unit (Btu) of energy. When only one fossil fuel is under consideration, the carbon intensity and the emissions coefficient are identical. When several fuels are part of a pathway, carbon intensity is based on their combined emissions coefficients weighted by their energy consumption levels.

CATALYST – A substance that can increase or decrease the rate of a chemical reaction between the other chemical species without being consumed in the process.

CATALYZED – A reaction supported by a catalyst.

CELLULOSIC – Anything composed of or sourced from cellulose. Cellulosic feedstocks for biofuels include crop residues, wood residues, dedicated energy crops, and industrial and other wastes.[36]

CONTINUOUS FLOW DIGESTER – A feedstock loading method for anaerobic digesters where feedstocks are constantly fed into the digester and digested material is continuously removed. [37]

COVERED LAGOON – (also ANAEROBIC LAGOON) A deep impoundment, essentially free of dissolved oxygen, which promotes anaerobic conditions. The process typically takes place in deep earthen basins, and such ponds are used as anaerobic pretreatment systems. Anaerobic lagoons are typically used for two major purposes: 1) Pretreatment of high strength industrial wastewaters. 2) Pretreatment of municipal wastewater to allow preliminary sedimentation of suspended solids as a pretreatment process.[38]

CRYO OR CRYOGENIC – Refers to temperatures below -150°C.[39]

CONSTANT DOLLAR -- A constant dollar is an adjusted value of currency used to compare dollar values from one period to another. Due to inflation, the purchasing power of the dollar

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[34] Lexico dot com https://www.lexico.com/en/definition/capex
[35] Energy Commission Web Page carbon-capture-utilization-storage https://www.energy.gov/carbon-capture-utilization-storage
[36] Energy Commission Web Page Ethanol Feedstocks https://afdc.energy.gov/fuels/ethanol_feedstocks.html
[37] US EPA Web Paeg "Types of Anaerobic Digesters" https://www.epa.gov/anaerobic-digestion/types-anaerobic-digesters
[38] US EPA Web Page on Digester Lagoons https://www3.epa.gov/npdes/pubs/alagoons.pdf
[39] NIST Web Page "About Cryogenics" https://www.nist.gov/mml/acmd/cryogenics/aboutcryogenics

changes over time, so in order to compare dollar values from one year to another, they need to be converted from nominal (current) dollar values to constant dollar values. Constant dollar value may also be referred to as real dollar value.[40]

COVERED LAGOON -- An anaerobic lagoon is a deep impoundment, essentially free of dissolved oxygen, which promotes anaerobic conditions.[41] This type of lagoon is used to process animal waste at dairies. Such lagoons generate methane as the animal manure decomposes. A covered lagoon is one with a plastic cover to capture the methane produced by decomposition. Tier 1 covered lagoon refers to a covered lagoon that is double lined to provide extra protection from groundwater contamination from leaching of the contents of the lagoon.

CREDIT WORTHINESS -- The extent to which a person or company is considered suitable to receive financial credit, often based on their reliability in paying money back in the past.[42]
CURTAILMENT - A reduction in the output of a generator from what it could otherwise produce given available resources, typically on an involuntary basis.[43]

DECARBONIZE -- Reduce the amount of gaseous carbon compounds released in or as a result of (an environment or process).[44]

DIGESTER – Built systems (lagoons or tanks) where digestion takes place[45]

DIMETHYL ETHER (DME) – A synthetically produced alternative to diesel for use in specially designed compression ignition diesel engines. Although dimethyl ether can be produced from biomass, methanol, and fossil fuels, the likely feedstock of choice for large-scale DME production in the United States is natural gas. Because of its lack of carbon-to-carbon bonds, using DME as an alternative to diesel can virtually eliminate particulate emissions and potentially negate the need for costly diesel particulate filters.[46]

DISADVANTAGED COMMUNITIES (DAC) - Disadvantaged communities are communities designated by CalEPA, pursuant to Senate Bill 535 (De León), using the California Communities Environmental Health Screening Tool ("CalEnviroScreen"). CalEnviroScreen was developed by the Office of Environmental Health Hazard Assessment to identify communities in California most burdened by pollution from multiples sources and most vulnerable to its effects, considering socioeconomic characteristics and underlying health status. Disadvantaged communities are identified by census tract and are those that scored at or above the 75th percentile.[47]

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[40] Investopedia dot-com https://www.investopedia.com/terms/c/constantdollar.asp
[41] US EPA Web Page on Anaerobioc Lagoons https://www3.epa.gov/npdes/pubs/alagoons.pdf
[42] Lexico dot-com https://www.lexico.com/en/definition/creditworthiness
[43] L. Bird, J. Cochran, and X. Wang, "Wind and Solar Energy Curtailment: Experience and Practices in the United States," *Natl. Renew. Energy Lab.*, no. March, p. 58, 2014.
[44] Lexico dot-com https://www.lexico.com/en/definition/decarbonize
[45] US EPA Web Page "frequent-questions-about-anaerobic-digestion" https://www.epa.gov/anaerobic-digestion/frequent-questions-about-anaerobic-digestion
[46] Energy Commission Page on DME https://afdc.energy.gov/fuels/emerging_dme.html
[47] Energy Commission Web Page on Diversity   https://ww2.energy.ca.gov/commission/diversity/definition.html

DISPATCHABLE - Refers to sources of electricity that can be used on demand and dispatched at the request of power grid operators, according to market needs. Dispatchable sources can be turned on, off, and can adjust their power output.[48]

DUCK CURVE - Named after its resemblance to a duck—is a 24-hour plot that shows the difference in electricity demand and the amount of available solar energy throughout the day. During the middle of the day, when the sun is shining brightest, solar power peaks and then drops off as electricity demand peaks in the evening.[49]

ECONOMY OF SCALE -- Economies of scale exist where the industry or plant exhibits decreasing average long-run costs with size.

ELECTROCHEMICAL - Describes a process or device capable of either generating electrical energy from chemical reactions or using electrical energy to cause chemical reactions. The electrochemical cells which generate an electric current are called voltaic cells or galvanic cells and those that generate chemical reactions, via electrolysis for example, are called electrolytic cells.[50]

ELECTROLYZER - Devices that use an electric current to provide the energy that splits a water molecule (H_2O) into hydrogen (H_2) and oxygen (O_2). Hydrogen gas is generated on the negative side while oxygen gas is generated on the positive.[51]

ENERGY CROP – Biomass crops dedicated for use for energy.[52]

EXAJOULE – The exajoule (EJ) is equal to one quintillion (10^{18}) joules.[53]

EXPERT ELICITATION -- Expert elicitation involves the process of seeking carefully reasoned judgments from experts about an uncertain quantity or process in their domain of expertise, often in the form of subjective probability distributions.[54]

FIXED O&M - Fixed O&M costs are operations and maintenance expenses that do not vary based on production volume of a facility.

FINANCEABILITY -- Ability for something to be financed or receive financing.[55]

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[48] P. L. Joskow, "American Economic Association Comparing the Costs of Intermittent and Dispatchable Electricity Generating Technologies" THE One Hundred Twenty Third Annual Meeting OF THE AMERICAN ECONOMIC Published by : American Economic Association Stable URL : http://ww," *Am. Econ. Rev.*, vol. 101, no. 3, pp. 9–13, 2011.

[49] US DOE Article "Confronting the Duck Curve" https://www.energy.gov/eere/articles/confronting-duck-curve-how-address-over-generation-solar-energy

[50] Georgia State University Hyperphysics Web Page http://hyperphysics.phy-astr.gsu.edu/hbase/Chemical/electrochem.html

[51] US DOE Hydrogen Production Web Page on Electrolysis https://www.energy.gov/eere/fuelcells/hydrogen-production-electrolysis

[52] US DOE Billion Ton Report https://www.energy.gov/sites/prod/files/2016/08/f33/BillionTon_Report_2016_8.18.2016.pdf

[53] *McGraw-Hill Dictionary of Physics*, Fifth Edition (1997). McGraw-Hill, Inc.

[54] National Academies of Science http://nationalacademies.org/hmd/~/media/Files/Activity%20Files/Research/DrugForum/2014-Feb-13/February%2012%20-%20Session%20III%20-%20Morgan.pdf

[55] Definition-of dot-com https://www.definition-of.com/financeability

FORECOURT -- An open area in front of a large building or fueling station.[56]

FUEL CELL ELECTRIC VEHICLE (FCEV) - A zero-emission vehicle that runs on compressed hydrogen fed into a fuel cell "stack" that produces electricity to power the vehicle.
GASIFICATION – The process where biomass fuel is reacted with sub- stoichiometric quantities of air and oxygen usually under high pressure and temperature along with moisture to produce gas which contains hydrogen, methane, carbon monoxide, nitrogen, water and carbon dioxide. The gas can be burned directly in a boiler or scrubbed and combusted in an engine-generator to produce electricity. The three types of gasification technologies available for biomass fuels are the fixed bed updraft, fixed bed downdraft and fluidized bed gasifiers. Gasification is also the production of synthetic gas from coal.

GASIFIER – A gasification reactor. Some types of gasifiers include fixed-bed, entrained-flow, and fluidized-bed.[57]

HYDROTHERMAL – of or relating to the action of water under conditions of high temperature.[58]

GEOSPATIAL -- Relating to or denoting data that is associated with a particular location.[59]

GIGAWATT (GW) -- One thousand megawatts (1,000 MW) or, one million kilowatts (1,000,000 kW) or one billion watts (1,000,000,000 watts) of electricity. One gigawatt is enough to supply the electric demand of about one million average California homes.

GIGAWATT-HOUR (GWH) -- One million kilowatt-hours of electric power. California's electric utilities generated a total of about 302,072 gigawatt-hours in 2007.

H2@SCALE -- H2@Scale is a concept that explores the potential for wide-scale hydrogen production and utilization in the United States to enable resiliency of the power generation and transmission sectors.[60]

INTERMITTENT - Coming and going at intervals: not continuous.[61] Used to describe electric generation resources whose production is controlled by resource availability such as wind and solar energy.

JOULE -- A unit of work or energy equal to the amount of work done when the point of application of force of 1 newton is displaced 1 meter in the direction of the force. It takes 1,055 joules to equal a British thermal unit. It takes about 1 million joules to make a pot of coffee.

[56] Lexico dot-com https://www.lexico.com/en/definition/forecourt
[57] National Energy Technology Lab Web Page on Gasifier Types https://www.netl.doe.gov/research/Coal/energy-systems/gasification/gasifipedia/types-gasifiers
[58] Collins Dictionary dot-com https://www.collinsdictionary.com/us/dictionary/english/hydrothermal
[59] Lexico dot-com https://www.lexico.com/en/definition/geospatial
[60] US DOE H2@Scale Web Page https://www.energy.gov/eere/fuelcells/h2scale
[61] Merriam Webster dot-com https://www.merriam-webster.com/dictionary/intermittent

LEVELIZED COST OF ENERGY (LCOE) - Defined as the total lifetime cost of an investment divided by the cumulated generated energy by this investment.[62]

LEARNING CURVE - A curve plotting performance against practice especially one graphing decline in unit costs with cumulative output.[63]

LIQUEFACTION - The process of making something, especially a gas, liquid.[64]

LIQUID ORGANIC CARRIER – A class of materials that can be reversibly hydrogenated in large central plants using established industrial methods with high efficiency through recovery and utilization of the heat liberated in the exothermic hydrogenation reaction[65]

LOAN GUARANTEE -- A guaranteed loan is a loan that a third-party guarantees – or assumes the debt obligation for – in the event that the borrower defaults. Sometimes, a guaranteed loan is guaranteed by a government agency, which will purchase the debt from the lending financial institution and take on responsibility for the loan.[66]

MARKET BARRIERS – The term includes barriers to entry which is the economic term describing the existence of high start-up costs or other obstacles that prevent new competitors from easily entering an industry or area of business. Barriers to entry benefit existing firms because they protect their revenues and profits.[67] As used in the renewable hydrogen roadmap project, the term also includes barriers to successful growth of the market as a whole.

MEGAWATT (MW) - One-thousand kilowatts (1,000 kW) or one million (1,000,000) watts. One megawatt is enough electrical capacity to power 1,000 average California homes. (Assuming a loading factor of 0.5 and an average California home having a 2-kilowatt peak capacity.)

MEGAWATT HOUR (MWh) - One-thousand kilowatt-hours, or an amount of electrical energy that would supply 1,370 typical homes in the Western U.S. for one month. (This is a rounding up to 8,760 kWh/year per home based on an average of 8,549 kWh used per household per year [U.S. DOE EIA, 1997 annual per capita electricity consumption figures]).

MERCHANT HYDROGEN -- The merchant hydrogen market is classified as hydrogen produced by a producer and sold to a consumer by pipeline, bulk tank or cylinder (including small cylinders) truck delivery. This hydrogen can be generated from a central production facility or onsite.[68]

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[62] A. Mohammadi and M. Mehrpooya, "A comprehensive review on coupling different types of electrolyzer to renewable energy sources," *Energy*, vol. 158, pp. 632–655, 2018.

[63] Merriam Webster dot-com https://www.merriam-webster.com/dictionary/learning%20curve

[64] Lexico dot-com   https://www.lexico.com/en/definition/liquefaction

[65] US DOE Web Page on Liquid Carriers
https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/liquid_carrier_h2_storage.pdf

[66] Investopedia dot-com https://www.investopedia.com/terms/g/guaranteed-loan.asp

[67] Investopedia dot-com https://www.investopedia.com/terms/b/barrierstoentry.asp

[68] US DOE Web Page on Hydrogen Production
https://www.hydrogen.energy.gov/pdfs/12014_current_us_hydrogen_production.pdf

METHANATION – A chemical process that converts carbon oxides and hydrogen in syngas to methane and water.[69]

MOORE'S LAW -- Moore's law here refers to the generalized statement that the cost Y of a given technology decreases exponentially with time as $Y(t) = B*exp(-mt)$.(Nagy et al. 2012)

NAMEPLATE CAPACITY - (also INSTALLED CAPACITY): The total manufacturer-rated capacities of equipment such as turbines, generators, condensers, transformers, and other system components.

OPTIMIZATION - Maximizing or minimizing some function relative to some set, often representing a range of choices available in a certain situation. The function allows comparison of the different choices for determining which might be "best." Mathematical optimization is the process of maximizing or minimizing an objective function by finding the best available values across a set of inputs.[70]

ORGANICS – (also ORGANIC COMPOUNDS) A large group of chemical compounds containing mainly carbon, hydrogen, nitrogen and oxygen. All living organisms are made up of organic compounds.

PADD (PETROLEUM ADMINISTRATION FOR DEFENSE DISTRICTS) -- The United States is divided by the U.S. Department of Energy into five PADD regions for planning purposes. The states within PADD V are Alaska, Arizona, California, Hawaii, Nevada, Oregon and Washington, which are linked closely by their oil supply network. Since very little petroleum product is export outside the district, PADD V is essentially a self-contained oil supply system with Alaska and California the main producers and California refining the majority of the crude oil consumed in the PADD.

PATHWAY -- A renewable fuel pathway includes three critical components: (1) feedstock, (2) production process and (3) fuel type. Each combination of the three components is a separate fuel pathway.[71] The term can also be extended to include transport and use steps to define a complete end-to-end series of steps from production through use.

PETAJOULE - The petajoule (PJ) is equal to one quadrillion (10^{15}) joules.[72]

POLYMER ELECTROLYTE MEMBRANE (PEM) Electrolyzer -Also called proton exchange membrane electrolyzers— use a polymer membrane as the electrolyte and protons as the charge carrier.

PRESSURE SWING ADSORPTION – A commonly used industrial process for the purification of gas streams. Pressure swing systems are based on selective adsorbent beds. A gas mixture is introduced to the bed at an elevated pressure and the solid adsorbent selectively "adsorbs"

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[69] National Energy Technology Lab Web Page on Coal to SNG https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/coal-to-sng

[70] J. S. Arora, "What is optimization?" Struct. Eng. Nat. Hazards Mitig., pp. 1608–1613, 1993.

[71] US EPA RFS Web Page on Fuel Pathways https://www.epa.gov/renewable-fuel-standard-program/what-fuel-pathway

[72] McGraw-Hill Dictionary of Physics, Fifth Edition (1997). McGraw-Hill, Inc.

certain components of the gas mixtures, allowing the unadsorbed components to pass through the bed as purified product gas.[73]

PROGRESS RATIO (PR) -- The ratio of final to initial costs associated with a doubling of cumulative output.[74]

PYROLISIS – The breaking apart of complex molecules by heating in the absence of oxygen, producing solid, liquid, and gaseous fuels.

REAL-TIME PRICING -- The instantaneous pricing of electricity based on the cost of the electricity available for use at the time the electricity is demanded by the customer.
REFORMATION – Chemical process of rearranging hydrocarbons to form a desired end product[75]

REFORMER – A device that performs reformation reactions.

SELF-SUSTAINING -- Able to continue in a healthy state without outside assistance.[76]

SOLID OXIDE ELECTROLYZER (SOEC) - Solid oxide electrolyzers use a hard, non-porous ceramic compound as the electrolyte and oxygen (O^{2-}) as the charge carrier.

SPATIAL -- Related to or existing within space. Spatial data can include information about the locations and shapes of geographic features and the relationships between them, usually stored as coordinates and topology.[77]

STEAM METHANE REFORMATION (SMR) – A mature production process in which high-temperature steam (700°C–1,000°C) is used to produce hydrogen from a methane source, such as natural gas. In steam-methane reforming, methane reacts with steam under 3–25 bar pressure (1 bar = 14.5 psi) in the presence of a catalyst to produce hydrogen, carbon monoxide, and a relatively small amount of carbon dioxide. Steam reforming is endothermic—that is, heat must be supplied to the process for the reaction to proceed.[78]

SUPPLY CHAIN -- The sequence of processes involved in the production and distribution of a commodity.[79]

SUPPLY CURVE -- The supply curve is a graphic representation of the correlation between the cost of a good or service and the quantity supplied for a given period. In a typical illustration,

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[73] NREL Hydrogen Refueling Appliance Report Page 3   https://www.nrel.gov/docs/fy02osti/32405b2.pdf
[74] Cambridge University Energy Policy Research Group Paper on Learning Curve
https://www.eprg.group.cam.ac.uk/wp-content/uploads/2014/01/eprg0703.pdf
[75] US EPA Web Page on Petroleum Refining Effluent Guidelines https://www.epa.gov/eg/petroleum-refining-effluent-guidelines
[76] Lexico dot-com   https://www.lexico.com/en/definition/self-sustaining
[77] esri GIS Dictionary   https://support.esri.com/en/other-resources/gis-dictionary/term/e013cf2e-5b34-466d-b98b-865dc50ed4f2
[78] US DOE Web Page on Hydrogen Production https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming
[79] Lexico dot-com   https://www.lexico.com/en/definition/supply_chain

the price will appear on the left vertical axis, while the quantity supplied will appear on the horizontal axis.[80]

TECHNO-ECONOMIC ASSESSMENT or TECHNO-ECONOMIC ANALYSIS (ABBREVIATED TEA) – A methodology framework to analyze the technical and economic performance of a process, product or service. TEA normally combines process modeling, engineering design and economic evaluation.[81]

TEMPORAL --Specifically referring to times or dates. Temporal data may refer to discrete events, such as lightning strikes, moving objects, such as trains, or repeated observations, such as counts from traffic sensors.[82]

TERMINAL – A facility to receive hydrogen for storage and later transport to end users. The definition is based on oil terminals which serve similar function and are defined as "an industrial facility for the storage of oil and/or petrochemical products and from which these products are usually transported to end users or further storage facilities."[83]

THERMOCHEMICAL (TC) – In biomass conversion, the chemical process of breaking down feedstocks using heat. Examples of thermochemical conversion processes include gasification and pyrolysis.[84]

TIME-OF-USE (TOU) RATES -- The pricing of electricity based on the estimated cost of electricity during a particular time block. Time-of-use rates are usually divided into three or four time blocks per twenty-four hour period (on-peak, mid-peak, off-peak and sometimes super off-peak) and by seasons of the year (summer and winter). Real-time pricing differs from TOU rates in that it is based on actual (as opposed to forecasted) prices which may fluctuate many times a day and are weather-sensitive, rather than varying with a fixed schedule.

TIPPING FEE -- A tipping fee is the charge levied upon a given quantity of waste received at a waste processing facility.[85] In the future, the waste processing facility may often be a renewable fuel production facility.
TRI-GENERATION – In fuel cell technology, an integrated energy system that generates three products: heat, electricity, and hydrogen.[86]

VARIABLE O&M - Variable O&M costs are operations and maintenance expenses that do vary based on production volume of a facility.

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[80] Investopedia dot-com   https://www.investopedia.com/terms/s/supply-curve.asp
[81] Wikipedia dot-org   https://en.wikipedia.org/wiki/Techno-economic_assessment
[82] esri GIS Dictionary https://support.esri.com/en/other-resources/gis-dictionary/term/e013cf2e-5b34-466d-b98b-865dc50ed4f2
[83] Wikipedia dot-org https://en.wikipedia.org/wiki/Oil_terminal
[84] US DOE Bioenergy Program Page on Thermochemical Conversion
https://www.energy.gov/eere/bioenergy/thermochemical-conversion-processes
[85] Wikipedia dot-com   https://en.wikipedia.org/wiki/Gate_fee
[86] US DOE Web Page on Fountain Valley Tri-gen   https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/tri-generation_fountainvalley.pdf

WRIGHT'S LAW -- Wright's law postulates that cost decreases at a rate that depends on cumulative production. Wright's law is often interpreted to imply "learning by doing".[87]

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[87] Nagy, Béla, J Doyne Farmer, Quan M Bui, and Jessika E Trancik. 2012. "Statistical Basis for Predicting Technological Progress."

ACRONYMS AND ABBREVIATIONS

AB – Assembly Bill

AD – Anaerobic Digestion or Digester

ARB – California Air Resources Board

BTR – Billion Tons Report, by the U.S. Department of Energy. 2016.

CCUS – Carbon Capture Utilization and Storage

CEPCI -- Chemical Engineering Plant Cost Index

CEQA – California Environmental Quality Act

CI – Carbon Intensity

CPUC – California Public Utilities Commission

CTP – Clean Transportation Program

DAC – Disadvantaged Community

DME – Dimethyl Ether

DOE – United States Department of Energy

dt – Dry Ton

EER – Energy Economy Ratio

EJ – Exajoule or Environmental Justice

EIA – Energy Information Administration

EIR – Environmental Impact Report

ELY – Electrolyzer

EPA – Environmental Protection Agency

FCEV – Fuel Cell Electric Vehicle

FOM – Fixed Operations and Maintenance

GJ – Gigajoule

GW – Gigawatt

GWh – Gigawatt hour

H2 – Hydrogen

H2A – United States Department of Energy Hydrogen Analysis Tool

HD – Heavy Duty

HHV – Higher Heating Value

LCFS – Low-carbon Fuel Standard

LCOE – Levelized Cost of Energy or Levelized Cost of Electricity

LDV – Light-duty Vehicle

LHV – Lower Hearing Value

LOHC – Liquid Organic Hydrogen Carrier

MD – Medium Duty

MJ – Megajoule

MMT – Million metric tonnes

MSS – Mobile Source Strategy

MSW – Municipal Solid Waste

MW – Megawatt

MWh – Megawatt-hour

NREL – National Renewable Energy Laboratory

OGV – Ocean-going Vessel

PADD – Petroleum Administration for Defense District

PEIR – Program Environmental Impact Report

PEM – Polymer Electrolyte Membrane or Photon Exchange Membrane

PJ – Petajoule

PSA – Pressure-swing Adsorption

PV – Photovoltaic

RD&D – Research Development and Demonstration

RH2 – Renewable Hydrogen

RIN – Renewable Energy Number

RPS – Renewable Portfolio Standard

SB – Senate Bill

SLCP – Short-lived Climate Pollutant Strategy

SMR – Steam Methane Reformer

TC – Thermochemical

TEA – Techno-economic Analysis

TOU – Time of Use

tpd – Tons per day

VOM – Variable Operations and Maintenance

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APPENDIX A:
Renewable Hydrogen Production Technology Characterization and Forecasts

Introduction and Overview

This appendix summarizes the results of the technology characterization task of the Roadmap for the Deployment and Buildout of Renewable Hydrogen Generation Plants (agreement number 600-17-008). The objective of the task is to assess and document the current and potential future cost and performance parameters of the primary renewable hydrogen production pathways. These cost and performance trajectories are a key input to the development of representative least-cost buildout scenarios to guide policy and planning.

Figure A-1 shows the various pathways for production of renewable hydrogen and renewable methane (which in combination with CO_2 is a feedstock for renewable hydrogen via methanation). The focus of this interim report is on the period from current to 2030. Three renewable hydrogen production technology classes are considered: electrolysis, thermochemical, and anaerobic digestion with reformation. Carbon capture is not considered in this study, although it might be considered in future work. Artificial photosynthesis is at the basic research phase and not likely to reach commercial maturity prior to 2030. Table A-1 summarizes the primary characteristics of the technologies considered in this assessment.

Figure A-1: Renewable and Zero-Carbon Hydrogen and Methane Pathways
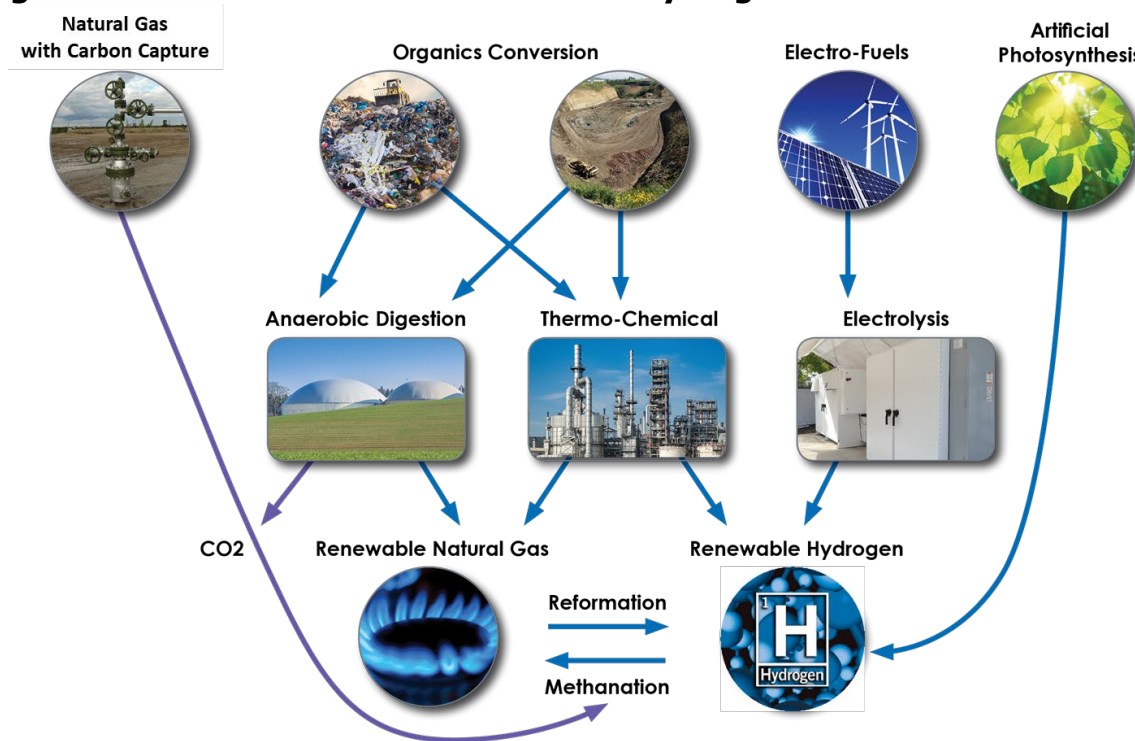
Source: UCI APEP

Table A-1: Renewable Hydrogen Production Technology Summary

Technology Group	Subgroups	Description	Deployment Status
Electrolysis	Alkaline Polymer Electrolyte Membrane (PEM) Solid Oxide	Uses applied voltage to drive a catalyzed electrochemical reaction completed via an electrolyte to evolve hydrogen and oxygen	Commercial
Anaerobic Digestion	High vs. low solids Batch vs. continuous Note: Tier 1 covered lagoon for dairy and complete mix continuous flow for MSW assumed for this study	Decomposition of organic material via anaerobic reaction to form methane, CO2 and minor constituents	Commercial
Thermochemical	Gasification (several types) Pyrolysis Hydrothermal Note: Gasification using circulating-fluidized bed assumed for this study	Use of heat and/or pressure to extract volatile material from biomass producing syngas (mostly hydrogen and carbon-monoxide) which is further reacted and purified to hydrogen or methane	Commercial Prototype

Source: UCI APEP

Multiple technologies and vendors are represented within each technology group. The present analysis is not intended to represent any view on which technologies or vendors will ultimately prove to be the most successful but rather to create representative scenarios for the resource mix needed to serve the growing demand for renewable hydrogen over time and identify investment requirements, policy support needed, barriers and solutions to support successful launch and scaling of the renewable hydrogen sector in California. This is closely analogous to the extensive body of analysis used to support the hydrogen refueling station (HRS) network deployment supported by the incentives authorized under Assembly Bill 118 (2007) and Assembly Bill 8 (2013).

Methods

A variety of methods are employed to forecast technology cost and performance. These include:

- Expert elicitation (researchers, equipment vendors).

- Progress rate or learning rate analysis (cost reduction based on time or cumulative production.

- Bottom-up analyses based on design, bill-of-materials and production scale.

- Analogy or proxy analysis.

- Current cost benchmarking or trend analysis based on vendor bids "as-built" data.

Depending on the availability of recent published reports and studies, different methods were employed for different technologies. Learning rate (or progress curve) analysis was a primary method and was applied to all technology groups. Several variants of learning rate or progress rate methods have been proposed for estimating technological progress and resultant reductions in cost and improvement in performance. These include Moore's law (Moore 1965), Wright's law (Wright 1936), and other variants (Nagy et al. 2012). Nagy et al. tested these different methods for estimating technological progress based on a database of 62 different technologies and showed that Wright's law and Moore's law perform essentially the same with a slightly better performance by Wright's law. Moore's law and Wright's law are both examples of single-factor models. Some researchers have suggested multi-factor models adding, for example, R&D spending as an additional parameter. Multi-factor methods face the challenge that obtaining factor data (such as market growth and R&D spend) can be challenging. Due to availability of data, only Wright's law was used for the present study.

Wright's law projects future capital costs based on the cumulative capacity produced (in contrast to Moore's law which uses time as the independent variable). The equation for Wright's law can be written as (Ferioli, Schoots, and van der Zwaan 2009):

$$C\ (p_t) = C\ (p_i)(\frac{p_t}{p_i})^{-b}$$

Where p_i is the cumulative production (total units or capacity produced from market entry to the initial time point of the analysis), p_t is the cumulative production at time t, and C is the unit cost as a function of cumulative production. b is an exponential learning parameter related to the learning rate (LR) by the equation LR = 1 - 2^{-b} where the learning rate is the relative reduction in cost for each doubling of cumulative production. Figure A-2 shows the probability distribution of learning rates for various industrial technologies collected from 108 studies (Ferioli, Schoots, and van der Zwaan 2009). The data show that most technologies show significant learning effect with most technologies above 10 percent. Technologies with negative learning rate are rare but this can occur if when long-term upward pressures impact cost due to factors such as regulation as would be seen with nuclear power plants. Learning rates generally decline as technologies reach full maturity. Lead-acid batteries are an example of a technology that has reached a low learning rate.

When applying Wright's Law (cost reduction based on cumulative global production) two primary factors must be established, the forward-looking growth in cumulative production and the learning rate. Figure A-3 illustrates the impact of uncertainty in learning rate and growth in cumulative production on cost progression.

All costs in this study are normalized to constant 2018 dollars ($2018). Substantial spread in cost data exists even for current costs. Some degree of variance relates to fundamental variation in project-to-project costs at a given time point due to unique site characteristics, local differences in cost factors and competitive factors. Uncertainty also exists based on a variety of factors including differences in scope of equipment included in reported costs, normalization of facility scale, differing currency mixes and uncertainty in cost indexation (inflationary adjustment). The range of potential impact of the various indexation factors is illustrated in Figure A-4. As shown in Figure A-5, the renewable hydrogen production pathways considered in this study also show significant scale dependence, although electrolysis shows lower scale sensitivity than gasification and anaerobic digestions. Differences in facility size must be normalized in order to accurately compare costs. Overall, the uncertainty in current cost benchmarks is in the range of +/- 25 percent.

Figure A-2: Probability Distribution of 108 Studies That Report Learning Rates in 22 Industrial Sectors
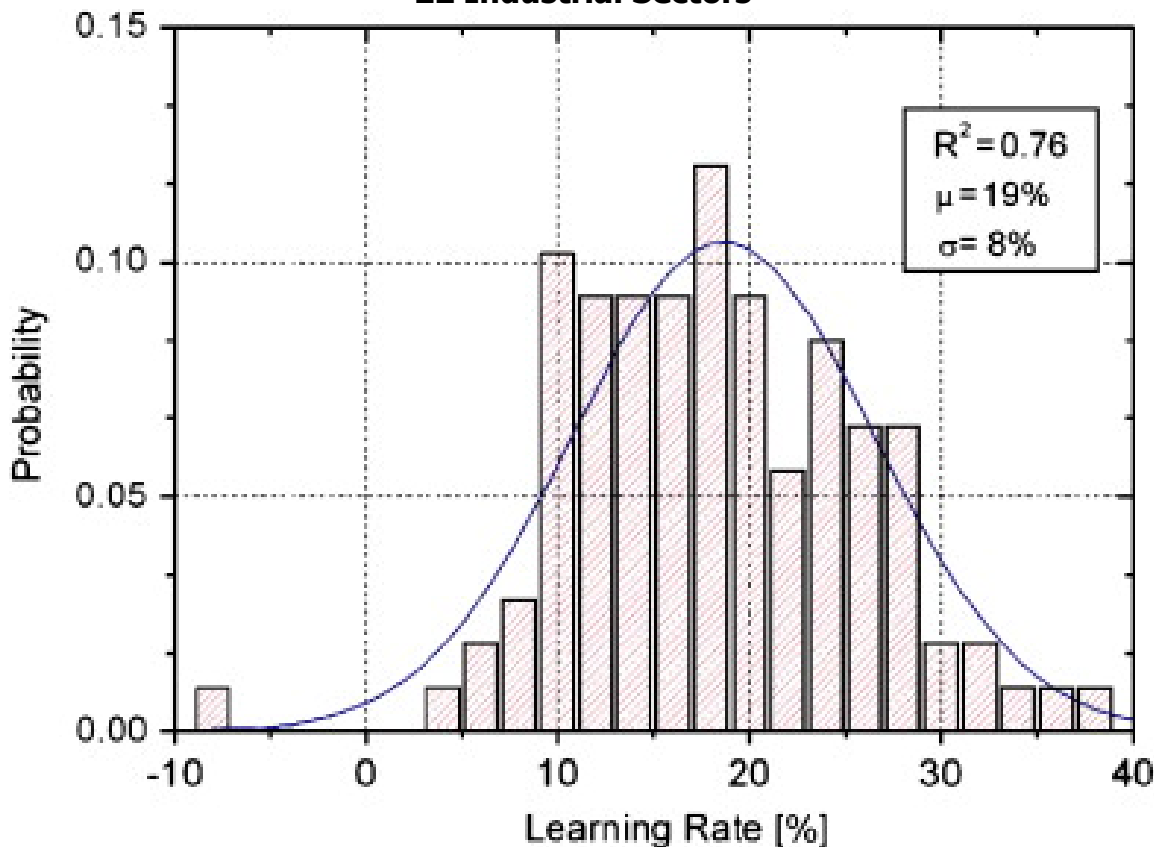
Source: (Ferioli, Schoots, and van der Zwaan 2009)

Figure A-3: Illustration of Learning Rate Sensitivities
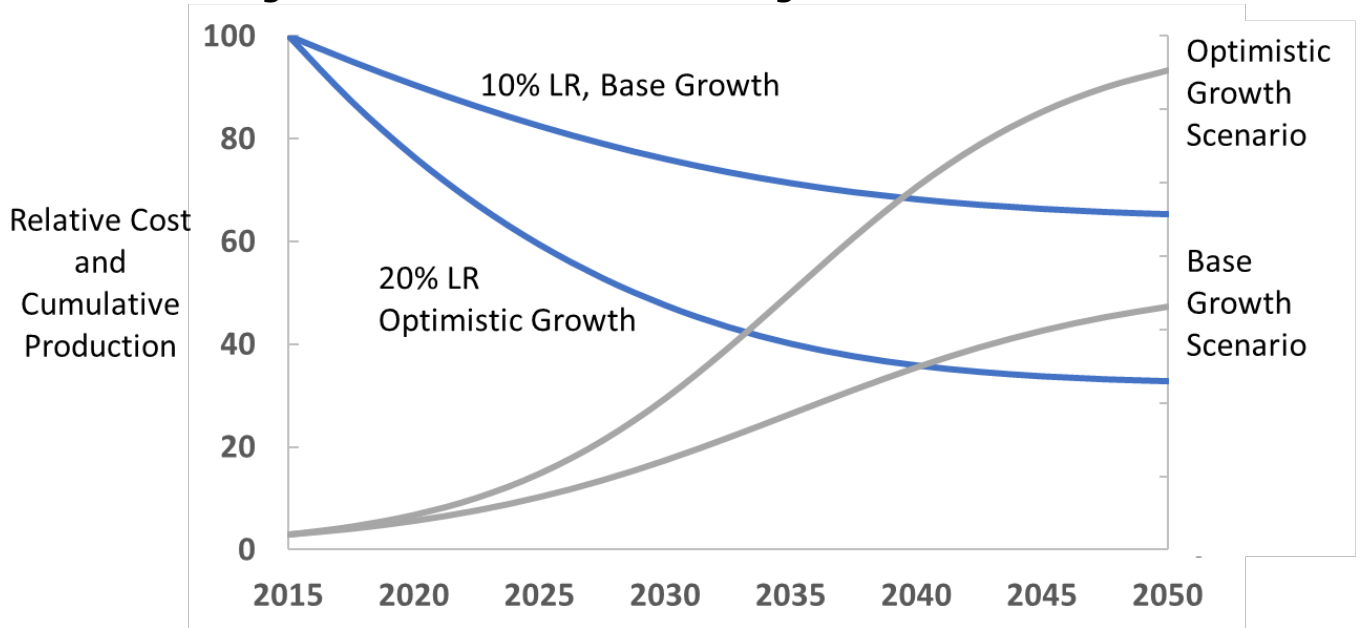
Source: UCI APEP

Figure A-4: Normalizing Indices Used in This Study
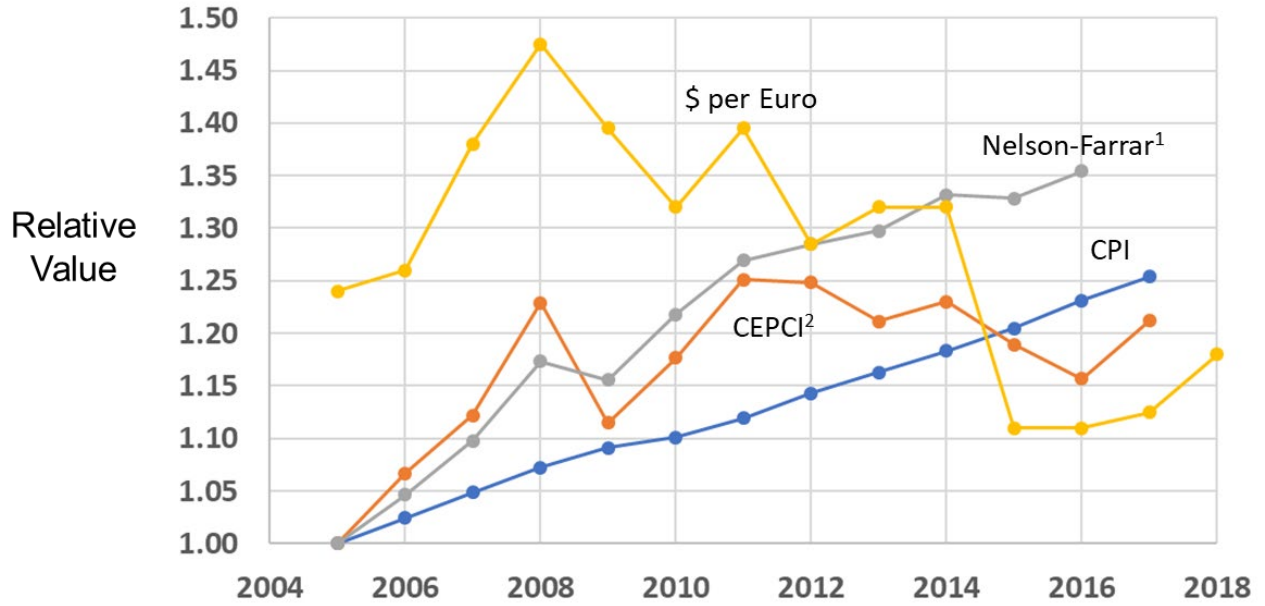
1 Refinery cost escalation index
2 Chemical Engineering Plant Cost Index

Source: UCI APEP

Figure A-5: Scale Dependency of Hydrogen Production System Capital Cost
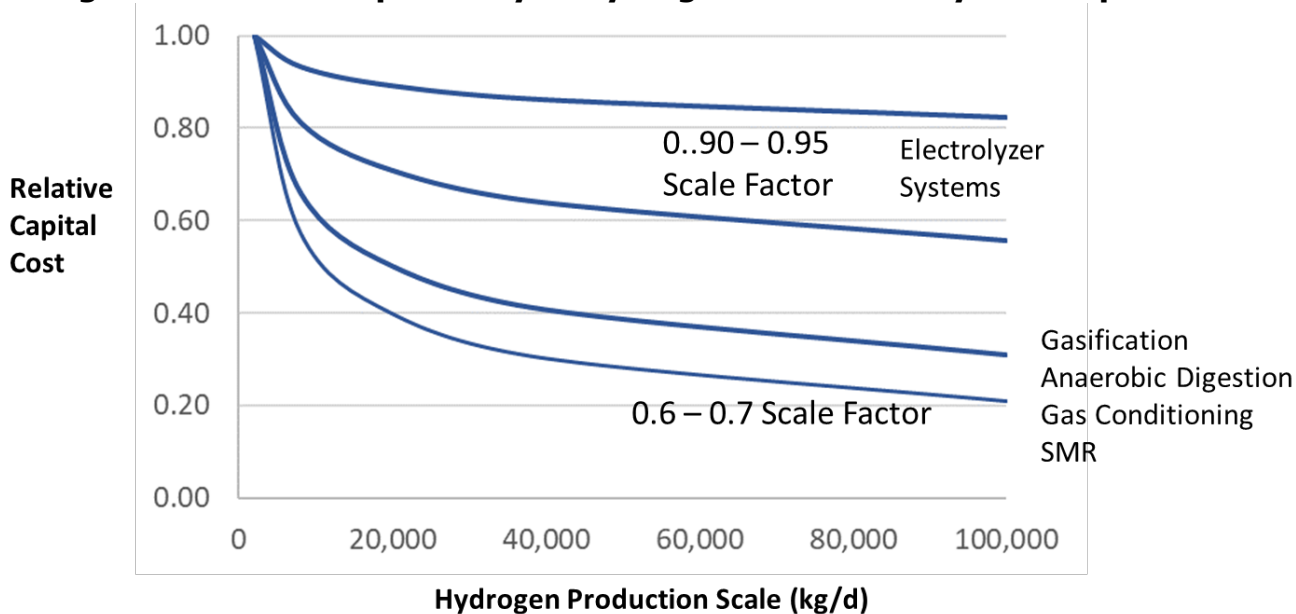
Source: UCI APEP

Electrolysis Cost and Performance Assessment

Overview and Technology Maturity

Electrolysis is the electrochemical process of splitting water into its constituents, hydrogen and oxygen, using electrical energy. The reaction is accomplished using an electrolyte to transfer ions between the anode and the cathode as shown in Figure A-6. Various electrolytes are used and require different operating temperatures and show differences in dynamic operation. Three types of electrolyzers were assessed in the present study: alkaline electrolyzers (AECs), proton-exchange membrane electrolyzers (PEMECs), and solid oxide electrolyzers (SOECs). Alkaline electrolyzers have been in commercial deployment since the 1960s and are commercially mature and an estimated global cumulative capacity base of about 25 GW_e (Schmidt, Gambhir, et al. 2017). PEM electrolyzers have been in commercial deployment for roughly 10 years and have a global cumulative capacity base of about 1 GW_e (ibid.). Solid oxide electrolyzers are in precommercial development and expected to reach commercial readiness in the early 2020s.

Electrolyzer Capital Cost Assessment

The current cost and performance of electrolyzer systems were benchmarked using a variety of sources including vendor bids from the recent CEC solicitation GFO-17-602 (602), recent published work from the U.S. Department of Energy, vendor interviews, and peer-reviewed literature. Cost and performance forecasts were derived through compilation of published forecasts, vendor input, and application of learning curve analysis. As a point of reference, Figure A-9 shows a typical cost breakdown for a complete, installed electrolytic hydrogen production system. The core technology components (stacks and power electronics) comprise roughly 55 percent of total cost. These cost elements offer the greatest potential for cost reduction based on R&D, design innovation, and production scale. General plant equipment

will benefit from purchasing volume and engineering and permitting from repeat effects and standardization.

Figure A-6: Electrolyzer Types
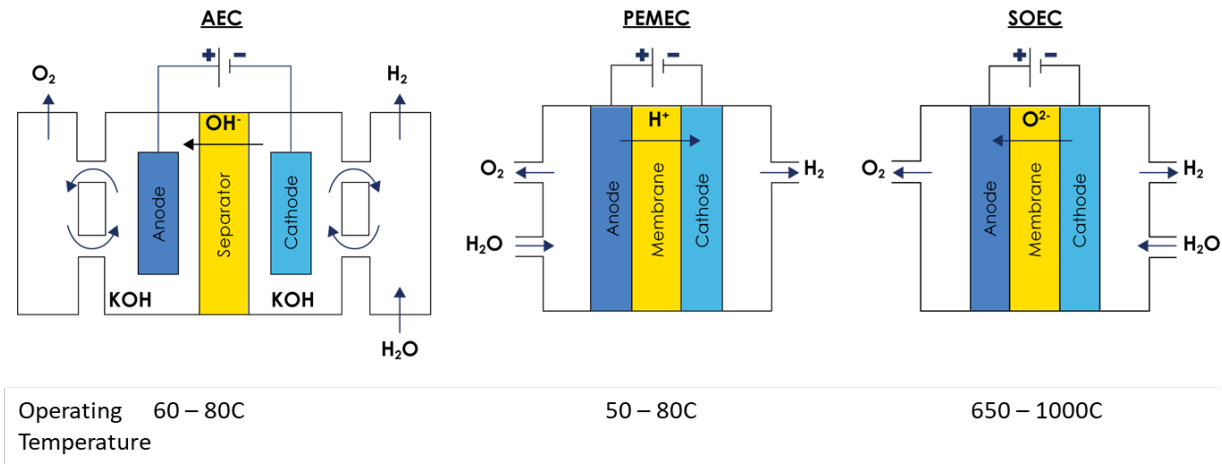
Table A-2 provides a summary of the primary sources used for the analysis. Figures A-8 and A-9 show the compiled data for PEM and alkaline electrolyzers. Solid-oxide electrolyzers will be addressed later in this section.

The GFO-17-602 bids reflect price rather than cost. However, the other sources include cost of capital (return on equity) in their assessment so all the data can be considered "cost" inclusive of cost of capital. The variation in the data is significant but most of the data for PEM systems cluster in a range of roughly $1,200/kW to $1,400/kW with an average of $1,320/kW. For this study, the project team took the average value of $1,320 as the base case, current cost for PEM systems with an uncertainty band of +/- 25 percent.

The data set for current alkaline electrolyzer costs is less extensive than for PEM. The expert elicitation study by Schmidt et al. provided a reference 2016 benchmark and 2020 cost projections (data were collected in late 2015) for alkaline electrolyzers as provided by 10 experts. One vendor also provided current cost information as part of the data for this study. The Schmidt forecast interpolated to 2018 yields a current cost of about $1,100/kW which is very close to the vendor provided estimate. An alternate approach is to consider data on relative (percentage difference in cost or cost ratio) rather than absolute. The Schmidt 2016 benchmark costs reflects alkaline systems 50 percent lower in cost than PEM and predicts a 15 percent to 35 percent differential in 2020. Vendor input suggests a current differential of 15 percent. For purposes of this analysis, a range of cost differential of 15 percent to 40 percent was used. Applying this range to the PEM base case of $1320/kW yields a range for alkaline system cost of roughly $800/kW to $1,100.

Figure A-7: Typical Electrolyzer Total System Capital Cost Breakdown
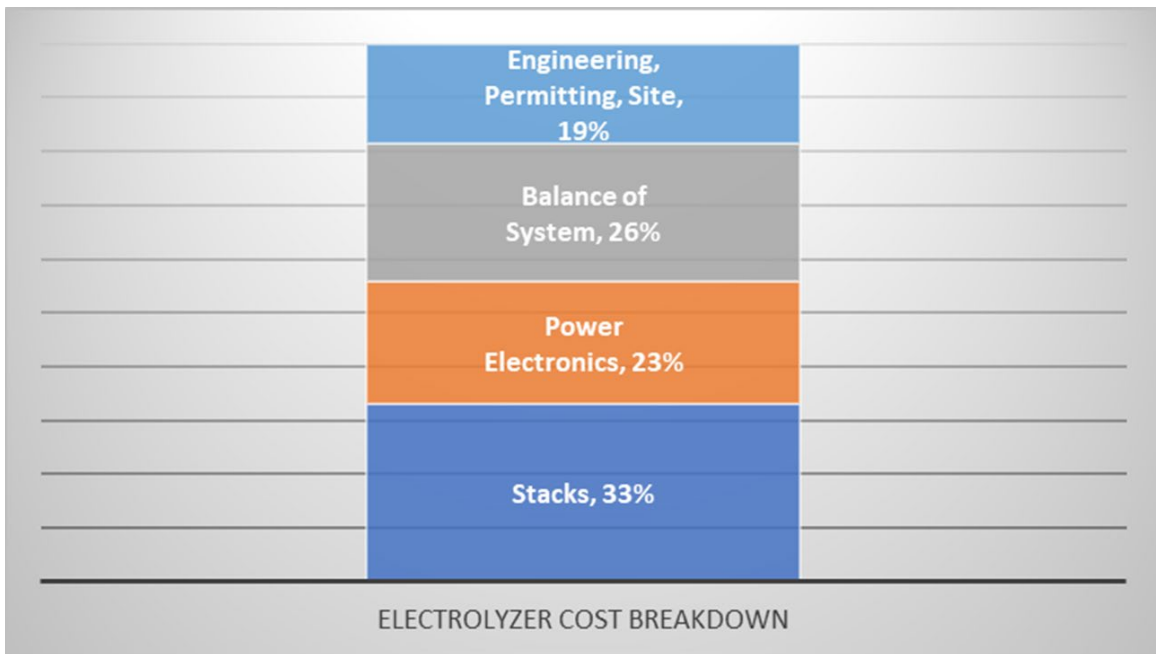
Source: UCI APEP based on (James and Moton 2014)

Table A-2: Primary Source for Electrolyzer Cost and Performance Analysis

Source	Scope and Method
(Schmidt, Gambhir, et al. 2017) Journal Article	Expert elicitation covering alkaline, PEM and solid-oxide electrolysis
(Schmidt, Hawkes, et al. 2017) Journal Article	Learning curve
(Bertociolli 2014) EU Report	Literature review and manufacturer input
(James and Moton 2014) DOE Report	Reference design analysis for PEM systems
GFO-17-602 bids to CA Energy Commission	Cost and efficiency data as provided in bid documents
Electrolyzer Companies	Interviews

Source: UCI APEP

Figure A-8: Cost Data and Projections for PEM Electrolyzer Systems (Installed System at MW Scale)
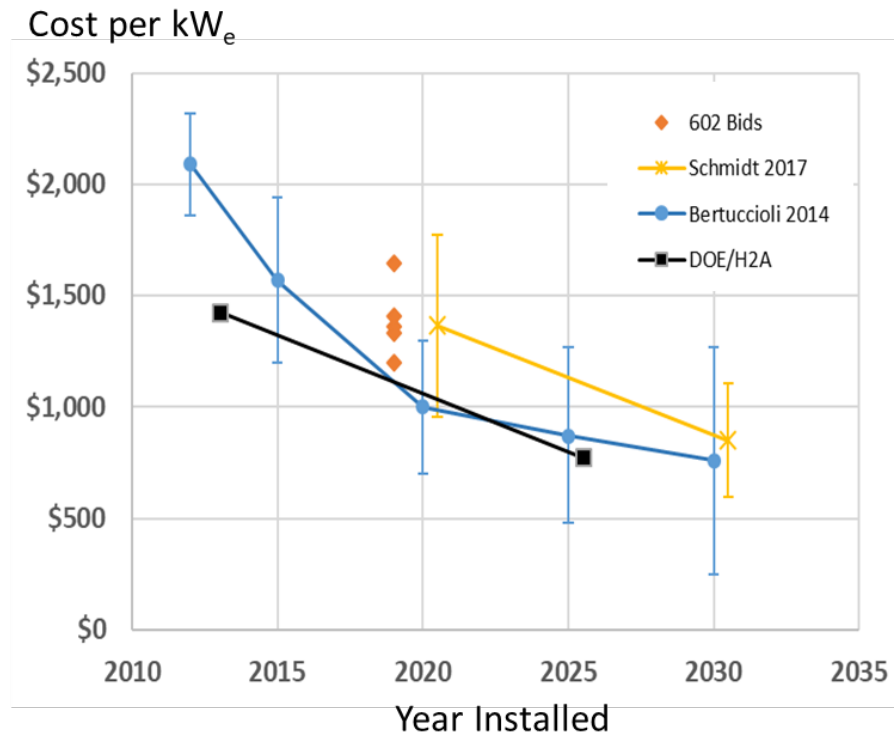
Sources: See Table A-2

Despite the lower cost and similar efficiency of alkaline systems, PEM was the predominant technology in the recent GFO-17-602 bids. Interview participants attributed this to the compact footprint of PEM systems and the need to manage a caustic electrolyte when employing alkaline technology.

All the forecast studies (Schmidt, Bertuciolli and DOE/H2A) project cost reduction of 30 percent to 50 percent over a 10-year horizon (with both alkaline and PEM falling within that range) as the technologies scale up. In general, alkaline technology is expected to show somewhat less cost reduction than PEM such that the technology costs become closer over time.

Solid oxide electrolyzers are expected to enter the market in the early to mid-2020s. As an emerging technology, SOEC system costs are on a steep improvement curve but, based on the Schmidt expert elicitation and interviews for this study, are expected to fall within the range of PEM and alkaline technologies from market entry through 2030 after which they may achieve superior cost and performance if commercialization is successful.

Figure A-9: Alkaline Electrolyzer System Costs (Installed System at MW Scale)

Cost per kW$_e$

Legend: Schmidt 2017 AEC, Vendor Data, PEM Discounted

Year Installed
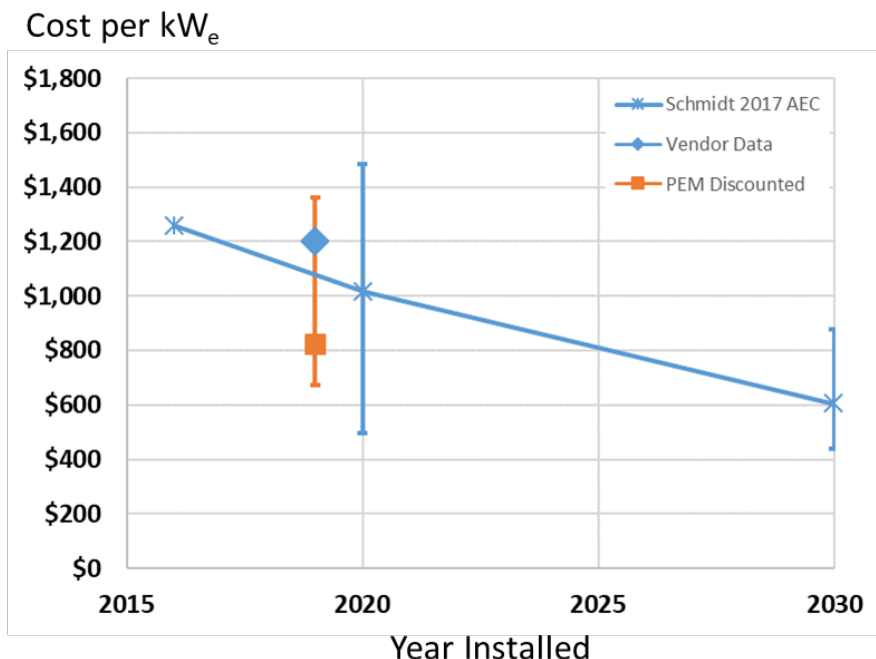
Sources: See Table A-2

Data (Schoots et al. 2008) show a compound average growth rate in electrolytic hydrogen production capacity of about 7 percent based on data through 2002. This was taken as the conservative case for the present analysis. Given the increased global activity in electrolyzers in power-to-gas and transportation fuel use, a higher growth rate of 15 percent was used for the optimistic case. For comparison, utility-scale solar installations have shown a sustained growth rate of more than 40 percent annually from 2009 through 2017 (International Energy Agency (EIA) 2018b) and the global electric vehicle population is forecast to show a 33 percent compound average growth rate from 2020 to 2030 (International Energy Agency (EIA) 2018a). Applying the noted learning and growth rates projects a cost reduction of 22 percent to 40 percent from current through 2030 for alkaline technology and of 28 percent to 50 percent for PEM technology. These reductions fall within the range of the published projections cited here.

As the technology selection for individual future projects is not known, the electrolyzer cost band to be used for this study will be a composite of all electrolyzer types. Figure A-10 shows the overall cost envelop for electrolyzer technologies to be used in this study through 2030. Projecting continued cost improvement at the same range of learning rates, the 2050 electrolyzer optimistic and conservative costs are projected to be $200 to $700 per kilowatt full installed cost. The data used for the electrolyzer cost analysis are for systems in the 1 MW to 3 MW range. A scale factor of 0.9 will be used for projecting cost of larger central installations.

Electrolyzer Conversion Efficiency and Operating Costs

Conversion efficiency is an important parameter in the economics of electrolytic hydrogen production. The total hydrogen production cost becomes higher as the unit cost of the input electricity increases. (Electricity cost assumptions are addressed in a later part of this study.)

Significant variation is present in reported and projected conversion efficiencies for the various electrolyzer types as shown in Figure A-11. Despite the variation across sources, agreement exists in the potential relative improvement in conversion efficiency over time with 10-year improvement potential in the range of 5 percent to 10 percent. For this study, the DOE current and future H2A PEM electrolysis cases (DOE H2A (U.S. Department of Energy) n.d.) were used.

Other non-electricity operating costs include fixed O&M (primarily replacement of components over the life of the system) and variable O&M (such as labor and consumable materials). These inputs were also taken from the H2A cases. Table A-3 below summarizes the current and 2030 values. An additional 5 percent improvement in conversion efficiency is assumed in 2050 (about half the near-term progress rate).

Figure A-10: Aggregate Electrolyzer Cost Forecast Current Through 2030
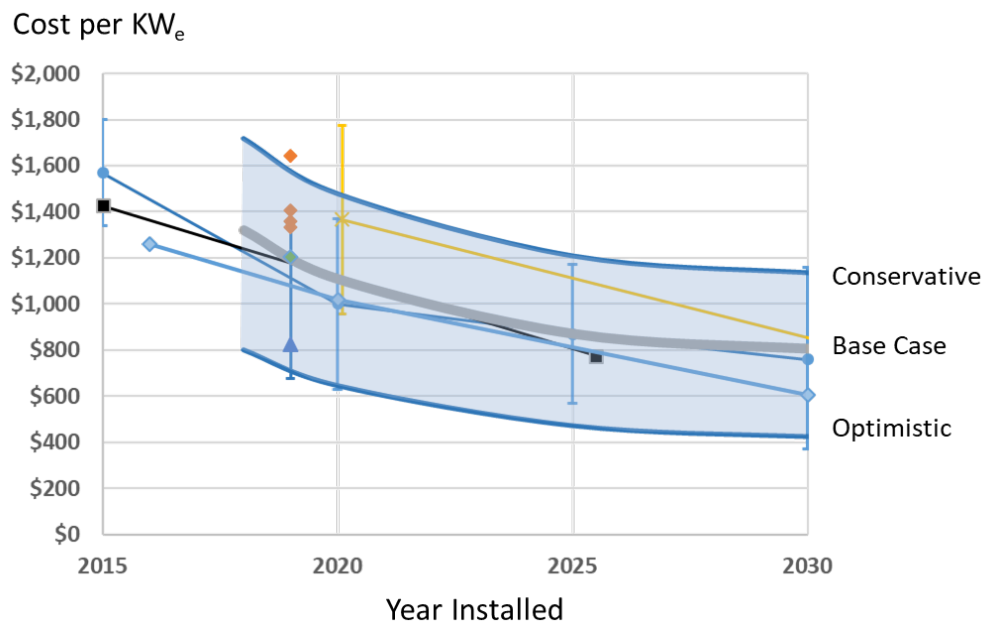
Source: UCI APEP

Methanation

Electrolytic hydrogen (and other forms of hydrogen) can be combined with CO_2 to form methane in a process called methanation. If the source of CO_2 is biogenic and the input electricity is renewable, the resultant fuel is renewable methane. Cost and energy penalties are incurred for adding the necessary process elements, but an advantage is gained in being able to transport product gas over the natural gas pipeline system and to maintaining the flexibility to product either hydrogen or methane. The necessary equipment adds roughly 25 percent to 35 percent to the project capital cost (Shaffer et al. 2019). The feasibility of this pathway for hydrogen production will be assessed based on the overall economics of the supply and delivery chain.

Figure A-11: Electrolyzer Conversion Efficiency Forecasts
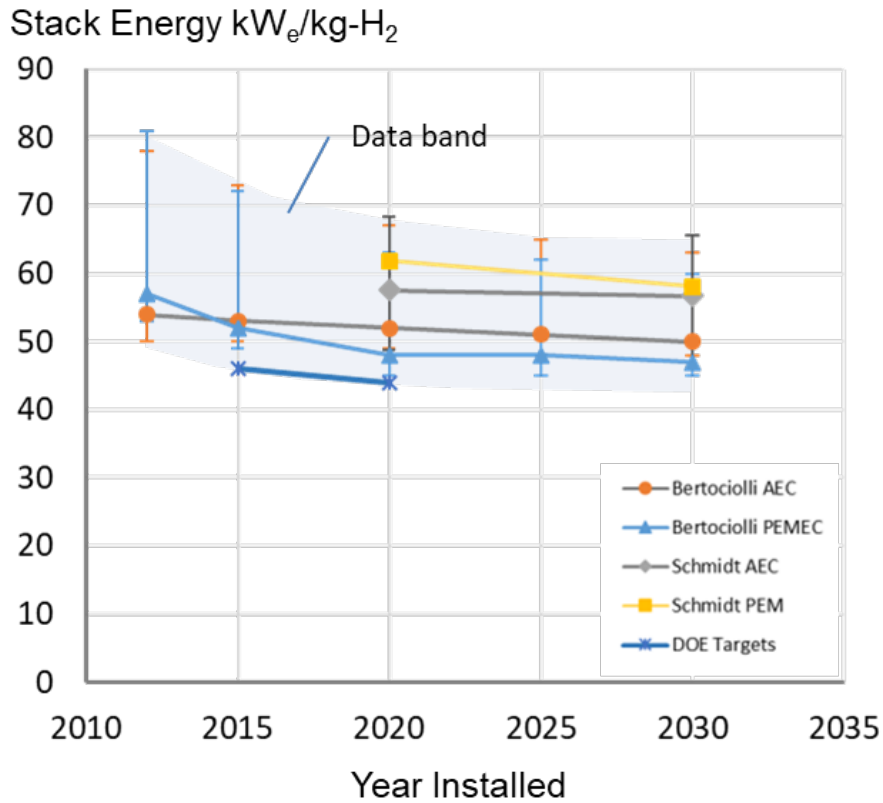
Sources: UCI APEP from references as noted

Table A-3: Electrolyzer Operating Parameters and Operating Cost

Electrolyzer Operating Parameters	Current	2030
Stack Electricity Use	49.2 kWh/kg	46.7 kWh/kg
Total System Electricity Use	54.6 kWh/kg	50.2 kWh/kg
Stack Life / Replacement Cost	60,000 hours 15% of Total Capex	85,000 hours 15% of Total Capex
Operation and Maintenance Expense	3% of Capex (3 MW) 1.75% of Capex (30 MW) 7-year stack life (15% of new system direct cost)	Pro-rate with Capex 9-year stack life
Water Consumed	4.76 gallons/kg	3.98 gallons/kg

Source: See Table A-2

Electrolyzer Siting and Permitting

Electrolyzer systems have a relatively small footprint, produce virtually no air emissions, and are acoustically benign. For these reasons, stakeholders report minimal difficulty with electrolyzer citing and permitting and that most industrially zoned land with adequate footprint and access to the electric grid (and gas grid if interconnected) is suitable for electrolyzer siting. Methanation projects also require access to a renewable CO2 source. Siting and permitting requirements are shown in Table A-4.

Table A-4. Electrolyzer System Siting and Permitting Requirements

Parameter	Requirement
Zoning	Industrial
Footprint	1 MW = 40 feet by 80 feet 30 MW = 0.25 acres
Feedstock Logistics	Proximate to electric transmission and/or collocated with dedicated renewable generation
Utilities	MW to multi-MW Electrical interconnection Water interconnection Natural gas interconnection depending on configuration
Ingress/Egress	1 tanker per day per 1,000 kg/d of production
Permitting	Minimal emissions so can be sited in nonattainment areas Can fall within existing CEQA approvals in industrial parks and existing projects' local building permits
Local Issues	Minimal emissions, visual or noise impacts

Source: UCI APEP, GFO-17-602 bids

Anaerobic Digestion, Conditioning, and Reformation Cost and Performance Assessment

Anaerobic digestion refers to the decomposition of organic matter in the absence of oxygen to produce methane, carbon dioxide and other minor constituents depending on the feedstock. The product gas is termed "biogas." The primary steps in the process are shown in Figure A-12. Because the organic feedstock is produced through a continuous carbon cycle (the carbon in the organic material is removed from the atmosphere during the growth cycle of plants), the material is a renewable resource. The methane in biogas can be converted through reformation to hydrogen. The gas is generally purified prior to conversion (CO2 and minor constituents removed) and, if adequately purified, can be transported over the natural gas system. Purified biogas is referred to as biomethane. Biomethane is interchangeable with conventional natural gas and can be converted to hydrogen via the same supply chain as fossil methane. Reformed biomethane, produced primarily from landfill gas, is the primary source of renewable hydrogen currently being dispensed in California today.

The full range of organic waste streams (and potentially energy crops) can be converted via anaerobic digestion although dry, woody material is more suitable for gasification. Digester feedstock can be broadly classified into low-solids substrates, which are defined as approximately <10 percent total solids, and high-solids substrates which are typically 20-40 percent total solids, respectively (Karthikeyan and Visvanathan 2013). In addition, digester

systems can be continuous flow (systems that receive feedstock continuously) or batch (discrete batches of feedstock are processed and removed after which the vessel is refilled). Several common types of digester systems are depicted in Figure A-13 although numerous design variations have been developed. Covered lagoon systems are the dominant technology for dairy digesters currently under development and are classified as low-solids, continuous flow systems. Continuous flow, high-solids systems are the dominant technology group for food and green waste. This is the assumed technology for processing landfill-diverted organic municipal solid waste for this study.

Figure A-12: Primary Steps in Anaerobic Digestion of Organic Feedstock

Hydrolysis

Large Polymers → Simple Monomers

↓

Acidogenesis

Simple monomers → VFAs

↓

Acetogenesis

VFAs → $CH_3COOH + CO_2 + H_2$

↓

Methanogenesis

$CH_3COOH → CH_4 + CO_2$

$CO_2 + 4H_2 → CH_4 + 2H_2O$
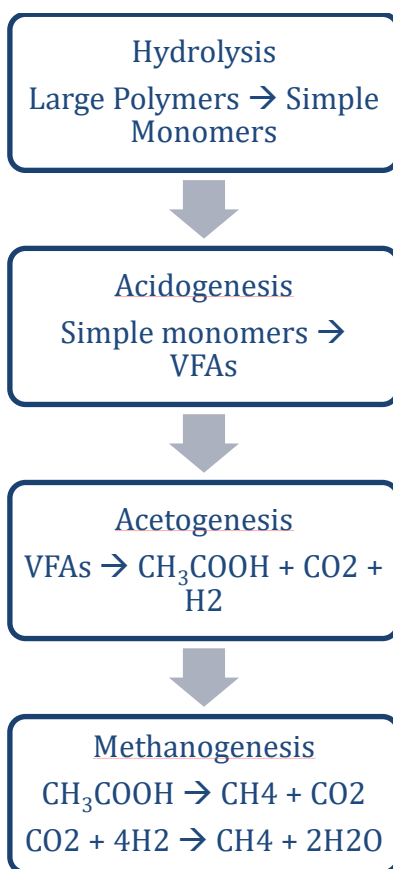
Source: (Shaffer et al. 2019)

Anaerobic digestion is a commercially mature technology that is widely used internationally for wastewater treatment and management of livestock waste. (Black & Veatch 2017) estimate 480 food and yard waste digesters worldwide. The EPA AgSTAR database (AgSTAR 2018) shows 278 animal waste digesters that have been constructed in the United States since 1997 and an annual growth rate in installations of 10 percent per annum over the most recent 10 years. Commercial systems are currently in operation in California for wastewater treatment, dairy manure management and processing of diverted food and green waste.

Figure A-14 shows representative costs and cost breakdown for two key classes of digesters, Tier 1 (double-lined) covered lagoon dairy digesters and above-ground, continuous-flow digesters (assumed for food and green waste). The tank digester cost and performance are representative of other designs that use concrete structures and have significant feedstock pre and postprocessing.

Figure A-13: Representative Anaerobic Digester Configurations
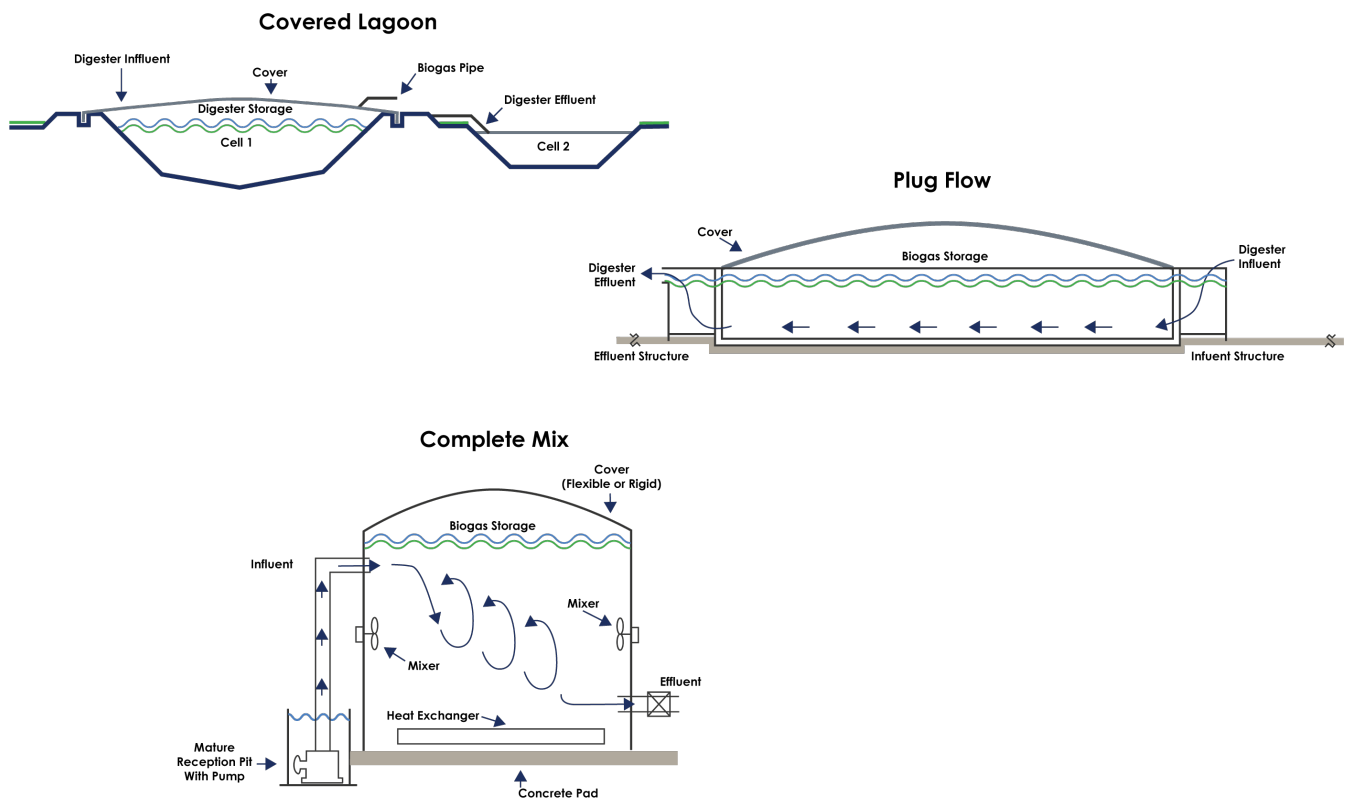
Source: UCI APEP

Figure A-14: Typical Total System Cost Breakdown for Anaerobic Digester Systems

$100 - $200/(MMBTU/yr)

$200 - $300/(MMBTU/yr)
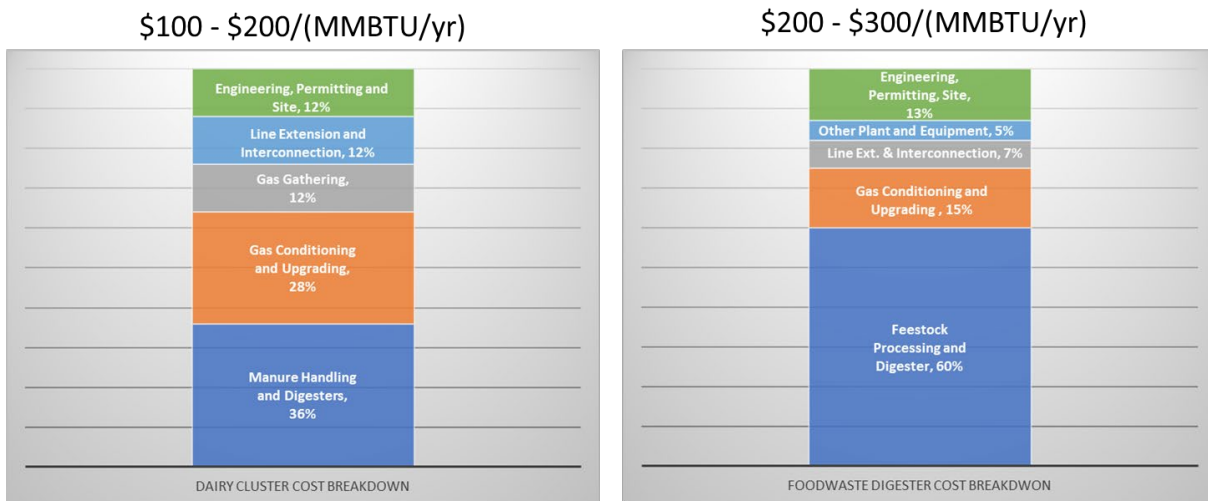
Source: Vendor data, ClimeCo and UCI APEP analysis

Figure A-15 shows the cost for Tier 1 covered lagoon and manure handling systems from a variety of sources as summarized in Table A-5. For this study, the best-fit curve shown was taken as the base-case current cost for covered lagoon systems.

Figure A-16 provides data for above-ground digester systems and includes full-system cost (feedstock management, digester, digestate management, gas conditioning, and interconnection). The Black and Veatch data are from a detailed study conducted in 2015 specific to the California market and show high and low ranges for two facility types. The costs are for reference system designs developed for the study. Costs were estimated based on vendor bids and actual project cost data. The cost information in the B&V report was converted to $2018 using the CPI and escalated according to the CEPCI. As can be seen, the batch system is about 20 percent less costly than the continuous, complete mix system. The data point for the CR&R project is based on published news reports on the project production capacity and capital cost. For this study, the base-case cost for complete-mix tank digester systems is given by the grey curve in the Figure A-16 with high and low bands spanning the available data. This will be used as the basis for above-ground digesters for food and green waste digestion.

No published studies on cost improvement potential for digester systems were found in the literature search conducted for this study. Interviews for this study indicate the potential for modest cost reductions through reduced soft costs, design standardization and procurement volume. The capital cost forecasts for biomethane will be discussed following the discussion of biogas conditioning and gas system interconnection.

Table A-5: Primary Source for Biomethane Cost and Performance Analysis

Source	Scope and Method
(Black & Veatch 2017) Consultant Report	Bottom-up study of cost and performance base on reference designs
(Bauer et al. 2013) Agency Report	Cost and performance profiles for five gas clean-up technology based on vendor bids
(Blumenstein, Siegmeier, and Detlev 2016) Journal Article	Study of agricultural digester economics for on-site power generation in Germany
ClimeCo Consultant Report (unpublished)	Compilation of vendor bids
CR&R Press articles	Press information and news articles on project design, scope and cost for CR&D Perris facility. (Lucas 2017; Goldstein 2017; Eisenmann 2015)
DOE H2A Case Studies. https://www.hydrogen.energy.gov/ h2a_prod_studies.html	Bottom-up cost and performance model for steam methane reformer facilities "CurrentCentral_H2Prod_NatGas_no_CO2Seq_3.110.xlsm", "FutureCentral_H2Prod_NatGas_no_CO2Seq_3.110.xlsm".
(Leme and Seabra 2017)	Comparative study if biogas conditioning technologies for application in Brazilian agriculture
(Ong et al. 2017) CEC Report	Survey of biogas conditioning technologies
U.S. EPA. "AgStar: Biogas Recovery in the Agriculture Sector". https://www.epa.gov/agstar	Dairy digester case studies and agricultural digester database
Project Developers	Interviews on technology cost and performance

Source: UCI APEP

Figure A-15: Tier 1 Covered Lagoon Digester System Capital Cost (Total System Installed)

$$y = 2375.6x^{-0.395}$$
$$R^2 = 0.7643$$
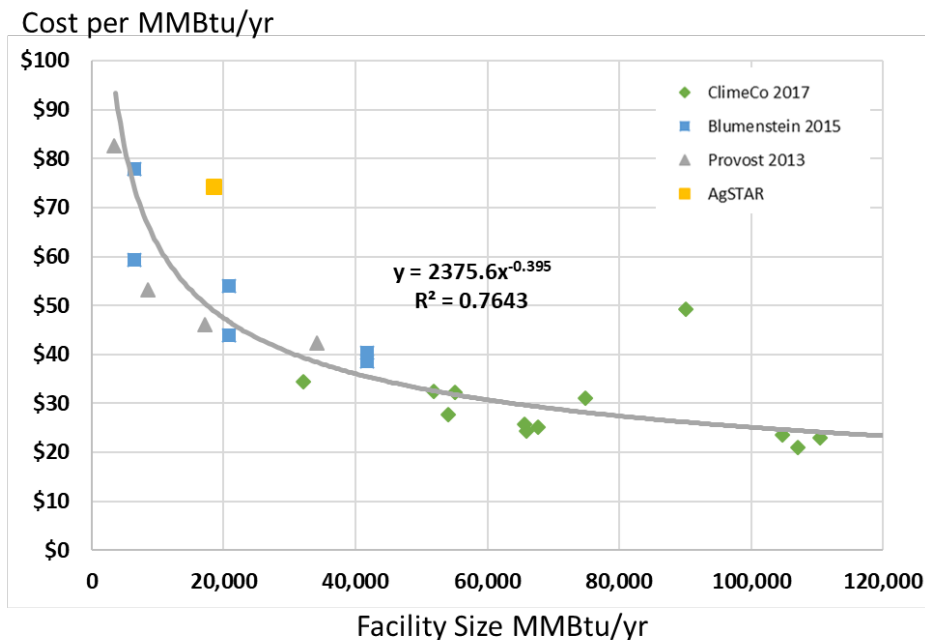
Sources: UCI APEP with data from sources as noted

Figure A-16: Above-Ground Continuous Flow Digester System Capital Cost (Total System Installed)
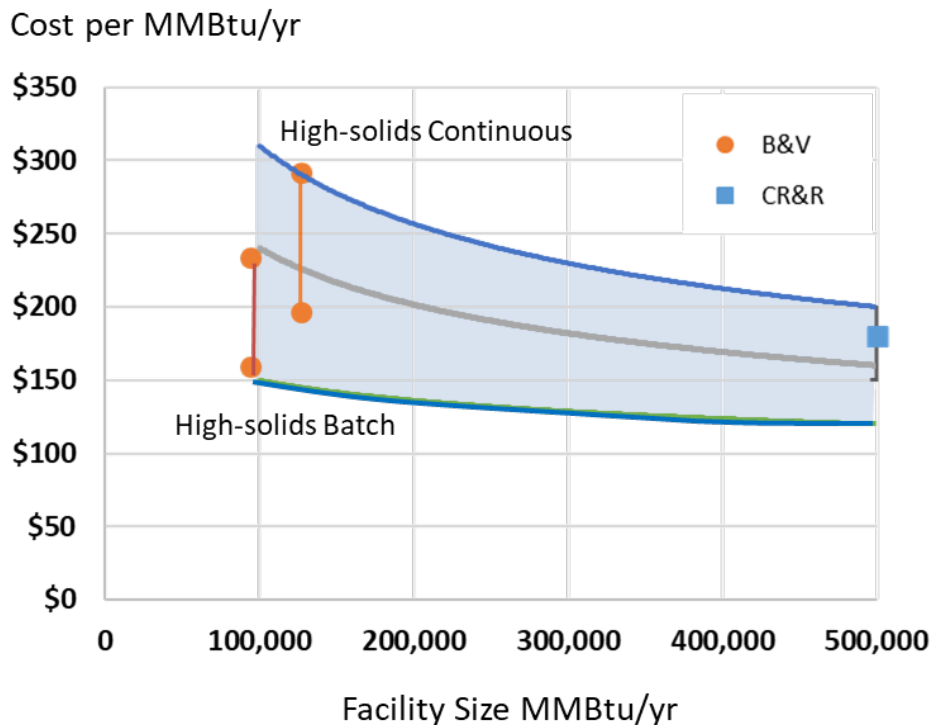
Source: UCI APEP with data from sources as noted

Biogas Conditioning, Upgrading, and Pipeline Interconnection

A variety of techniques can be used to purify and condition biogas to pipeline quality. Biomethane projects have employed a variety of gas upgrading technologies including:

- Pressure swing adsorption.

- Membranes.

- Amine scrubbers.

- Water scrubbers.

- Cryo separation (not fully commercial).

A further description of biogas clean-up technology can be found in (Williams, Kaffka, & Oglesby, n.d.). (Bauer et al. 2013) assessed the cost of the various biogas upgrading technologies and found that the cost of the various systems was closely grouped (Figure A-17); therefore, the data presented here are not differentiated by conditioning technology. Project-to-project variation in cost is seen based on raw biogas composition such as methane fraction, presence of sulfur, nitrogen, siloxanes and other constituents. Figure A-18 summarizes the best available recent cost information for gas conditioning based on global sources (left side of the Figure A-18) and for California-only projects with all data adjusted to $2018. Both data sets show good correlation. The data from Bauer are systematically lower than other sources, but this result may be due to differences in scope are for balance of system or inclusion of contingency and soft costs in the developer (ClimeCo and Black & Veatch) data that may not have been included in the Bauer data. Currency conversion may also be a factor. The California-only data show good agreement between ClimeCo and Black & Veatch. The best-fit curve shown was taken as the current cost basis for this study.

Gas clean-up and conditioning technologies are mature but less so for biogas applications and are still experiencing significant development activity to reduce cost and improve performance. Evolution of global installations of biogas upgrading systems presented in (Bauer et al. 2013) show a compound annual growth rate in installations between 2002 and 2012 of about 25 percent per annum. Even at modest learning rates, this rate of growth can be expected to drive significant cost reduction.

Compression and pipeline interconnection are required for gas-grid connected systems. The cost of these facilities depends on throughput (scale factor of 0.6 to 0.7) and distance from the primary facilities to the pipeline. The costs for interconnection, including compression, were drawn from a variety of sources, primarily those that filed information to the docket in the CPUC proceeding on pipeline biomethane (CPUC 2015) and are summarized in Table A-6. Costs for interconnection in other states are estimated to be significantly less than the California-based costs in Table A-6 with costs reported at $75,000 to $500,000 (CPUC 2015). For this study, interconnection costs will to be assumed to be $2.5 million reducing to $1.25 million by 2030.

Figure A-17: Capital Cost Comparison of Primary Biogas Conditioning Technologies
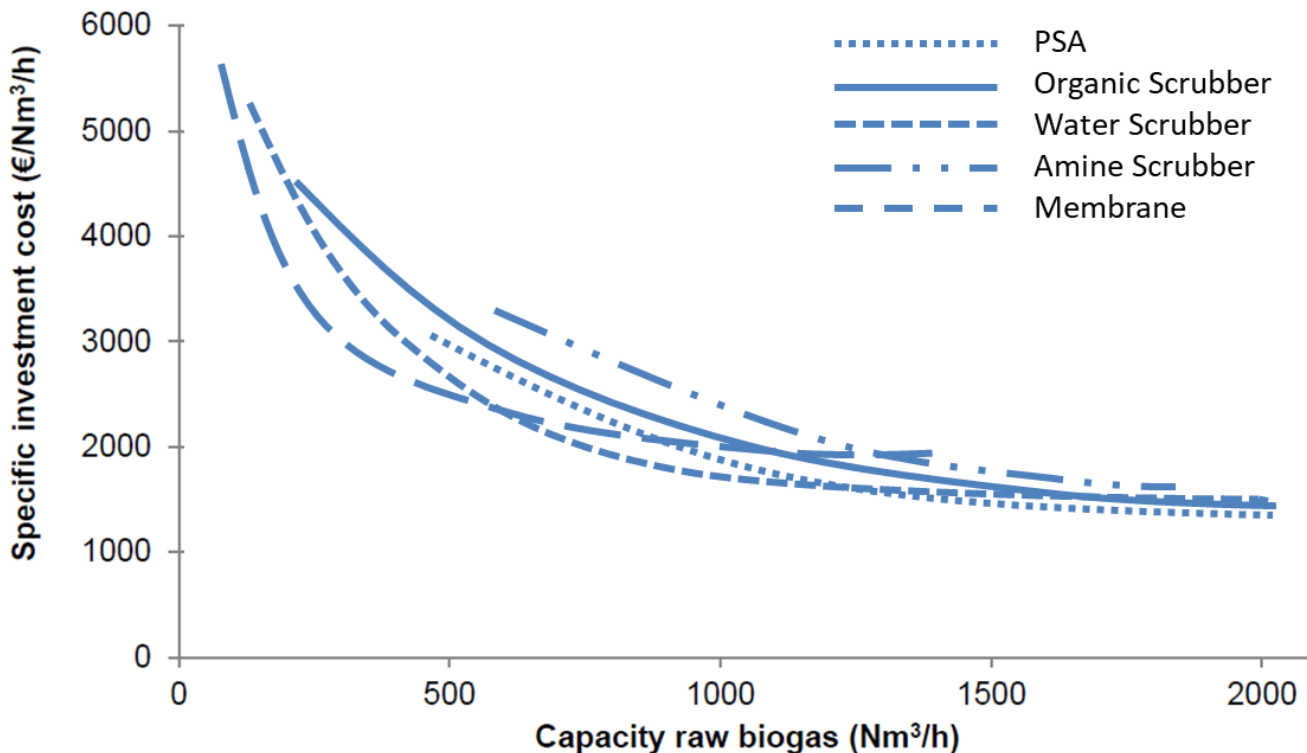
Source: After (Bauer et al. 2013)

Figure A-18: Capital Costs for Biogas Conditioning Technologies
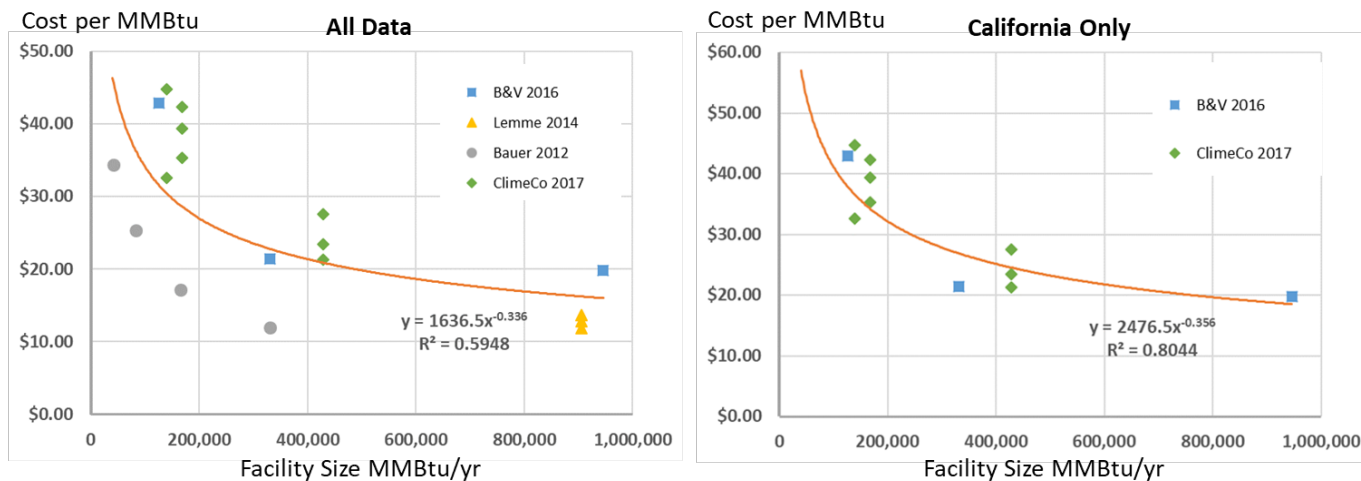
Sources: UCI APEP with data from sources as noted

Table A-6: Gas System Interconnection Facilities and Costs

Phase	Process	Cost
Pre-injection	Receipt Point Facility Construction	$1.2 million to $1.9 million (one-time)
Pre-injection	Pre-Injection Testing	$14,000 (one-time)
Interconnection	Pipeline Construction	$50-$250 per foot
Post-injection	Testing, monitoring, etc.	$520 to $2,083 per month
Post-injection	O & M for Point of Receipt Facility	$3,500 to $7,610 per month
Total Costs	Total cost for interconnection	$1.5 million to $4.1 million (CA) $75,000 to $500,000 (US)

Source: UCI APEP with data from (CPUC 2015), (Lucas 2016), ("Renewable Natural Gas: Monetary Incentive Program for Biomethane Projects" 2016)

Capital Cost Forecast for Anaerobic Digester Pipeline Biomethane

A learning curve approach was used to forecast the capital cost of facilities producing pipeline biomethane as a feedstock for renewable hydrogen. Feedback from stakeholder interviews indicates modest potential improvement for anaerobic digesters, with more technology innovation occurring in the conditioning and upgrading area and substantial room for cost reduction for interconnection facilities. Based on this, a modest learning rate of 10 percent was used for this analysis. A low-end market growth of 10 percent per annum was assumed based on historical growth in agricultural digesters in the United States and an upper range of 25 percent per annum based on the growth in biogas clean-up systems from (Bauer et al.). Total plant cost, shown in Figure A-19, is based on the cost forecasts presented above for digester systems, conditioning and upgrading and interconnection. The remaining system and indirect costs were estimated using the cost breakdown splits in Figure A-16. Projection to 2050 at a moderated growth of 7 percent and learning rate of 5 percent yields 10 percent additional cost reduction relative to 2030.

Methane-to-Hydrogen Reformation

The last technology component needed in the biogas-to-hydrogen pathway is reformation. Steam methane reformation (SMR) of natural gas is currently the most common method of hydrogen production. Reformation technology is very mature, but the DOE nonetheless forecasts 25 percent cost reduction potential over a 10-year horizon as shown in Figure A-20. SMR is very scale sensitive and development of alternative technologies with lower scale sensitivity is an important research goal. One such concept is the Compact Hydrogen Generator being developed by the Gas Technology Institute (GTI) with funding from the DOE. According to GTI, the technology has the potential to have a footprint about 10 percent that of conventional SMR with higher yield and lower capital cost (Subbaraman and Mays 2017). For

this study, the cost of new methane reformation facilities will be assumed to decline by 25 percent from current through 2030 and an additional 10 percent by 2050 by analogy with the assumptions for anaerobic digester technology.

Figure A-19: Capital Cost Forecast for Anaerobic Digester Pipeline Biomethane
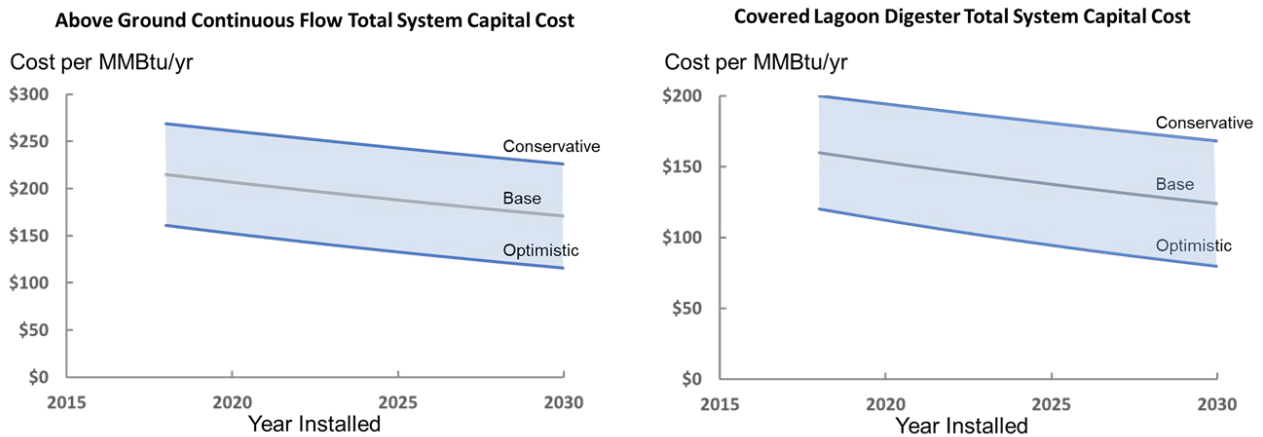
Sources: UCI APEP

Figure A-20: Current and Future Steam Methane Reformation Capital Costs
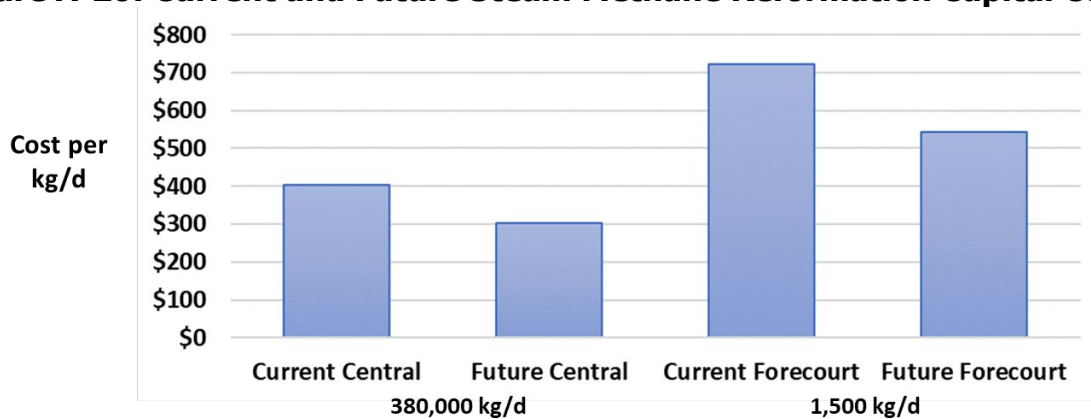
Sources: DOE H2A Cases (DOE H2A (U.S. Department of Energy) n.d.)

Reformation via Tri-generation

Tri-generation refers to a methane-fueled fuel cell system producing power and heat that can also produce hydrogen as a co-product. In these systems, a reformation step is present that converts methane fuel to hydrogen that is then directed to the fuel cell stacks for production of power and heat. The system can be controlled to produce variable amounts of power and excess hydrogen. For this analysis, tri-generation is considered a form of reformation.

Anaerobic Digester System Conversion Efficiency and Operating Costs

Table A-7 presents current and future conversion efficiency and operating cost data for anaerobic systems based on analysis conducted by UCI APEP (Shaffer et al. 2019). A further 5 percent in efficiency improvement is projected for 2050.

Table A-7: Anaerobic Digestion Conversion Efficiency and Operating Costs

	Covered **Lagoon** Current	Covered **Lagoon** 2030	Above-Ground Continuous Current	Above-Ground Continuous 2030
Conversion Efficiency (LHV)	38%	42%	50%	55%
Annual Fixed Maintenance O&M	4% of Capex	4% of Capex	4% of Capex	4% of Capex
Variable O&M ($/MMBtu)	1.25	1.25	2.50	2.50

Source: UCI APEP with data from sources in Table A-5

Anaerobic Digester Siting and Permitting Requirements

Siting and permitting requirements for anaerobic digester projects are summarized in Table A-8 below.

Table A-8: Anaerobic Digester System Siting and Permitting Requirements

CEQA	CEQA
Zoning	Industrial
Footprint	5 acres for 100,000 MMBtu/yr facility
Feedstock Logistics	Accessible to refuse hauling routes
Utilities	Natural gas interconnection Electrical interconnection Water interconnection
Ingress/Egress	~30 trucks/day for 100,000 MMBtu/yr facility
Permitting	• CEQA • Solid waste permit (difficult to obtain so sites with existing permits are preferred) • Air emission permits (flare) • Construction permits
Local Issues	Generally, require substantial separation from residential areas due to odor, traffic and noise

Source: UCI APEP

Thermochemical Conversion Systems Cost and Performance Assessment

"Thermochemical conversion" refers to processes that use temperature and, in some cases, pressure to convert biomass to hydrogen or methane. Systems of this class can also produce liquid fuel. Those pathways are outside the scope of the current study. A variety of thermochemical processes can be used to convert biomass to fuels. These include gasification, pyrolysis and hydrothermal processing. The present study focuses on gasification, the most technically mature technology, and uses gasification as a proxy for the group.

Gasification units are classified according to the gasifying medium (oxygen, steam, air) and the reactor technology used (fixed/moving bed, fluidized bed, entrained flow). Representative system configurations are shown in Figure A-21 with the associated size ranges are shown in Figure A-22. The fixed bed gasifiers can be further classified by the flow of the gasifying medium: updraft, downdraft, side draft/cross flow. Fluidized bed gasifiers are classified according to the extent of fluidization, i.e., distribution of bed material throughout reactor (circulating) or bed concentrated at the reactor bottom (bubbling). Entrained flow technology is not currently used for biomass gasification because of the requirement for fine particles given the short residence times (Basu 2013) unless biomass is being co-fed into a coal gasification unit. The commercial availability of each technology was inventoried in 2000 for the European Commission through industry surveys (Knoef 2000). Analysis of this inventory showed that downdraft gasifiers accounted for 75 percent of commercially available products with fluidized beds accounting for 20 percent, updraft for 2.5 percent and 2.5 percent of other types (Bridgwater 2006).

A comprehensive review of development and deployment status of biomass gasification systems in California and internationally (primarily Europe) shows limited deployment with less than 100 commercial units worldwide (Williams, Kaffka, and (California Biomass Collaborative, University of Caifornia 2017). Although biomass gasification shares technology elements in common with the more widely deployed coal gasification technology, biomass gasification systems have different fuel handing requirements and different gasification behavior and can be regarded to as a separate technology group that is at the at the early commercial deployment stage.

A key issue for biomass gasification is gas clean up, particularly for the production of gaseous fuels (Basu and Basu 2013; Heidenreich, Müller, and Foscolo 2016). The key contaminants to be removed are tar (formed during pyrolysis) and fine particulates. Some gasification technologies show better performance with respect to tar and fine particulate production with tradeoffs being typical, for example, between tar production and other performance parameters.

Updraft moving bed gasifiers are one of the oldest and simplest gasifier designs. This is the design used in the well-known Sasol liquid fuel production plant in South Africa. The updraft gasifier uses the heat from combustion efficiently given the good heat recovery that results from the counter flow arrangement. This leads to higher carbon conversion efficiencies and deals better with moisture. However, the updraft arrangement does lead to higher tar production. The downdraft configuration results in lowest tar production of all types because the product gas leaves the reactor at the bottom passing through the hot ash where favorable

conditions for tar cracking exist (Basu and Basu 2013).

Fluidized bed gasifiers were first studied in the 1920s by Winkler, and, in fact he developed a commercial air blown fluidized bed gasifier (Basu 2006; EPA 2007). Fluidized bed gasifiers offer good mixing and uniform temperature distributions as well as large thermal inertia, which allow for flexibility in the biomass feedstock type. However, these systems also typically have high tar and fine particulate production in addition to lower conversion efficiencies (Yang and Chen 2015). Entrained flow systems require pulverized fuel particles to be used (<0.15 mm) making this technology difficult to use with biomass. However, the syngas produced has very low or zero tar content in addition to high carbon conversion efficiencies.

Figure A-21: Representative Gasifier Configurations

Updraft Gasifier

Downdraft Gasifier

Fluid-Bed Gasifier

Circulating Fluid-Bed Gasifier

Entrained Flow Gasifier
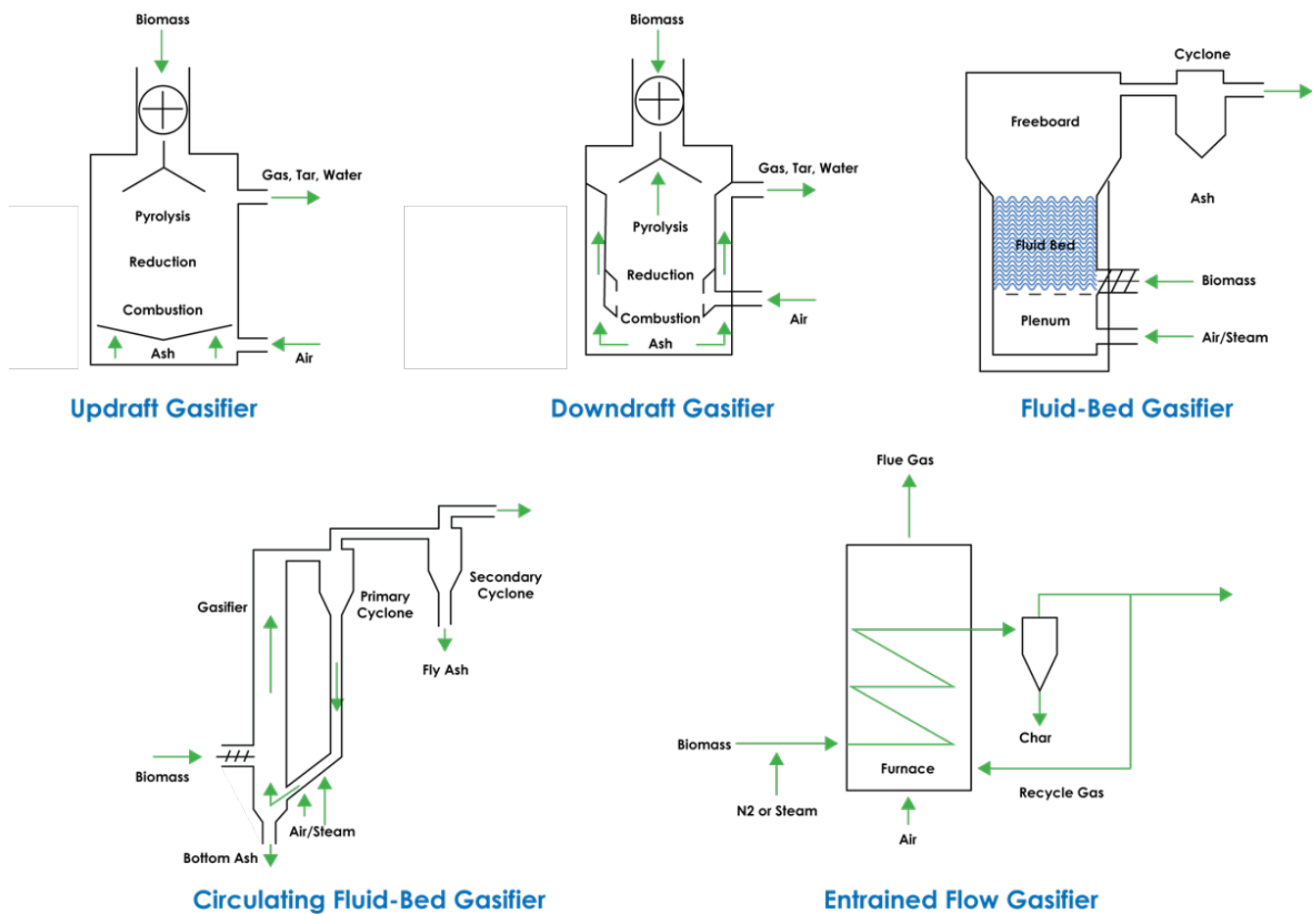
Sources: UCI APEP

Figure A-22: Size Range for Various Gasifier Designs
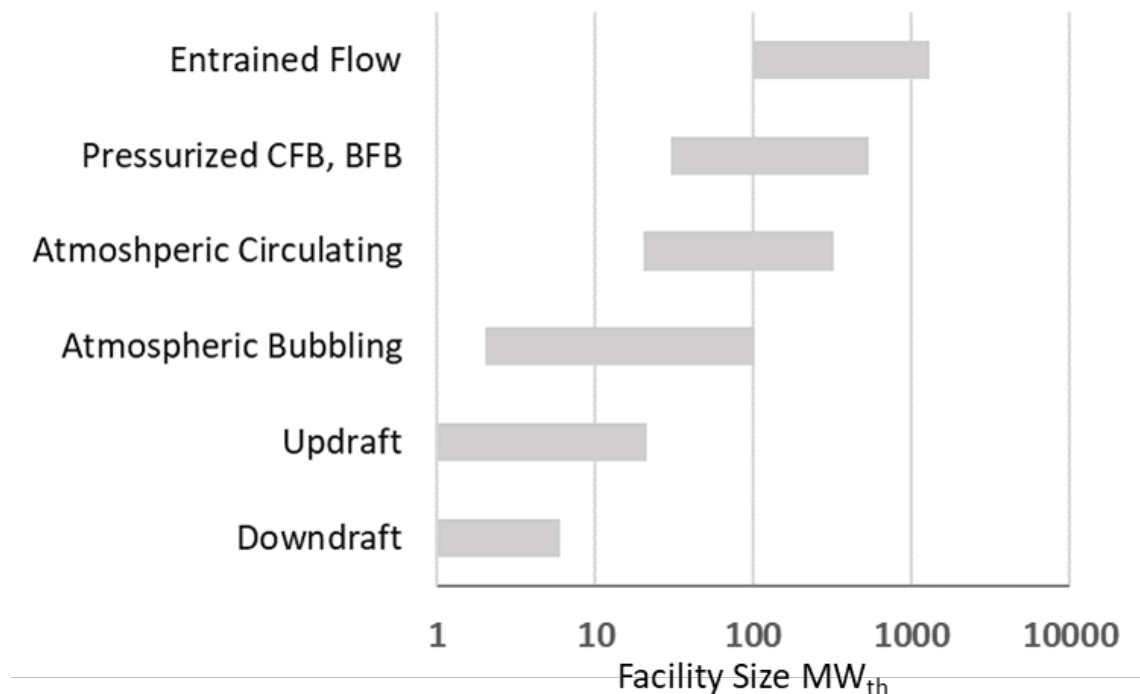
Other more novel gasifier designs include multistage, dual-bed, chemical looping (sorption enhanced), plasma, and new concepts integrating filtration and secondary tar reduction directly into the gasifier (Basu and Basu 2013; Yang and Chen 2015; Heidenreich, Müller, and Foscolo 2016). Staged gasification is the creation of different temperature zones by staging the addition of oxidant. First investigated in 1994, it was found to decrease the tar yield significantly (Bui, Loof, and Bhattacharya 1994). More recent research has developed biomass gasifiers with three stages, i.e., FLETGAS concept (Gómez-Barea et al. 2013; Heidenreich et al. 2016). Other staged biomass gasification designs include the VIKING gasifier, Carbo-V, and LT-CFB (Heidenreich et al. 2016). Dual-bed gasification separates the combustion and gasification processes into two reactors and circulates the bed material between the two reactors to provide thermal integration. The benefit of this separation is avoiding dilution of the syngas stream as a result of the addition of air to supply the oxidant. Dual-bed biomass gasifiers include the well-known Güssing gasifier, the Silvagas process developed by Battelle, a patented process by FERCO, and the MILENA gasifier developed in the Netherlands (Heidenreich et al. 2016). The chemical looping concept involves the use of a sorbent to produce two gas streams. Plasma gasification is fuel-flexible and exhibits destruction of contaminants and pollutants but requires a substantial input of electric power. Additional advanced concepts, such as integrating the filtration and secondary tar removal steps into the freeboard of the gasifier, are being developed. This integration has been named the UNIQUE gasifier concept and has been deployed at a pilot gasifier in Europe called UniFHY (Heidenreich et al. 2016).

Table A-9 summarizes the primary sources used to develop the cost and performance current state cost and performance benchmarks and forecasts for gasifier technology.

Gasifier Capital Cost

Figure A-23 below shows a representative project cost breakdown for a complete gasification system (DOE H2A (U.S. Department of Energy) n.d.). Figure A-24 shows cost data from various sources (described in Table A-9) with system size represented by output (kg/d) or input energy (MW_{th}). The correlation is slightly better when normalized on input energy. As can be seen in the Figure A-25, normalized cost is quite sensitive to system scale, exhibiting a scale factor of 0.7. Due to the strong dependence of capital cost on plant size, hydrogen production systems are assumed be 100 MW_e and above. The cost data show systems whose end product is hydrogen along with those whose end product is methane. Based on the data analyzed, a statistically significant difference in plant cost between the two products is not observed based on this data set. However, based on comparison of the equipment sets employed, plants producing pipeline methane will be assumed to carry a 10 percent higher capital cost than plants producing hydrogen.

Published information on cost reduction potential for gasifier systems is limited. The H2A future case scenario (DOE H2A (U.S. Department of Energy) n.d.) reflects a 7 percent reduction in capital cost based on specific design improvements (single technology generation). A study by the National Research Council (Offutt et al. 2004) projected a 50 percent cost reduction potential from initial commercial unit to a potential future unit, reflecting what the authors call "future optimism" and at-scale production volume. Given the limited deployment of biomass gasification systems since that study, that level of potential can be assumed to remain.

For forecasting future cost of gasification systems for this study, a learning curve approach was employed. A modest learning rate of 10 percent was used. Low and high market growth rates of 10 percent and 25 percent were assumed. This leads to a range of cost reduction relative to current of 15 percent to 35 percent by 2030. The midpoint will be used as the base case for this study with a +/- 25 percent uncertainty band for the current cost. The resultant capital cost forecast for a 125 MW_{th} system is shown in Figure A-25. As with anaerobic digestion technology, a lower rate of growth and learning is assumed beyond 2030, yielding a cost reduction of an additional 10 percent relative to 2030 in 2050.

Table A-9: Primary Sources for Gasification Cost and Performance Analysis

Source	Scope and Method
(Black & Veatch 2017) Consulting Study (unpublished)	Bottom-up study of cost and performance base on reference designs
(Corradetti and Desideri 2007) Journal Article	Comparative assessment of economics of biomass gasification for hydrogen versus electricity production
(Difs et al. 2010) (Fahlén and Ahlgren 2009) Journal Articles	Techno-economic analysis of biomass gasification in district heating applications in Sweden
(Gassner and Maréchal 2012) Journal Article	Economic optimization of methane production from biomass gasification
DOE H2A Case studies. https://www.hydrogen.energy.gov/ h2a_prod_studies.html	Point design analysis and detailed economic assessment with current state and future parameters for reference gasifier system
(Johansson 2013) Journal Article	Study of the economics of use of methane produced through biomass gasification for steel production
(Offutt et al. 2004) National Academy of Engineering	Multi-technology study and economic assessment of hydrogen production through use
(Sentis 2011) Journal Article	Point design study and techno-economic analysis for small-scale gasifier system in the E.U.
(Spath et al. 2005) Journal Article	Point design study and techno-economic analysis for midscale gasifier system in the U.S.
(Tock and Maréchal 2012) Journal Article	Analysis of techno-economics of coproduction of hydrogen and electricity from lignocellulosic biomass
(Matthew Summers et al. 2015) CEC Report	Point design study and techno-economic analysis for small-scale gasifier CHP system in California
(Salkuyeh, Saville, and MacLean 2018) Journal Article	Comparative assessment of techno-economics of hydrogen production through various gasification technologies
(Williams, Kaffka, and (California Biomass Collaborative, University of Caifornia 2017) CEC Report	Status overview of biomass gasifier development and deployment in California and Europe

Source: UCI APEP

Figure A-23: Representative Gasifier System Cost Breakdown
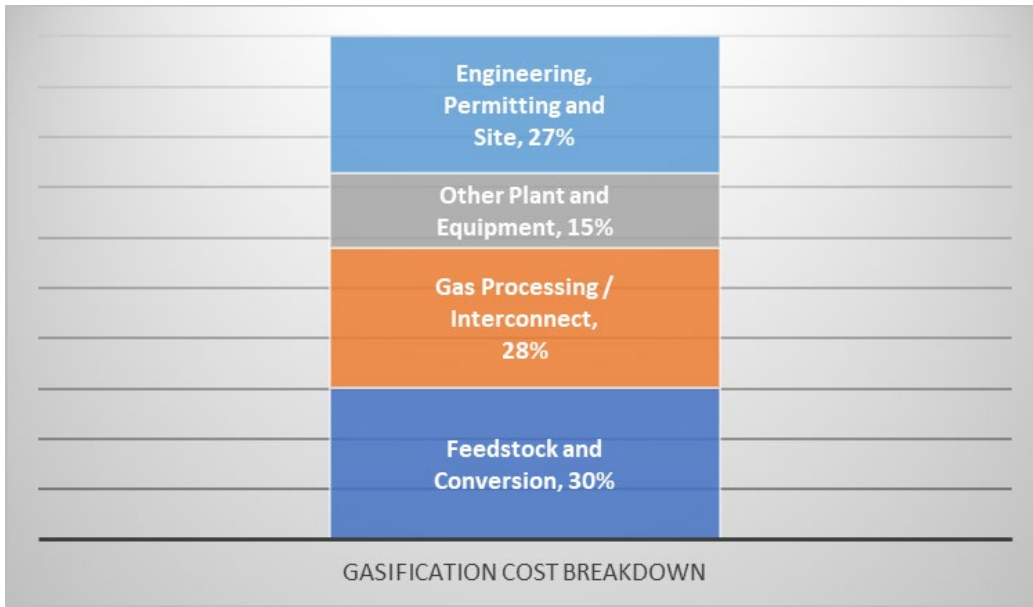
Source: DOE H2A Case Study

Figure A-24: Gasification System Capital Costs

$$y = 53164x^{-0.279}$$
$$R^2 = 0.6539$$

$$y = 6375.3x^{-0.372}$$
$$R^2 = 0.7503$$
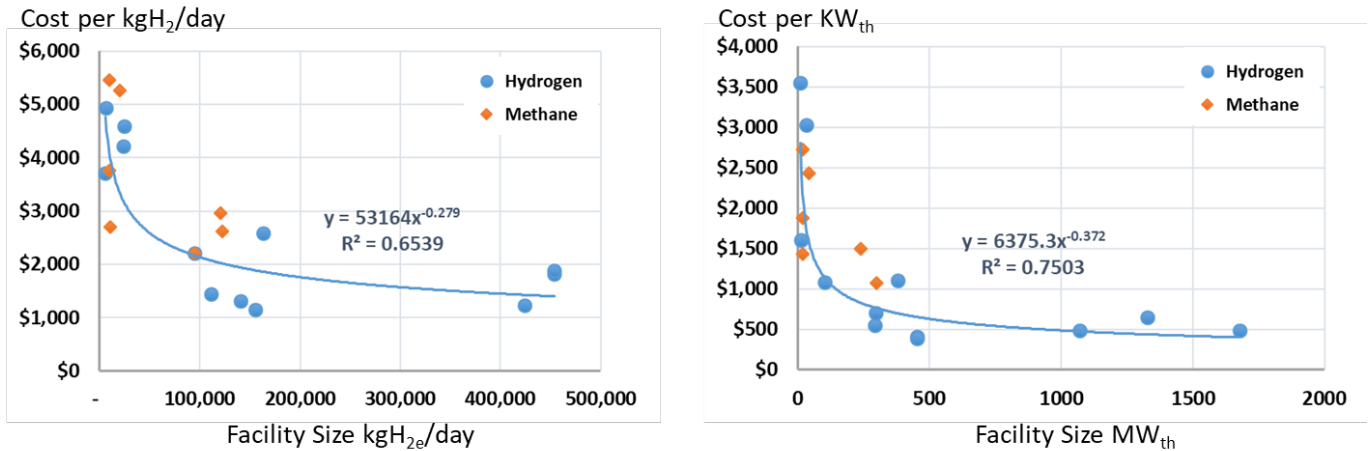
Source: UCI APEP from sources in Table A-9

Figure A-25: Biomass Gasifier Cost Forecast for 125 MW$_{th}$ System

Cost per kW$_{th}$
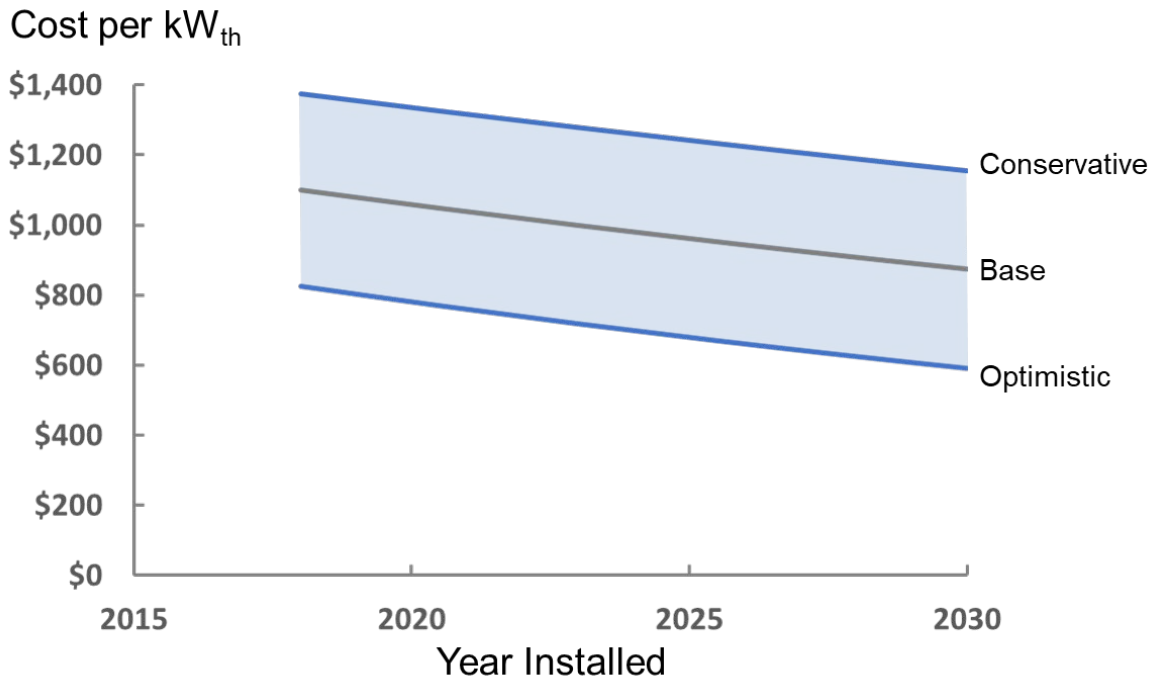
Gasifier Conversion Efficiency and Operating Cost

Table A-10 presents the conversion efficiency and operating costs for gasification systems based on the sources presented in Table A-9. An additional 5 percent efficiency gain is assumed for 2050 relative to 2030. The methanation block improves efficiency at the expense of operating cost.

Table A-10: Gasifier Conversion Efficiency and Operating Costs

Gasifier	Hydrogen Current	Hydrogen 2030	Methane Current	Methane 2030
Conversion Efficiency (LHV)	54%	62%	67%	72%
Fixed Maintenance O&M $/kW-yr	40	26	59	39
Variable O&M $/kW	6	4	13	8

Gasifier Siting and Permitting Requirements

Gasifier siting and permitting requirements are shown in Table A-11.

Table A-11: Gasification System Siting and Permitting Requirements

Parameter	Requirement
Zoning	Industrial or Agricultural
Footprint	~10 acres minimum for 100 MW_{th} facility
Feedstock Logistics	Proximate to woody biomass sources
Utilities	• Natural gas interconnection • Electrical interconnection • Water interconnection
Ingress / Egress	~30 trucks/day for 100 MW_{th} facility
Permitting	• CEQA • Air emission permits (large-scale combustion) • Construction permits
Local Issues	Generally, require substantial separation from residential areas due traffic and noise.

Source: UCI APEP, industry sources

Hydrogen Production Costs

Calculating the total production cost for renewable hydrogen requires specification of feedstock cost (or tipping fee revenue in some cases). Development of cost scenarios for feedstock will occur under a separate task of this project. However, the current and future cost and performance information presented in the prior sections allows the non-feedstock hydrogen production cost (or feedstock conversion cost) of the various technologies to be estimated. Figure A-26 presents the capital cost per unit of nameplate capacity for the primary conversion technologies from current through 2030. The cost of reformation is included in the cost of the anaerobic digestion pathways. Figure A-27 presents the corresponding hydrogen production costs excluding feedstock cost. These values were developed using the cost and performance estimates from the present study in the DOE H2A model (DOE H2A (U.S. Department of Energy) 2018a, 2018b) with a 20-year project life, 100 percent equity financing and an after-tax internal rate of return of 10 percent.

Figure A-26: Capital Cost per Unit of Renewable Hydrogen Production Capacity
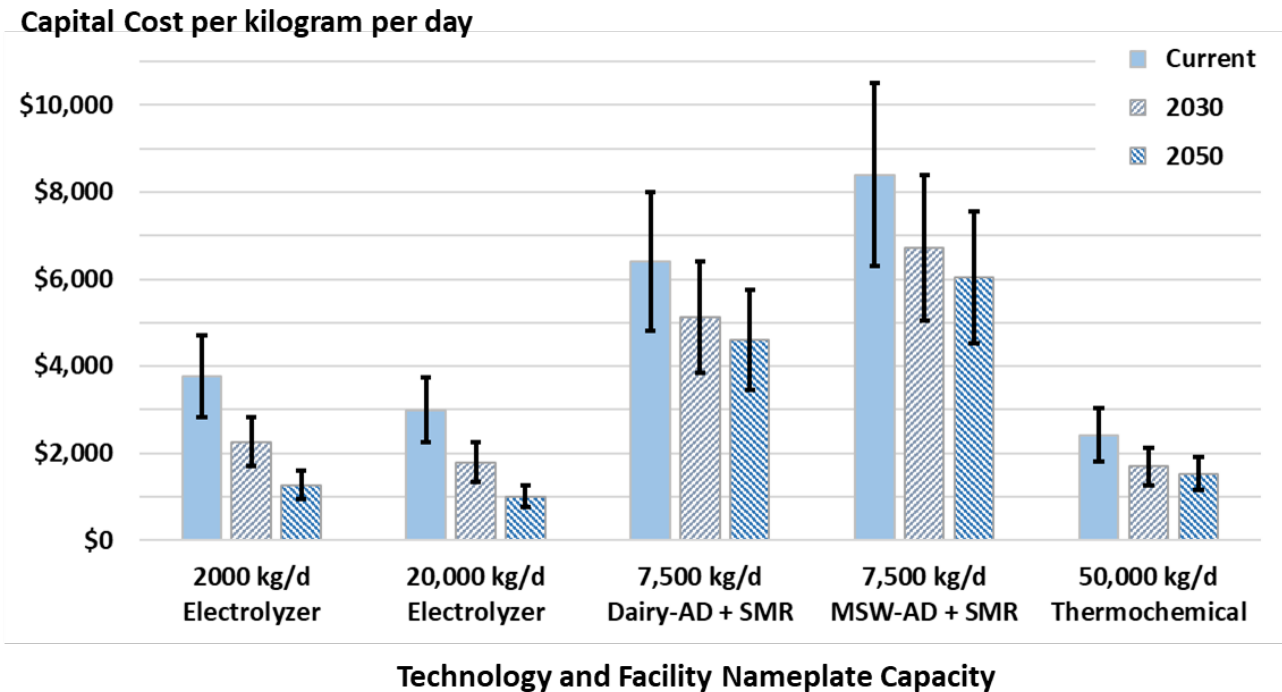
Source: UCI APEP

Figure A-27: Non-feedstock Renewable Hydrogen Production Costs
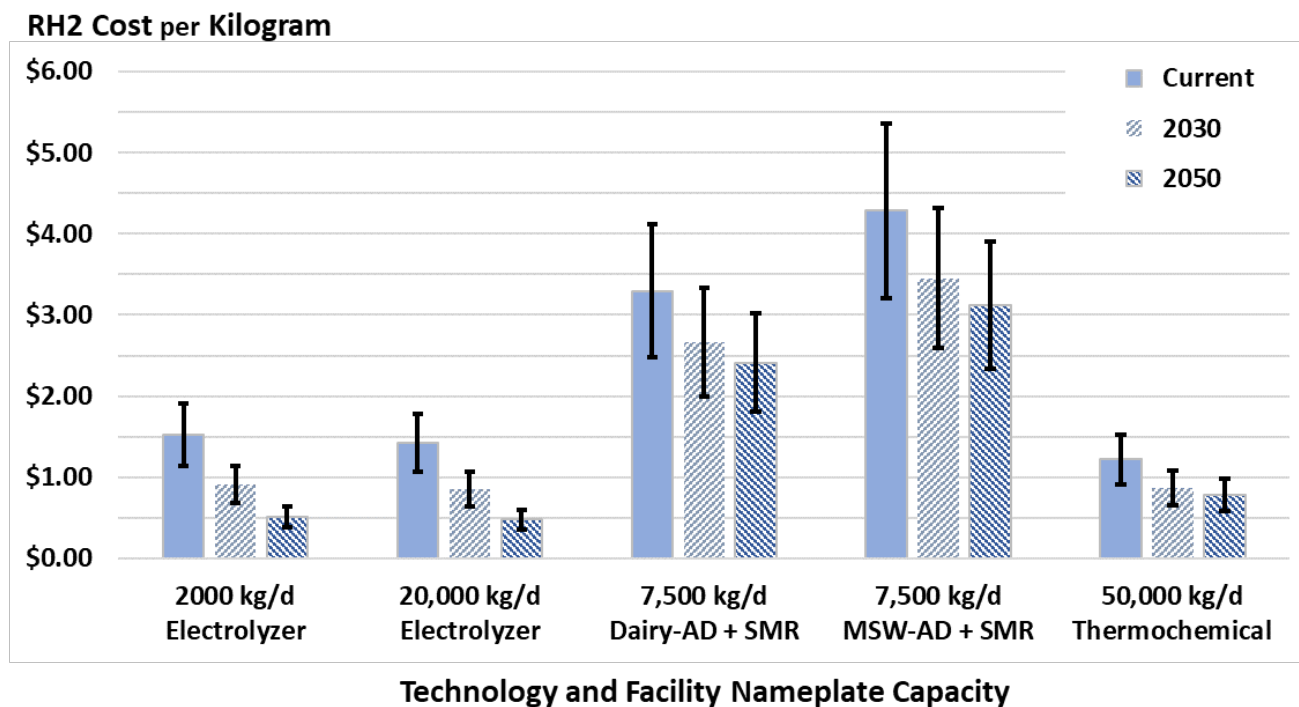
Source: UCI APEP

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APPENDIX B:
Renewable Hydrogen Production Facility Siting Analysis and Buildout Scenarios

Introduction and Purpose

This appendix describes the methodology and results of the siting analysis and buildout scenarios developed for the renewable hydrogen production roadmap project. The purpose of the siting analysis is to identify areas suitable for development of renewable hydrogen production facilities and to choose optimal locations for adding production capacity to serve renewable hydrogen demand as it grows over time. This methodology employs commercially available geospatial tools and a UCI-APEP developed cost-minimization model to create facility buildout scenarios consistent with defined constraints and assumptions. The analysis screens locations defined by 4 km by 4 km cells (this defines the degree of resolution of candidate locations). The renewable hydrogen production facility buildout scenarios are intended to be representative rather than precisely predictive of the timing and location of facility construction which will ultimately be decided by private developers. The analysis scope and methodology are further described below.

Scope

Three primary hydrogen production facility types were treated in this analysis: electrolysis, thermo-chemical conversion (gasification is used to represent the thermochemical group), and reformed biomethane produced by anaerobic digestion. Preferred siting areas for central-scale facilities were determined based on land availability and zoning, proximity to feedstock, and proximity to and availability of necessary utilities and infrastructure. As described in Chapter 3, this analysis considered the following organic feedstock supplies for thermochemical conversion and anaerobic digestion: forest thinning and waste, agriculture/crop residue, food waste, other organic fraction of municipal solid waste, manure, wastewater and landfills. For electrolyzer siting, both self-generated renewable energy and grid-supplied energy are considered.

Reformation and liquefaction facilities are key, capital intensive, processing facilities that fall between primary production and the hydrogen transport supply chain. Siting for these facilities is also within the scope of the analysis. Liquefaction facilities are assumed to be collocated with central-scale reformation facilities or thermochemical conversion facilities so are not separately addressed. Reformation facilities are sited through the same methodology as primary production facilities.

Site Screening Method

The siting analysis is conducted at a 4 km x 4 km resolution using geographic information system (GIS) layers containing relevant data such as electric transmission line locations, natural gas transmission line locations, land use classifications, availability and location of biomass feedstock, roadways, rail lines, and population density data. Specific data sets are referenced on individual figures. Figure B-1 provides a high-level process flow for the site

screening and ranking process. Table B-1 summarizes the key siting criteria for each central-scale facility type.

Table B-1: Primary Siting Requirements for Central Renewable Hydrogen Production and Related Facilities

Facility Type	Feasibility Screening Criteria
Electrolyzers	High wind and solar resource areas with transmission access or transmission access within 50 miles of demand
Dairy Anaerobic Digesters	Existing dairy farms in clusters of 5 to 10 with an anchor farm of >5,000 milking cows
Food and High-moisture Organic Anaerobic Digesters	Along current and historical landfill disposal routes with adequate area for 100,000 MMBtu per year facility size Existing wastewater treatment and resource recovery facilities
Thermochemical Conversion Facilities	Forest areas and agricultural areas (crop residue) with site suitable for 50,000 kg/d RH2 facility size outside non-attainment areas
SMR Facilities	Outside non-attainment areas close to natural gas transmission and highway transport
Liquefaction Facilities	Collocated with SMR facilities or production facilities with production capacity of minimum 30 tonnes hydrogen per day

Source: UCI APEP and source noted on feedstock maps below

Local-scale electrolysis and potentially small-scale reformation may be part of the supply mix beyond 2030 should those technologies progress and supportive policies (such as electric rates) be put in place. For the local production scenario, facilities are assumed collocated with hydrogen refueling stations. Station locations are assumed to be those defined in the future hydrogen refueling station preferred siting analysis developed by the California Air Resources Board using the CARB CHIT and CHAT models[88], and no additional location analysis was performed for this study (California_Air_Resources_Board 2018).

Exclusion Criteria

Some areas are unsuitable for development of large-scale facilities for renewable hydrogen production or processing. Rough terrain areas and inaccessible locations such as military bases and protected lands are excluded (Figure B-2). Residential and high-density commercial areas are also not suitable for large-scale facility development.

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[88] CHIT stands for California Hydrogen Infrastructure Tool and CHAT for California Hydrogen Accounting Tool

Feedstock

Access to feedstock is a primary siting criterion for all production pathways. Proximity to woody or dry biomass is generally the dominant siting criterion for thermochemical systems. Proximity to organic waste hauling routes is similarly critical for organic waste digestion facilities whereas dairy projects are hosted on large farms so that manure does not need to be transported. For electrolyzers, electric transmission and distribution costs are effectively feedstock transport costs and, under current electric rate structures, provide a strong incentive for electrolyzers to be located on the same site as their primary electric feedstock. Figure B-3 shows the primary facility siting areas based on feedstock availability. Figures B-4 through B-7 depict the primary feedstock sources for the various technologies: high solar and wind resource areas for electrolyzers, manure, wastewater and landfill facilities for anaerobic digestion, and high forest and agricultural residue areas for thermochemical conversion. Both water and electricity can be considered feedstock for electrolysis; however, water supply is treated here as a site utility that is available to all otherwise qualified sites.

Primary Infrastructure

All the renewable hydrogen production technologies require access to primary electricity, natural gas, transportation, and water infrastructure. The relative importance of electricity and gas supply and takeaway capacity varies by technology type and is a primary siting criterion. Figures B-8 through B-11 show the electric transmission system, the natural gas high-pressure system, the primary highway and rail freight routes, and the primary water supply system in California.

Optimal Site Selection—Delivered Renewable Hydrogen Cost and Community Impacts

Once all other constraints for facility siting have been met (site is qualified as "feasible"), cost minimization and community impacts define final selection/ranking among otherwise qualified sites. Minimizing transportation costs for hydrogen from production facility to demand points is a key factor in cost minimization. Through 2030, light-duty vehicles will be the dominant source of renewable hydrogen demand. Figure B-12 shows the hydrogen refueling station 2030 forecast demand density developed by the ARB as part of the AB 8 implementation program (California_Air_Resources_Board 2018).

Facilities generating significant NOx and/or PM emissions are excluded from disadvantaged communities as defined in the CalEnviroScreen 3.0 database and from all nonattainment areas (Figure B-13 and Figure B-14). Although not included in the scenarios here, TC and SMR facilities that meet ultra-low emissions criteria may be sited in the disadvantaged community and nonattainment exclusion areas (most legacy biomass projects are sited in these areas). Community impacts are multi-facetted and include local air emissions, visual impacts and traffic (negative factors) and job creation on the positive side. In the absence of a validated weighting of job creation against other factors, this analysis uses NOx emissions as a single community impact factor and excludes reformation and thermochemical conversion facilities from siting in non-attainment areas in disadvantaged communities.

Figure B-1: Siting Analysis Process Flow

H2 Fueling Station Heat Maps →

Local-scale Electrolysis
- Co-located with hydrogen refueling station – use existing heat maps from ARB

Data layers:
- Electric Transmission
- Gas Transmission
- Topography / Land Use
- Biomass Resources
- Roads and Rail
- Population density

Assign attributes to each cell →

Apply Exclusion Criteria
- Mountainous areas
- Protected lands
- Residential areas

If not excluded, then evaluate for each technology

Central Electrolysis
- In solar or wind resource area, or on electric transmission line
- Highway and/or rail access
- 10 acre site availability

Dairy AD
- Anchor herd of 5000 milking cows
- Proximate to natural gas transmission

OFMSW (Food) AD
- Existing WRRF, permitted refuse facility or existing refuse route
- Proximate to natural gas transmission

SMR
- Proximate to natural gas transmission
- Highway and/or rail access
- 10 acre site availability

Gasification
- Proximate to biomass resource
- Highway and/or rail access
- 10 acre site availability

For each cell and each technology:

If min. criteria met, then assign score, else, not a candidate site

Scoring based on cost and community impacts

Note: Liquification facilities co-located with SMR facilities as applicable

Source: UCI APEP

B-4

Figure B-2: California Siting Areas Excluded Due to Terrain
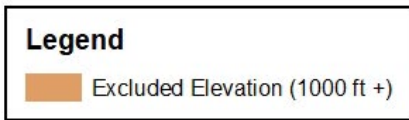
Legend

Excluded Elevation (1000 ft +)

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: U.S. Geological Survey (2016)

Figure B-3: Primary Resource Areas for Renewable Hydrogen Production and Conversion
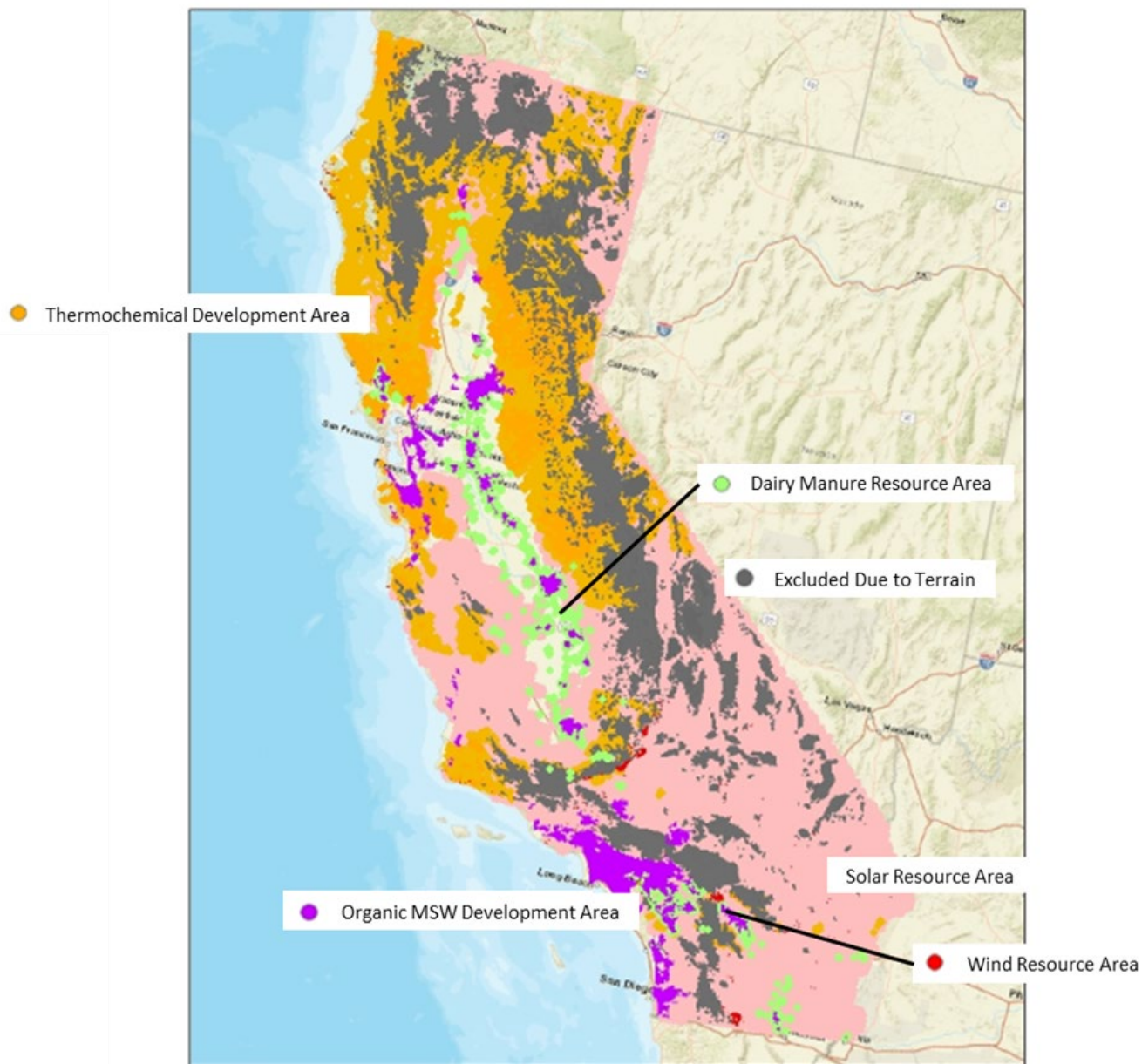
Source: UCI APEP from multiple U.S. EPA, U.S. DOE, and California agency datasets

Figure B-4: California Solar Resource Potential
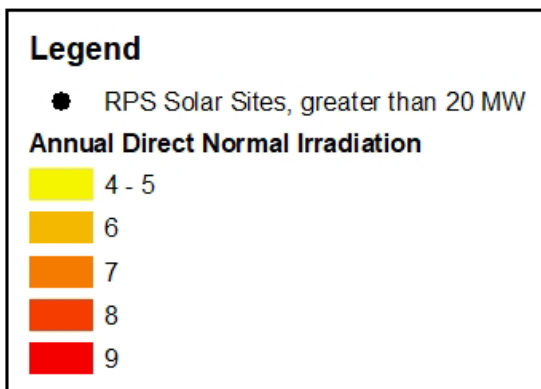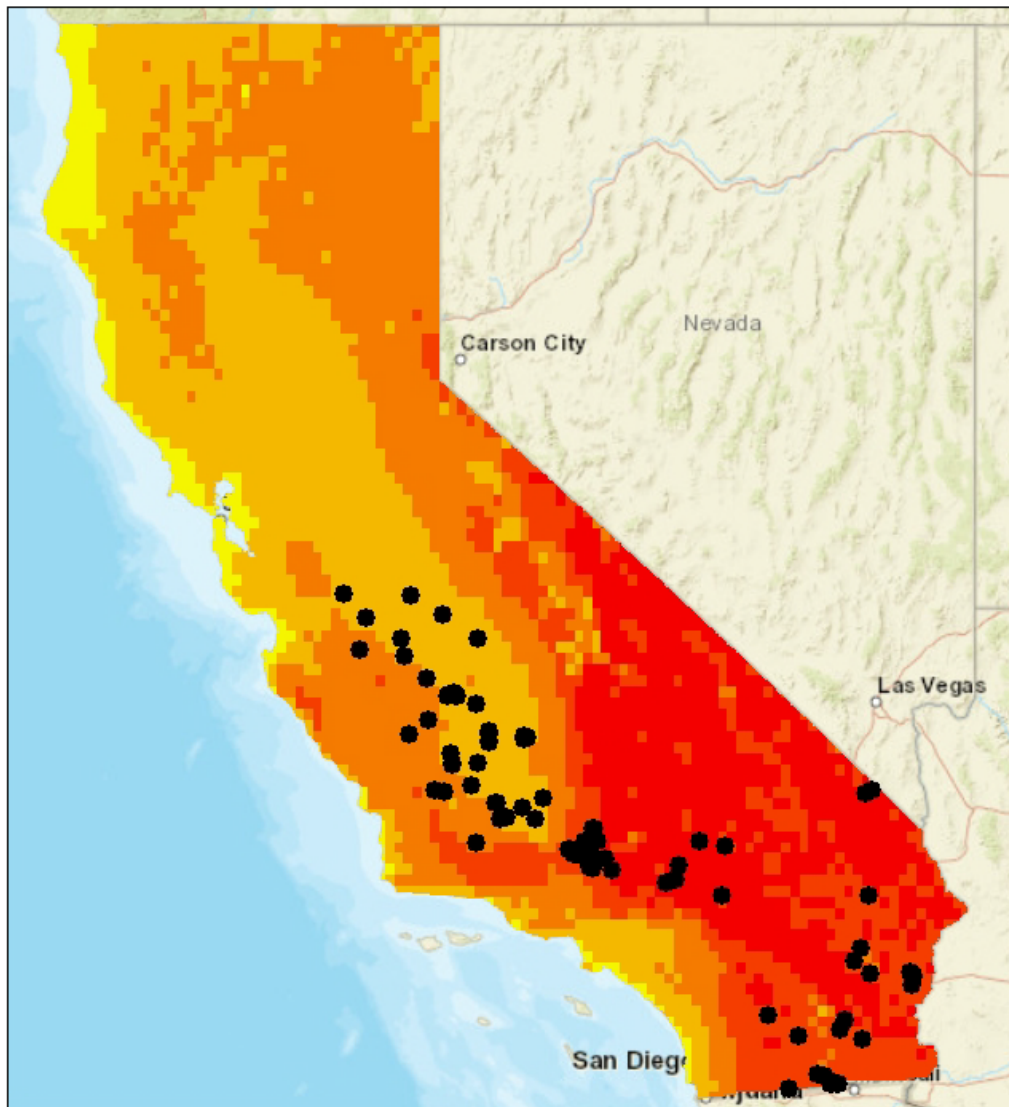
Legend

● RPS Solar Sites, greater than 20 MW

Annual Direct Normal Irradiation

- 4 - 5
- 6
- 7
- 8
- 9

Source: National Renewable Energy Laboratory (2012a)

Figure B-5: California Wind Resource Potential
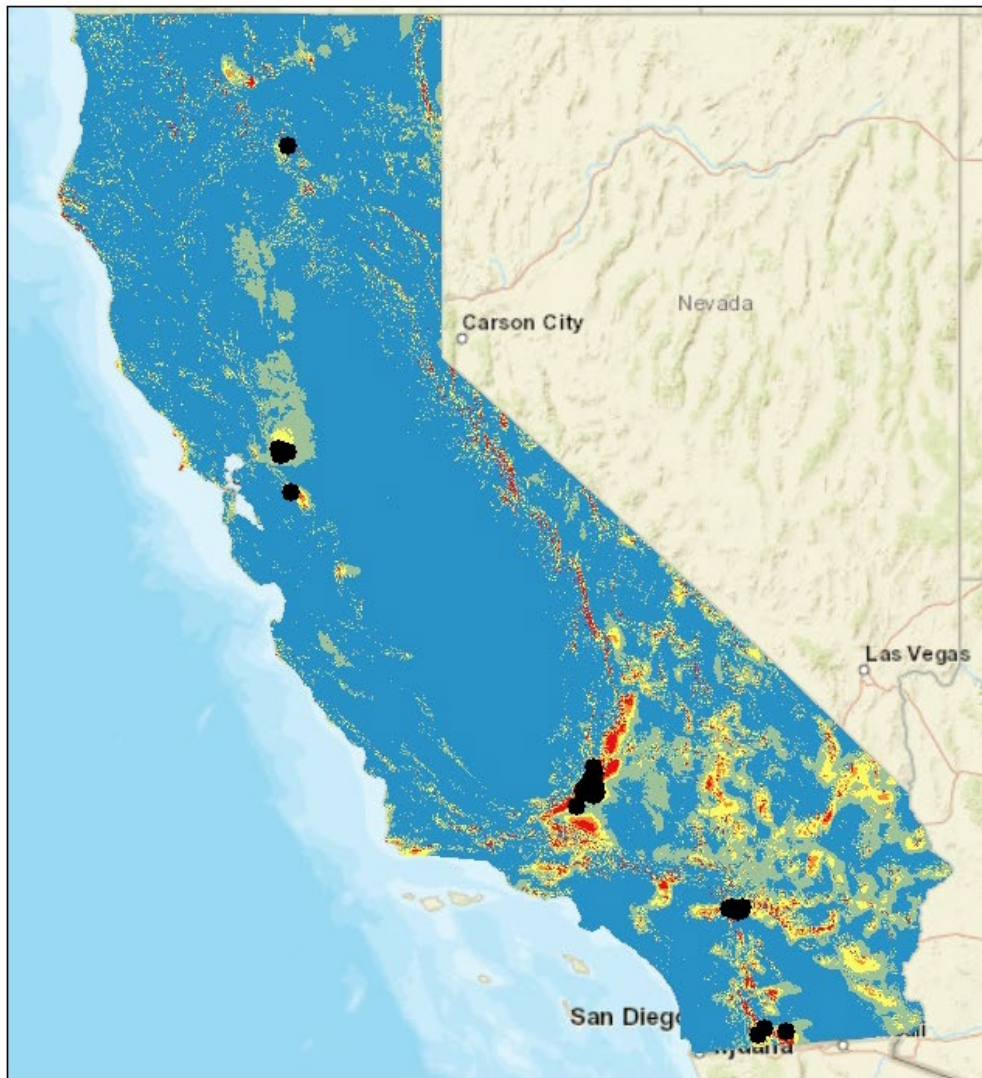
Source: National Renewable Energy Laboratory (2012b)

Figure B-6: Forest Biomass and Agricultural Residue Density

Source: Langholtz, B. M. H. J., Stokes, L. M., and Eaton. (2016)

Figure B-7: California Dairy Herd Density and Active Projects
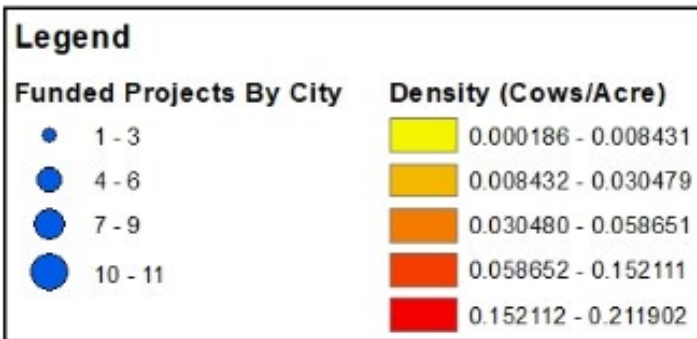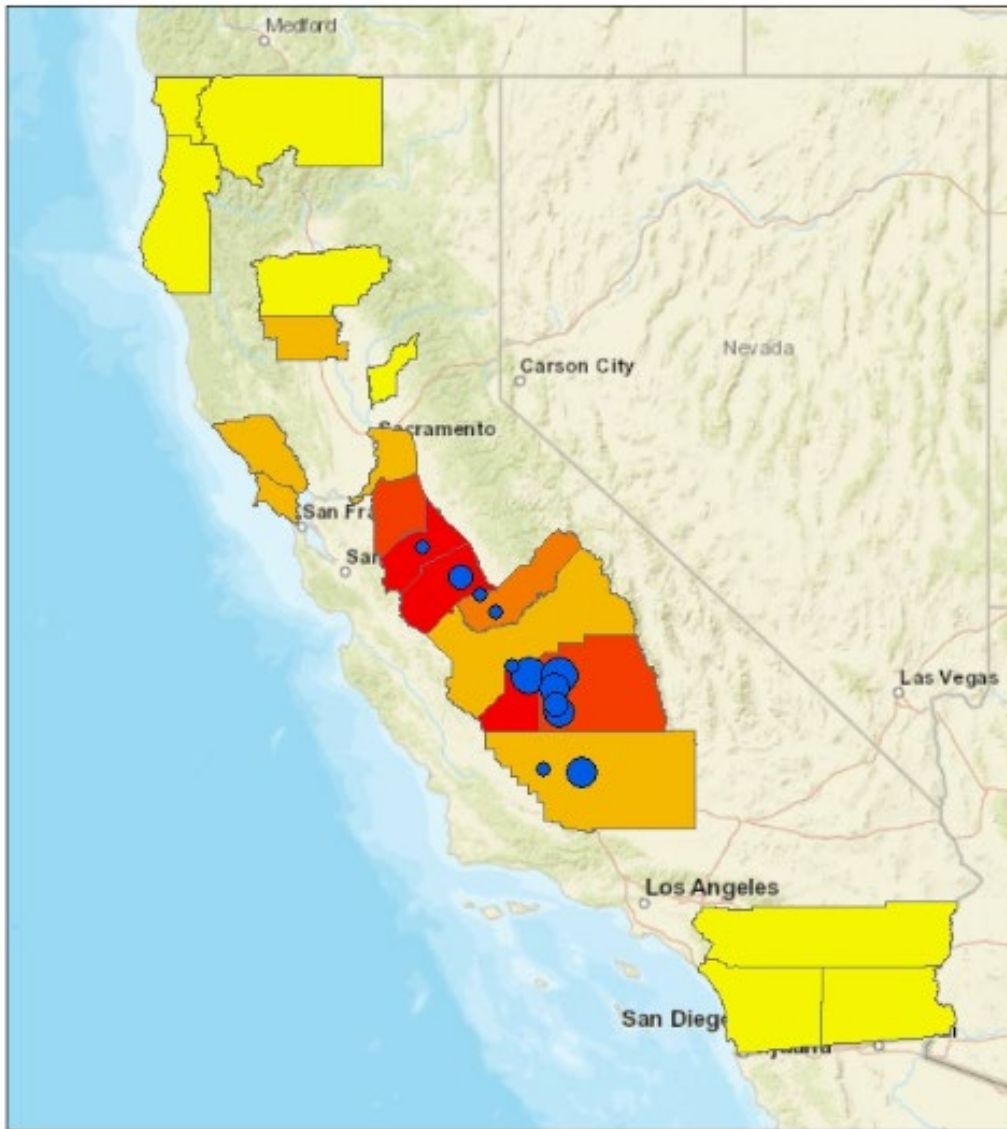
Legend

Funded Projects By City
- 1 - 3
- 4 - 6
- 7 - 9
- 10 - 11

Density (Cows/Acre)
- 0.000186 - 0.008431
- 0.008432 - 0.030479
- 0.030480 - 0.058651
- 0.058652 - 0.152111
- 0.152112 - 0.211902

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: Dapper, Tang, and Vilsack (2012) and California Public Utilities Commission (2019)

Figure B-8: California Organic-Waste Landfills and Major Connecting Highways (Candidate Locations for Food and High-Moisture Organics)
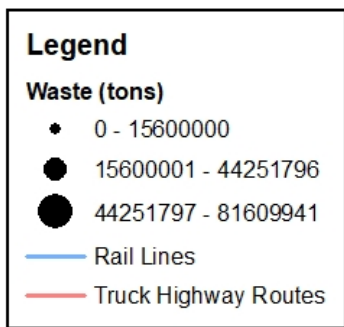
Legend

Waste (tons)
- • 0 - 15600000
- ⬤ 15600001 - 44251796
- ⬤ 44251797 - 81609941
- — Rail Lines
- — Truck Highway Routes

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: U.S. EPA (2019b) and California Department of Transportation (2013 and 2018)

Figure B-9: California Electric Transmission System
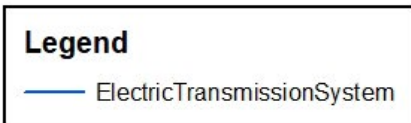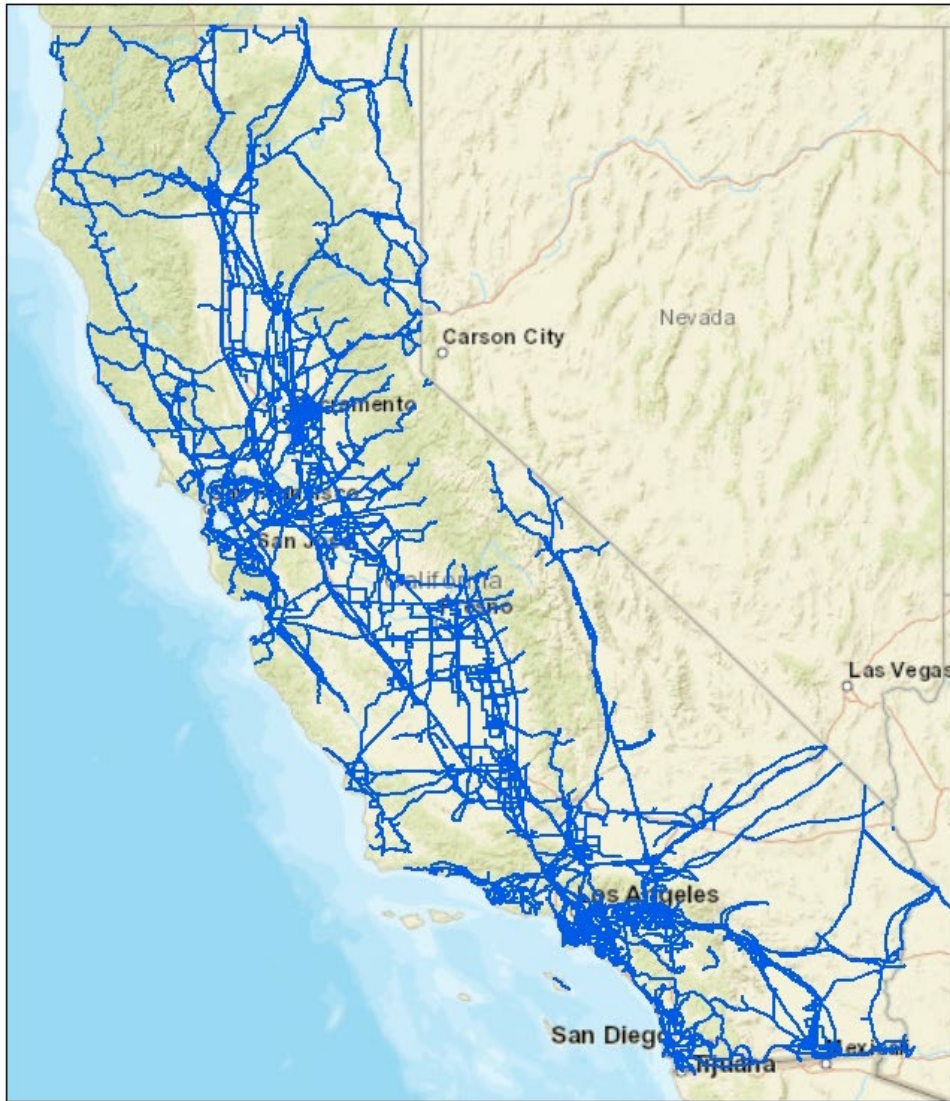
Legend

—— ElectricTransmissionSystem

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: CEC GIS Unit (2018a)

Figure B-10: California Natural Gas High-Pressure System

Legend

🟥 Natural Gas High Pressure System

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: CEC GIS Unit (2018b)

Figure B-11. California Highway and Rail Freight Transport System

Legend

— Rail Lines

— Truck Highway Routes

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: California Department of Transportation (2013) and (2018)

Figure B-12: California Primary Water Supply

Source: California Department of Water Resources; https://mavensnotebook.com/the-notebook-file-cabinet/californias-water-systems/

Figure B-13: 2023 Hydrogen Refueling Station Demand Point Evolution

Source: California Air Resources Board (2018)

Figure B-14: Clean Air Act Nonattainment Areas
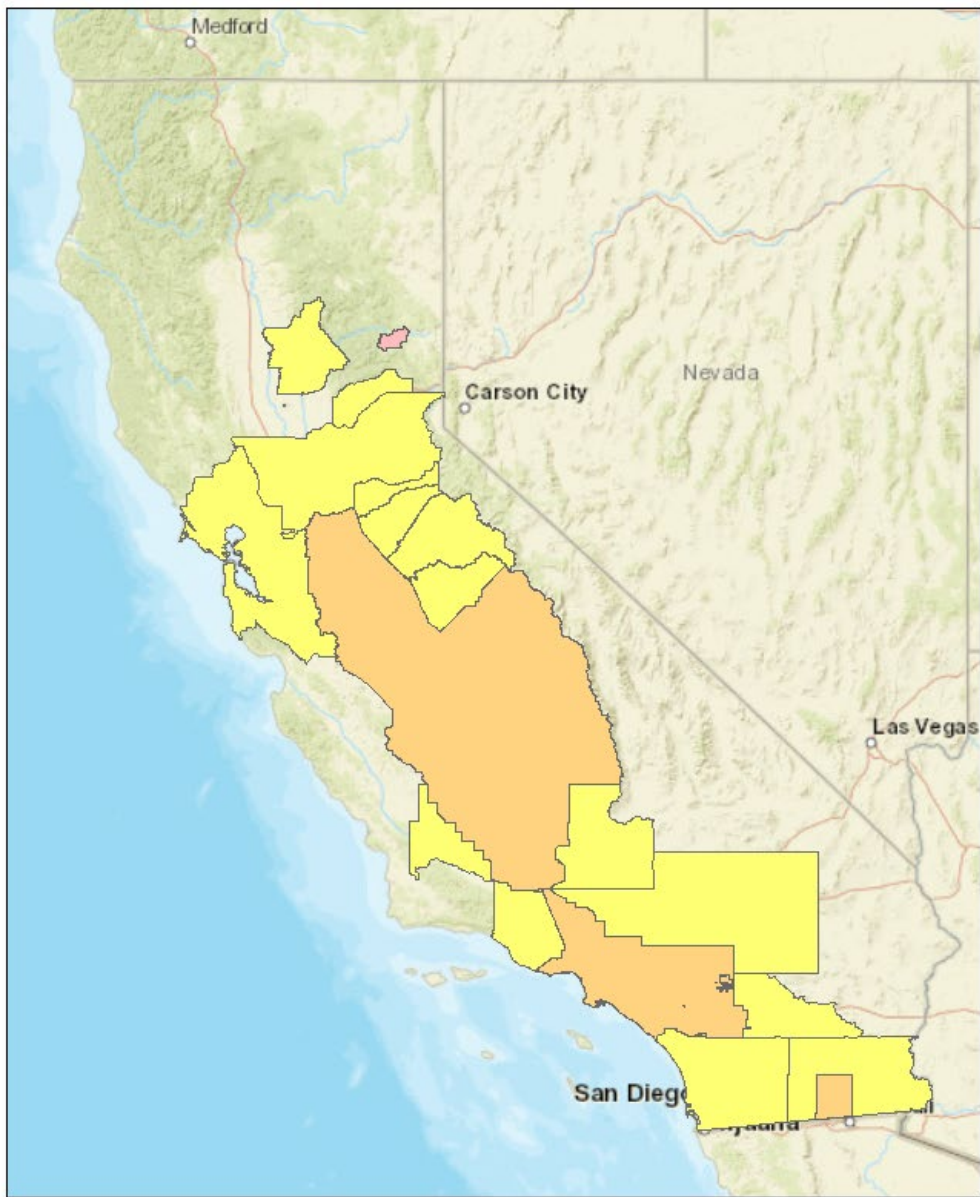
Legend

- Ozone and PM 2.5 Non-Attainment Area
- PM 2.5 Non-Attainment Area
- Ozone 8hr Non-Attainment Area

Service Layer Credits: Sources: Esri, HERE, Garmin, USGS, Intermap, INCREMENT P, NRCan, Esri Japan, METI, Esri China (Hong Kong), Esri Korea, Esri (Thailand), NGCC, © OpenStreetMap contributors, and the GIS User Community

Source: U.S. EPA (2019a)

Figure B-15: California Disadvantaged Communities

Legend

Cal EnviroScreen Disadvantaged Communities (DACs)

Cal EnviroScreen DACs in ozone and PM non-attainment areas
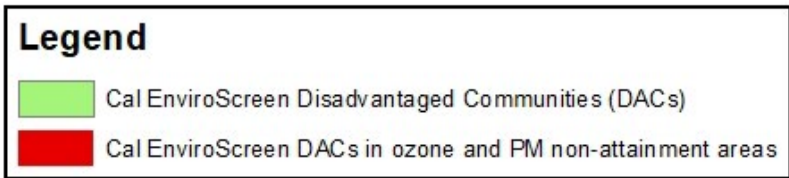
Source: CalEnviroScreen (2018) and U.S. EPA (2019a)

Renewable Hydrogen Production Facility Buildout Scenarios

Serving the evolving demand for renewable hydrogen will require the construction of many new renewable hydrogen production facilities and associated facilities such as liquefaction and terminal facilities. The precise number and mix of facilities depend upon many factors, including facility size, relative progress on cost reduction, cost and availability of feedstock, organic waste recovery mandates, and the value of environmental credits, among others. The facility deployment scenarios presented here are intended to represent the general evolution of the renewable hydrogen supply portfolio under assumptions representing the range of likely outcomes and should not be taken as literal predictions of site locations. The actual location of facilities within preferred resource areas involves a variety of factors and details beyond the general considerations used here, for example, the availability and price of land.

Facility buildout scenarios were developed by calculating the new production capacity needed in each time horizon and determining the optimal mix of new capacity additions to serve the incremental demand. Modest over-capacity is allowed within the first five years of market development to ensure that all facility types gain commercial validation prior to rapid market growth beginning in the late 2020s. The following assumptions were employed in the development of the deployment scenarios:

- The analysis deals only with renewable hydrogen demand (and does not address non-renewable hydrogen demand).[89]

- Reference facility sizes are assumed, as shown in Table B-2.

- Agency-supported commercial pilots for electrolyzer and gasifier projects are specified for all scenarios in the period before 2030.

- The buildout of anaerobic digestion facilities to process dairy manure and landfill-diverted organics are assumed to follow the scenarios developed for the California Air Resources Board Short-Lived Climate Pollutant strategy, and the product is assumed to be pipeline-injected biomethane (CA_Air_Resources_Board 2016).

- The demand for new reformation facilities to produce renewable hydrogen from pipeline biomethane is based on scenario assumptions on the share of biomethane allocated to hydrogen (as opposed to methane or liquids) with a base-case assumption of 50 percent.

- Mandates for recovery of forest material (for example, to reduce wildfire risk) and agricultural waste are possible in the future, but the base case assumes only economic adoption and assumes that up to 75 percent of feedstock is available for hydrogen production via thermochemical conversion (with the remainder allocated to renewable natural gas and liquid fuel).

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89 Some facilities, such as reformation facilities and electrolyzers, can product both renewable and nonrenewable hydrogen, depending upon the feedstock composition. The analysis presented here represents only renewable hydrogen demand as described in Chapter 1 of this report.

- Thermochemical conversion systems are assumed ready for first commercial deployment in 2023 and are constrained to three facilities built through 2028.

- Renewable hydrogen to support renewable integration is evenly split between electrolytic hydrogen (power-to-gas) and hydrogen from organic sources power turbines and fuel cells delivering dispatchable renewable electricity.

- The base-case assumption is that the LCFS program remains in place until 2050, with the reference carbon intensity beyond 2030 (current program and point) ramping down to 20 percent of 2012 level by 2050 and that LCFS credit price stays at the cap ($200 per $MTCO2_e$ escalating with inflation) for the life of the program.

- The spatial demand distribution for all transportation applications is assumed to follow the demand density analysis in the CARB AB 8 report (California_Air_Resources_Board 2018). Ammonia production demand is assumed to be located in high-agriculture areas, and all other applications are assumed to use the natural gas system for transport and delivery (so the pipeline is the "demand point").

- Hydrogen transport costs assume liquid supply chain for thermochemical and biomethane pathways and gaseous for electrolytic hydrogen.

- Roughly 50,000 kg per day of new renewable hydrogen production nameplate capacity has been announced for completion by 2021 in or adjacent to California. This new capacity is assumed completed for calculating incremental capacity needs.

Subject to the assumptions listed above, buildout scenarios were developed by adding facilities in each period to serve incremental demand. The mix of facilities (market share) was determined based on policy-driven build, feedstock availability, and cost minimization. The primary trade-off variables in the facility selection and siting optimization are presented in Table B-3. The research team developed several scenarios to represent potential outcomes for renewable hydrogen demand and relative share of different technologies, as shown in Table B-4. The facility siting analysis assumes central-scale facilities are used. Some portion of production capacity may be provided by forecourt production in the future. Such cases would reduce the number of central facilities deployed and would instead add capacity at hydrogen refueling locations, as shown in Figure C-3.

Table B-2: Reference Facility Sizes

Technology	Facility Size (Nameplate)	Comment
Thermochemical Conversion	25,000 kg RH2 per day commercial pilots 50,000 kg per day through 2030 and 150,000 kg per day beyond 2030	Initial projects slightly below efficient scale to minimize initial project cost for agency-sponsored projects with size increasing to efficient scale once full commercial validation is achieved
Anaerobic Digestion	7,500 kg RH2 per day	Based on current project activity
Reformers (and Associated Liquefaction System)	30,000 kg RH2 per day	Reformers and liquefier assumed collocated Size matches announced Air Liquide project
Electrolyzer	5,000 kg RH2 per day for initial pilots growing to 20,000 kg RH2 per day by 2030 and beyond	Based on manufacturer input on minimum efficient size for central production
Forecourt Systems	N/A	Sized based on the size and demand of host hydrogen refueling stations

Source: UCI APEP

Table B-3: Primary Site Selection Trade-Offs by Technology

Technology/Pathway	Primary Site Selection Determinant or Trade-Off
Thermochemical Conversion	Feedstock transport cost (a function of feedstock density) versus cost of transport of gaseous or liquid hydrogen
Anaerobic Digestion	Livestock density and proximity to natural gas pipeline for dairy Refuse route density and proximity to natural gas pipeline for organic MSW
Reformers (and Liquefaction System)	Proximity to demand and access to natural gas and electric transmission
Electrolyzer	Resource collocated systems: wind or solar resource quality versus proximity to demand Grid-supplied systems: proximity to demand

Source: UCI APEP

Table B-4: Buildout Scenario Assumptions

Scenario	Demand	Technology Cost
Base-Case	Mid Case	Base case for all technologies
High-Demand	High Case	Base case for all technologies
Low-Demand	Low Case	Base case for all technologies
High-Electrolysis	Mid Case	Electrolyzer cost progression favorable relative to others (capital cost, efficiency, input electricity cost)
High-Thermochemical	Mid Case	Thermochemical conversion cost progression favorable relative to others (capital cost, efficiency, feedstock)
High-Biomethane	Mid Case	75% allocation of biomethane to hydrogen production (proxy for hydrogen value chain cost reduction)

Source: UCI APEP

Early Market Policy-Supported Facility Additions

A 30,000-kilogram-per-day facility operating at 90 percent capacity factor produces enough hydrogen to supply 35,000 light-duty vehicles. The roughly 36,000 kilograms per day of capacity under construction to serve the hydrogen transportation market will be adequate to supply the sector until 2023 to 2025. By 2030, at the forecast growth rate, there will be demand for multiple new facilities per year. However, through the late 2020s, demand growth will not be adequate to allow full utilization of mid (5,000 to 10,000 kg per day) or large (30,000 kilograms per day or larger) within the first year of operation.

The buildout scenarios of the roadmap buildout assume that the state continues to sponsor electrolytic renewable hydrogen production facilities and initiates support for gasification facilities to ensure that these technologies are fully proven and established as the market begins to accelerate in the late 2020s and early 2030s. This policy-driven facility build will require financial support to compensate for reduced facility utilization in the early years of operation. To reduce the required financial support, the assumed facility sizes are below the typical facility sizes assumed for the mature market but large enough to represent full commercial scale. Table B-5 shows the policy-driven additions specified for the buildout scenarios. All remaining capacity additions are driven by relative production cost and feedstock availability as specified for each scenario. To the extent that the policy-driven facility capacity differs from the assumptions in Table B-5, any capacity additions needed under the various scenarios would be served by reformed biomethane from landfills or dairies because these are the low-cost, commercially proven pathways through the 2020s. With these specified additions, the RH2 production base reaches full utilization by 2022 to 2027, depending on demand scenario as shown in Figure B-16. Figures 17 and 18 show the temporal buildout of renewable hydrogen facility capacity for the various scenarios. Time-phased geospatial maps for the various scenarios are shown in Figures B-19 to B-30.

Table B-5: Policy-Driven Facility Additions in the Early Market Period

Technology	Demand Case	Period 2022 – 25	Period 2026 - 30	State Support	Subsidy Cost
Gasification	All cases	1 x 25 MT/d	1 x 25 MT/d	50% capital cost grant or loan guarantee valued at 20% of capital cost	$35M - $85M
Electrolysis	High	5 x 5 MT/d	2 x 20 MT/d	50% capital cost grant for first 5 projects; 25% for next 2	~$50M
Electrolysis	Medium and Low	4 x 5 MT/d	1 x 5 MT/d 2 x 20 MT/d	50% capital cost grant for first 5 projects; 25% for next 2	~$50M
				Total State Support	$85 - $135M

Total State Support $85M - $135M Source: UCI APEP

Figure B-16: Effect of Policy-Driven Renewable Hydrogen Facility Build on Facility Utilization
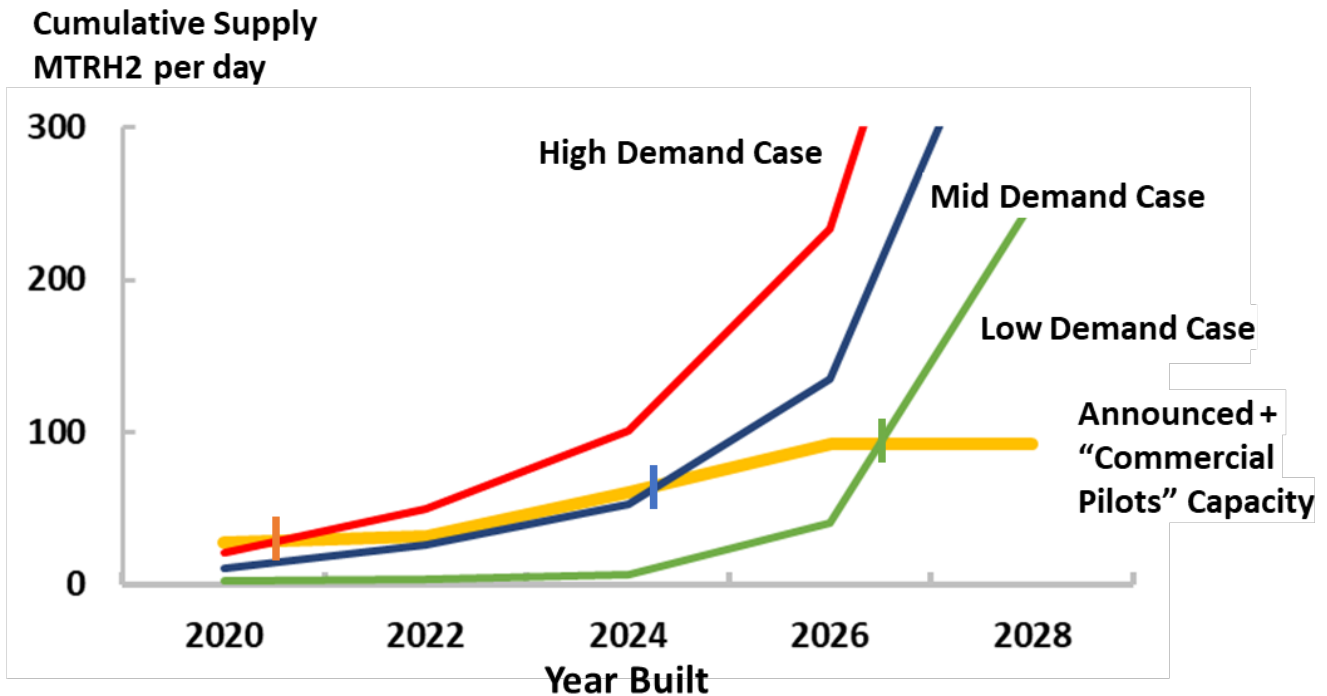
Source: UCI APEP

Figure B-17: Temporal Buildout Scenarios for Alternative Demand Cases
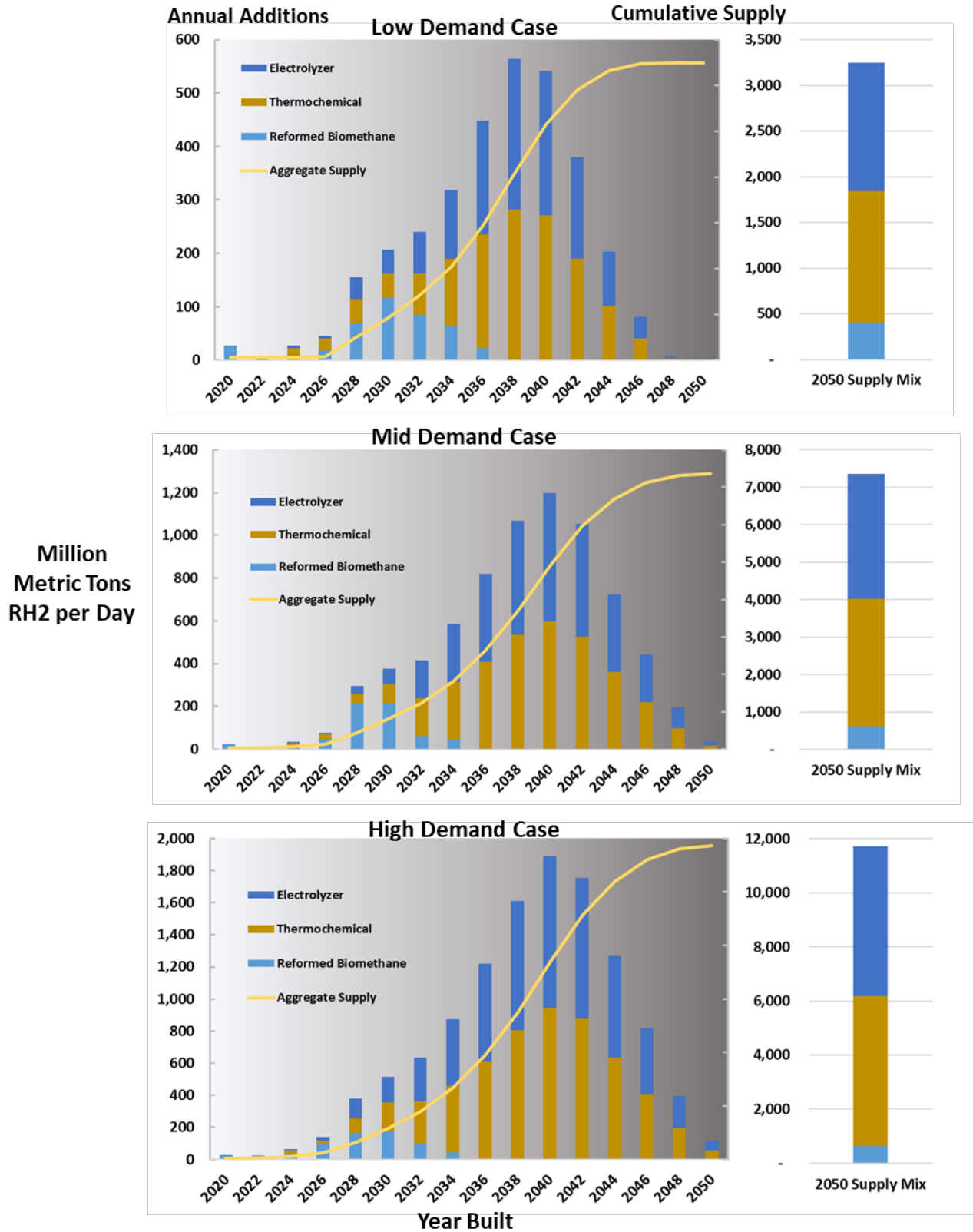
The darkening background in the out years reflects lower degree of detail in the underlying analysis.
Source: UCI APEP.

Figure B-18: Temporal Buildout Scenarios for Alternative Technology Shares and Mid-Case Demand
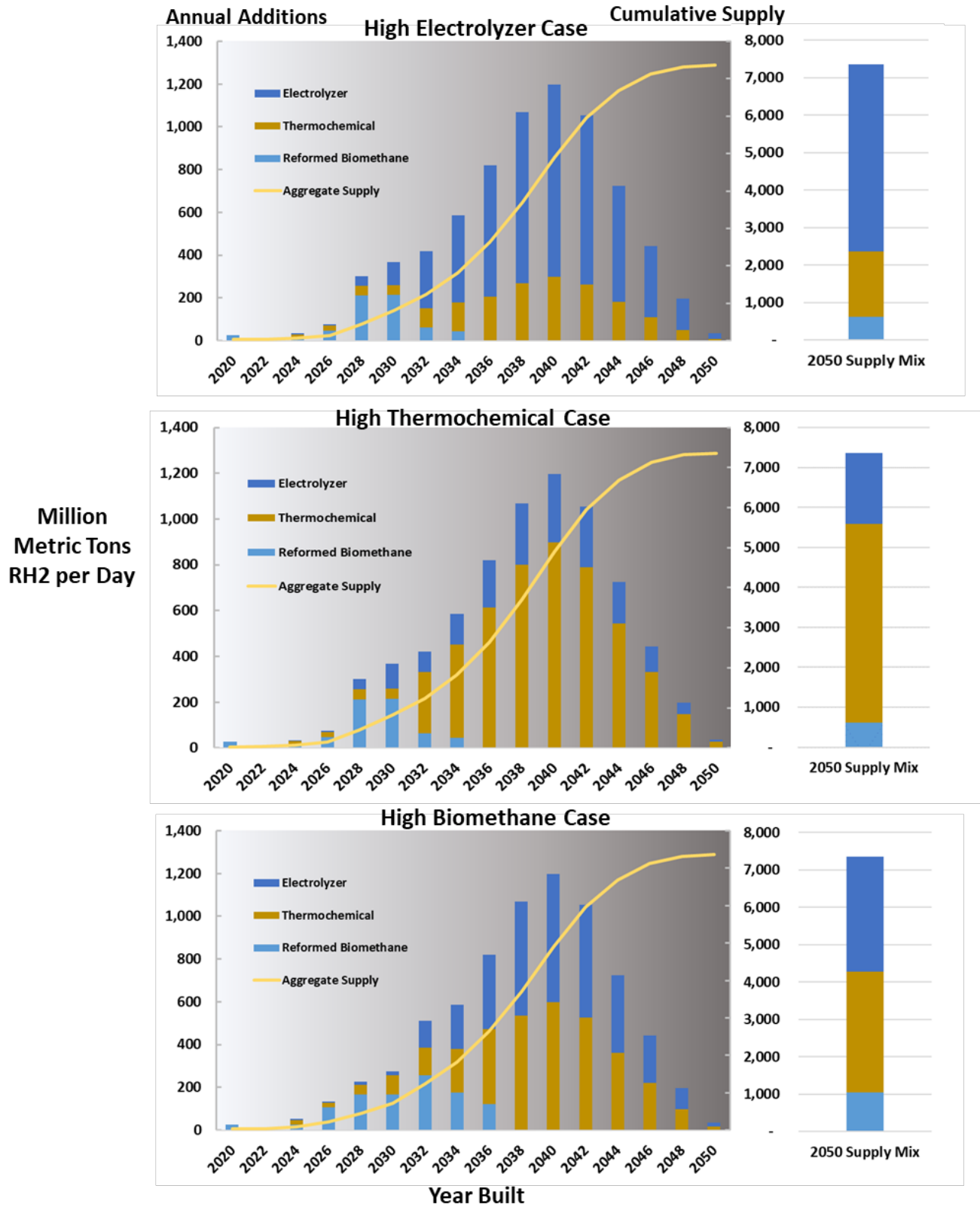
Source: UCI APEP

Figure B-19: Mid-Case Buildout and 2030 Spatial Detail

2030 Spatial Detail

Technology	Count
● Electrolyzer Solar	13
+ Electrolyzer Wind	6
☆ Thermochemical	5
⬠ Dairy	24
▲ Organic MSW	19
☐ SMR	21
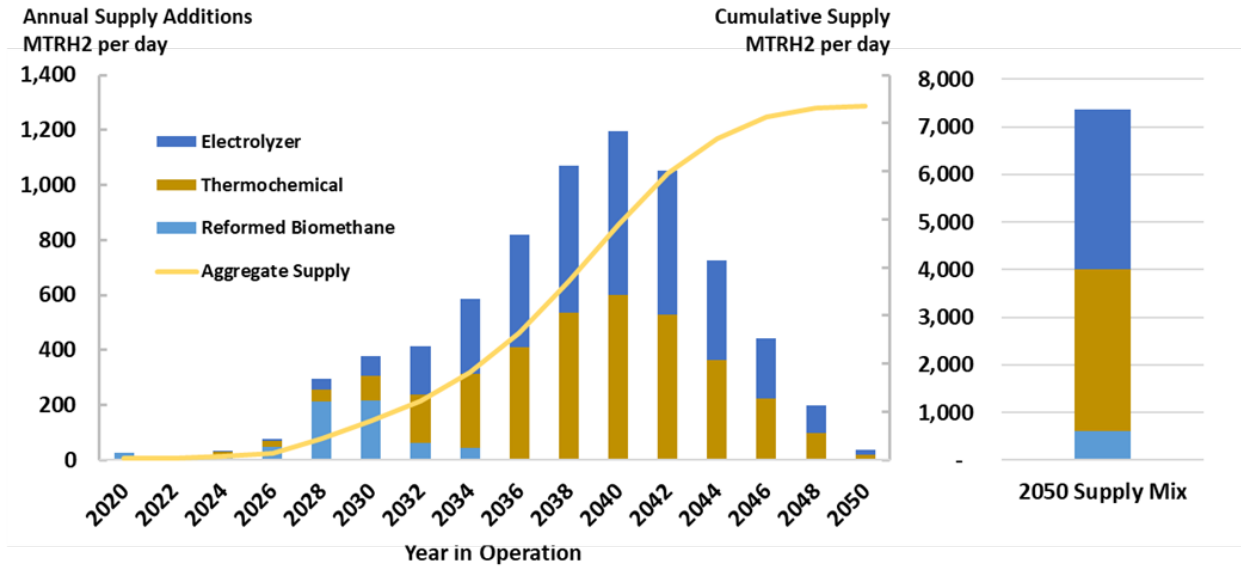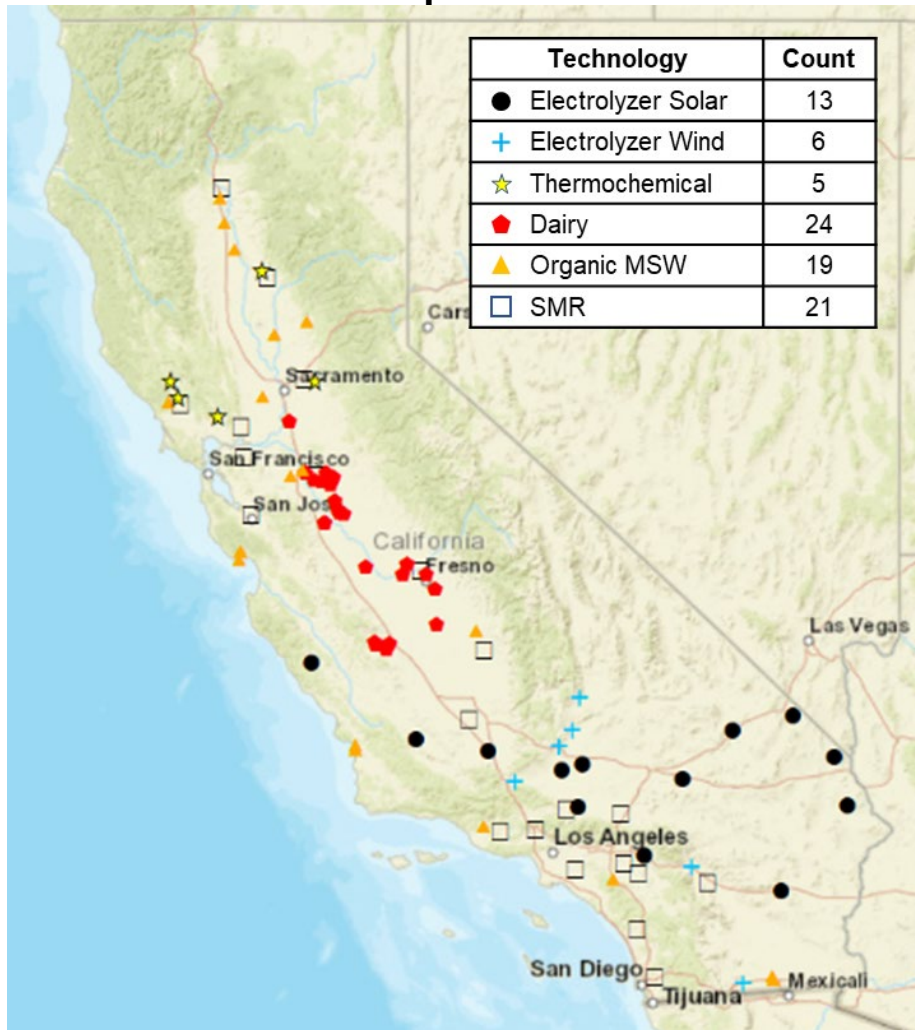
Source: UCI APEP

Figure B-20: Mid-Case Spatial Buildout Progression
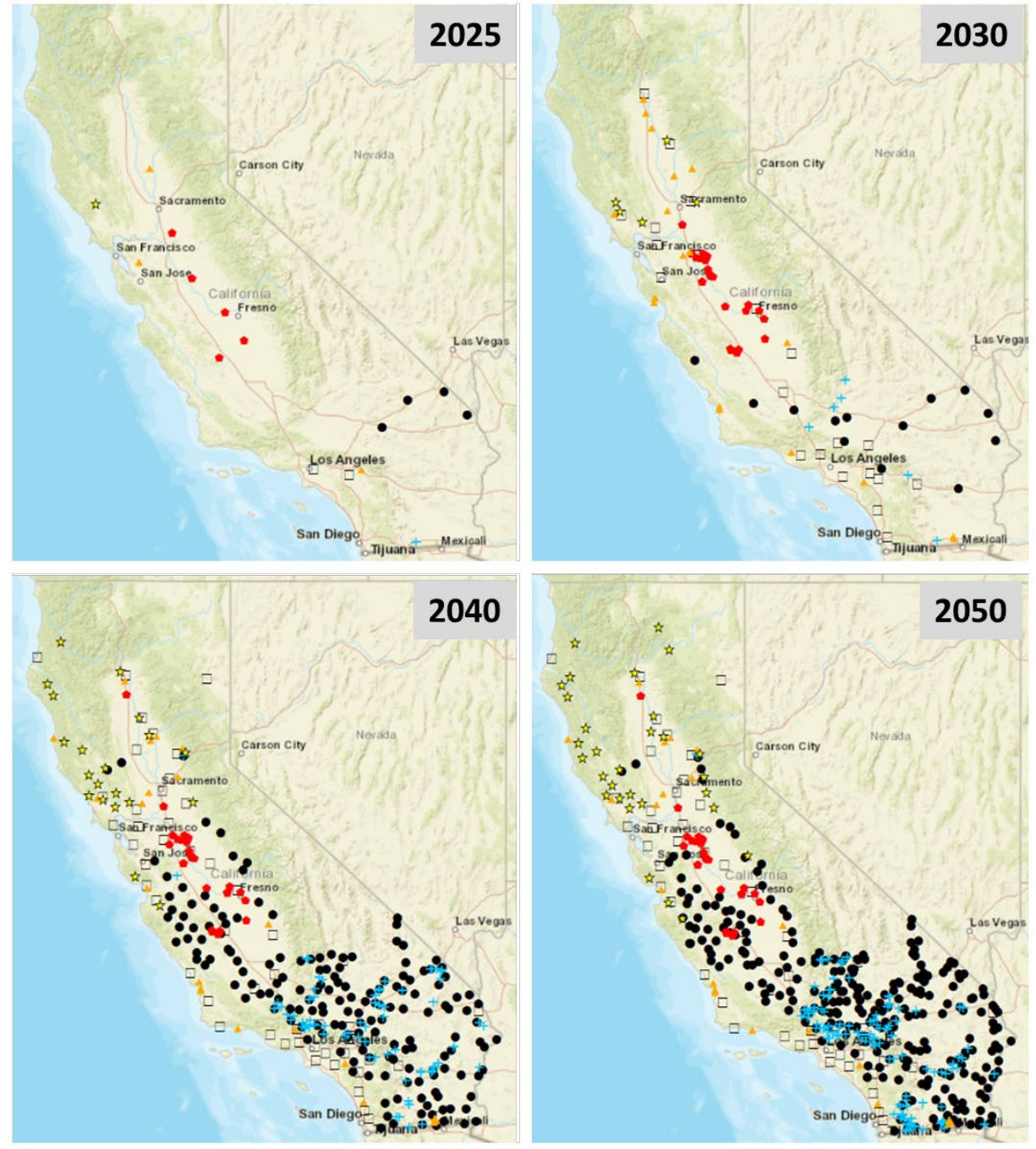
Technology Count by Year	2025	2030	2040	2050
● Electrolyzer Solar	4	13	169	265
+ Electrolyzer Wind	1	6	72	113
☆ Thermochemical	1	5	20	30
⬠ Dairy	5	24	28	28
▲ Organic MSW	3	19	21	21
☐ SMR	2	21	51	51

Source: UCI APEP

Figure B-21: High-Case Buildout and 2030 Spatial Detail

Annual Supply Additions
MTRH2 per day

- Electrolyzer
- Thermochemical
- Reformed Biomethane
- Aggregate Supply

Cumulative Supply
MTRH2 per day

2050 Supply Mix

Year in Operation

2030 Spatial Detail

Technology	Count
● Electrolyzer Solar	29
+ Electrolyzer Wind	12
☆ Thermochemical	8
⬟ Dairy	25
▲ Food	19
□ SMR	21

Source: UCI APEP

B-28
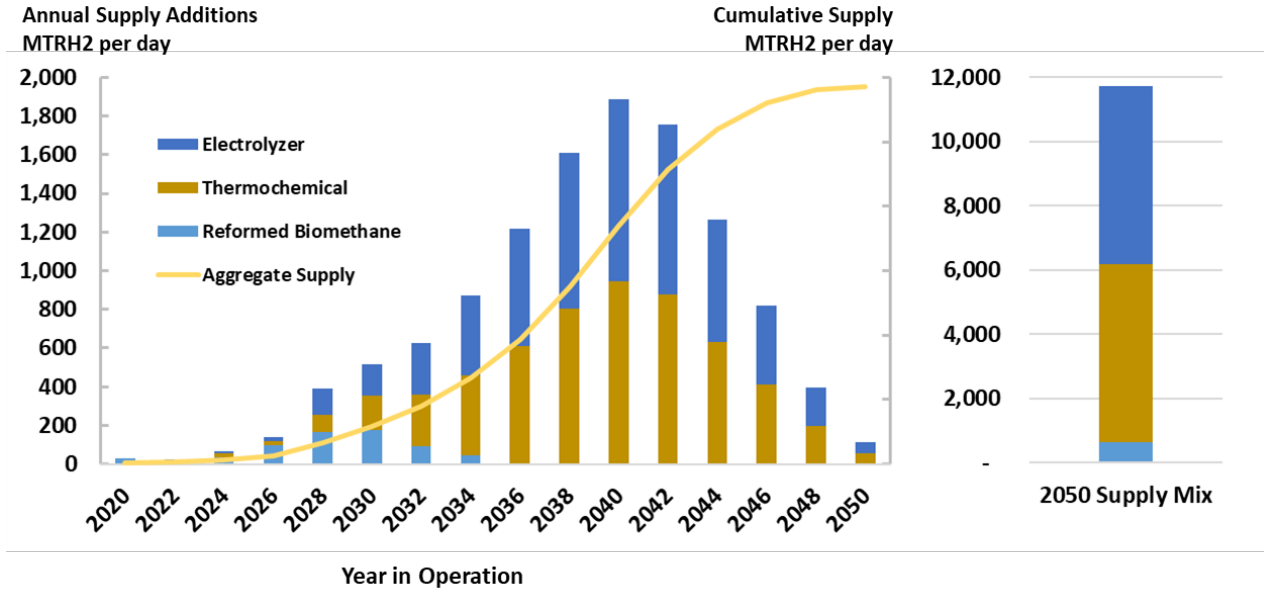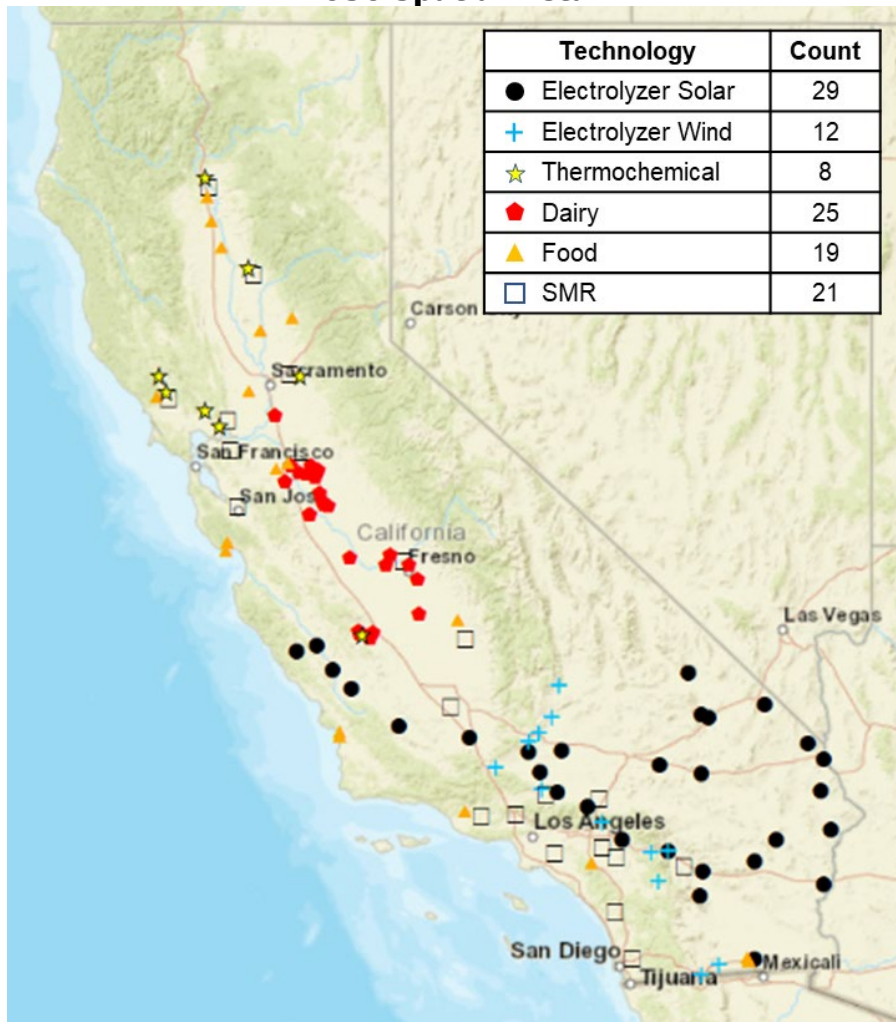
Figure B-22: High-Case Spatial Buildout Progression
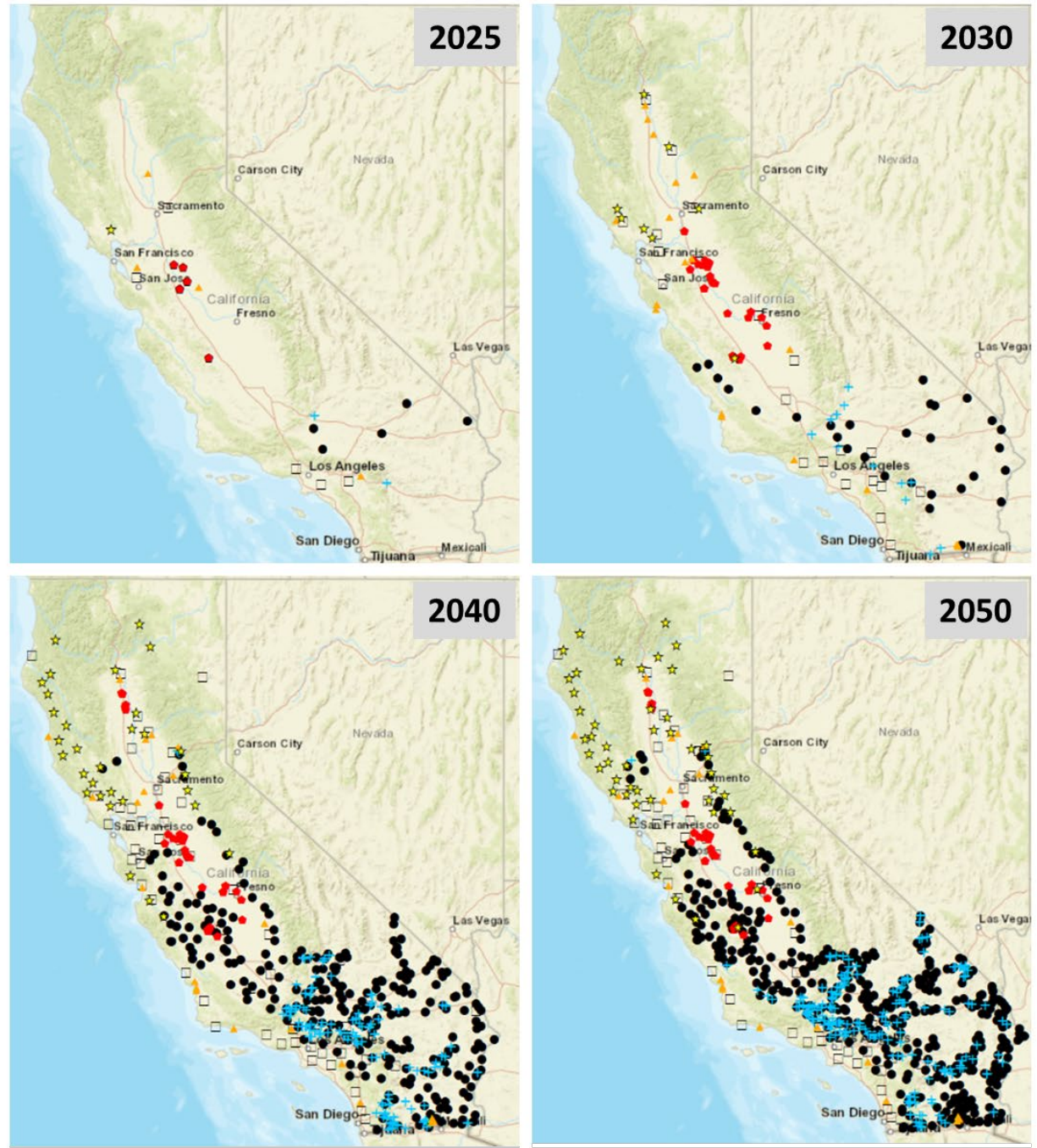
Technology Count by Year		2025	2030	2040	2050
●	Electrolyzer Solar	5	29	265	435
+	Electrolyzer Wind	2	12	114	186
☆	Thermochemical	1	8	31	47
⬠	Dairy	6	25	32	32
▲	Organic MSW	4	19	21	21
☐	SMR	5	21	54	54

Source: UCI APEP

B-29

Figure B-23: Low-Case Buildout and 2030 Spatial Detail

Annual Supply Additions
MTRH2 per day

Cumulative Supply
MTRH2 per day

Legend:
- Electrolyzer
- Thermochemical
- Reformed Biomethane
- Aggregate Supply

Year in Operation

2050 Supply Mix

2030 Spatial Detail

Technology		Count
●	Electrolyzer Solar	8
+	Electrolyzer Wind	4
☆	Thermochemical	4
⬠	Dairy	24
▲	Food	17
□	SMR	13
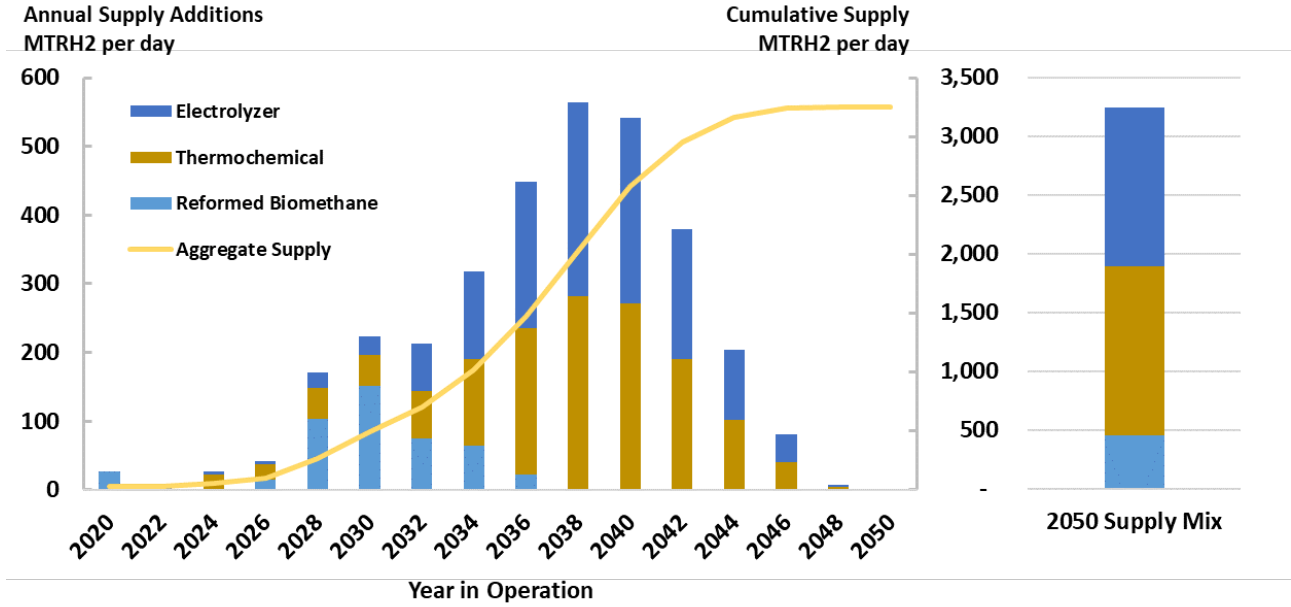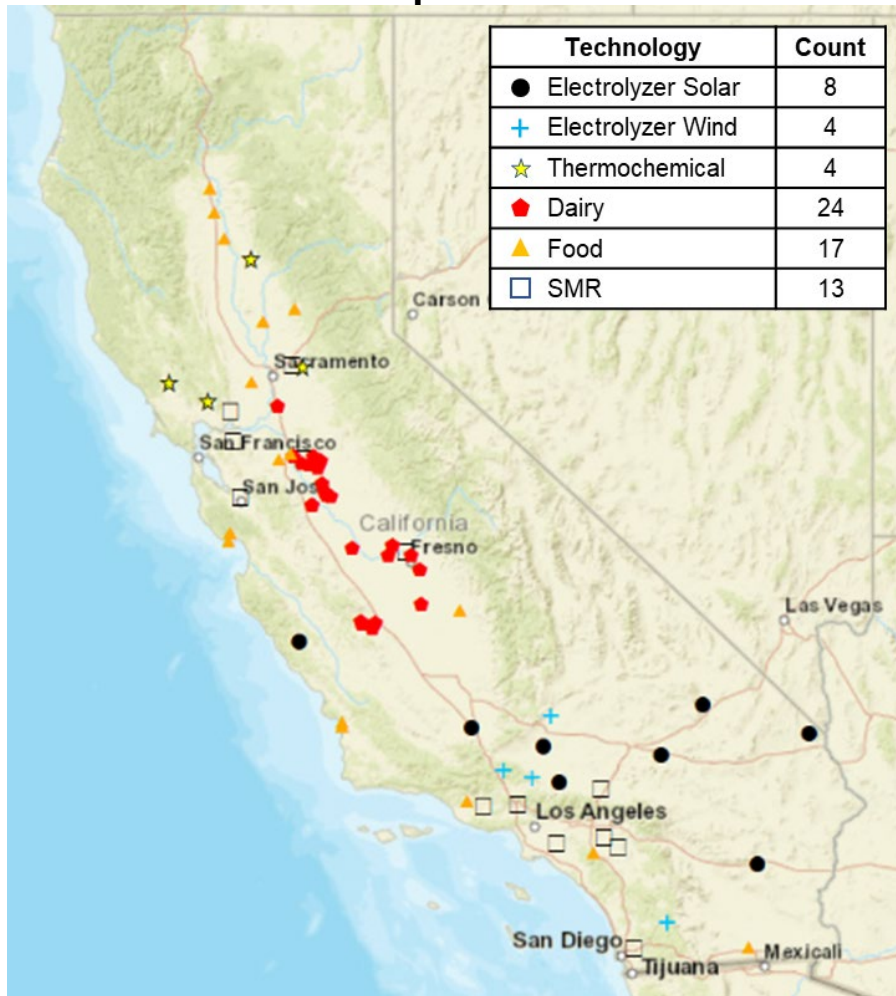
Source: UCI APEP

Figure B-24: Low-Case Spatial Buildout Progression
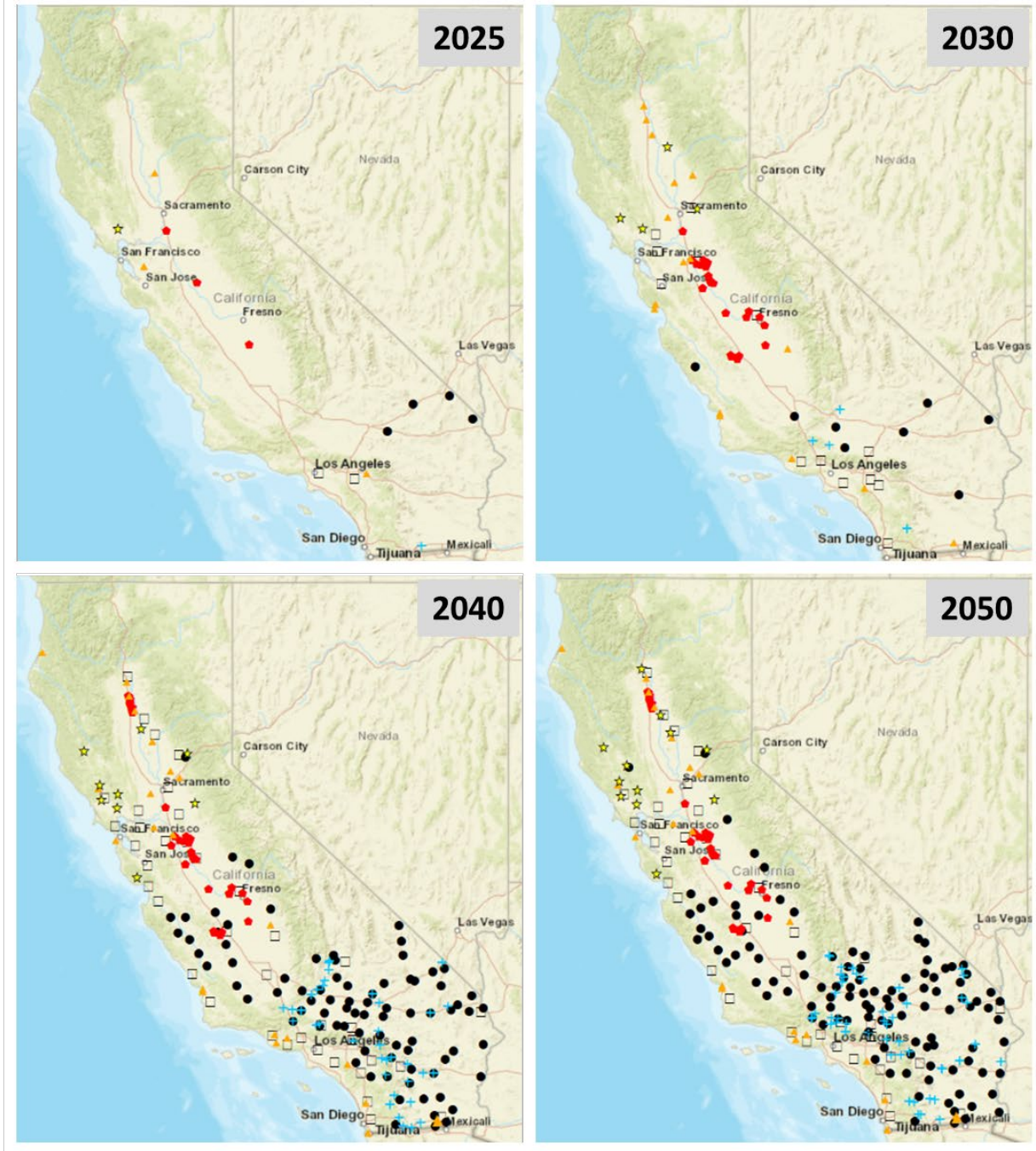
Technology Count by Year	2025	2030	2040	2050
● Electrolyzer Solar	4	8	83	110
+ Electrolyzer Wind	1	4	36	47
☆ Thermochemical	1	4	12	14
⬠ Dairy	2	24	33	33
▲ Organic MSW	0	17	24	24
☐ SMR	1	13	39	39

Source: UCI APEP

Figure B-25: High-Thermochemical-Case Buildout and 2030 Spatial Detail

Annual Supply Additions
MTRH2 per day

Cumulative Supply
MTRH2 per day

Legend:
- Electrolyzer
- Thermochemical
- Reformed Biomethane
- Aggregate Supply

2050 Supply Mix

2030 Spatial Detail

Technology		Count
●	Electrolyzer Solar	15
+	Electrolyzer Wind	6
☆	Thermochemical	5
⬟	Dairy	24
▲	Food	19
□	SMR	21
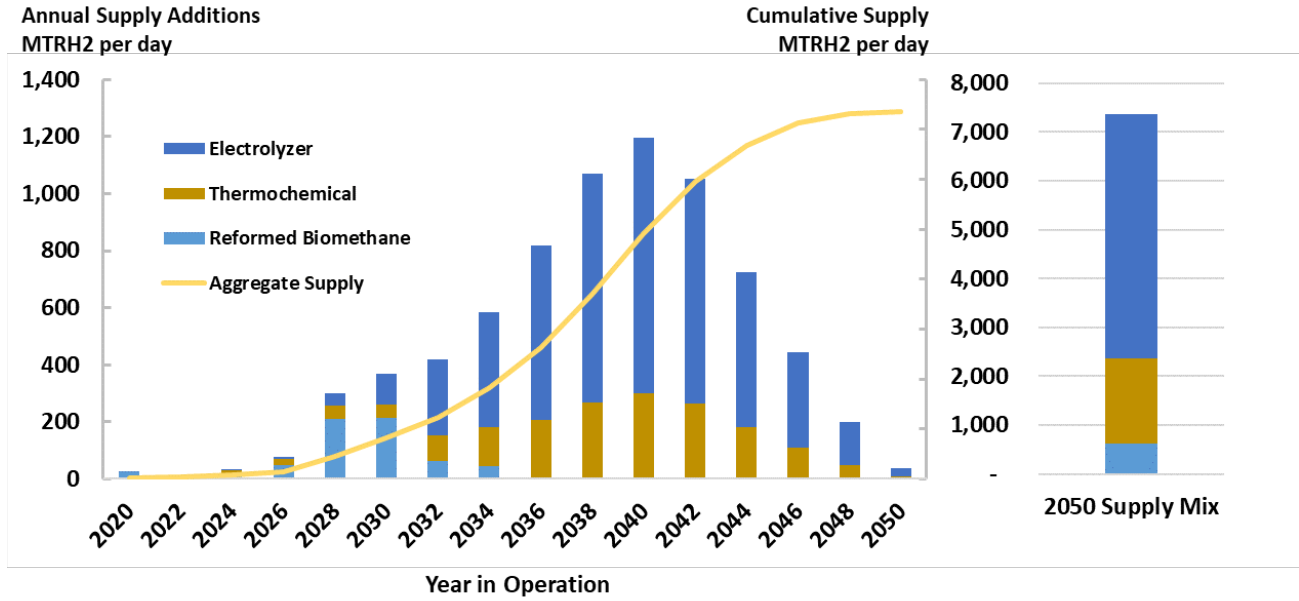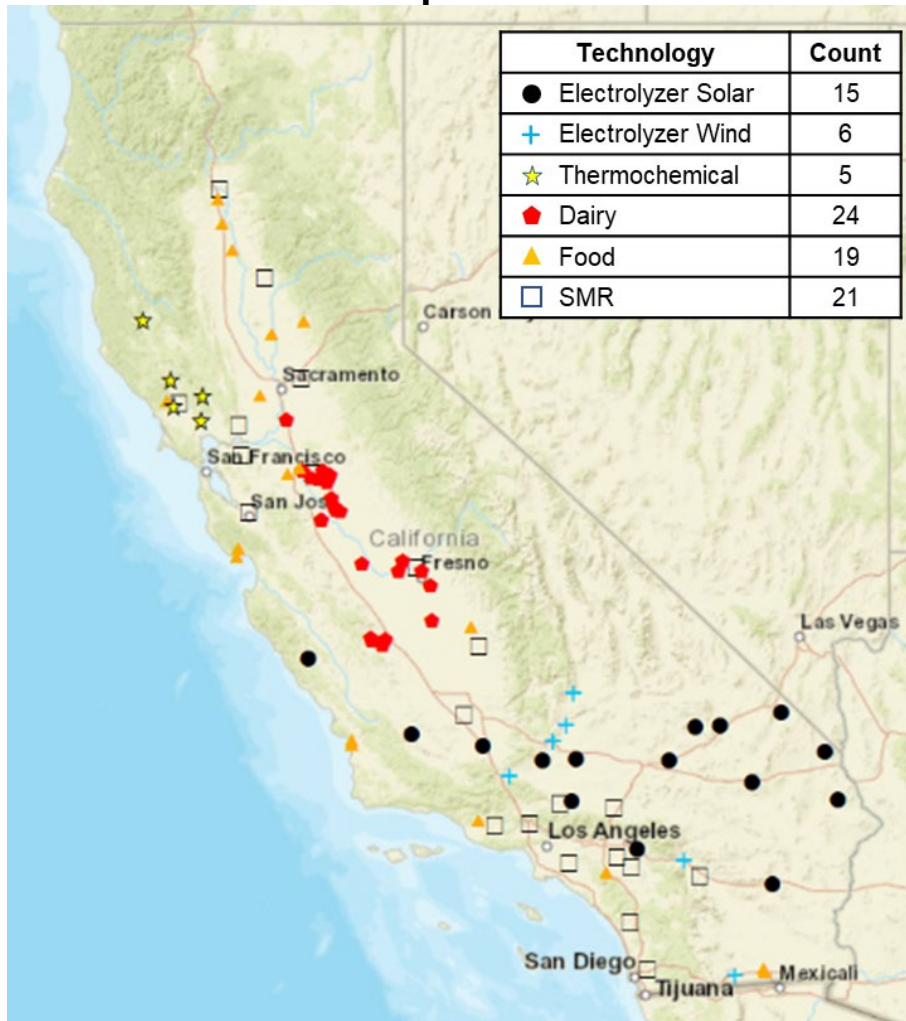
Source: UCI APEP

Figure B-26: High-Thermochemical-Case Spatial Buildout Progression
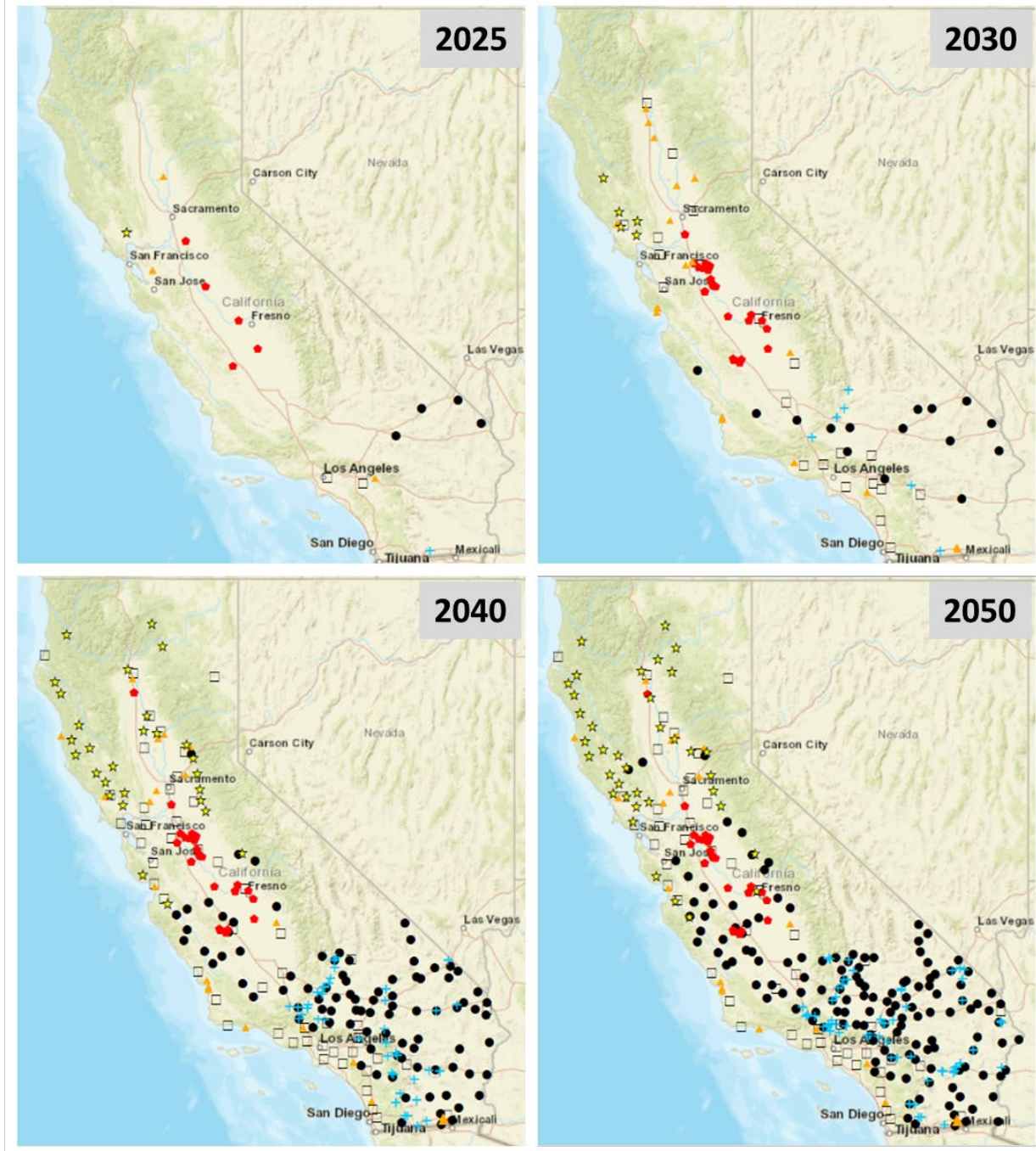
Technology Count by Year	2025	2030	2040	2050
● Electrolyzer Solar	4	15	92	141
+ Electrolyzer Wind	1	6	40	60
☆ Thermochemical	1	5	28	41
⬠ Dairy	5	24	28	28
▲ Organic MSW	3	19	21	21
□ SMR	2	21	51	51

Source: UCI APEP

Figure B-27: High-Electrolyzer-Case Buildout and 2030 Spatial Detail

2030 Spatial Detail

Technology		Count
●	Electrolyzer Solar	16
+	Electrolyzer Wind	7
☆	Thermochemical	4
⬠	Dairy	24
▲	Food	19
□	SMR	21
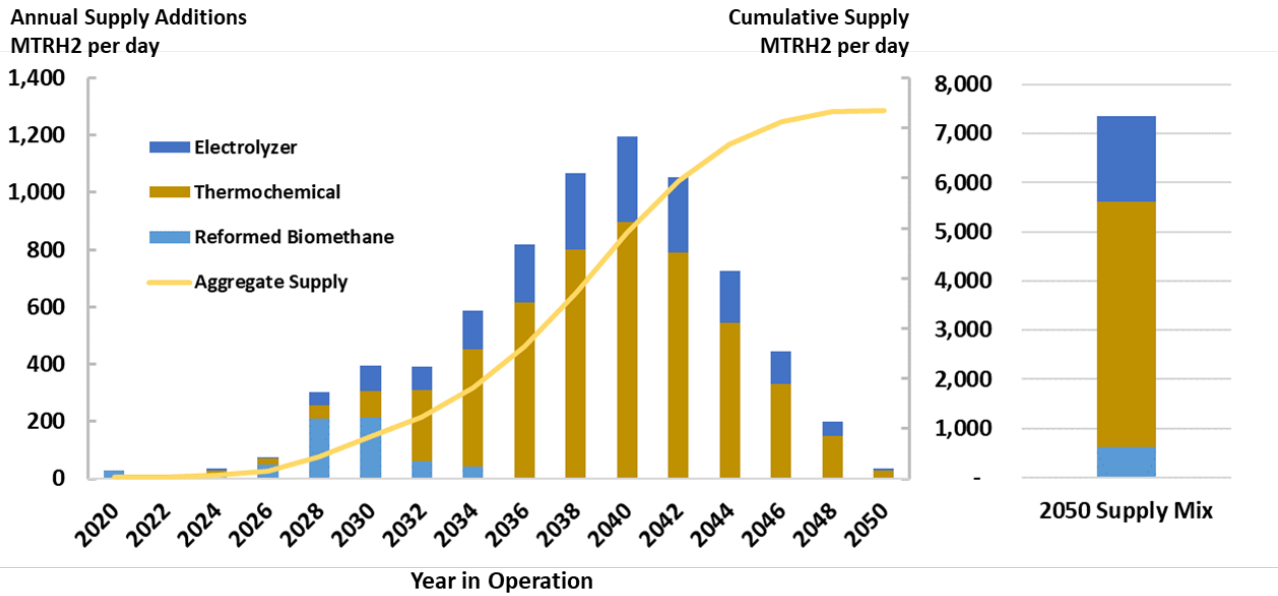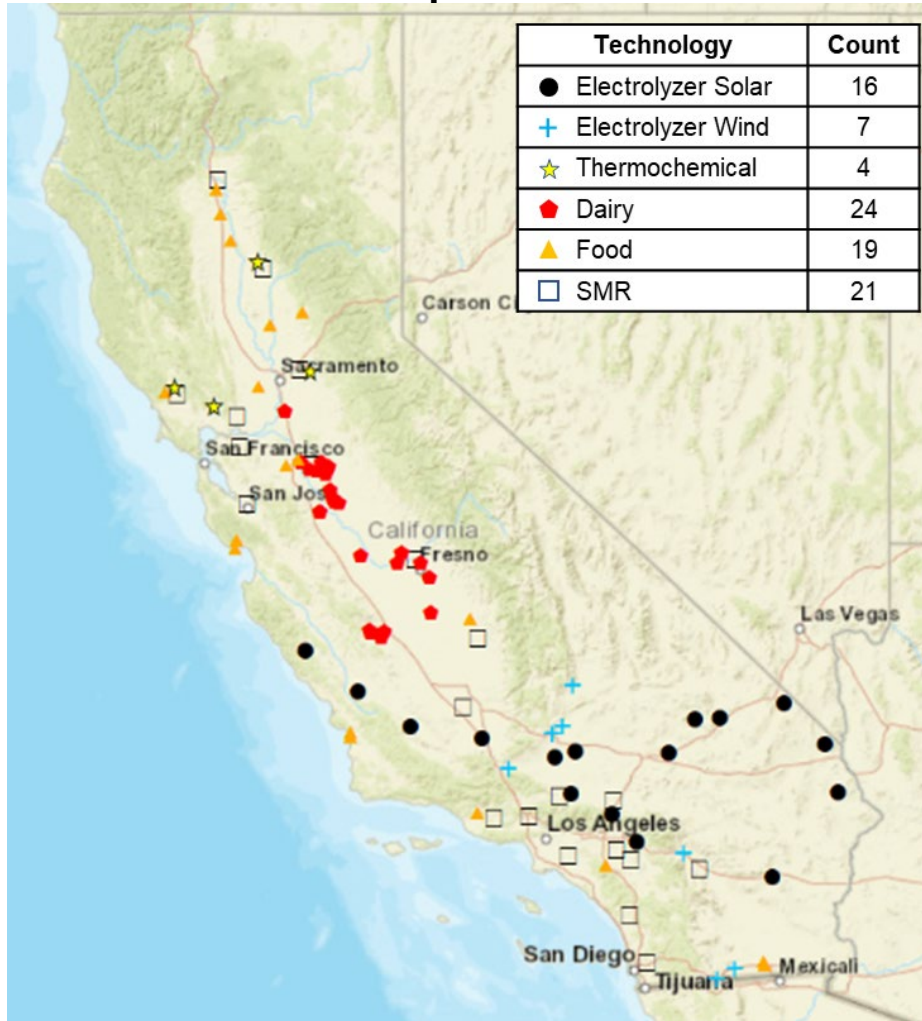
Source: UCI APEP

Figure B-28: High-Electrolyzer-Case Spatial Buildout Progression
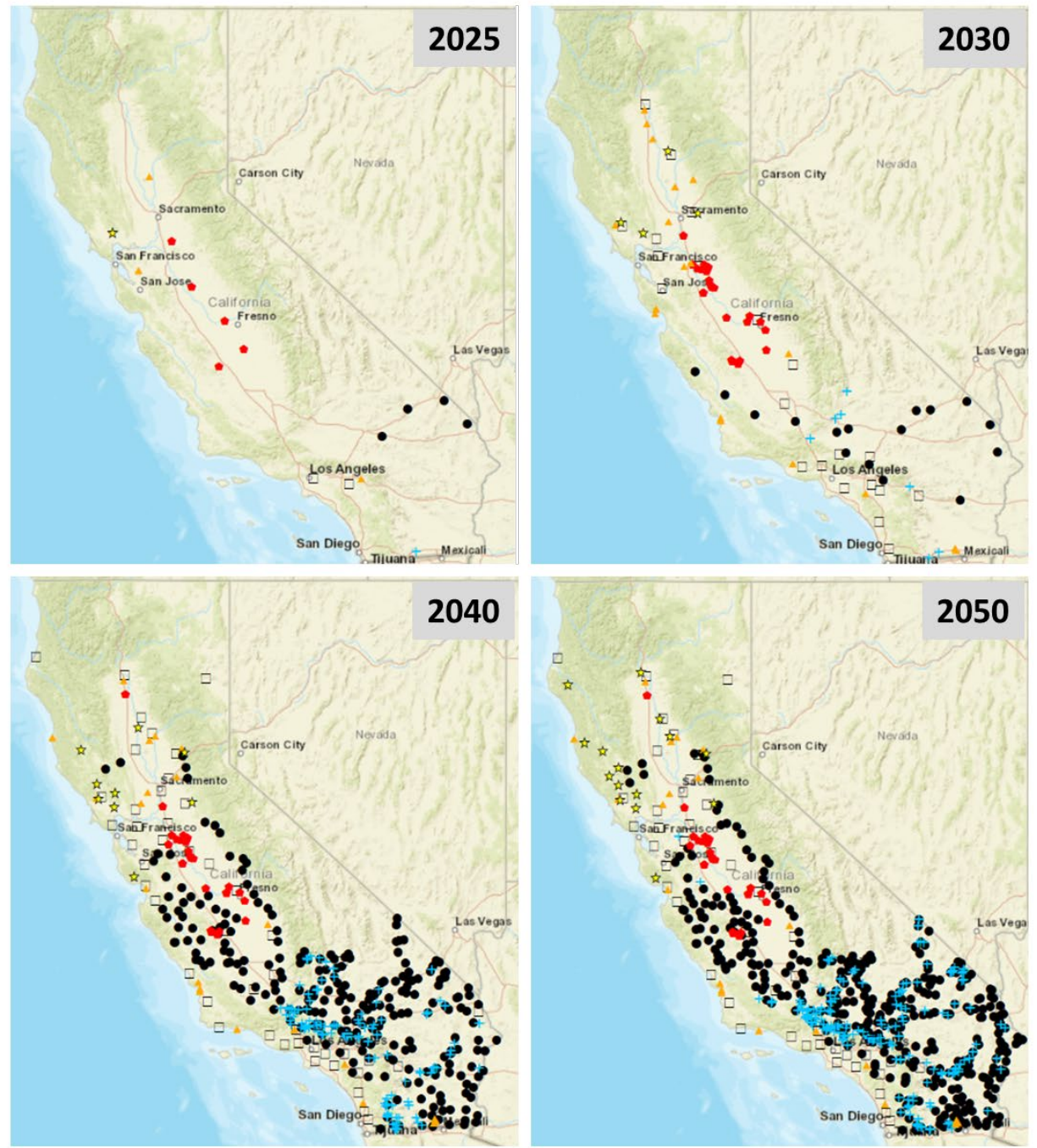
Technology Count by Year	2025	2030	2040	2050
● Electrolyzer Solar	4	16	249	390
+ Electrolyzer Wind	1	7	106	170
☆ Thermochemical	1	4	12	17
⬠ Dairy	5	24	28	28
▲ Organic MSW	3	19	21	21
☐ SMR	2	21	51	51

Source: UCI APEP

Figure B-29: High-RNG-Case Buildout and 2030 Spatial

Annual Supply Additions
MTRH2 per day

Cumulative Supply
MTRH2 per day

Legend:
- Electrolyzer
- Thermochemical
- Reformed Biomethane
- Aggregate Supply

Year in Operation

2050 Supply Mix

2030 Spatial Detail

Technology	Count
● Electrolyzer Solar	15
+ Electrolyzer Wind	6
☆ Thermochemical	5
⬠ Dairy	24
▲ Food	19
☐ SMR	21
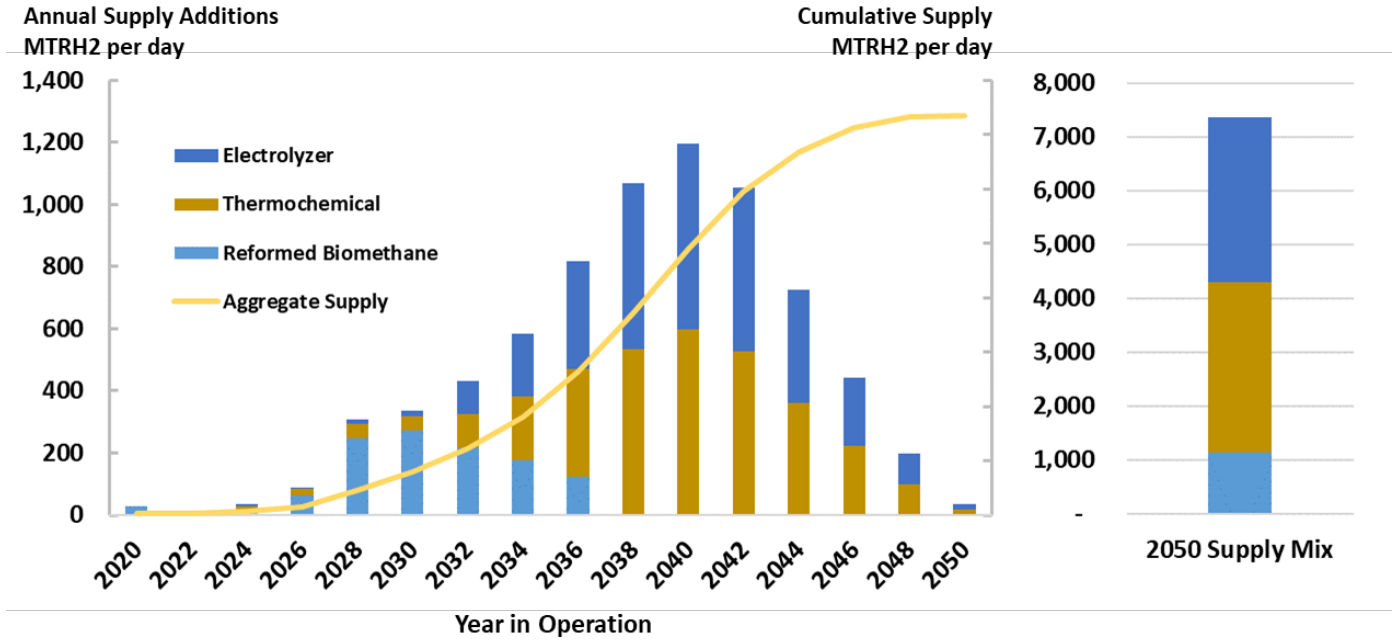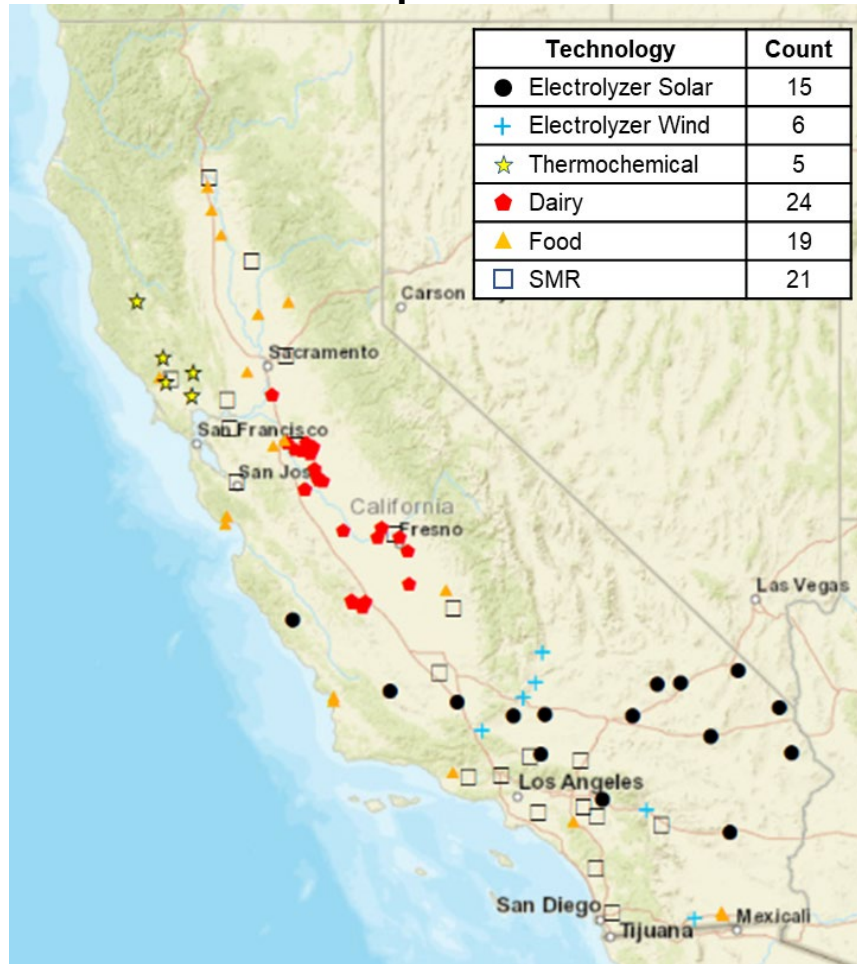
Source: UCI APEP

Figure B-30: High-RNG-Case Spatial Buildout Progression
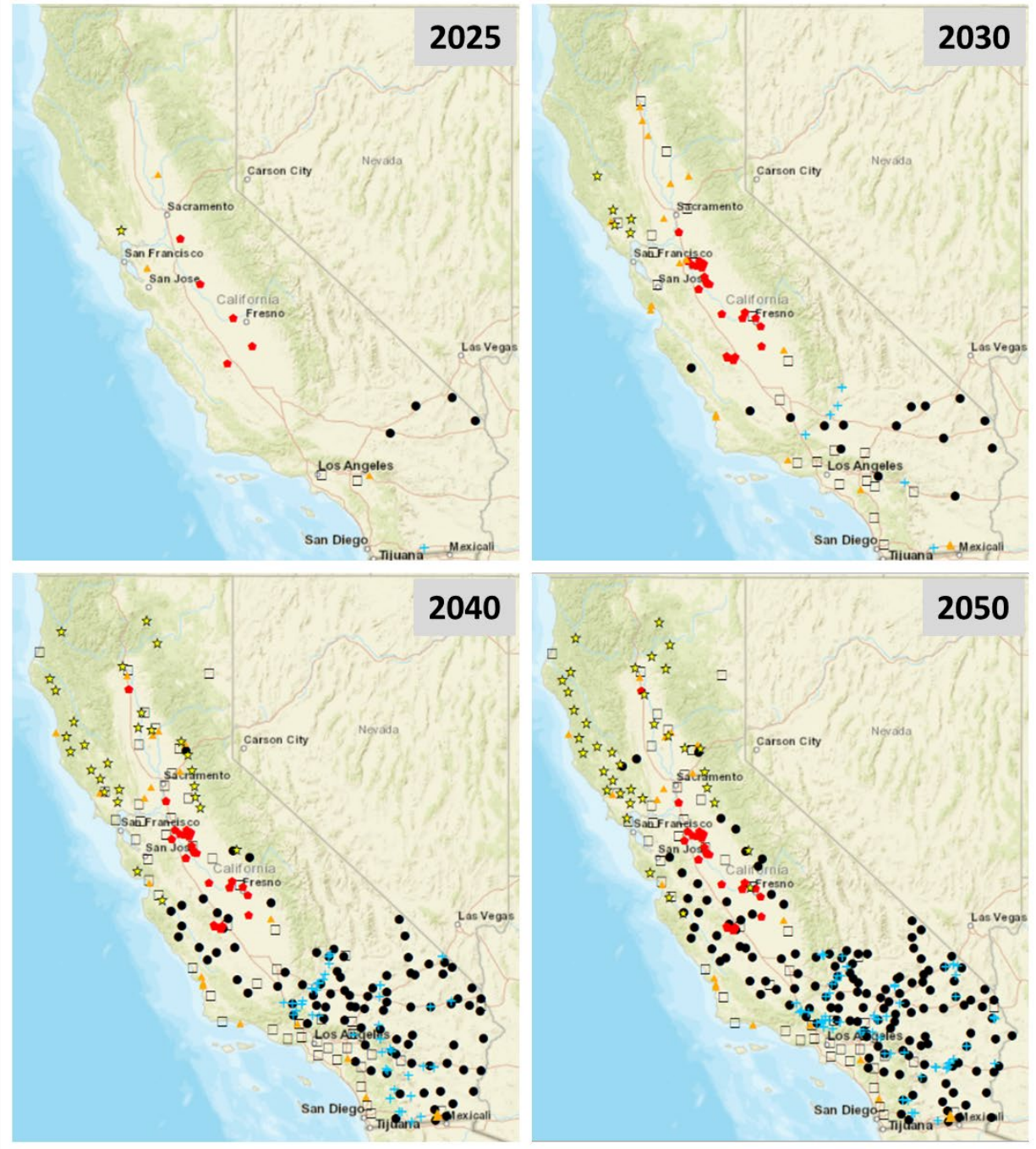
Technology Count by Year	2025	2030	2040	2050
● Electrolyzer Solar	4	15	92	141
+ Electrolyzer Wind	1	6	40	60
☆ Thermochemical	1	5	28	41
⬠ Dairy	5	24	28	28
▲ Organic MSW	3	19	21	21
□ SMR	2	21	51	51

Source: UCI APEP

Conclusion

The various scenarios developed for renewable hydrogen demand and facilities to supply that demand show that hundreds of new renewable hydrogen production facilities will be needed over the coming 30 years under all scenarios. While the buildout required may appear daunting, the number of production facilities needed is comparable in scale and number to the buildout that will be required to meet the 2045 electricity decarbonization goal. The more than 100 large-scale renewable electricity projects that have been built to date and the rapid scaling of project development activity in the dairy sector provide a degree of confidence that the renewable hydrogen production sector can form and scale to meet the demands of the market. Supportive policies from the involved state agencies can help increase the likelihood that the launch and scaling of the renewable hydrogen production sector goes according to plan.

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APPENDIX C:
Renewable Hydrogen Production Roadmap for California

Purpose of the Roadmap

This roadmap guides future state policy and funding decisions to support the successful buildout of a robust renewable hydrogen sector as a key part of California's zero-carbon economy. It also serves as a source of information for the public and interested stakeholders. A key objective is to define steps needed to support an optimal deployment of renewable hydrogen production facilities synchronized with the growing demand for renewable hydrogen. This document provides a summary of analysis and findings detailed elsewhere in this project final report and supporting appendices on technology forecasts, renewable hydrogen demand, and renewable hydrogen production facility siting and buildout scenarios.

As depicted in Figure C-1, hydrogen can serve the full range of transportation applications and renewable hydrogen can play an important role in decarbonizing transportation. Beyond transportation, renewable hydrogen can play a broader role as an important element of the future, integrated, zero-carbon energy and transportation sectors illustrated in Figure C-2. The roadmap seeks to support successful evolution toward this future through rigorous analysis of evolving demand, technologies needed to serve that demand, and options for effective policy support. This roadmap builds on the extensive body of work on optimal hydrogen refueling station network deployment by addressing the supply side of the hydrogen value chain as well as assessing additional sources of future demand.

Figure C-1: Hydrogen in Transportation

Photo Credits: UCI APEP, Hyundai, Toyota, Honda

Figure C-2: One Vision of the Future Energy and Transportation Ecosystem
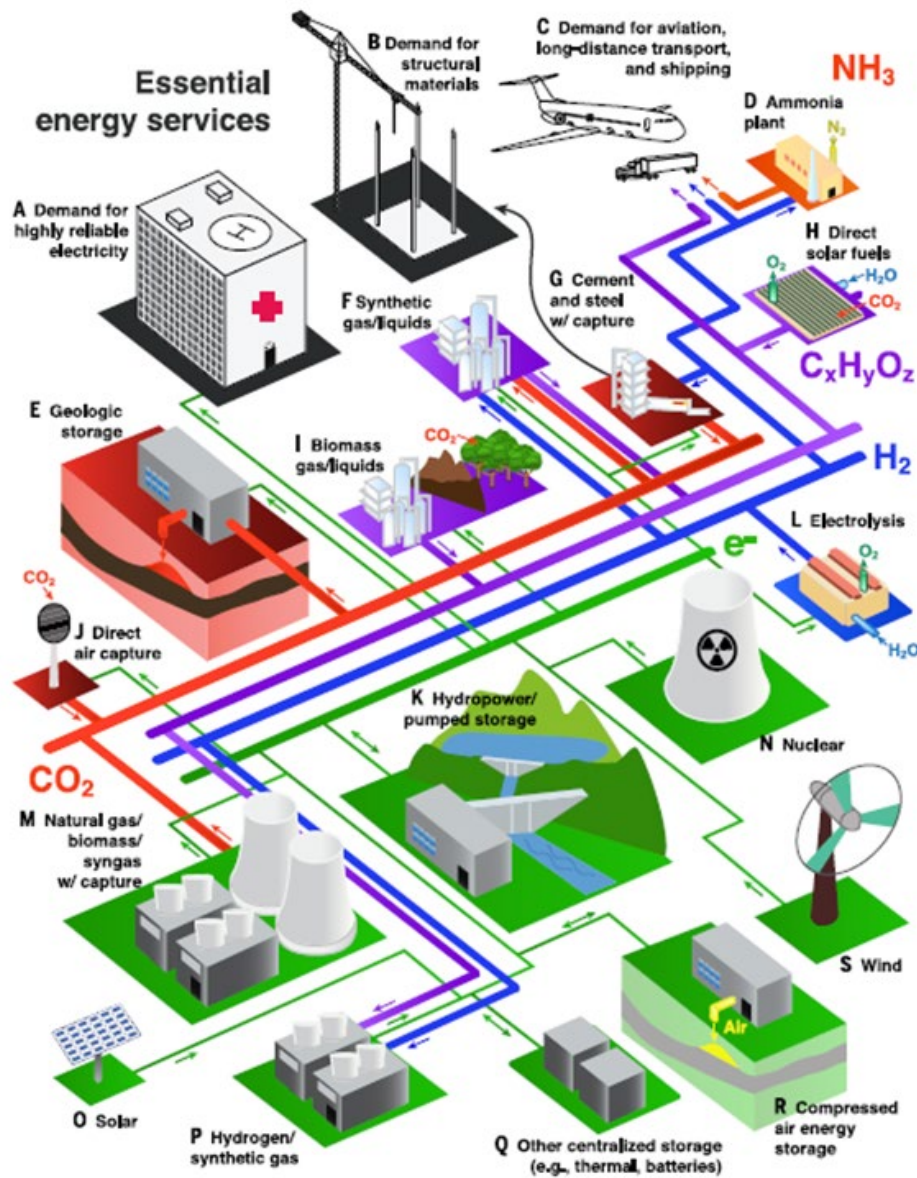
The blue pathways could be pipelines or trucking of hydrogen. K, Q, and R have energy storage.

Source: From Davis et al., *Science 360*, 1419. (2018)

Building on Global Action

Many regional and national governments—including the European Union, Japan, Australia, Korea, and China—have articulated clear visions and policy frameworks embracing zero-carbon hydrogen as a foundation of their long-term energy strategies.[90] Major international

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90 European Hydrogen Roadmap https://www.fch.europa.eu/news/hydrogen-roadmap-europe-sustainable-pathway-european-energy-transition ; Japan Hydrogen Roadmap https://www.meti.go.jp/english/press/2019/0312_002.html%20;

corporations have done the same. The Hydrogen Council, an association of 60 major international companies, has committed to the bold goal of achieving 100 percent zero-carbon hydrogen by 2030 as part of a comprehensive vision for the future of hydrogen, providing nearly 20 percent of primary energy in 2050.[91] Global auto manufacturers Toyota, Honda, and Hyundai have launched hydrogen-fueled vehicles, China has launched more than 50 hydrogen transit buses, and Nikola, Toyota, and Kenworth are developing hydrogen-fueled heavy-duty trucks. At the national level, the U.S. Department of Energy has established a major initiative to pursue hydrogen solutions across the economy through its H2@Scale initiative.

Progress in California

Going back as far as Governor Arnold Schwarzenegger's hydrogen highway vision in 2004,[92] California has been the national leader in embracing hydrogen as part of the transportation and energy future. The state has established through Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) a program administered by the CEC to fund at least 100 publicly available hydrogen fueling stations. As a result, California is now the global leader in launching and scaling the light-duty hydrogen fuel cell electric vehicle sector with 41 hydrogen refueling stations in operation, more than 30 under construction, and an industry vision of growing the network to 1,000 stations by 2030.[93] California has nearly 7,000 hydrogen vehicles on the road and vehicle population projected to reach nearly 50,000 in five years,[94] and as many as 1,000,000 by 2030.[95] Through a combination of private capital and CEC funding, nearly 50 tonnes per day of new renewable-capable hydrogen production capacity has been announced to serve the California market, enough to supply more than 60,000 hydrogen vehicles. The California Fuel Cell Revolution document envisions how the station network could grow to 1,000 stations, using spatial analysis developed by the California Air Resources Board (Figure C-3). California is once again demonstrating its global leadership in advancing clean energy and transportation solutions.

The Opportunity

Hydrogen is well suited for transportation applications that require long range and large amounts of on-board storage. Beyond the transportation sector, hydrogen can play an important role in long-duration grid-energy storage and is a primary input to fertilizer manufacture, refining, industrial processes, and next-generation steel making. All these

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Australia Hydrogen Roadmap https://www.csiro.au/en/Do-business/Futures/Reports/Hydrogen-Roadmap; Korea Times on Korea Hydrogen Roadmap https://www.koreatimes.co.kr/www/tech/2019/01/419_262238.html%20; China Fuel Cell Vehicle Roadmap www.ihfca.org.cn/file/FCV%20Tech%20Roadmap.pdf%20
91 Hydrogen Council Home Page www.hydrogencouncil.com
92 California Governor's Executive Order (EO) S-07-04
93 The California Fuel Cell Revolution: A Vision for Advancing Economic, Social and Environmental Priorities. The California Fuel Cell Partnership. July 2018.
94 California Air Resources Board. 2018. "2018 Annual Evaluation of Fuel Cell Electric Vehicle Deployment & Hydrogen Fuel Station Network Development."
95 The California Fuel Cell Revolution (see footnote 91).

application areas create opportunity for the use of renewable hydrogen as these applications and sectors decarbonize.

So how big an opportunity does the renewable hydrogen economy represent for California? Assuming continued policy support and consumer adoption, renewable hydrogen could contribute nearly $2 billion to the California economy by 2030 and $18 billion by 2050, providing about 15 percent of California's energy consumption across all sectors.[96] This contribution will create tens of thousands of green energy jobs; ensure continued progress on reducing air pollution, which disproportionately impacts California's most vulnerable and disadvantaged communities; and play a critical, arguably indispensable, role in enabling California to go the last mile and reach 100 percent zero-carbon energy. The state needs to maintain its early momentum and scale up its efforts to make this a reality.

Figure C-3: California HRS Optimal Buildout to 1,000 Stations
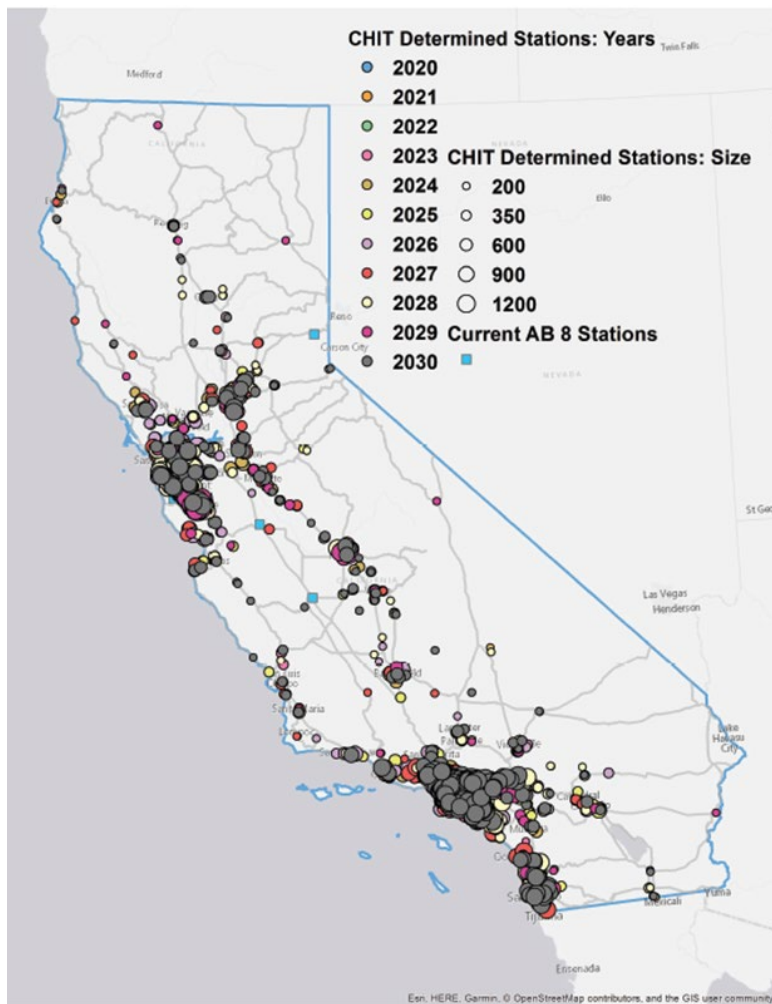
Source: California Air Resources Board 2018 AB 8 Report

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96 Assuming California ultimate energy consumption in 2050 of 2.8 exajoules (estimate from E3 "Deep Decarbonization" report CEC-500-2018-012).

Figure C-4: Potential California Renewable Hydrogen Demand Growth

Million kg-RH2/yr
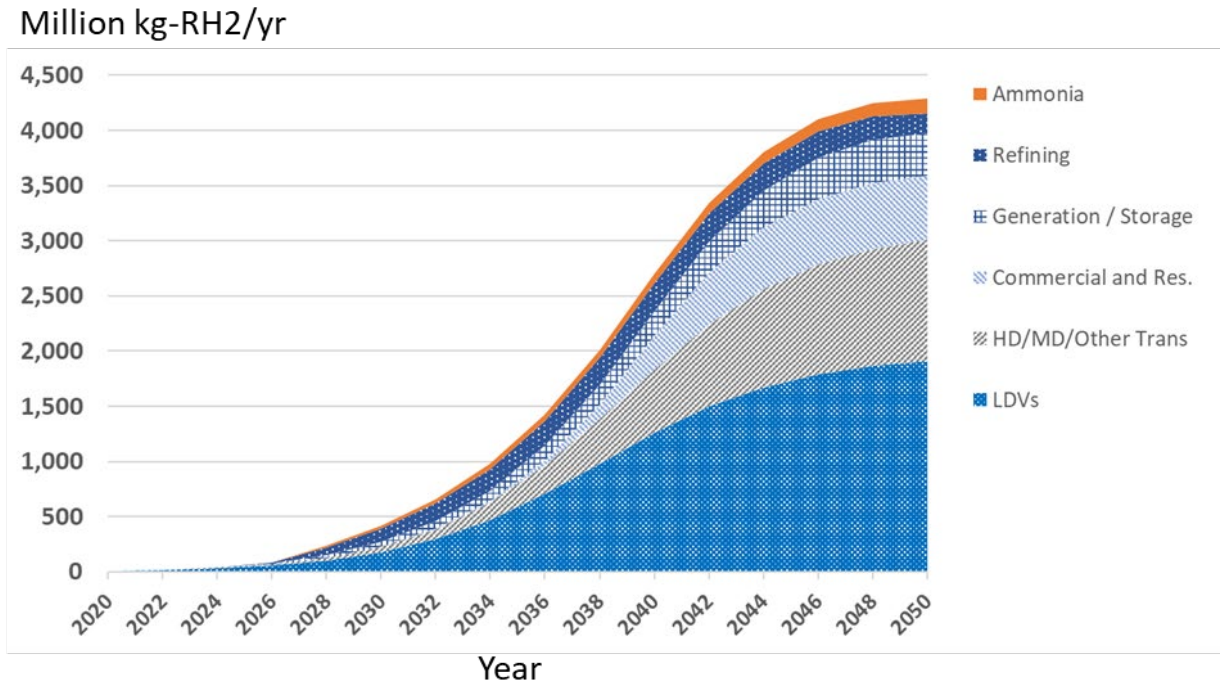
Source: UCI APEP

Sources of Supply

Renewable hydrogen (hydrogen from 100 percent renewable inputs) can be produced in a variety of ways as shown in Figure C-5. The primary methods are 1) electrolysis or "splitting water" – taking H_2O and splitting it into hydrogen and oxygen using renewable electricity; 2) reformation of biomethane produced through anaerobic digestion, and 3) extracting the hydrogen content from organic material through thermochemical processes such as gasification.[97] Biomass used as fuel does not produce net carbon emissions because of its continuous growth and regrowth cycle. California has abundant resources to produce hydrogen from both these pathways. Virtually all hydrogen produced today comes from reformation of natural gas using a process called steam methane reformation (SMR). Methane derived from organics material, referred to as biomethane, can also be converted to hydrogen via SMR and the product hydrogen is renewable. Although limits exist on the amount of renewable electricity and biomass resources that can be developed in California, the in-state resource potential is vast. It is more than adequate to serve foreseeable demand.

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97 See final report glossary for definitions of electrolysis, anaerobic digestion, thermochemical conversion and gasification.

Siting Analysis and Buildout Scenarios

Today, nearly 55,000 kilograms per day of conventional merchant hydrogen production capacity (which is capacity not integrated into refinery operations) is in operation in California. The largest facilities are the Praxair plant in Ontario and the Air Products facility in Sacramento.[98] The current capacity serves the non-transportation, conventional merchant hydrogen market and is not considered renewable hydrogen supply capacity for this analysis. Six new projects targeting the California hydrogen transportation market and capable of producing or processing renewable hydrogen have been announced over the past since 2017:

- Air Liquide—30,000 kilogram per day capacity steam methane reformer and liquefaction plant that will be capable of processing pipeline biomethane into renewable hydrogen.[99]

- Air Products—second liquefaction unit plant (capacity not announced).[100]

- Fuel Cell Energy and Toyota—1,200 kilogram-per-day tri-gen facility at the Port of Long Beach.[101]

- Stratos Fuels—5,000 kilogram-per-day nameplate electrolytic hydrogen production facility powered by renewable electricity made primarily from wind turbines, with funding support from the CEC.[102]

- H2B2—1,000 kilogram-per-day electrolytic hydrogen production facility powered by renewable electricity from solar photovoltaic panels, with funding support from the CEC.[103]

- Sunline Transit – 900 kg per day electrolytic hydrogen production facility.[104]

The future buildout of renewable hydrogen facilities in California will be driven largely by cost and availability of feedstock (biomass and renewable electricity). Figure C-6 shows the primary development areas for the various production technologies and feedstocks. Several buildout scenarios were developed for the roadmap based on varying assumptions regarding demand and relative progress of technologies. Details can be found in Appendix B of the project final report. Figures C-7 and C-8 show the buildout under the high-demand scenario. Meeting the high-case demand scenario requires over 1,000 metric tonnes per day of new renewable hydrogen production capacity by 2030 and nearly 12,000 metric tonnes per day of capacity by 2050.

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98 U.S. Department of Energy cited in the EIN Renewable Hydrogen Roadmap https://einow.org/rh2roadmap
99 Air Liquide Press Release https://energies.airliquide.com/air-liquide-build-first-world-scale-liquid-hydrogen-production-plant-dedicated-supply-hydrogen%20
100 Air Products Press Release www.airproducts.com/Company/news-center/2019/01/0107-air-products-to-build-second-liquid-hydrogen-productions-facility-in-california.aspx%20
101 Greentech Media Article on Toyota Hydrogen Facility https://www.greentechmedia.com/articles/read/toyota-fuelcell-energy-renewable-power-hydrogen-plant%23gs.we4tfe
102 GFO-17-602 Revised NOPA https://www.energy.ca.gov/sites/default/files/2019-05/GFO-17-602_NOPA_revised.pdf
103 Ibid.
104 NEL Hydrogen Press Release https://nelhydrogen.com/press-release/awarded-usd-8-3-million-hydrogen-electrolyser-fueling-station-contract/%20

Figure C-5: Renewable Hydrogen Production Pathways
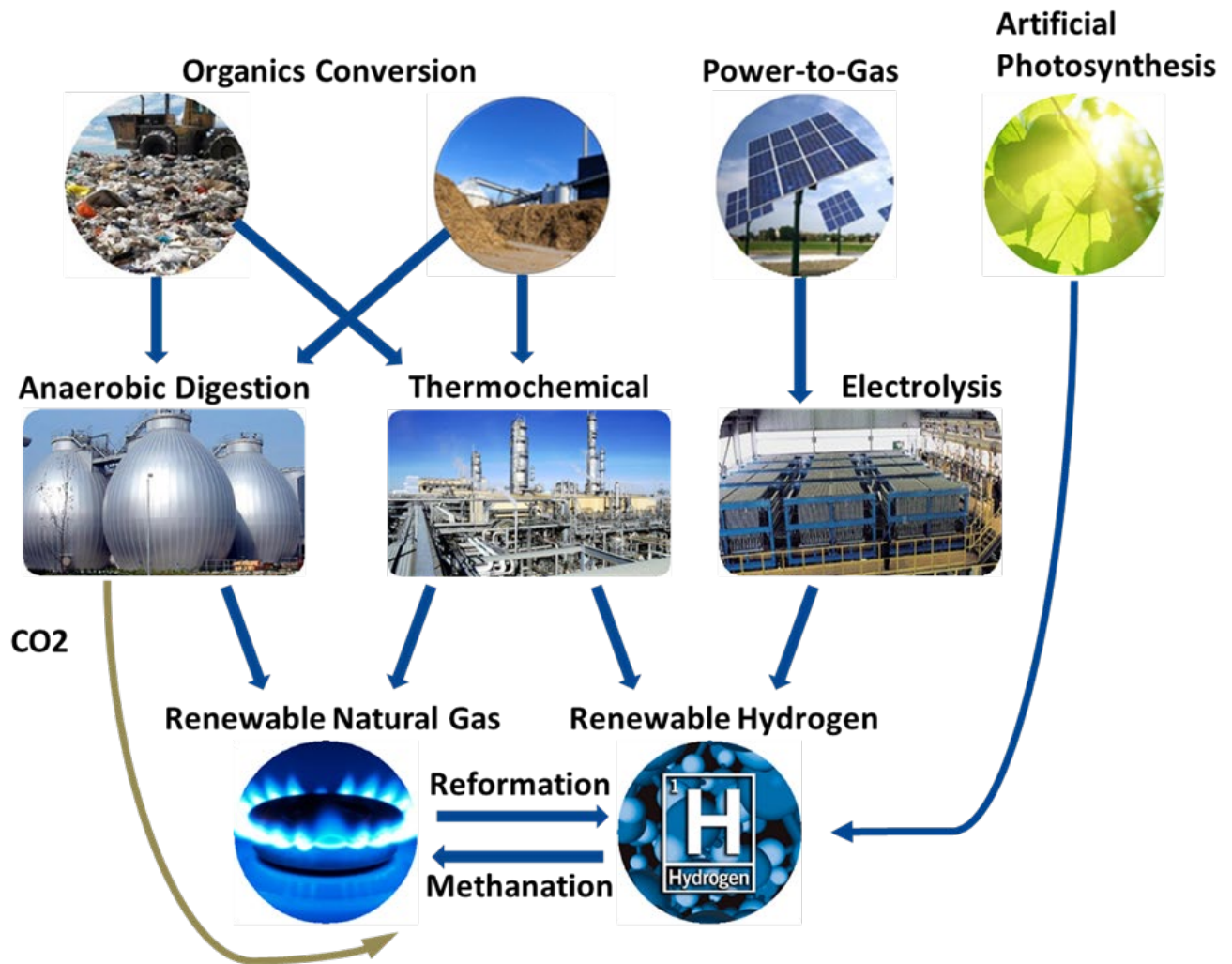
Source: UCI APEP

Figure C-6: Primary Resource Areas for Renewable Hydrogen Production and Conversion
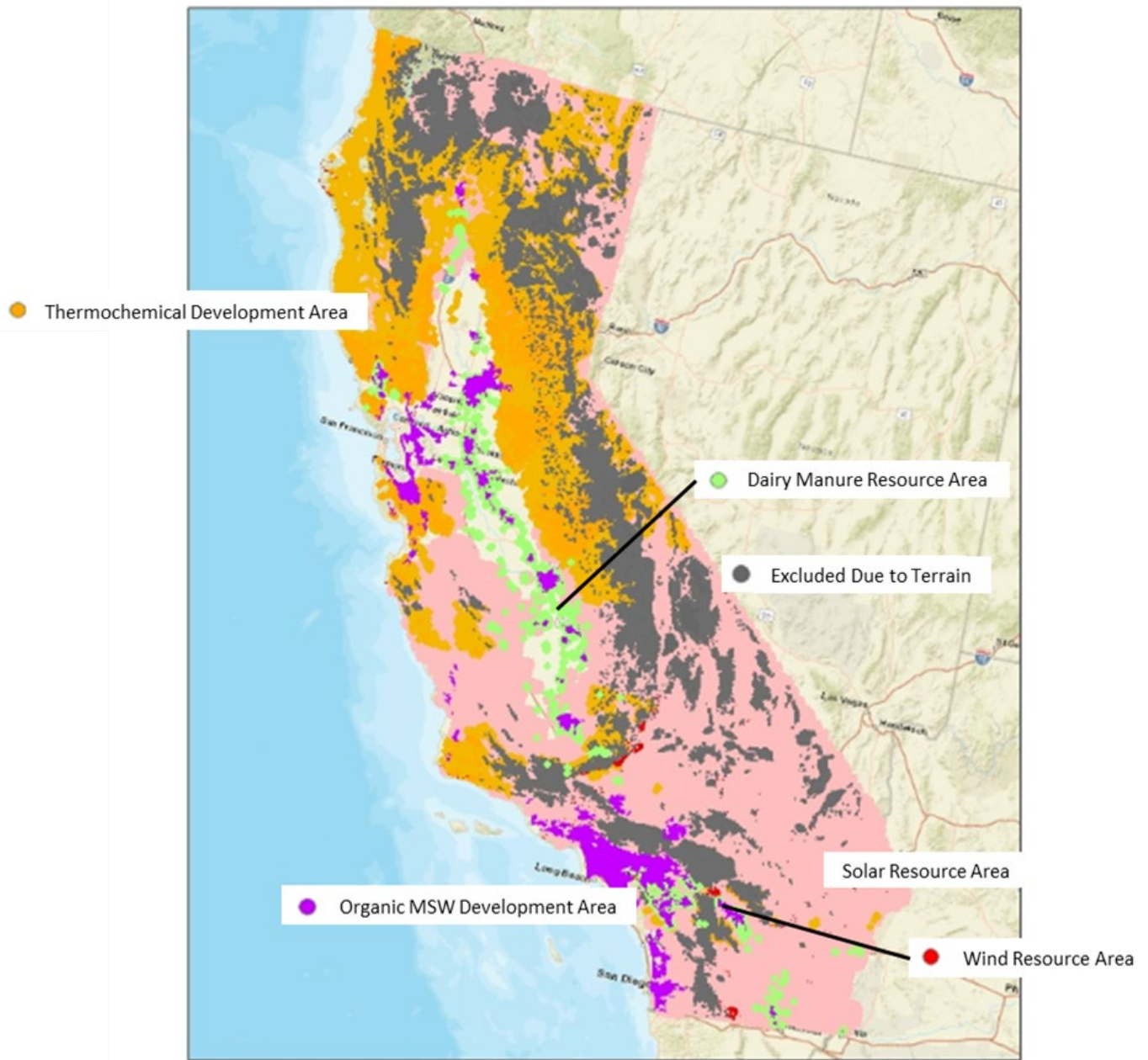
Source: UCI APEP from multiple U.S. EPA, U.S. DOE, and California agency datasets

Figure C-7: Mid-Case Buildout and 2030 Spatial Detail
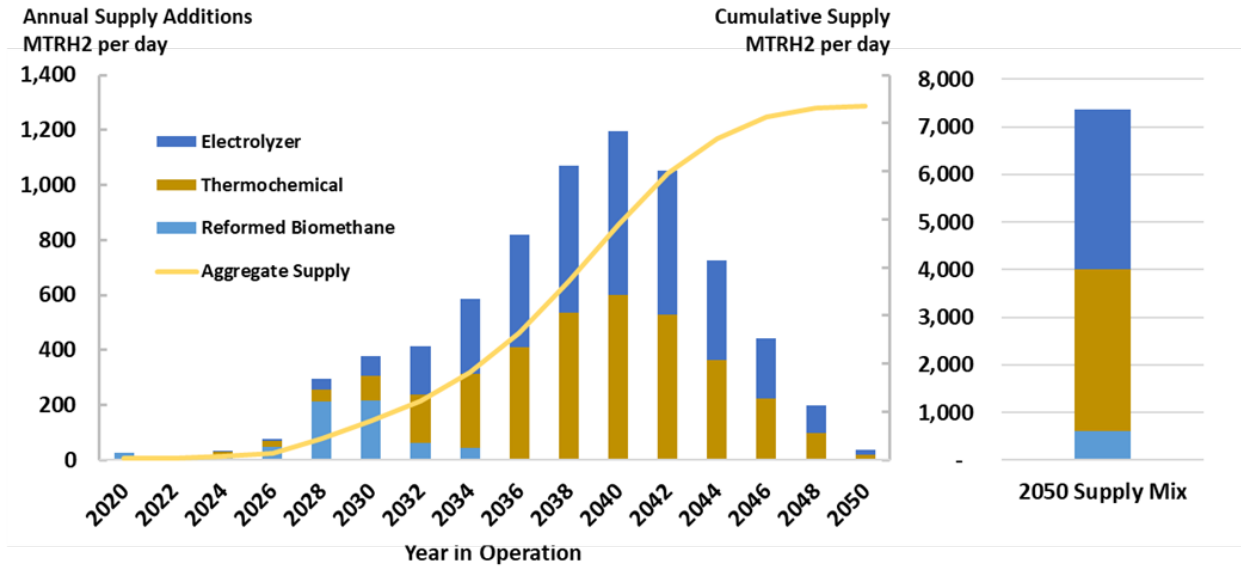
2030 Spatial Detail
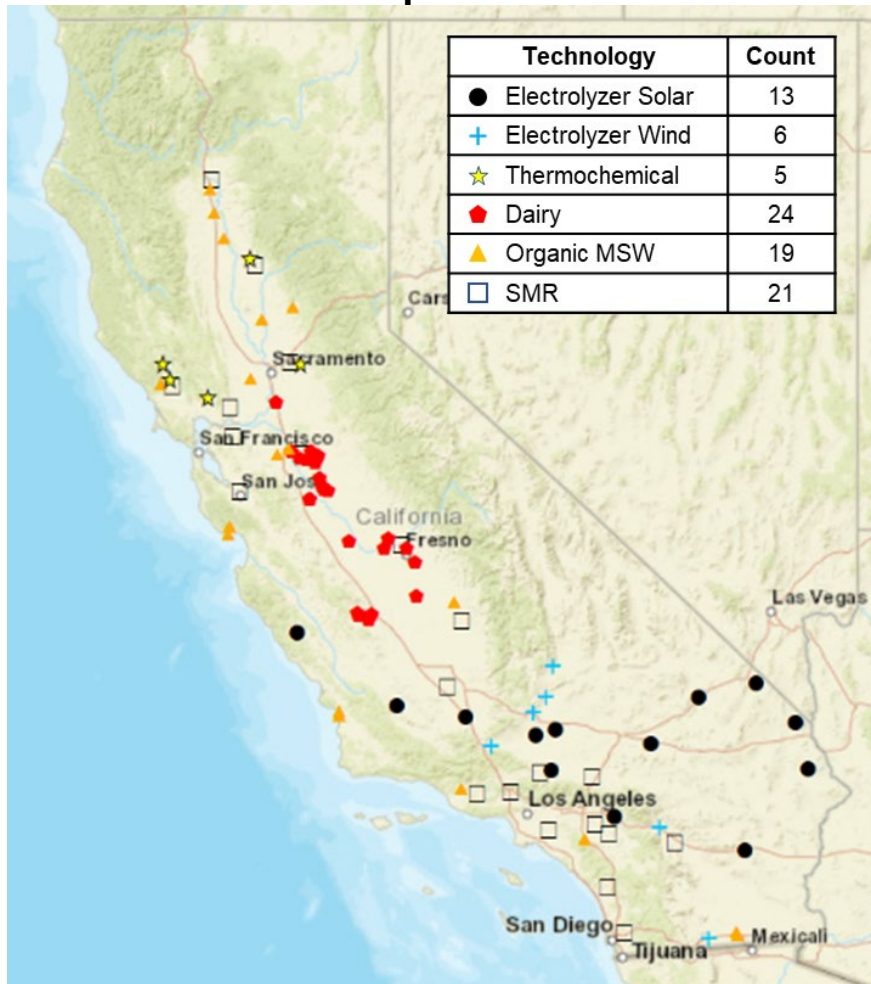
Source: UCI APEP

Figure C-8: Mid-Case Spatial Buildout Progression
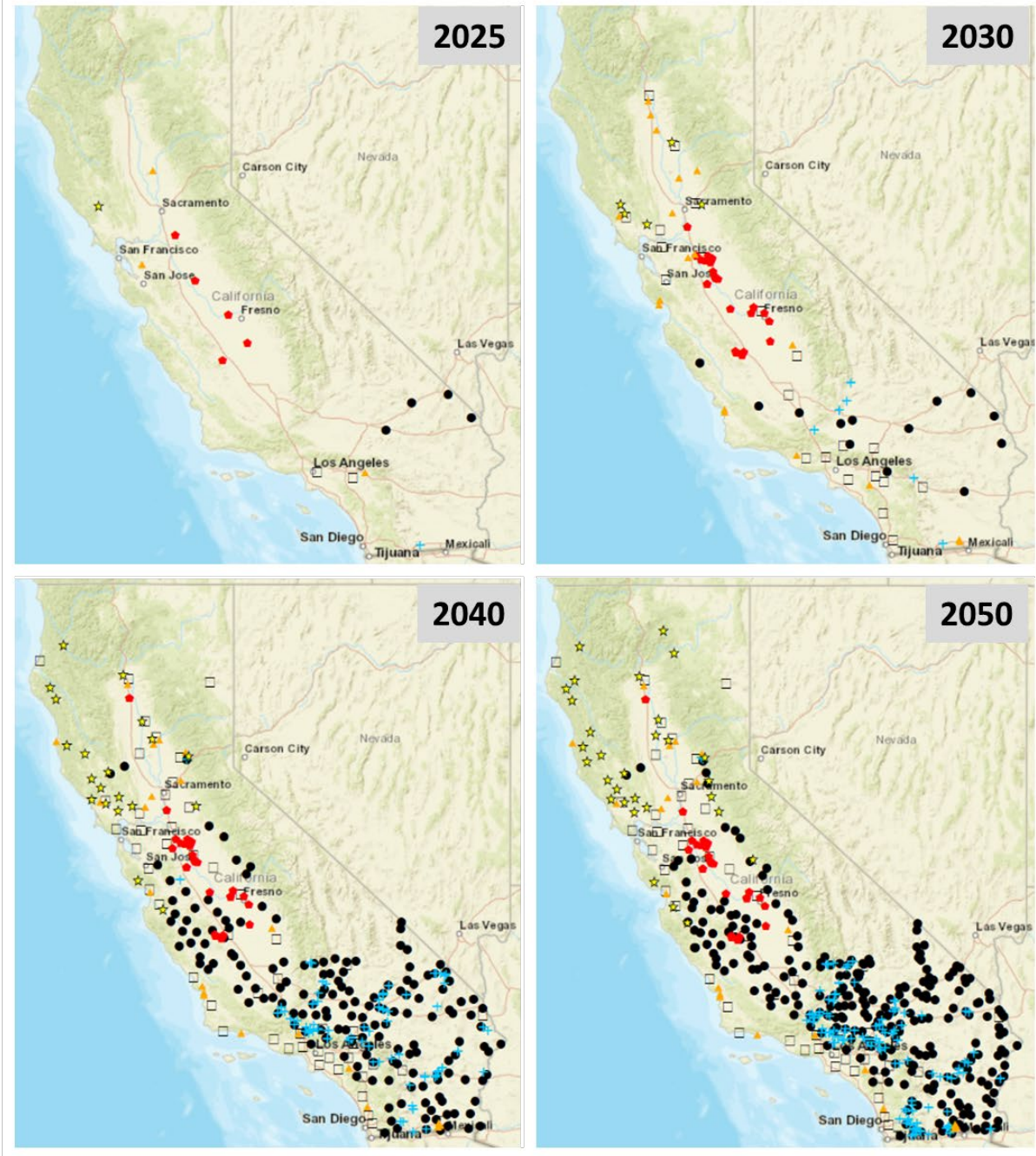
Technology Count by Year	2025	2030	2040	2050
● Electrolyzer Solar	4	13	169	265
+ Electrolyzer Wind	1	6	72	113
☆ Thermochemical	1	5	20	30
⬠ Dairy	5	24	28	28
▲ Organic MSW	3	19	21	21
☐ SMR	2	21	51	51

Source: UCI APEP

C-10

Hydrogen, the Duck Curve, and the Seasons

Hydrogen produced through electrolysis can play an important role in promoting the integration of a high fraction of solar and wind on the electric grid. It envisions the use of electrolyzers as a controllable load to help manage the peaks and valleys in solar and wind production while producing renewable fuel. The concept is sometimes referred to as power-to-gas.

Solar and wind energy form the foundation of any strategy for the clean energy future. These resources are abundant and can provide more than enough energy to serve all current and future needs of California. (Solar and wind resource potential is more than 70 times the current annual demand in California.)[105] However, one major "catch" crops up. The timing of energy produced from wind and solar resources does not match the daily 24-hour demand for energy. Both types of resources also produce varying amounts of energy over each day, week, and season. The daily production pattern of renewable resources leads to an electricity production-relative-to-load profile that has become known as the "duck curve" (Figure C-9).

Figure C-9: The Duck Curve
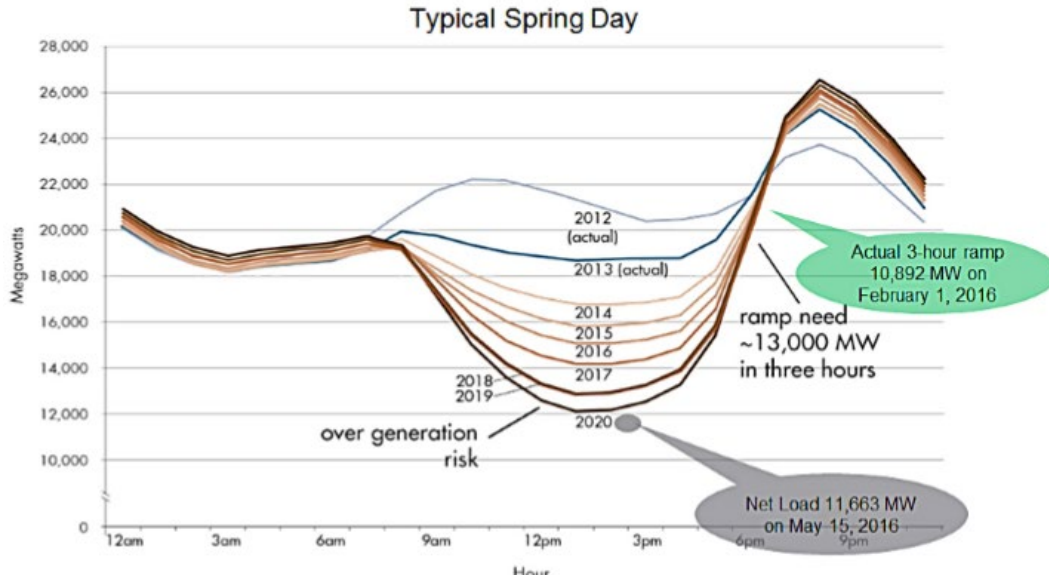
Source: California Independent System Operator
https://www.caiso.com/Documents/FlexibleResourcesHelpRenewables_FastFacts.pdf

This name comes from the shape of the power-supply curve that must come from nonintermittent (dispatchable) resources. The net load shape is determined primarily by the production profile of solar resources with high solar production during the middle of the day and no solar production during nighttime hours. This phenomenon can lead to excess solar power production during the middle of the day—power produced with no demand to serve.

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105 A. Lopez et. al. 2012. U.S. Renewable Energy Technical Potentials: A GIS-Based Analysis. National Renewable Energy Laboratory Technical Report NREL/TP-6A20-51946 and California demand form Energy Information Administration.

This excess power can be significant during some days (Figure C-10). Using this overproduction of renewable power to produce renewable hydrogen is a promising solution to this issue.

What about variations in solar and wind production across seasons? As shown in Figure C-11, seasonal variation in solar and wind production is substantial with about 10 percent of total supply out of sync with demand on a monthly time scale. In some months, over-production occurs, and in some months, under-production is seen. Hydrogen can be stored over long durations with minimal loss. It can be stored in large quantities at comparatively low cost per unit of stored energy, particularly when geological storage is used. These features make hydrogen energy storage ideal for day-to-night, multiday, and seasonal storage.

Figure C-10: Excess Renewable Power Production on a High-Solar Day in 2030
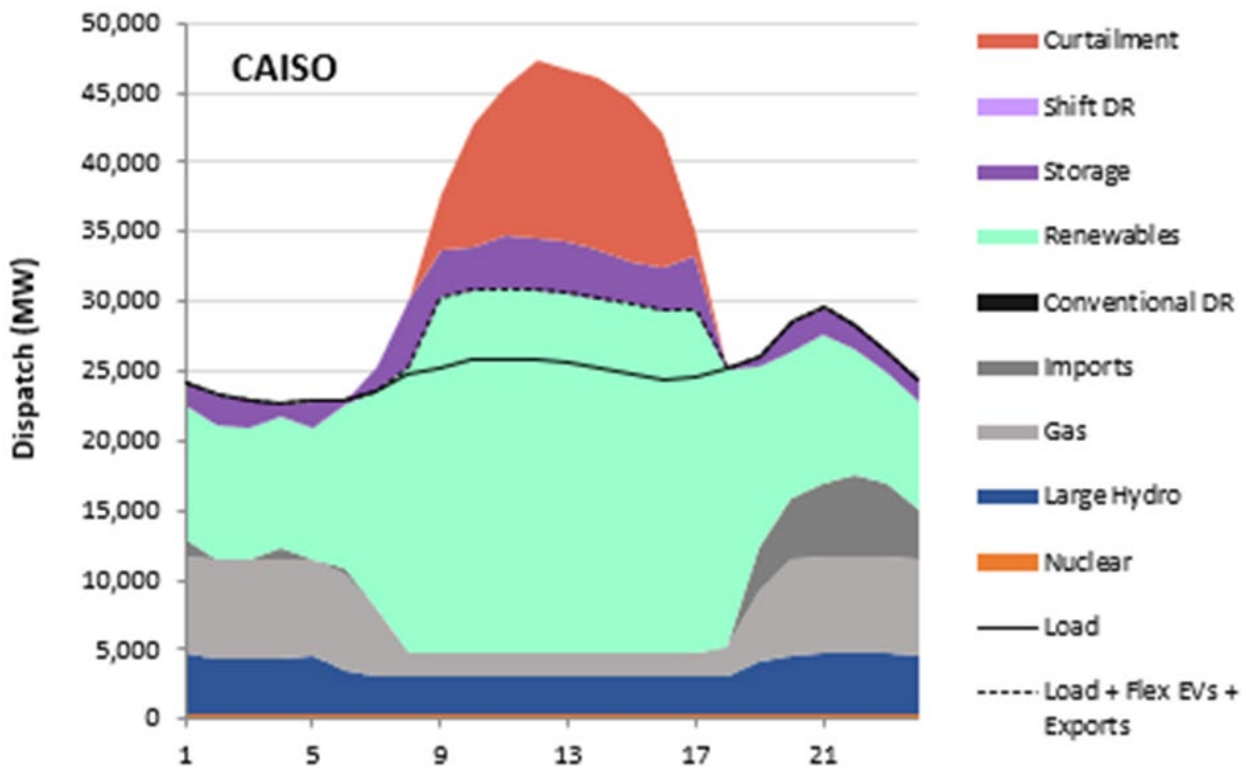
Source: RESOLVE Case 42mmt_Ref_20180416_2017_IEPR. https://www.cpuc.ca.gov/General.aspx?id=6442457210

Figure C-11: Monthly Average Load vs. Wind and Solar Production at 100 Percent Renewable Fraction
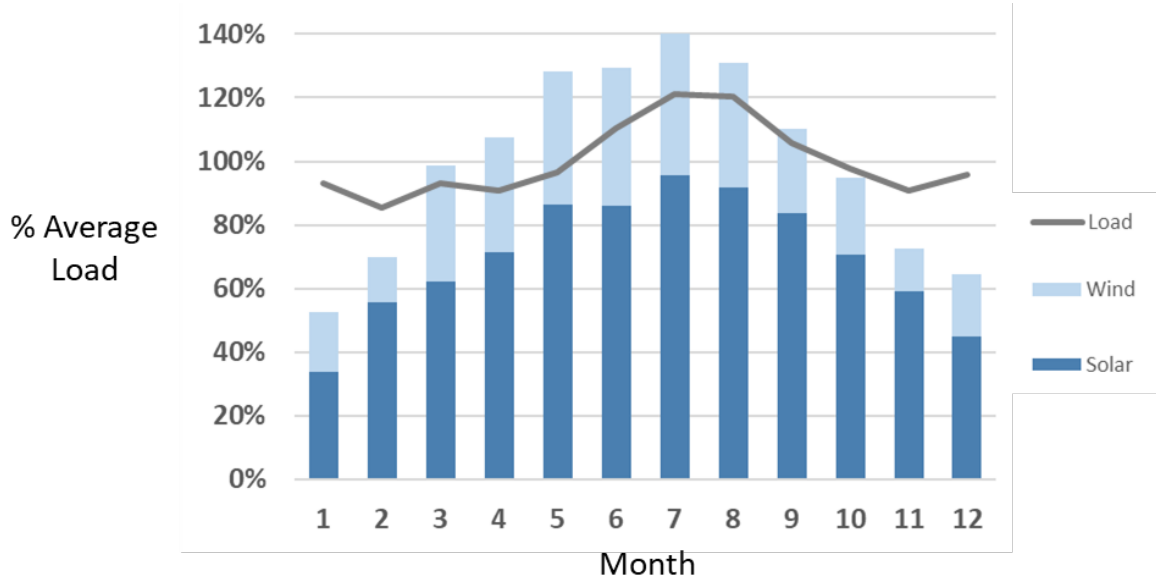
Source: UCI APEP. Load and production profiles from California ISO 2016 actuals with wind and solar scaled to 100 percent of demand

Getting Renewable Hydrogen to Where It's Needed

Unlike natural gas, an existing network of pipelines and geological storage to move hydrogen gas around is not in place. Such infrastructure may evolve beyond 2030 when demand for renewable hydrogen grows to the point that dedicated infrastructure is economically viable. In the meantime, other approaches to hydrogen transport and storage must be used. Figure C-12 shows the two approaches in use in California:

1) Compressing the hydrogen to increase density and move it in tube trailers, tanker trucks, or rail cars to the point of use and using high-pressure tanks for storage.

2) Cooling the hydrogen to the point at which it becomes liquid and transporting the liquid via truck or rail using liquid-hydrogen tankers and employing cryogenic storage tanks for storage.

Compression and liquefaction technologies are fully mature commercially but need additional research, development, and deployment scale to reduce cost. Cost reduction is important because the plant-gate-to-station elements constitute about one-third of the dispensed cost of hydrogen based on the cost analysis done for this roadmap developed using the DOE HDSAM tool.

Figure C-12: Hydrogen Delivery Chain
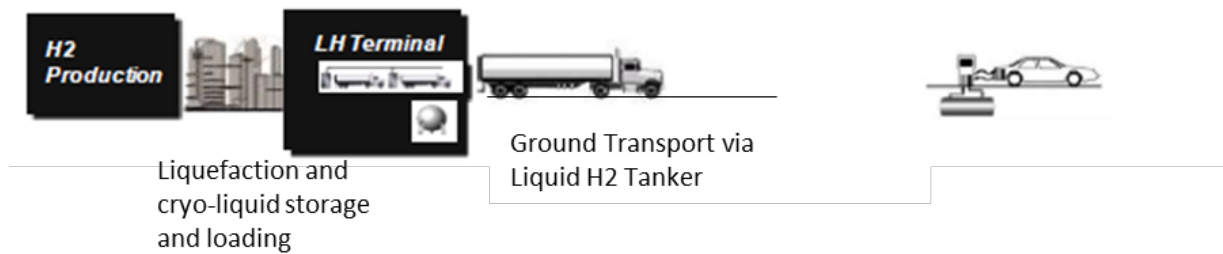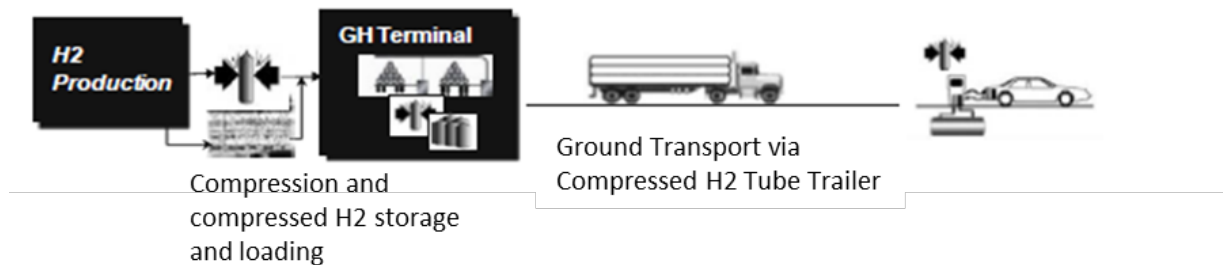
Source: UCI APEP adapted from DOE H2A Delivery Scenario Analysis Model Version 3.0 (HDSAM 3.0) User's Manual

Pipeline transport, possibly including geological storage, may be the low-cost approach in the future, as has proven to be the case for natural gas. A small hydrogen pipeline system serving the refineries in Southern California is in place and is used to supply one hydrogen station. However, significant expansion of hydrogen pipeline infrastructure is not likely to evolve until beyond 2030, when demand for renewable hydrogen grows to the point that dedicated infrastructure is economically viable. The technology is well proven, however, and more than 2,000 miles of dedicated hydrogen pipelines for serving refinery applications in the Gulf Coast are in operation. In addition, the western United States has numerous geologic formations that could be used for hydrogen storage, such as existing natural gas storage facilities, depleted oil fields, and salt caverns in nearby western states.

Blending hydrogen into the natural gas system is another transport and storage approach suitable for some applications (such as any application that would otherwise use biomethane). Most use cases do not recover pure hydrogen at the point of use but rather use the methane hydrogen blend directly. Hydrogen separation is an option although additional cost is incurred. The natural gas utilities in California are investigating standards for hydrogen blending within the natural gas system. If the CPUC establishes the necessary standards, the natural gas utilities may begin, over the next few years, to provide low-cost transport and storage for applications that can take advantage of this pathway.

Several steps in the supply chain are eliminated by production of hydrogen at the point of use . Station-scale electrolysis and reformation at the fueling location produce hydrogen locally. Primary energy for electrolysis is drawn from the electric grid, and reformers use directed

biomethane delivered via the natural gas grid. While this approach eliminates terminal and road transport costs, local (also called "forecourt") production is uncommon because economies of scale make that approach more expensive than alternatives. Forecourt solutions also require additional space on site, which may not be available at many locations. Future cost reduction through technology advances and expected increases in station size may lead to greater use of this approach, particularly for medium- and heavy-duty stations and larger stations in areas of lower development density.

Self-Sustainability—Achieving Abundant, Ubiquitous, and Affordable Renewable Hydrogen Supply

A self-sustainable renewable hydrogen sector can be defined as one in which growing, consumer-driven demand is met by a steady flow of private investment across the supply and delivery chain that is adequate to serve that demand. On the demand side, policies to support decarbonization and pollution reduction from transportation, energy production, commercial and industrial uses, and homes are the key. On the supply side, cost reduction and greater production and delivery capacities must be achieved for the potential demand to be met.

The demand analysis for the roadmap projects that transportation will be the primary driver of renewable hydrogen demand through 2030 and likely remain the largest use of renewable hydrogen even as other sources of demand mature beyond 2030 (Figure C-4). One kilogram of hydrogen is equivalent to about one gasoline gallon. The cost of dispensed hydrogen vehicle fuel in California today, with an average renewable fraction of 40 percent, averages around $16 per kilogram (roughly the energy equivalent of 1 gallon of gasoline and the cost equivalent of $6.40 per gallon when adjusted for the higher fuel economy of hydrogen vehicles).[106] The roadmap analysis estimates that the cost of 100 percent renewable hydrogen would be about $1/kg higher (based on a price of $12/MMBtu for landfill biomethane and $4/MMBtu for conventional natural gas), although low-carbon fuel standard credits may fully offset this differential, depending on pathway CI and credit prices.

The current price is high, relative to a near-term target of $6.00 to $8.00 per kilogram for dispensed hydrogen and a long-term goal of $4.00 per kilogram, reported industry participants interviewed for the roadmap. Industry expects that these cost points will ensure that hydrogen is cost-competitive, on a fuel-economy adjusted basis, with conventional and electric-drive fuel costs. This analysis of potential cost reduction for dispensed renewable hydrogen based on scale economies, learning effects, and innovation leads to a projection of potential cost reduction across the renewable hydrogen production and supply chain of 40 percent to 60 percent by 2030, tracking toward the $4 to $6 per kilogram by 2050 (Figure C-13).[107] Reaching these prices will require targeted policy support and incentives to bridge the current nascent sector to a self-sustaining one by the mid- to late 2020s. The 2018 ARB AB 8 report

106 Baronas, Jean, Gerhard Achtelik, et al. 2018. *Joint Agency Staff Report on Assembly Bill 8: 2018 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California.* California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2018-008.
107 Project final report Appendix B.

discussed the conditions for achieving a self-sustaining hydrogen fueling station network, and quantitative financial analysis of these conditions is ongoing. It's important to consider the entire production and delivery chain when assessing self-sustainability, and, as discussed below, the supply chain upstream of the hydrogen station will need support comparable to that for stations.

Figure C-13: Cost of Dispensed 100 Percent Renewable Hydrogen
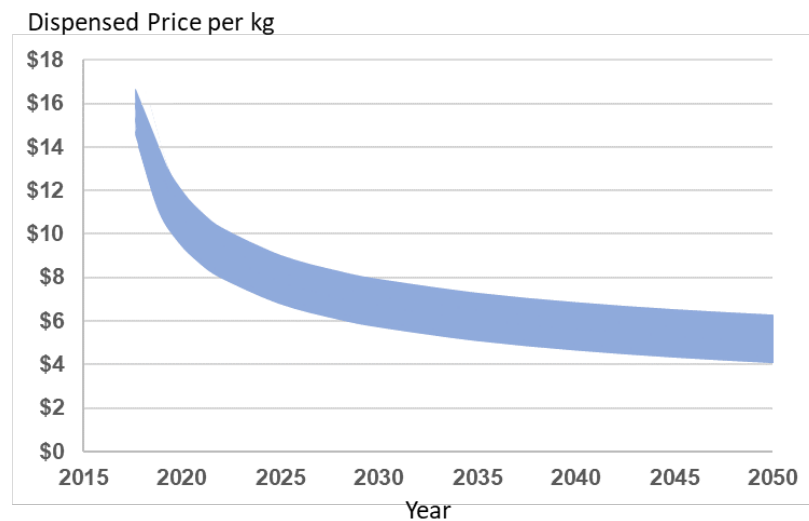
Source: UCI APEP

Recommendations

Charting the course.

1 Extend Hydrogen Infrastructure Support to the Entire Supply Chain

The CEC's Clean Transportation Program has funded 64 hydrogen refueling stations.[108] In addition, the CEC has sponsored a substantial amount of research on hydrogen for transportation and awarded funding for two projects with a total production capacity of 6,000 kg/day of 100 percent renewable hydrogen. However, additional support is needed for commercial, dedicated renewable hydrogen production projects and emerging technologies across the supply chain. In general, dual-purpose facilities such as steam methane reformers, which can serve both conventional and renewable hydrogen markets, and biomethane projects, which can serve both hydrogen and CNG markets, are financially viable without additional state support. However, as described below, electrolytic hydrogen and gasification have unique features that necessitate additional support, as do emerging technologies across the supply chain such as small-scale reformers and liquid carriers.

Like reformers, electrolyzers can produce either renewable or conventional hydrogen, depending on the source of the electricity used in the process. However, electrolytic hydrogen

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108 Baronas, Jean, Gerhard Achtelik, et al. 2018. *Joint Agency Staff Report on Assembly Bill 8: 2018 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California.* California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2018-008.

produced from non-renewable grid electricity is several times more costly than hydrogen produced from natural gas through steam-methane reformation. As a result, investments in electrolyzers dedicated to producing renewable hydrogen for a relatively new and growing market like hydrogen refueling stations represent more of a risk than conventional systems that supply hydrogen to established industries. For this reason, incentives may be needed to stimulate investment. Gasification is a promising renewable hydrogen production technology but requires full-scale commercial demonstration before wide-scale deployment can occur. Next-generation reformation and liquefaction technologies have the potential to significantly reduce the cost of dispensed renewable hydrogen and should receive support.

The form of financial support for renewable hydrogen production and related facilities could take any of several forms, such as a capacity credit program similar to the Low Carbon Fuel Standard (LCFS) Hydrogen Refueling Infrastructure (HRI) capacity credits (provided that eligible feedstocks and renewable electricity sources are used), capital grants, and loan guarantees. The amount of financial support needed for the renewable hydrogen production sector to reach self-sustainability depends on several factors, including the form of support.

The research team developed two support scenarios to scope the magnitude of support required. One uses only capital grants, and the other uses loan guarantees for the gasification projects. Both assume that anaerobic digestion projects are commercially viable without incremental support.[109] The first scenario assumes the state provides grants through the market launch phase of 50 percent of capital cost for five electrolyzer projects of 5,000-kilogram-per-day nameplate capacity stepping down to 25 percent for an additional two projects 10,000-kilogram-per-day nameplate capacity and 50 percent grants to two commercial-pilot gasification projects of 25,000-kilogram-per-day nameplate capacity. The project sizes are less than ideal but large enough to serve as commercial references for future financing. The cost of this program of support would be nearly $120 million and would ensure adequate renewable hydrogen capacity through the mid-2020s. If the gasification projects were to be supported with loan guarantees rather than grants, the program cost would be reduced to $80 million, estimating the cost of the guarantee at 20 percent of project cost.[110]

2 Support Production Capacity Expansion

The state has created a well-functioning program to support hydrogen station development through Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) to carefully plan, encourage through incentives, and track station buildout and operating performance. The competitive

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109 Landfill gas is the lowest cost resource and is commercially mature. Dairy projects receive support under the California Department of Food and Agriculture grant program, as well as subsidies mandated through SB 1383 and generate the most LCFS credits of any pathway. Landfill diversion projects receive tipping fees adequate to make such projects commercially viable.

110 The ability to secure commercial financing via loan guarantees is not certain but a 20 percent guarantee cost is conservative relative to the loss experience rate and actuarial estimates of default rate for loans to energy project guaranteed under the DOE Loan Guarantee Program (LGP) program. The upper estimate reported in the 2016 General Accounting Office report on the program was a credit subsidy cost of 15 percent of the loan amount. This would be 12 percent of project cost for an 80 percent loan.

award of incentives, mandatory reporting, and active incorporation of learning has led to a successful public-private partnership. In addition to helping ensure adequate availability of fueling infrastructure to serve the early FCEV market, the program has helped shed light on areas for improvement to promote cost reduction with each generation of stations.

A key collateral feature of the program is that planning transparency and management of incentives have enabled a smooth build cycle for the station sector in which adequate new station capacity is being added without needing a dynamic wherein short supply pushes up prices to attract new capacity. No corresponding program is currently in place for the renewable hydrogen production and supply chain. Although the ability of renewable hydrogen production facilities to use nonrenewable feedstock to serve conventional merchant hydrogen markets reduces demand risk to some degree, the overall demand risk is substantial, and programmatic intervention to enable a smooth buildout of supply is likely necessary. Incentives tuned to capacity expansion and technology progress targets can serve this role.

3 Attract Private Capital and Develop Robust Markets

In addition to state support during the launch phase as discussed above, the timely buildout of facilities and infrastructure needed to enable wide-scale adoption of hydrogen as an energy and transportation solution will require a steady flow of private capital into the sector. Realizing the necessary capital flow will require that prospective investors foresee the opportunity to achieve an acceptable return on investment while accounting for risk and uncertainty. In addition, transparent and well-functioning markets are critical to the long-term success of the sector for investors and consumers. Factors that enable this include a broad and diverse array of market participants, low barriers to entry, ready access to market information such as pricing, and an effective mechanism for connecting buyers and sellers across the value chain (such as commodity exchanges and procurement platforms). Although the private sector must play a primary role in achieving these goals, the state can also play an important role.

State policies and programs should be designed to ensure that the renewable hydrogen sector can attract private capital sufficient to meet capital needs in a well-functioning and established renewable hydrogen market structure by the mid- to late 2020s. Financeability requires successful operating history for the relevant technologies, relative certainty of feedstock availability, and relative certainty of a secure stream of revenue from renewable hydrogen sales. The current status of the financeability of key renewable hydrogen production technologies is summarized in Table C-1.

The renewable electricity and the battery-electric vehicle sectors have addressed the commercial lending gap largely through public-utility-sponsored procurement and investment programs. These programs use the creditworthiness of the host utility either through direct utility financing or through long-term revenue contracts to finance investment. Other approaches are needed to serve a similar role in launching and scaling the renewable hydrogen production and supply sector. The Clean Transportation Program hydrogen refueling station grant funding program and the recently approved LCFS HRI capacity credits support

the refueling station part of the supply chain, but additional program elements are needed for renewable hydrogen production and capital-intensive elements of the supply chain.

The renewable hydrogen market is in an early stage. No fully dedicated renewable hydrogen production facilities are operating in the state. Reformed biomethane using existing SMR capacity is the dominant supply approach. The market has few participants and no transparency on pricing or terms.

Several elements should be considered in developing programs to support renewable hydrogen supply expansion by addressing the financing gap or otherwise supporting market development or both.

- Transparent and widely communicated information on expected demand growth and planned production and supply capacity additions can help private investors in planning development to match market demand. The Clean Transportation Program hydrogen refueling station build program has been very successful in this regard through vehicle population surveys of the vehicle manufacturers and detailed planning analysis for new hydrogen station additions by CARB and CEC. Such efforts should be expanded to include renewable hydrogen production and additional sources of demand, particularly for medium- and heavy-duty applications.

- Incentive eligibility should continue and extend the selection factors employed in the hydrogen refueling station program and the initial renewable hydrogen production solicitation (GFO-602) including:

  o Match funding.

  o Strength of the project commercial plan and track record of the applicant.

  o Technology diversity and encouragement of new entrants.

  o Disadvantaged community impacts.

  o Carbon reduction.

- LCFS credits are an important source of value for the entire renewable (and conventional) hydrogen production and supply chain, but uncertainty of future credit value reduces introduces significant investment risk. An LCFS credit price support mechanism was proposed during the most recent legislative session in response to the requirements of SB 1383.[111] Should such a mechanism be put in place, it is important that it apply to hydrogen and not only dairy biomethane, as originally proposed.

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111 AB 1156 (Garcia, 2018) LCFS Price Support Mechanism
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201920200AB1156

Table C-1: Commercial Financeability of Key Renewable Hydrogen Technologies

Renewable Hydrogen Technologies	Commercially Financeable?	Comments
Hydrogen Refueling Station	Close	The risk of LCFS price declines is a remaining gap
SMR	Yes	100% financeable. Proven commercial technology with ability to secure revenue through conventional hydrogen production.
Liquefaction Facility	Yes	100% financeable. Proven commercial technology with ability to secure revenue through conventional hydrogen production.
Anaerobic Digester	Close	Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) provides mandates that will make dairy projects suitable for commercial lending including subsidies and LCFS price support. AD projects using landfill diverted feedstock receive contracted tipping fees; LCFS price support mechanism may be needed for full financeability.
Electrolyzer	No	Capital costs declining but currently above levels required for cost competitiveness. Lack of long-term RH2 off-take agreements that incorporate LCFS value close to the current market creates a financing barrier.
Gasifier	No	Technology is not fully commercial Requires high capital investment ($100M+). Lack of long-term RH2 off-take agreements with firm pricing for LCFS value creates a financing barrier.

Source: UCI APEP

- The state should also consider developing incentive programs such as grants, capacity credits, or loan guarantees specifically allocated to renewable hydrogen production and related high-capital-cost facilities, the availability of which should be tied to optimal buildout strategies. Because loan guarantee programs typically require similar documentation and credit risk assessment to conventional project finance, such programs can provide a smooth evolution to pure commercial financing. In addition, in contrast to grant programs, such programs have the potential to return borrowed funds to the sponsor. Examples of such programs include the U.S. DOE loan guarantee program[112] and the green bond program proposed by former California state Treasurer John Chiang.[113]

- Agencies providing grants or incentives can promote price transparency in the renewable hydrogen market by publishing anonymized pricing and related data on

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112 DOE Loan Program Office page https://www.energy.gov/lpo/loan-programs-office; GAO DOE Loan Program Report https://www.gao.gov/assets/680/675595.pd.
113 California Treasurer Green Bond Report
https://www.treasurer.ca.gov/greenbonds/publications/reports/green_bond_market_01.pdf.

contracts for the purchase or sale of renewable hydrogen from projects receiving state support. The LCFS program and the Clean Transportation Program hydrogen refueling station program already require reporting of key data on costs, quantities, and other operational elements. However, unbundled (separate) price or cost of renewable hydrogen and associated volumes is not among the publicly reported data.

- Operational reporting requirements for funded projects should be developed in consultation with project financing entities, such as banks currently lending to energy and transportation infrastructure projects, to ensure that reported metrics address the information needs of future prospective private lenders.

- State agencies, in collaboration with stakeholders, should systematically identify market barriers in assessing the development of the renewable hydrogen production and supply sector and include supplier diversity (number and demographics) in incentive, environmental credit, and grant program award criteria

- The market for biomass feedstock is not well formed, and secure long-term feedstock agreements will be necessary for commercial viability of projects using biomass. State agencies should convene a stakeholder process to explore approaches to addressing this issue such as establishing an exchange or clearing house.

4 Reduce Barriers to Development in California

The development of infrastructure projects in California can be challenging. Impediments cited by developers include onerous California Environmental Quality Act (CEQA) requirements for some types of projects, prevalence of local opposition to new development often based on misperceptions about impacts of proposed projects, high labor rates, differing requirements across local jurisdictions, high utility rates, and high tax rates. Some of these issues, such as wage rates and general state tax rates, are likely issues that will remain facts of life in California. However, state agencies can act to enable project development through efforts to harmonize local requirements,[114] streamlining of permitting processes[115] and approval of program environmental impact reports. In addition, incentives that encourage development in California should continue.

Action in the California dairy sector provides a model for the renewable hydrogen sector. Driven by California's Short-Lived Climate Pollutant Reduction Strategy (SLCP Strategy) and industry action, the state has undertaken important steps to streamline permitting for dairy biomethane projects:

- Approved a trade-group-developed program environmental impact report (PEIR) to relieve much of the burden on individual projects to develop environmental impact reports required under the California Environmental Quality Act (CEQA).

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114 The Energy Commission and Go-Biz have been assisting with local permitting issues for stations for several years. This approach should be extended to the entire production and delivery chain.
115 CalEPA has led such an effort for dairy projects. See CalEPA Dairy Program Site
https://calepa.ca.gov/digester/%20.

- The California Environmental Protection Agency has spearheaded the establishment of a consolidated permitting process to assist project developers in navigating the permitting process.

5 Design Programs and Incentives Holistically Across Fuel Types

In designing programs to provide support for renewable hydrogen production, consideration should be given to other programs that may provide support to some pathways. For example, all the organic feedstocks that are candidates for hydrogen production can also be used to produce biomethane (which itself is a primary potential feedstock for renewable hydrogen). Biomethane projects receive support developed in response to Senate Bill 1383 for which electrolytic and thermochemical hydrogen production systems do not currently qualify.

In addition, some primary organic feedstocks are currently subject to, and others are likely to become subject to, mandates that will affect the price of that feedstock for fuel production. For example, current state law directs that regulations be adopted requiring the diversion of 75 percent of the organic material that would otherwise be disposed of in landfill by 2025.[116] Dairies are not currently under mandate to capture methane emissions, but the California Air Resources Board has stated the intent in its Short-Lived Climate Pollutant (SLCP) strategy to mandate capture in the future.[117] The pressing need for forest management to reduce wildfire risk raises the strong potential for mandates for forest thinning and other measures to gather and remove combustible material from forests.[118] Such organic waste mandates may lead to payments (known as "tipping fees," which are disposal payments) by feedstock sources. This is currently the case with landfill-diverted food waste. Potential tipping fee revenue should be considered in any feedstock or technology-differentiated project support programs when assessing the amount of support needed.

In considering appropriate levels of support for hydrogen infrastructure and ways in which the requirements compare to battery-electric vehicle infrastructure, policy makers should compare support levels across the full deployment cycle (notionally, at least 10 years of deployment) and should consider all sources of effective subsidy.

6 Establish Electricity Tariffs for the Unique Benefits of Electrolyzers

Electrolyzers consuming grid electricity pay retail rates on tariff schedules that depend on the voltage level at which the electrolyzer interconnects. An electrolyzer receiving service on a standard commercial or industrial rate in California would pay an average of about $0.11 to $0.14 per kilowatt-hour for grid electricity,[119] which currently has a renewable fraction

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116 Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) C Link to bill text
https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383.
117 ARB Short-Lived Climate Pollutant Final Report
https://www.arb.ca.gov/cc/shortlived/meetings/03142017/final_slcp_report.pdf.
118 Wildfire Mitigation Report
119 EIA Table F Retail Electric Rates;
https://www.eia.gov/electricity/monthly/epm_table_grapher.php?t=epmt_5_6_a.

approaching 35 percent.[120] For electrolyzers interconnected at the transmission level, time-of-use rates would provide a relatively close proxy to wholesale electricity rates but would require the electrolyzer to receive the grid-average blend of renewable and conventional energy and would not convey ownership of renewable energy credits to the electrolyzer operator. In contrast, an electrolyzer using collocated wind or solar energy generation would incur a cost of about $0.03 per kilowatt hour for 100 percent renewable energy, albeit with much less siting flexibility and a lower capacity factor.

To enhance their revenue generation through LCFS credit strategies, electrolytic hydrogen producers must have the ability to source their own wholesale electricity. In the absence of electric tariffs that provide this capability, electrolytic hydrogen producers must either accept the limitation of current tariff structures, or produce their own electricity from dedicated, collocated renewable generation facilities. Such limitations constrain the ability to optimally site electrolyzers in relation to the renewable hydrogen distribution network.

Electrolyzers can also provide grid services such as frequency support, voltage support and ramping. A knowledge gap currently exists regarding the future value of such services and the revenue streams that might be available to electrolytic hydrogen production facilities. Additional research or inclusion of value analysis of these functions in the electric utility integrated resource planning process, or both, would promote revenue forecasting for electrolyzer project developers.

Utility-sponsored programs such as real-time rates (that rate charged tracks the wholesale market price in real time) with optional renewable-only tariff provisions (an ability for a customer to specifically buy renewable electricity and not the average mix) and dispatchable load tariffs (program allowing the utility to control a load) compensating electrolyzers for providing grid support would create easy access to electricity markets and would be particularly valuable for smaller projects not positioned to interact directly with wholesale markets. For larger or more sophisticated projects, direct access programs under which electrolyzer owners could procure their own power, pay transmission access charges, and interact directly with the wholesale market for grid services, might be most effective. Regulatory proceedings under the authority of the California Public Utilities Commission and, possibly, the California Independent System Operator are needed to address these issues.

7 Facilitate Access to the Natural Gas System for Renewable Hydrogen Transport and Storage

Renewable hydrogen produced through reformation of biomethane generally uses the natural gas system for storage and delivery of the biomethane feedstock to the reformation facility. This is the most common pathway used for renewable hydrogen production under the LCFS program today. State programs instituted under mandates contained in SB 1383 have defined standards for pipeline injection and provided subsidies for interconnection for biomethane

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120 CEC RPS Tracking Report;
https://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

producers. No similar programs are in place for methane produced from electrolytic hydrogen or for hydrogen directly injected onto the natural gas system as a blendstock. Senate Bill 1369 (Skinner, Chapter 567, Statutes of 2018) directs state agencies, including the California Public Utility Commission (CPUC), to consider uses of green electrolytic hydrogen, but specific action by the CPUC beyond fact-finding workshops has not yet been initiated. Expanding existing programs and tariffs to include electrolytic hydrogen and methane is necessary to ensure a level playing field for electrolytic hydrogen and methane.

Gasifiers generally produce both methane and hydrogen. Clarity on the permissible hydrogen fraction for pipeline-injected biomethane is important for developers of gasification projects wishing to access the natural gas system to properly design their gas processing and conditioning systems.

Although substantial evidence suggests that hydrogen fractions as high as 20 percent can be safely permitted in the natural gas supply,[121] California has yet to establish hydrogen blending limits. Timely action is needed to ensure that renewable hydrogen fuel producers receive the same open access to the common-carrier pipeline system as other fuel types.

8 Take Steps to Ensure That a Mixed Gas/Liquid Supply Chain Does Not Create Barriers to Market Access

The hydrogen supply chain is developing as a mix of gaseous and liquid transport and storage, with 17 stations employing liquid storage and the remainder using compressed gas, according to the CARB 2018 AB 8 report. Stakeholders report different perspectives on whether the future supply chain will be dominated by liquid or compressed gaseous transport and storage. It is likely that the future network will include substantial fractions of both cryo-liquid and compressed-gas stations. Other transport and storage approaches are also under development, such as liquid organic hydrogen carriers, ammonia, DME, and others that may enter the supply mix in the future. These too would need to be integrated into the production and supply network.

Economic principles would suggest that, in a fully mature market, competitive forces will likely be adequate to ensure that the sector evolves to the most cost-effective production and supply chain configurations. However, in the early market, policy interventions may be required to ensure that otherwise promising technologies and business models have appropriate access to the supply chain. For example, one of the benefits of electrolyzer systems is that they are modular and can be deployed at modest scale without major diseconomies of scale. However, integration into the liquid hydrogen supply chain may pose a challenge. Liquefaction facilities show strong economies of scale and, as a result, dedicated liquefaction facilities collocated with electrolytic production facilities face a cost barrier. At the same time accessing remote liquefaction facilities incurs cost for transport, new facilities to receive hydrogen via truck or rail and requires access to available liquefaction capacity. This

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121 See, for example, Oney, F., T.N. Veziroglu, and Z. Dulger, 1994, "Evaluation of Pipeline Transportation of Hydrogen and Natural Gas Mixtures," *International Journal of Hydrogen Energy* 19(10):813–822.

creates a potential barrier to accessing the liquid hydrogen supply chain. Other emerging technologies may face similar barriers.

Where barriers exist, state policy makers may wish to consider some form of incentives to promote market access for new entrants and emerging technologies. Potential approaches include additional incentives for projects facing supply-chain access barriers or incentives for critical supply-chain access points (such as liquefaction facilities) to provide capacity to third parties.

9 Ensure That Renewable Hydrogen Development Advances Social Justice

The buildout of the renewable hydrogen sector offers many potential benefits to disadvantaged communities through the creation of high quality, green-energy jobs, and by supporting the transition to zero-emission transportation solutions, displacing fossil fuels and their associated emissions that disproportionately impact disadvantaged communities. However, depending on the technology and supply chain model, they may also create additional truck traffic from feedstock supply and/or outbound trucking of renewable hydrogen. Noise and visual impact can also be of concern. It is recommended that state programs providing support for renewable hydrogen production and related facilities apply a social justice screen with a scoring rubric designed in consultation with stakeholders from the relevant communities. The objective of such a scoring system would be to assess net community benefits, with local economic development and clean-technology deployment weighed against potential negative impacts such as congestion, noise, and aesthetics.

10 Act to Ensure That Program Eligibility, Environmental Accounting, and Lack of Definitions Are Not Barriers to Renewable Hydrogen Development

As programs are developed to support the transition to clean transportation and clean energy solutions, eligibility requirements relying on specific definitions must be developed. For example, the California Renewables Portfolio Standard relies upon specific definitions for qualifying resources, as does the CPUC storage procurement mandate. The federal renewable fuel standard provides renewable identification number (RIN) credits of varying types (and values) for specific qualifying fuels.[122] Senate Bill 100 (De León, Chapter 312, Statutes of 2018) mandates that California reach 100 percent zero-carbon electricity by 2045. These programs, and other similar current and future programs, ensure environmental integrity and achievement of goals by clearly defined standards and eligibility requirements. However, these provisions can also have the effect of excluding or disadvantaging technologies or use cases not envisioned at program inception. As discussed below, these effects can create unnecessary barriers to the evolution of the renewable hydrogen production (and supply) sectors.

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122 EPA Renewable Fuel Standard Page; https://www.epa.gov/renewable-fuel-standard-program.

Federal RIN credits provide a significant subsidy for eligible fuels. D3 (cellulosic biofuel) RIN credits are trading at roughly $2 per diesel gallon equivalent.[123] Hydrogen derived from renewable feedstocks is not currently eligible to generate RINs, whereas several biomethane pathways are. Three RIN pathway applications for renewable hydrogen from biomethane are pending but not approved.[124] This difference in eligibility tends to skew biomethane supply toward compressed natural gas as an end fuel, placing renewable hydrogen at a relative disadvantage. It is recommended that interested stakeholders take collective action, for example, through their trade organizations, to secure RIN pathway approval for renewable hydrogen.

In current state rulemakings and regulatory proceedings, terms such as "renewable gas," "renewable methane," and "green electrolytic hydrogen" have been used in discussion of scope and applicability of various programs and regulations. At present, no consistent definition of the terms renewable or zero-carbon hydrogen have been established. To the extent that mandates or incentive programs or both rely on such definitions (which, by necessity, they will), it is critical for fuel producers and purchasers to have clarity on definitions to support investment and purchasing decisions. This clarity is critical to the buildout and scaling of the renewable hydrogen sector. Some working definitions are provided in Table C-2 below. Low-carbon, net zero carbon and zero carbon are also terms that have or may appear in legislation and/or regulation that need to be clearly defined.

Table C-2: Renewable Fuel Working Definitions

Term	Definition
Biogas (CPUC adopted definition)	Mixture of methane (major constituent) and CO_2 (typically 20% to 40% CO_2 by volume) and minor constituents derived from bio sources – cannot be introduced onto the common carrier natural gas system without cleanup
Biomethane (CPUC adopted definition)	Biogas that has been conditioned (cleaned and purified) to meet pipeline standards comprised primarily of methane with small remaining amounts of CO_2
Biosyngas	Hydrogen rich gas (with high fraction of carbon monoxide, CO) produced through gasification of biomass, from which (near) pure hydrogen or methane (with additional CO_2) can be synthesized
Renewable Methane	Methane formed by combining hydrogen (generally from electrolysis) with CO_2 – it is renewable if the feedstock for the hydrogen is renewable and if the CO_2 is biogenic or captured from the atmosphere or other source of CO_2 certified to be climate-neutral
Renewable Natural Gas	While generally used interchangeably with biomethane, includes as well renewable electrolytic methane
Renewable or Green Hydrogen	Hydrogen produced using only renewable feedstock including renewable electricity, biomass or other forms of renewable energy such as solar energy
Renewable Gas	All the above

Source: UCI APEP with stakeholder input

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123 EPA RIN Price and Volumes Page; https://www.epa.gov/fuels-registration-reporting-and-compliance-help/rin-trades-and-price-information.
124 EPA Rnewable Fuels Pending Applications; https://www.epa.gov/renewable-fuel-standard-program/pending-petitions-renewable-fuel-pathways.

Carbon intensity provides a consistent framework that has worked well in the LCFS program. Program eligibility based on feedstock or source, as in the federal renewable fuel standard program, is another viable approach, provided that the addition of new feedstocks is explicitly provided for in program design. Technology or process-specific incentives to support nascent technologies or processes of high potential with defined expiration provisions can play an important role in advancing the sector. However, standards or eligibility or both based on technology or process should be used with great caution to avoid conveyance of inappropriate market advantages or disadvantages. Renewable hydrogen market participants and trade organizations must act proactively to ensure that statutes and regulations do not directly or indirectly disadvantage renewable hydrogen.

11 Increase State RD&D Investment in High-Impact Areas

Realizing the substantial (40 to 60 percent) cost reduction potential across the renewable hydrogen production and supply chain requires sustained international policy support to achieve global scale and drive learning effects. Also needed are sustained research, development, and demonstration programs to augment scale effects with fundamental improvements. The United States Department of Energy (U.S. DOE) within its Fuel Cell Technology Office (FCTO) is sponsoring a robust program of research under the hydrogen-at-scale (H2@Scale) cross-lab initiative and manages a board program of research as shown in Figure C-14.[125]

Figure C-14: Hydrogen and Fuel Cell RD&D Organizing Framework
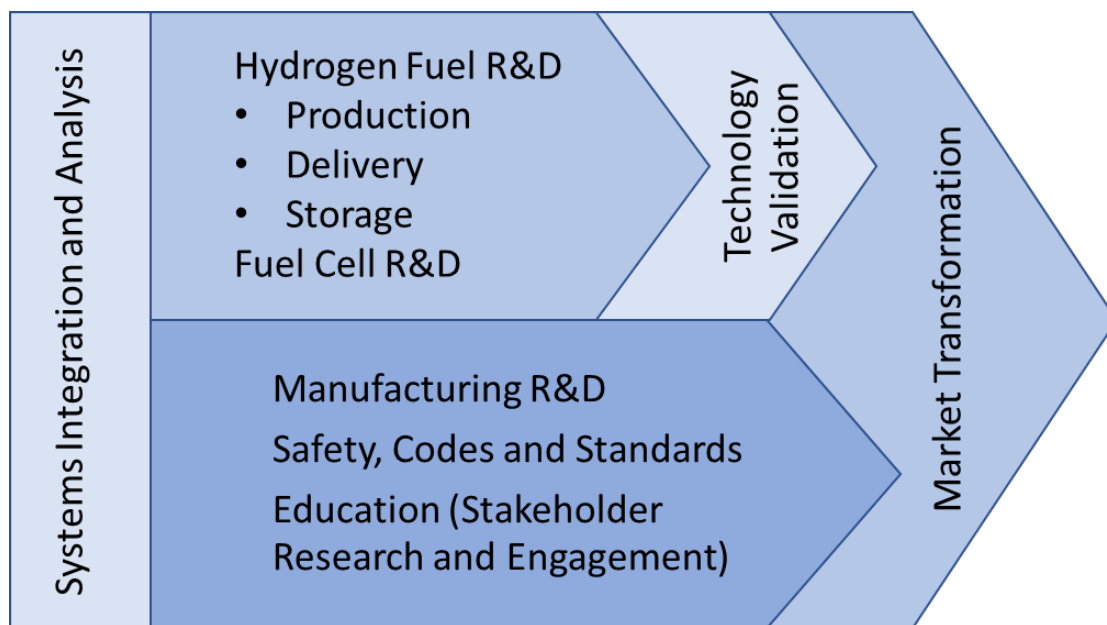
Source: After DOE Fuel Cell Technologies Office

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125 DOE H2@Scale Home Page https://www.energy.gov/eere/fuelcells/h2scale.

The H2@Scale program features focused research at the materials, components, and systems levels in hydrogen production, storage, and systems. California can augment this program of research to address issues of specific priority to California and bridge U.S. DOE research through technology-to-market activities such as full-scale commercial demonstration programs. Notably, the H2@Scale program does not place specific focus on renewable hydrogen production, which amplifies the importance of California RD&D activities specific to renewable hydrogen. Some specific areas of RD&D that are of specific importance to California include:

- Cost and performance tracking and market forecasting of renewable hydrogen production and supply chain infrastructure to guide investor and policy-maker decisions.

- Full-scale commercial demonstration of high-impact-potential technologies such as gasification, and novel technologies across the production and supply chain, particularly those supporting production and storage at the station scale.

- Quantification of the value of joint benefits enabled by renewable hydrogen between the transportation, electric, and natural gas systems (sometime referred to as "sector coupling").

- Development of optimal electric and gas rate structures and market designs as they relate to renewable hydrogen.

Additional detail and specific research topics to maximize leverage of federal RD&D are described in more detail in Appendix D of this project final report.

Conclusions

Renewable hydrogen has the potential to play a significant role in the California zero-carbon economy. While transportation, particularly in longer-range and high-fuel-consumption applications, will likely be the primary application area, opportunities for the use of renewable hydrogen exist across the entire economy. With continued State policy and program support, the renewable hydrogen production sector can become self-sustaining within the next decade. This new sector of the economy will not only play a key role in decarbonizing transportation and energy but has the potential to create hundreds of thousands of high-quality, green jobs.

APPENDIX D:
Research, Development, and Demonstration (RD&D) Needs Assessment

Overview—Need for RD&D

To extend and build upon the renewable hydrogen production roadmap[126] and support the advancement of the renewable hydrogen sector in California, research, development, and demonstration (RD&D) is necessary. The foundation of the RD&D needs assessment is the extensive literature review conducted in the development of the roadmap. The assessment represents the observations of the research team on gaps in the current knowledge base and areas needing further development beyond what has been accomplished in the current roadmap effort. It is noted that the U.S. Department of Energy (DOE) H2@Scale[127] initiative is pursuing research on many relevant topics with a particular focus on fundamental research and technology development. The research topics recommended in this document address areas that are of specific relevance to the buildout of the renewable hydrogen sector in California and are complementary to and synergistic with U.S. DOE-sponsored research.

As a broad theme, cost reduction is the most critical gap to close. The U.S. DOE long-term goal (post 2030) for the dispensed cost of hydrogen as a vehicle fuel is $4 per kilogram. At that price point, hydrogen would be cost-competitive with both conventional fuel and battery-electric drive on a cost-per-mile basis. Achieving the necessary cost trajectory (Figure D-1) in a safe, highly reliable, and consumer-friendly ecosystem will require sustained action across a range of RD&D areas from core technology development to system analysis, advanced manufacturing, and market transformation. As a leading global market in renewable hydrogen, California plays a critical and unique role in validating technology progress, exploring policy and regulatory frameworks including sector coupling, collecting real-life data on consumer and stakeholder issues and behavior, and other on-the-ground issues.

The framework used in the U.S. DOE Fuel Cell Technologies Office Multi-Year RD&D Plan[128] provides a useful framework for categorizing RD&D needs (Figure D-2). California can augment this program of research to address issues of specific priority to California and to bridge U.S. DOE research through market-specific analysis and technology-to-market activities such as full-scale commercial demonstration programs. Notably, the U.S. DOE program does not currently place specific focus on renewable hydrogen production, and this amplifies the need for and importance of California RD&D activities specific to renewable hydrogen. In addition, based on the findings of this project, systems analysis and integration, technology validation, and market transformation activity specific to the California market and regulatory environment are needed.

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126 Energy Commission contract 600-17-008, "Roadmap for the Deployment and Buildout of Renewable Hydrogen Generation Plants"

127 DOE H2@Scale Home Page https://www.energy.gov/eere/fuelcells/h2scale

128 DOE Fuel Cell Technologies Office Multi-year R&D Plan
https://www.energy.gov/eere/fuelcells/downloads/fuel-cell-technologies-office-multi-year-research-development-and-22

Figure D-1: Cost of Dispensed Renewable Hydrogen

Dispensed Price per kg
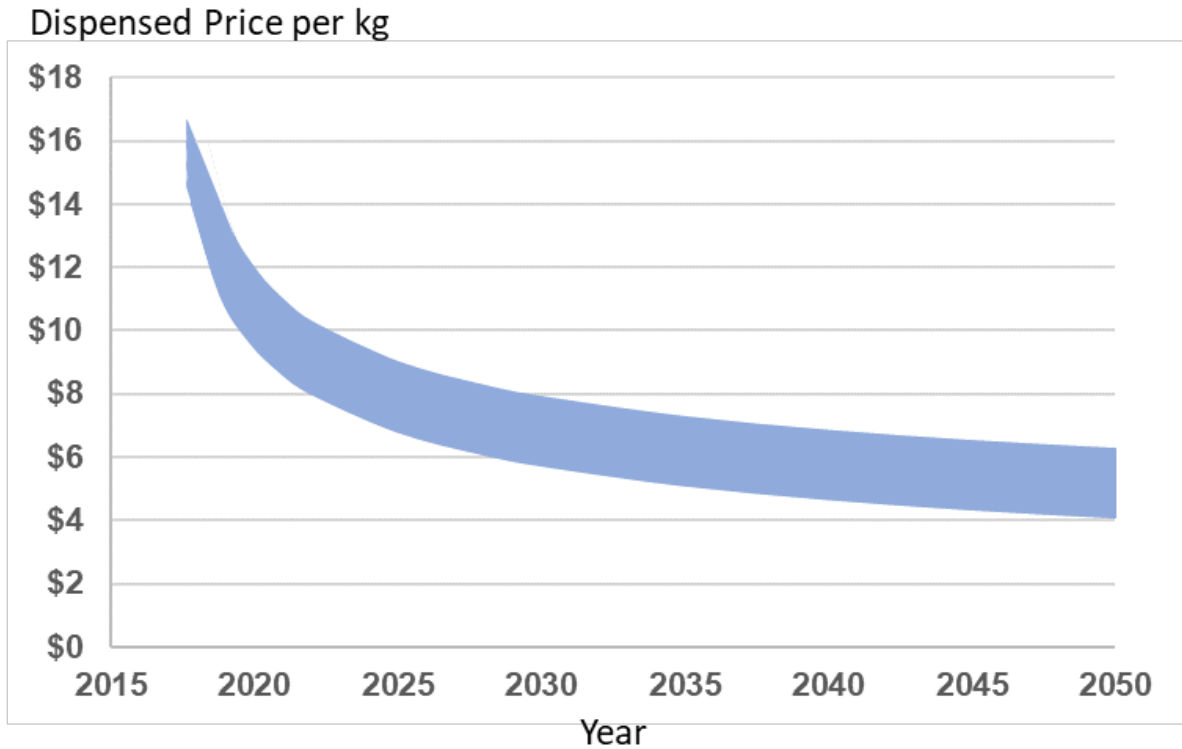
Source: UCI APEP

Figure D-2: RD&D Organizing Framework

Source: After DOE Fuel Cell Technologies Office

Some research, development and demonstration themes that are of specific importance to California and that maximize leverage and synergy with U.S. DOE research include:

- Cost and performance tracking and forecasting of renewable hydrogen production facilities and supply chain infrastructure to guide investor and policy-maker decisions.

- Global and California-specific demand forecasting to anchor technology forecasts and investment planning.

- Quantification of the value of sector coupling enabled by renewable hydrogen between the transportation, electric and natural gas systems.

- Development of optimal electric and gas rate structures and market designs as they relate to renewable hydrogen.

- Field deployment and commercial validation of high-impact-potential technologies such as gasification.

- Field demonstration of late-stage pre-commercial technologies across the production and supply chain that show the potential to reduce cost and improve supply reliability and safety.

- Stakeholder research and engagement in the unique context of the California policy environment and its position as a global early adopter of hydrogen solutions.

Recommendations for Further Research

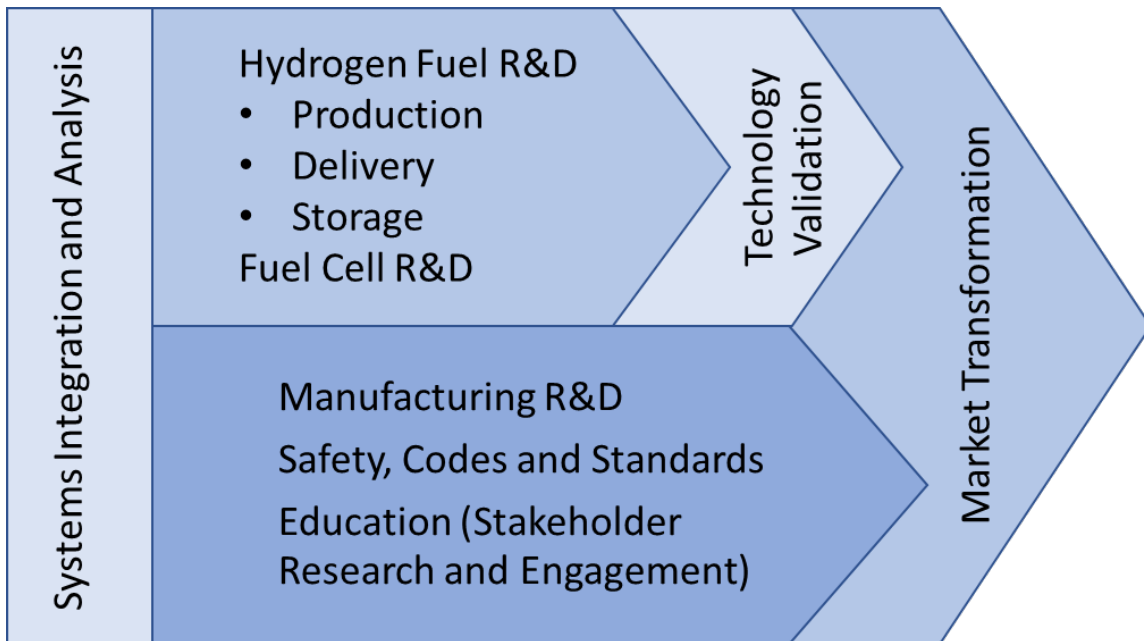Research, development and demonstration recommendations are grouped into several categories:

Renewable Hydrogen Production Technology

Renewable Hydrogen Feedstock Supply

Demand, Adoption and Impacts Analysis

Supply-Chain Forecasting and Optimization

Impacts of Electrolytic Hydrogen Production on the Electric Grid

Further discussion is provided below.

Production Technology

Potential Effect of Emerging Renewable Hydrogen Production Technologies

Several technologies are at low technology readiness levels (commercial introduction beyond five years in the future), such as artificial photosynthesis (water splitting using direct sunlight and catalyst) and reversible cells (electrochemical devices that can operate as both electrolyzers and fuel cells). These technologies could have a significant impact on renewable hydrogen supply potential and cost beyond 2030. Comprehensive assessment of "next-generation" technologies for hydrogen production is beyond the scope of the current RH2 Roadmap but is needed to better understand the potential evolution of hydrogen supply and cost in the 2030 to 2050 timeframe.

As-Built and Operational Data Collection and Analysis

The range of current cost and performance reported in the literature, provided by stakeholders and contained in vendor bid information gathered for the Renewable Hydrogen Roadmap, was wide for all technologies assessed. A systematic effort to gather and analyze data on project cost and operating performance would reduce the uncertainty in the current cost and performance status and thereby reduce the range of uncertainty in future costs.

Potential Role of Carbon Capture, Utilization and Storage in the Renewable Hydrogen Production Sector

Carbon capture, utilization, and storage (CCUS) provides the opportunity to create zero-carbon hydrogen from low-cost, conventional natural gas or negative carbon cycles for biomass pathways. The CEC led the U.S. DOE-sponsored WESTCARB multi-stakeholder CCUS initiative from 2003 to 2013 with the mission to investigate and advance carbon capture in the western region. However, RD&D activity on the topic has been limited in recent years. Nationally, renewed interest is building in investigating the potential role of carbon capture and the use of captured CO_2 to produce useful products to sequester or recycle carbon. Research has advanced on direct-air capture and capture of CO_2 from combustion exhaust. A technology characterization and forecasting effort similar to that conducted in this study for renewable hydrogen of zero-carbon hydrogen produced via CCUS would provide a more complete picture of the zero-carbon hydrogen supply curve evolution over time.

Renewable Hydrogen Feedstock Supply

Assessment of the Potential Role of Energy Crops for the California Renewable Fuels Sector

Perspectives vary on the potential role of energy crops (plants of high energy content, such as certain strains of tall grass, grown specifically as an energy source) as feedstock for renewable fuel. The Billion-Ton Report (U.S. Department of Energy 2016) envisions a major role for energy crops in the biomass resource mix. Other studies are more pessimistic on the potential for energy crops as a source of supply in California (Mahone et al. 2018). A comprehensive analysis of energy crop potential in California that accounts for crop production, harvesting costs, and full-cycle analysis of land-use impacts, water use, community impacts, and other factors to assess the societal benefit of pursuing energy crop development in California would enhance understanding of the renewable hydrogen supply curve beyond 2030.

Organic feedstock allocation based on fuel pathways cost and carbon intensity forecasting

Organic pathways have strong potential as a source of renewable hydrogen. However, these feedstocks can also be used to create other renewable fuels such as methane and various liquid hydrocarbons. The allocation of feedstock to these alternative pathways will depend upon the relative economics of the alternatives, and these economics will evolve over time. The hydrogen supply analysis in this RH2 Roadmap project has relied upon high-level assumptions on the available supply of organic feedstock for hydrogen production. A more refined analysis would use economic allocation to evaluate the availability of each feedstock. Such an analysis should include all production, supply, and vehicle pathways to represent the

economics to the end user. The assessment should also include the value of environmental credits and any other sources of revenue other than fuel sales (for example, tipping fees and coproducts) that can influence the sales price of fuel.

Demand, Adoption, and Impacts Analysis

Analysis of Global Market Growth in RH2 to Support Learning Curve Analysis

Learning curve or progress curve analysis has proven to be an accurate method of forecasting cost and performance improvement across a range of technologies, including solar photovoltaics, wind turbines, batteries, and a broad range of other technologies. Wright's Law, a method that quantifies "learn by doing," forecasts the technology progress and cost reduction of a product as a function of cumulative production (aggregate quantity of product produced since market introduction) and has proven to be a reliable forecasting method. However, the application of this method requires forecasting of global demand for the subject technology. To increase the level of certainty in future costs for renewable hydrogen production in California, a comprehensive review and synthesis of global forecasts for production (final demand) of systems across the renewable hydrogen production and supply chain are needed.

Economic Adoption Modeling for Renewable Hydrogen Solutions

Renewable hydrogen is targeted toward transportation, energy storage, industrial processes, and heating decarbonization. Yet renewable hydrogen is just one among several decarbonization options for these uses. The demand scenarios used in the RH2 Roadmap rely on a variety of assumptions regarding the relative role of hydrogen in decarbonizing the various applications discussed in the demand analysis, yielding an uncertain set of predictions. Adoption scenarios with more rigorous underpinning based on economic adoption modeling would reduce the uncertainty in future demand scenarios.

Public and Key Stakeholder Perceptions

Achieving California's climate and other environmental goals will impose costs and compliance burdens across sectors and communities. Stakeholder understanding of the pros and cons of alternative solutions is important to ensuring that the most effective policies are pursued. Anecdotal information suggests that current public awareness and understanding of the role of hydrogen in the future energy and transportation sectors are low. In addition, some stakeholders have misperceptions regarding environmental impacts, safety, and community impacts of hydrogen for transportation and other uses. Key stakeholders include the public, potential adopters of hydrogen solutions (such as passenger and fleet vehicle purchasers), and community advocates (particularly social justice advocates). Policy makers and their advisors are the key decision makers on program designs and funding and should be a focus of outreach and education. A more specific understanding of stakeholder perspectives would enable more effective education and outreach to remove barriers to adoption of renewable hydrogen solutions and advance appropriate policies in support of that goal.

Continuity of Supply and Supply-Chain Reliability

Early-market experience in providing hydrogen (renewable and conventional) to serve the light-duty fleet has shown that the nascent market is vulnerable to supply disruptions. Such events can erode satisfaction among early adopters and can impede attraction of new adopters. RD&D is needed to better understand and develop means to address the points of vulnerability in the supply and delivery system, including redundancy and backup supply options. This analysis should include the entire supply chain and would include assessment of known weaknesses such as fire suppression and seals exposed to cryogenic temperatures.

Air Emissions and Other Community Impacts Analysis

The RH2 Roadmap includes consideration of community impacts in siting analysis at a qualitative level. A more comprehensive and quantitative analysis of air emissions impacts of alternative buildout scenarios would characterize the potential magnitude of these impacts. Quantitative analysis of other impacts such as job creation, visual impacts, and congestion would deepen understanding of the various benefits and costs associated with renewable hydrogen production at the community level. Such analysis should include scientifically designed research on affected stakeholder ranking of impacts (such as visual impact versus job creation).

Supply-Chain Forecasting and Optimization (Plant Gate to Point of Use)

The renewable hydrogen production-through-dispensing chain has numerous variations because of alternate modes of transport and storage (gaseous or liquid; truck, rail, or pipeline) and the scale and location of supply chain elements. The pathway combination, or combinations, that are ultimately the most cost-effective and reliable are uncertain and will evolve over different stages of the market. The potential for disruptive or evolutionary technology shifts creates stranded-asset risk for investors. The compatibility of alternative pathways coexisting in the market has not been studied. The consequences of transferring from one set of deployed pathways to a new mix of pathways has also not been studied. Such analyses would shed light on investment risk and provide insight to policy makers on potential action. Some specific analyses that would help guide optimal deployment planning are described below.

More Rigorous Design Basis and Footprint Analysis for On-Site Solutions

On-site (forecourt) solutions for hydrogen production have the benefit of eliminating the need for road transport of hydrogen to refueling stations (and other future points of use). Such an approach has the potential to be the low-cost solution in some situations. Forecourt solutions are high cost and pose footprint challenges. However, additional technology progress may address these issues. Analysis is needed to compare projected future dispensed-cost-of-hydrogen scenarios featuring forecourt solutions based on up-to-date information on available and developmental technologies and international experience with distributed-scale hydrogen production through electrolysis and reformation. Analyses by the U.S. DOE have not focused on forecourt solutions. The NREL analysis in Appendix A of *Assembly Bill 8: 2018 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California* (Baronas, Jean, Gerhard Achtelik 2018) also does not address forecourt solutions. Forecasting analysis, field validation, and demonstration of forecourt solutions are all needed as well.

Downscaling Liquefaction and Reformation

The most common pathway for renewable hydrogen production today uses steam-methane reformation of renewable methane. In addition, the use of liquefaction is emerging as one of the dominant pathways for the next generation of projects. Both these technologies are scale-sensitive, creating an incentive for large-scale plants. Large facility scale imposes siting constraints, increases local traffic burden, and imposes a higher single-project financing burden than would smaller-scale facilities. Active development of solutions to reduce the minimum efficient scale is ongoing and the subject of developmental research under U.S. DOE sponsorship. Cost and performance forecasts supporting the RH2 Roadmap need to be extended to include a more comprehensive assessment of the potential evolution of small-scale systems. The emerging California renewable hydrogen market is an ideal testbed and demonstration platform for such facilities.

Mixed Gas-Liquid Supply Chain Integration and Optimization

Interview participants in the RH2 Roadmap project and respondents to the survey summarized in the 2018 joint-agency AB 8 report (Baronas, Jean, Gerhard Achtelik 2018) reflect a range of views on whether liquid hydrogen or gaseous hydrogen will be dominant in the future supply chain. It appears likely that there will be both gaseous and liquid supply in the hydrogen transportation sector for the foreseeable future. Research and analysis are needed to assess the implications of such a mixed-mode configuration from the perspective of hydrogen producers that are not vertically integrated. In addition, developmental work is ongoing for a variety of liquid hydrogen carriers, including liquid organic hydrogen carriers (LOHC), ammonia, and dimethyl ether (DME), which have different characteristics and logistics than the cryogenic-liquid pathway in use today. The potential cost, timeline for deployment, and integration with refueling station operations need to be assessed. As these solutions mature, field demonstration will also be needed.

Transition to Dedicated Pipeline Transport for Renewable Hydrogen

When hydrogen demand between supply areas and demand centers is high enough to maintain high utilization, pipelines are the most cost-effective mode of transport for hydrogen based on the HDSAM model. A rigorous analysis of the optimal buildout of dedicated hydrogen infrastructure in California would clarify the prospects and priorities for dedicated hydrogen pipelines in the future. Such an analysis should be based on spatially and temporally resolved supply and demand and include routing constraints for new hydrogen pipelines and related infrastructure, the potential for synergy with or conversion of natural gas infrastructure and expected regulatory requirements, permitting, and community impacts.

Renewable Hydrogen Fuel Production, Electric Grid Integration and Joint Optimization ("Sector Coupling")

Electrolyzers have the unique feature among renewable hydrogen pathways of using electricity as feedstock. Liquefaction facilities are large consumers of electricity as well, so electricity carbon footprint and cost play a major role in liquid-hydrogen pathways. The hydrogen production schedule, or duty cycle, can create favorable and unfavorable impacts on overall grid cost and reliability. The future, highly renewable grid, with many distributed resources, will need to integrate technology with the ability to operate dynamically in ways that reduce

supply and demand mismatch, the need for rapid ramping of grid resources, and local voltage and frequency stresses. Renewable hydrogen can also serve as a fuel for turbines and fuel cells, which are dispatchable renewable generators. System-dynamic and technoeconomic analysis is needed to model the operational limits and two-way economic value potential of operating high-electricity-consuming hydrogen production facilities in a way that optimizes grid and hydrogen producer economics. Such analysis should include developing and modeling potential market design and utility rate structures.

APPENDIX D REFERENCES

Baronas, Jean, Gerhard Achtelik, et al. 2018. "Joint Agency Staff Report on Assembly Bill 8 : 2018 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California."

Mahone, Amber, Vivian Li, Nancy Ryan, and Guido Franco. 2018. "Deep Decarbonization in a High Renewables Future (CEC)."

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APPENDIX E:
Interview Summary

This appendix briefly summarizes the more than 40 interviews conducted as part of the information gathering for this renewable hydrogen roadmap. Participants from across the renewable hydrogen supply chain and other interested stakeholders provided input on a variety of topic areas as summarized in Table E-1. The primary stakeholder groups included:

- Technology vendors.
- Renewable hydrogen and renewable methane project developers.
- Auto manufacturers.
- Industrial gas companies.
- Hydrogen station developers.
- Consulting engineers.
- Utilities.
- Agency staff.

Table E-1: Interview Topics and Themes

Topic Area	Themes
Market Evolution	• Market has "launched" but needs to scale • Most parties rely on CaFCP forecasts (upper scenario of 1M FCEV by 2030) but recognize the potential importance of applications beyond light duty vehicles, particularly MD/HD
Ability to Meet Long-term Goal of $4/kg dispensed	• $2/kg uncompressed at the plant gate is challenging but possible with scale and R&D • Building scale (project and sector) is the key to cost reduction • All-in cost of $4/kg very challenging but cost-per-mile parity ($6 - $8/kg dispensed) is within range by 2025 to 2030 (net of LCFS value) and around $10/kg in the next project generation
Best Pathways in the "End Game"	• Diversity of views but most see a mix of technologies with both central and localized deployment • Growing share for LH2 but most stakeholders expect both gaseous and liquid pathways to be present in the market for the foreseeable future
Barriers and Issues	• Uncertainty in LCFS credit values and in the pace of growth in demand for renewable hydrogen • Lack of reliability of supply could stall market acceleration • Need for sustained government support across budget cycles • Lack of access to low-cost renewable electricity as feedstock • Limited supply of biomethane for SMR pathways • Permitting challenges (depending on technology and location)

Source: UCI APEP