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DRAFT STAFF REPORT

Clean and Renewable Hydrogen for the Electricity and Transportation Sectors

Assessment of the Ability of Clean and Renewable Hydrogen to Support a Clean, Reliable, and Resilient California Grid and Transportation System

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California Energy Commission

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ABSTRACT

Achieving California's climate and energy goals requires a diverse portfolio of clean and renewable resources. Clean and renewable hydrogen is being used in limited quantities in the electricity and transportation sectors in California and has potential to support further diversification of resources. This report captures analysis of potential options for further developing clean and renewable hydrogen for these two sectors and the associated challenges. Hydrogen production pathways studied include technologies such as electrolysis, steam methane reformation, gasification, and pyrolysis. The analysis includes a range of feedstocks, including water, biogenic resources (resources derived from biomass and living organisms), and fossil gas (with carbon capture).

Keywords: clean hydrogen, biogas, renewable energy, electricity, transportation

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EXECUTIVE SUMMARY

California's policies are moving the state to economywide decarbonization (the process of reducing or eliminating greenhouse gas emissions), including key energy-intensive sectors such as electricity generation and transportation. For the electricity sector, the state is rapidly scaling up deployment of clean energy resources — particularly solar, wind, and energy storage — and analysis has shown that a diverse portfolio of resources is valuable to achieving the state's decarbonization goals. The state is also advancing low-carbon transportation strategies including electric and fuel cell vehicles. Some forms of transportation, such as aviation, off-road transportation, and long-haul trucking, however, may be challenging to electrify, and hydrogen may be capable of meeting some of these transportation needs.

Hydrogen has historically been produced using fossil gas in key industrial sectors, including in the oil and gas industry, generating the greenhouse gas carbon dioxide (CO_2) as a by-product. The Environmental Protection Agency estimated 10 MT of CO_2 emissions associated with California's 2022 hydrogen production facilities[1]. The greenhouse gas methane (CH_4) is also emitted in the production, processing, and transportation of fossil gas. To the extent that hydrogen is leveraged in meeting California's clean energy goals, hydrogen with lower greenhouse gas emissions will be necessary. This report refers to this as *clean and renewable hydrogen,* the production of which is from feedstocks and processes that substantially reduce greenhouse gas emissions. The CEC analyzed production of hydrogen using eligible renewable energy resources, or produced directly from eligible renewable energy resources, including biogenic resources (biomass and gas generated from renewables, such as renewable natural gas). Carbon-emitting production processes using fossil gas, when combined with carbon capture, are also evaluated production pathways.

There are many possibilities for how hydrogen might be produced and used to support California's clean energy goals. At the same time, there is no specific policy goal on the amount of clean and renewable hydrogen to be used in the electricity or transportation sectors. Without any goalpost to guide analysis of the potential for clean and renewable hydrogen in the state, CEC staff evaluated the opportunities and challenges associated with several future scenarios. These scenarios include different production pathways, storage, transport, and use of clean and renewable hydrogen for the electricity and transportation sectors. The analysis evaluates different feedstocks to produce hydrogen and related availability, as well as factors such as land and water use associated with different pathways.

Given the many potential pathways for hydrogen development in the state, the report analysis looks at illustrative scenarios in 2045. Staff used results from other state scenario planning activities, such as the 2021 and draft 2025 Senate Bill 100 (De León, Chapter 312, Statutes of 2018) modeling and the California Air Resources Board's (CARB) *2022 Scoping Plan for Achieving Carbon Neutrality* (2022 Scoping Plan Update) to explore hydrogen potential.

CEC staff developed scenarios for both the electricity and transportation sectors, as was done in the *2023 Integrated Energy Policy Report* (IEPR). CEC staff, with support from Guidehouse, Inc., expanded on the 2023 analysis by evaluating more pathways to meet hydrogen demand. Starting with illustrative demand scenarios, staff evaluated various resources to generate

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[1] Bracci, Justin, Adam Brandt, Sally M. Benson, Gireesh Shrimali, and Sarah D. Saltzer. 2022. "Pathways to Carbon Neutrality in California: The Hydrogen Opportunity." Stanford Center for Carbon Storage and Stanford Carbon Removal Initiative.

hydrogen with low emissions, including renewable energy and biogenic resources. Staff then examined various methods to produce hydrogen, which included electrolysis, steam methane reforming of fossil gas with carbon capture, steam reforming of renewable natural gas, gasification of biomass, and pyrolysis of fossil gas and renewable natural gas (biomethane or gas derived from organic waste). Staff then evaluated hydrogen storage, which included tanks and underground or subsurface reservoirs.

In addition, delivery methods by trucks, a dominant means of distribution of relatively small quantities, were evaluated. Although pipelines are viewed as an efficient method of transporting hydrogen, they were not evaluated extensively in this analysis because of the added complexity of assessing pipeline locations and costs. The final step in the process is hydrogen conversion to electric power and its use as a fuel in the transportation sector.

Key takeaways from the analysis include the following:

- **Scale drives infrastructure needs and hydrogen cost:** The demand for hydrogen in the power and transportation sectors is a key factor in driving investments for infrastructure buildout. The amount of hydrogen that can be produced and its related availability affect the cost of hydrogen. This is why an economy of scale, with larger plants and storage (or pipelines), would significantly reduce the capital expenditure (CAPEX) of production assets. (For example, doubling the size of a typical chemical production plant may only increase the price by about 50%. Some electrolysis systems may experience less economy of scale than technologies such as SMR or pyrolysis.)
- **Hydrogen's role in power generation:** Hydrogen's most promising power-generation role is as firm, dispatchable capacity for infrequent multi-day or seasonal reliability gaps via turbines or fuel cells, rather than as a primary fuel for routine day-to-day generation. It can complement variable renewables in systems where reliability needs and required storage duration extend beyond the range that batteries typically serve cost-effectively. However, there are economic and technical challenges such as production costs, delivery (dedicated pipelines), and storage.
- **Anticipated seasonal variation in electricity needs drive infrastructure strategy in the power sector:** If hydrogen is used to replace existing fossil gas-fired generation (such as meeting daily and seasonal demand when renewable electricity generation is not sufficient) in 2045, there would be large variations in seasonal demand for hydrogen. Unless the delivery had inherent flexibility, as could be the case with storage, the variations could lead to overbuilding production capacity. Depending on how much large-scale storage is available, production capacity may be as high as 7.4 times the demand of 1.59 million tonnes per year. If ample hydrogen storage is available, the dedicated hydrogen production capacity for the electric power sector could be the minimum value of 0.35 million tonnes per year.
- **The potential exists to more easily balance infrastructure build for transportation sector:** Demand profiles of the transportation sector are regular and do not have dramatic changes, but there are some seasonal variations. Potential excess capacity is only about 15 percent for both scenarios studied (baseline demands of 1.4 million and 0.81 million tonnes per year for upper and lower scenarios, respectively). When combining hydrogen production for transportation and electric power, the combined upper (higher-capacity) scenarios have a maximum production capacity of

4.5 times demand, and the combined lower scenarios could reach about 1.5 times demand.

- **High demand would require pipelines and potentially large storage options:** The supply/demand analysis shows that the magnitude of storage required in many cases is so large (for example, hundreds to thousands of tonnes of hydrogen) that tank storage is clearly impractical. In addition to storage, pipelines would be needed to move large amounts of hydrogen. California's geology creates opportunities and poses challenges for implementing geologic storage of hydrogen at the strategic quantities needed to meet the energy needs of the state for extended periods. While depleted oil and gas reservoirs offer potential for geological storage, and lined rock caverns are available, the suitability for hydrogen storage for either of these is not yet proven. Significant research and development efforts are needed, and the CEC initiated a $3 million grant with Lawrence Berkeley National Laboratory this year to assess the potential benefits, costs, technical feasibility, and operational risks of storing hydrogen in fossil gas underground storage facilities at two California sites.
- **Off-grid electrolysis offers advantages in terms of lower emissions compared to combustion technologies:** However, the limitations related to the land required for solar energy supply and the intermittent nature of electricity supply make electrolysis a challenging technology to implement in terms of cost and reliability. Onsite hydrogen production by electrolysis is limited to applications with modest needs; 7 acres of solar PV yield only about 140 kilograms of hydrogen per day.
- **There are limitations to relying solely on curtailed renewable power to operate commercial-scale hydrogen electrolysis:** To be economically viable, electrolysis plants need to operate with high and stable capacity factors. While curtailed power seems attainable, its scale and lack of reliability makes it an impractical sole source for a commercial plant requiring consistent large-scale output.
- **Challenges for hydrogen production pathways include cost competitiveness with traditional fuels (for example, hydrogen vs. fossil gas and diesel):** The prices of traditional fossil fuels such as fossil gas, coal, and diesel range from $2.50-$16/MMBtu, which is significantly cheaper than the cost of producing clean hydrogen. In March 2026,[2] retail gasoline prices averaged $45.29/MMBtu. Today, the cost of production (prior to profit, the delivery cost, and any retail markup) of traditional hydrogen production – SMR without carbon capture – is approximately $1.50-2.50/kg H2 ($11-19/MMBtu), whereas electrolytic hydrogen costs $3.50-$6.00 or more per kg H2 ($26-45/MMBtu). Hydrogen projects often require on-site or off-site storage to buffer fluctuations in demand and variability in renewable-powered production. Separately, given hydrogen's extensive federal and state safety and permitting oversight, regulatory requirements can constrain storage, siting, design, and operations, and can increase cost and schedule risk.
- **Hydrogen's Future Role in California:** To the extent that hydrogen will be used to meet California's ambitious climate goals, further development will be needed to levelize hydrogen costs and better understand hydrogen pathways and their impacts. The CEC

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[2] "Estimated Gasoline Price Breakdown and Margins." California Energy Commission. https://www.energy.ca.gov/estimated-gasoline-price-breakdown-and-margins

will continue to invest in hydrogen research and partner with our fellow state agencies in the role of hydrogen in California’s clean future.

Chapter 1: Introduction

Background

California is committed to decarbonizing its electricity and transportation sectors. For the electricity sector, the state is rapidly scaling up deployment of clean energy resources — particularly solar, wind, and energy storage. The state is also advancing low-carbon transportation strategies such as transportation electrification;[3] however, some forms of transportation, such as aviation, off-road transportation, and long-haul trucking, may be challenging to electrify.[4] Analysis conducted for the 2021 Senate Bill 100 report and the 2022 Scoping Plan[5,6] shows that diversity of resource types can effectively enable California to meet its clean energy goals. A diverse portfolio can also hedge against supply chain issues, which the energy industry has been experiencing in the last five years.

Hydrogen is produced primarily from fossil gas, resulting in greenhouse gas emissions. Hydrogen with a low carbon intensity is in limited use but has the potential, with further development, to support decarbonization in the electricity and transportation sectors. California has not developed a definitional standard for low-carbon-intensity hydrogen, and many times it is referred to as *clean* or *green hydrogen*. For this report, CEC staff applied the same approach as was used in the 2021 SB 100 report that refers to clean and renewable hydrogen. This is hydrogen that is produced using eligible renewable energy resources (for example, solar energy used to power electrolysis) or produced directly from eligible renewable energy resources (for example, from biomethane through pyrolysis). Production processes using fossil gas, when combined with carbon capture[7], are also considered in this definition.

This report focuses on the potential for clean and renewable hydrogen to support the electricity and transportation sectors. For the analysis, CEC staff, with support from Guidehouse, Inc., analyzed production pathways, potential options for storage (above ground and underground), and movement of hydrogen by trucks and pipelines. With no specific policy targets for the amount of hydrogen to be produced and used in the state to bound the analysis of demand, the CEC used illustrative demand scenarios for the electricity and transportation sectors. This was the approach used in the *2023 IEPR* analysis under Senate Bill

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[3] Electrification in transportation is the shift from fossil fuels to electricity to power vehicles.

[4] The most prominent difficulty at this time is the weight of the batteries required for these applications that require large amounts of on-board stored energy.

[5] Analysis is in the 2021 SB 100 Joint Agency Report, developed in response to Senate Bill 100 (De León, Chapter 312, Statutes of 2018). See: Gill, Liz, Aleecia Gutierrez, and Terra Weeks. 2021. *2021 SB 100 Joint Agency Report*. California Energy Commission. Publication Number: CEC-200-2021-001. https://www.energy.ca.gov/publications/2021/2021-sb-100-joint-agency-report-achieving-100-percent-clean-electricity

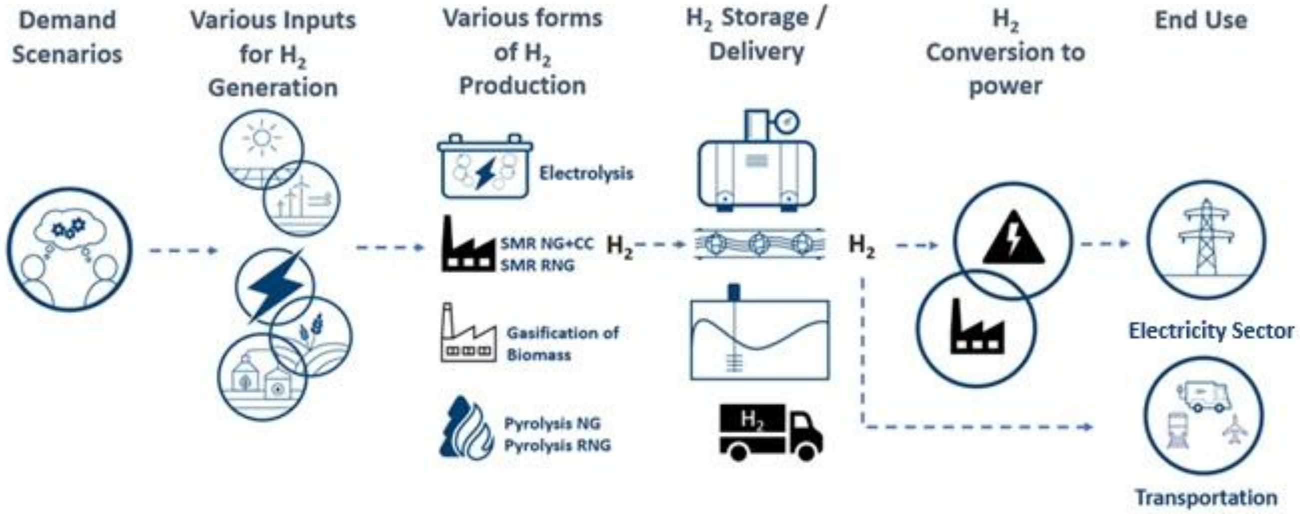
[6] 2022 Scoping Plan for Achieving Carbon Neutrality (2022 Scoping Plan Update) identifies the need for a diverse portfolio of clean energy resources. See: *2022 Scoping Plan for Achieving Carbon Neutrality*. 2022. California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/2023-04/2022-sp.pdf

[7] As part of mitigating the effects of global warming, carbon capture is the process of capturing carbon dioxide produced by the combustion of fossil fuels (or other industrial sources) and storing it in the subsurface (or utilizing it in products) before it enters the atmosphere.

1075 (Skinner, Chapter 363, Statutes of 2022), but staff expanded on that analysis in this report and used this study to support the *2025 IEPR.* For each scenario, the CEC evaluated the implications for feedstocks, production technologies, storage, transport, and end uses.

Hydrogen production pathways studied include technologies such as electrolysis, steam methane reforming, gasification, and pyrolysis. A diversified range of feedstocks were formularized to include water, biogenic resources, and fossil gas with carbon capture. This approach, which uses a mix of production pathways, is described in Figure 1 and illustrates the diversity of sources that could be used to supply the hydrogen that meets the demand of end-use scenarios.

Figure 1: 2025 Analysis of Hydrogen Production Pathways



Source: CEC (2025)

The California Air Resources Board (CARB) is conducting further analysis of the economywide potential of hydrogen under a requirement of SB 1075 (Skinner, 2022). The CARB report will cover the development, deployment, and use of hydrogen across all sectors as a key part of achieving the state's climate, air quality, and energy goals.[8] CARB will also prepare a life-cycle analysis of GHG emissions from various forms of hydrogen. That report is anticipated to be published in 2026.

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[8] "SB 1075 Report: Hydrogen Development, Deployment, and Use." California Air Resources Board. https://ww2.arb.ca.gov/our-work/programs/sb-1075-hydrogen

Chapter 2:
The Potential Use of Hydrogen in California

Key Takeaways

This chapter summarizes the current and potential use of hydrogen in the electricity and transportation sectors.

- Hydrogen use in the electricity sector offers the potential benefits of low- to no-emissions and increased reliability, but is limited largely due to technical, cost, and infrastructure challenges.
- Hydrogen shows promise as a solution for decarbonizing the transportation sector—especially in heavy-duty on-road, aviation, maritime, and rail applications. Additional challenges in this sector include fueling infrastructure and policy/regulatory support.

Hydrogen Usage in Demand Sector Overview

Hydrogen is widely used in various sectors, such as in industrial, electricity, and transportation, as summarized below:

- **Electric Power Production:** Hydrogen currently plays a role in the electricity power sector primarily through fuel cells, which offer high efficiency and zero emissions at the point of use. Hydrogen blending and hydrogen-capable gas turbines also currently play a limited role in electricity production and are primarily being evaluated through pilot projects. These efforts face technical, cost, and infrastructure challenges. Over time, renewable hydrogen could support grid reliability by providing firm generation and long-duration energy storage.
- **Transportation:** Hydrogen use in the transportation sector is currently concentrated in early commercial deployments and pilot applications. In California, hydrogen is being used in light-duty fuel cell vehicles supported by a developing fueling network, while medium and heavy-duty applications remain largely in the demonstration phase. Hydrogen may support decarbonization of transportation modes that are difficult to electrify, including long-haul trucking, aviation, maritime, and off-road uses. Broader deployment remains constrained by fuel costs, vehicle availability, and the scale of refueling infrastructure.
- **Industrial:** The bulk of current U.S. hydrogen consumption is used in industrial applications such as petroleum refining, fertilizer production, and chemical manufacturing. This demand is met primarily by hydrogen produced from fossil gas without carbon capture, resulting in significant greenhouse gas emissions. Use of clean and renewable hydrogen remains limited but is being tested in industrial pilot projects, including steelmaking and cement production, to reduce emissions. Broader adoption is constrained by high costs, infrastructure limitations, and regulatory uncertainty, including uncertainty around the availability and duration of federal tax incentives.

Hydrogen also supports agriculture applications. It can be used as fuel to power farming equipment such as tractors and irrigation pumps and, for nitrogen-based fertilizers, is the key input to ammonia production through the Haber-Bosch[9] process. Conversely, agriculture can also support hydrogen, as agricultural waste can be converted into syngas containing hydrogen through thermochemical processes such as pyrolysis or gasification.

Hydrogen for Electric Power Production

There are multiple roles that hydrogen can play, including as a long duration energy storage (LDES) medium and a fuel for dispatchable power generation. Clean and renewable hydrogen is increasingly viewed in California as a tool for enhancing the reliability and decarbonization of the electricity sector.[10] Hydrogen can be used for power production through electrochemical conversion in fuel cells or combustion in turbines. However, there are economic and technical challenges such as production costs, delivery (dedicated pipelines), and storage.

Key Applications

Dispatchable Power Generation

Hydrogen can be combusted in turbines or used in fuel cells to generate dispatchable electricity. Newer turbine designs can operate on hydrogen blends and, in some cases, higher hydrogen concentrations. For example, GE Vernova has developed combustion technologies designed to operate across a wide range of hydrogen concentrations, up to ~100 percent by volume.[11] Several California projects are evaluating hydrogen to reduce fossil gas use for power generation. LADWP'S Scattergood Generating Facility is planned to operate on a blend of up to 30 percent hydrogen and 70 percent fossil gas and would be dispatched during periods of peak demand or low renewable generation.[12] The Lodi Energy Center (LEC), a 300-megawatt combined-cycle power plant, has evaluated a 45 percent hydrogen blend using turbines designed for both hydrogen and fossil gas. Recent changes in federal funding have affected development timelines and project viability for some hydrogen power projects. Using clean and renewable hydrogen for dispatchable generation during periods of low renewable output or peak demand may support grid reliability and reduce emissions compared to unabated fossil gas generation, depending on hydrogen production pathways and supply. Hydrogen produced via electrolysis using renewable electricity and stored for later use in fuel cells represents an alternative approach to zero-emission dispatch, subject to cost and efficiency constraints.

Linear Generators

These are an emerging distributed generation technology that converts fuel, including hydrogen, directly into electricity without flame-based combustion or rotating components. Potential advantages include high efficiency, ultra-low criteria pollutant emissions, fuel

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[9] The Haber-Bosch process is an industrial method for synthesizing ammonia (NH3) accomplished by combining nitrogen and hydrogen gases.

[10] Hydrogen production pathways such as electrolysis, gasification, pyrolysis, and Steam Methane Reforming (SMR) with carbon capture, have low GHG emissions. However, there are other emissions, such as NOx (Nitrogen Oxides) that can be emitted because of high temperatures in combustion turbines. There are equipment and systems designed to abate NOx emissions from such processes; however, this was not analyzed in this study.

[11] "Hydrogen fueled gas turbines." GE Vernova. https://www.gevernova.com/gas-power/future-of-energy/hydrogen-fueled-gas-turbines

[12] *Scattergood Modernization Alternatives: Summary of Findings*. 2025. Los Angeles Department of Water and Power and the National Renewable Energy Laboratory. https://www.ladwp.com/sites/default/files/2025-03/Scattergood%20Moderniazation%20Alternative%20Study%20Final.pdf

flexibility, and dispatchability. A 2021 demonstration in Colton, California showed continuous operation providing dispatchable power that met approximately 80 percent of a grocery store's electricity demand.[13]

LDES

Hydrogen may support long-duration energy storage by approaches such as converting excess renewable electricity into hydrogen via electrolysis for storage and later conversion back into electricity. Like other LDES technologies, this process involves charging, storage, and discharging stages with associated efficiency losses. While hydrogen storage offers the theoretical advantage of storing large quantities of energy over extended durations, grid-scale deployment in California remains largely conceptual. The Calistoga Resiliency Center[14] implements LDES to provide up to 298 MWh (8.5 MW instantaneous peak) of islanded power in the event of a wildfire. Internationally, Austria's Underground Sun Storage 2030[15] project has demonstrated seasonal hydrogen storage in underground reservoirs.

Value-Chain Implications

Scaling hydrogen use in the power sector would require coordinated development of equipment, delivery systems, and storage infrastructure. Manufacturing backlogs for fossil gas turbines may constrain deployment of hydrogen-capable systems. Use of existing fossil gas pipelines raises technical, safety, and environmental considerations, including embrittlement and leakage. Alternative delivery approaches include liquefied hydrogen transported by truck, which introduces additional cost and energy losses. Storage options include compressed gas tanks, underground storage, and liquid hydrogen systems.[16]

Hydrogen for Transportation

When used in fuel cells, hydrogen produces zero tailpipe emissions and may support decarbonization of transportation modes where battery-electric systems face constraints related to weight, range, or refueling speed. Hydrogen's high energy density by weight and rapid refueling characteristics have supported early deployment in heavy-duty transportation, aviation, maritime shipping, and rail. Scaling remains constrained by production cost, limited refueling infrastructure, and energy losses across the hydrogen value chain. Applications discussed in this section include fuel cell electric vehicles, aviation, maritime, and rail.

Key Applications

Fuel Cell Electric Vehicles (FCEVs)

Fuel cell electric vehicles produce electricity onboard using hydrogen in a fuel cell. Hydrogen is electrochemically converted into electricity, water, and heat, with water vapor as the primary

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[13] Simpson, Adam, Kieth Davidson, and Mainspring Energy, Inc. 2024. *High-efficiency and Ultra-low Emissions Linear Generator Demonstration Project in Southern California*. California Energy Commission. Publication Number: CEC-500-2024-037. https://www.energy.ca.gov/sites/default/files/2024-05/CEC-500-2024-037.pdf

[14] "Calistoga Resiliency Center." Energy Vault. https://www.energyvault.com/projects/calistoga

[15] "Seasonal electricity storage in the form of hydrogen ready for scale-up." 2025. Underground Sun Storage 2030. https://www.uss-2030.at/en/

[16] Patel, Pinakin and Ludwig Lipp (T2M Global, LLC). 2024. *Ultra-high Efficiency, Lower-Cost, Green Electrolytic Hydrogen for Microgrids in California*. California Energy Commission. Publication Number: CEC-500-2024-008. https://www.energy.ca.gov/sites/default/files/2024-02/CEC-500-2024-008.pdf

tailpipe output. Most FCEVs use a fuel cell and battery combination, with the battery recapturing braking energy and supporting acceleration.[17]

Hydrogen can be used for light-duty, medium-duty, and heavy-duty vehicles. The uptake in FCEVs has led to deployment of more hydrogen fueling stations across California. As of October 2025, there are 60 light-duty fueling stations and one all-duty fueling station, with nearly 40 additional fueling stations planned. Most fueling stations are located in Southern California.[18]

On-road transportation is expected to represent a substantial share of future hydrogen demand, particularly in heavy-duty segments. The 2022 CARB Scoping Plan projects on-road vehicles could account for 44 percent of hydrogen demand by 2035 and more than 70 percent by 2045. The primary focus for hydrogen in on-road transportation is increasingly shifting towards heavy-duty applications where battery electric vehicles (BEVs) face more challenges associated with longer charging times and greater power requirements from charging equipment.

Light-duty trucking (LDT)

At present there are three commercially available light-duty FCEV models in California. The Toyota Mirai – which was the first commercial FCEV released in 2015 – is a sedan, with a driving range of 357 – 405 miles.[19] Hyundai's Nexo is a sports utility vehicle (SUV), with a driving range of 354 – 380 miles, was first released in 2018. Honda recently released a hydrogen version of their popular SUV, the CR-V. The CR-V Hydrogen, unlike the other FCEVs, can be charged using electricity, which can extend the driving range by 29 miles, allowing for an overall range of 270 miles.[20]

Heavy-duty trucking (HDT)

This includes long-haul freight transport, where the combination of long distances, heavy payloads, and quick refueling requirements make heavy-duty FCEVs an attractive option. Batteries for long-haul trucks can be prohibitively heavy, reducing payload capacity, and recharging times are usually longer than standard refueling times, impacting operational efficiency. New stations for heavy-duty fuel cell electric trucks are under development, with an estimated 150 heavy-duty semi-trucks operating on California's roads. Of these, over 100 are the Nikola Tre model, and 35 are Hyundai XCIENTs. In February 2025, Nikola filed for voluntary Chapter 11 bankruptcy protection, citing market and macroeconomic factors that impacted its ability to continue operating. Hyroad Energy announced its acquisition of 113 Nikola Tre trucks, spare parts, software platforms, and other assets from the Nikola bankruptcy auction. Hyroad Energy has stated that the trucks will be deployed primarily in California, where it will develop hydrogen refueling infrastructure for Nikola trucks and offer support for the existing trucks and those that it acquired. Hyundai continues to assert its plans to produce the XCIENT, unveiling its 2025 model at the Advanced Clean Trucks exposition in

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[17] "How Do Fuel Cell Electric Vehicles Work Using Hydrogen?" U.S. Department of Energy. https://afdc.energy.gov/vehicles/how-do-fuel-cell-electric-cars-work

[18] "Hydrogen Refueling Stations in California." California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/hydrogen

[19] "Vehicle Search." Alternative Fuels Data Center. https://afdc.energy.gov/vehicles/search

[20] Honda positions the battery as delivering "EV driving around town," with hydrogen being primarily used "for longer trips." See: "2025 CR-V e:FCEV." Honda. https://automobiles.honda.com/cr-v-fcev

Anaheim. The 2025 model includes a 68 kg hydrogen tank and provides a range of up to 450 miles.

Drayage and regional haul

Trucks involved in drayage (short-distance transport of goods, often to/from ports) and regional haul operations, which often feature high daily mileage and return-to-base operations, are also considered strong candidates for FCEV adoption. Researchers from UC Davis project that FCEVs could serve 35 percent of drayage trips and approximately 60 percent of long-haul trips in California by 2045, underscoring the perceived suitability of hydrogen for these segments.[21]

Buses

Fuel cell electric buses (FCEB) are a proven application of heavy-duty fuel cell electric transportation. AC Transit, which is based in Oakland, has the longest history – over 15 years – of deploying fuel cell electric buses. Foothill Transit, Sunline Transit and Orange County Transit together operate over 100 FCEBs. In 2023, Santa Cruz Metropolitan Transit Authority placed the largest order of FCEBs in the United States to date, a total of 57. Small, rural transit agencies with challenging hilly terrain and long routes are also considering or have ordered FCEBs, which offer longer range and faster refueling compared to battery electric buses. [22]

Key Limitations

Hydrogen use in the transportation sector faces barriers including competition from battery-electric vehicles, limited refueling infrastructure, high vehicle and fuel costs, market uncertainty related to original equipment manufacturers, and evolving policy frameworks.

Despite the promise, the hydrogen FCEV market, especially for heavy-duty vehicles, faces several significant hurdles.

Competitiveness with other ZEV Technologies

Although battery electric trucks are also at an early stage of adoption and face some challenges for adoption, there are more battery electric trucks than FCEV trucks, nearly ten times more.[23] Further, heavy-duty battery electric vehicle technologies share many of the same components and manufacturing practices as those for light-duty BEVs, which have seen exponential growth in the last decade. This relationship and its influence on other competitiveness factors below suggest that battery electric trucks are at an advantage against FCEV trucks. Fleet managers are more likely to prefer to invest in one ZEV technology only, and the market currently appears to be leaning toward battery electric trucks.

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[21] Fulton, Lewis, Alan Jenn, Christopher Yang, Andrew Burke, Tri Dev Acharya, Xinwei Li, Joan Ogden, et al. 2023. *California Hydrogen Analysis Project: The Future Role of Hydrogen in a Carbon-Neutral California*. UC Davis Institute of Transportation Studies. https://escholarship.org/uc/item/27m7g841

[22] Villareal, Kristi. 2023. *Final Staff Report on Senate Bill 643: Clean Hydrogen Fuel Production and Refueling Infrastructure to support Medium- and Heavy-Duty Fuel Cell Electric Vehicles and Off-Road Applications*. California Energy Commission. Publication Number: CEC-600-2023-053-SF.

[23] "Medium- and Heavy-Duty Zero-Emission Vehicles in California." California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/zero-emission-vehicle-and-infrastructure-statistics-collection/medium

Fueling infrastructure

Another critical barrier is the limited availability of hydrogen refueling stations (HRS) capable of serving heavy-duty vehicles. While California has the most extensive light-duty HRS network in the U.S., stations designed for heavy-duty vehicles (with higher capacity, faster fill rates, and suitable access for large trucks) are scarce. As of mid-2024, reports indicated only a handful of public HRS in the U.S. were suitable for medium- or heavy-duty vehicles. Based on figures from 2024, at least 60 HRS were planned to support fleets of approximately 5,000 Class 6-8 trucks and 1,000 fuel cell electric buses in California. [24] However, achieving this build out may be challenging given recent funding cuts.

Cost competitiveness

Hydrogen FCEVs currently have a higher upfront purchase price than comparable diesel trucks and often BEVs. Furthermore, the cost of hydrogen fuel at the pump needs to decrease significantly to achieve parity with diesel. The Clean Air Task Force (CATF) suggests hydrogen needs to reach \$4-\$5/kg to be competitive if diesel is \$3-\$4 per gallon.[25]

Vehicle availability and OEM stability

While several manufacturers are developing and deploying FCEV trucks, the market has experienced recent turbulence. The bankruptcies of startups like Nikola, Hyzon Motors, and Quantron have created uncertainty and highlighted the financial and infrastructure-related challenges facing new entrants. These events underscore a potential market shakeout, where startups heavily reliant on venture capital struggle with high upfront costs and the slow pace of infrastructure development. In contrast, established OEMs like Toyota, Hyundai, Daimler Truck, and Volvo, with deeper financial resources and existing market presence, appear better positioned for the long-term development of hydrogen trucking, albeit proceeding with caution. Despite these setbacks, Class 8 FCEV deployments achieved a record 165 units in 2024. Nikola, for instance, was able to wholesale 200 hydrogen fuel cell trucks for the first three quarters of 2024, 88 of which were sold in Q3.[26]

Policy rollbacks

The California Air Resources Board rescinded its request for federal approval of its Advanced Clean Fleets regulation, which would have required additional zero-emission medium- and heavy-duty fleets.[27] This is due to significant legal challenges that occurred in 2025 as a result of federal regulatory shifts. The regulation still applies to various fleets in the states, such as municipal fleets.

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[24] "California's renewable hydrogen hub officially launches." Hydrogen Fuel Cell Partnership. https://h2fcp.org/content/californias-renewable-hydrogen-hub-officially-launches-0

[25] "Hydrogen Fuel Cells for Heavy-Duty Trucking." Clean Air Task Force. https://www.catf.us/resource/hydrogen-fuel-cells-heavy-duty-trucking/

[26] "Nikola Records Sales of 88 Hydrogen-Powered Class 8 Trucks for North American Customers in Q3 2024." Nikola Corporation. https://nikolamotor.com/nikola-records-sales-of-88-hydrogen-powered-class-8-trucks-for-north-american-customers-in-q3-2024-200-total-sold-this-year

[27] Parkes, Rachel. 2025. "Future of US hydrogen heavy-duty truck market in doubt as California abandons plans to phase out diesel models." Hydrogen Insight. https://www.hydrogeninsight.com/transport/future-of-us-hydrogen-heavy-duty-truck-market-in-doubt-as-california-abandons-plans-to-phase-out-diesel-models/2-1-1765658

Value-Chain Implications

Supporting a significant FCEV fleet requires a robust hydrogen value chain, encompassing:

- **Production:** Large-scale production of clean and renewable hydrogen.
- **Distribution:** Transporting hydrogen from production sites to refueling stations can involve pipelines (requiring new builds or extensive upgrades to existing fossil gas pipelines due to hydrogen's embrittlement potential), cryogenic liquid hydrogen tankers, or high-pressure gaseous tube trailers. The challenge of hydrogen distribution infrastructure is substantial, involving not just the number of stations but the fundamental logistics and cost of moving hydrogen, which is inherently more complex and potentially costlier than for gasoline or diesel.
- **Storage:** On-site storage at HRS, typically as high-pressure compressed gas or liquid hydrogen. The choice between centralized hydrogen production hubs with extensive distribution networks versus more decentralized, on-site production at refueling stations involves complex trade-offs in terms of capital cost, operational efficiency, and land use.

Table 1: Hydrogen in on-road heavy-duty transport: status, challenges, and key players in California

Aspect	Current Status (California Focus)	Key Challenges	Major OEMs/ Stakeholders Involved	Outlook
Vehicle Availability (HD FCEVs)	Limited but growing; pilot/demonstration fleets (e.g., port drayage, logistics). Some commercial offerings emerging.	High upfront vehicle cost, model availability, maintenance & repair network.	Toyota, Hyundai, Daimler Truck, Symbio, Volvo Trucks, PACCAR (Kenworth), Cummins (powertrains), New Flyer	Gradual increase in model availability expected. Legacy OEMs likely to lead. Market consolidation ongoing.
Fueling Infrastructure (HD HRS)	Severely limited; There are four public HD-capable stations (appears to be sufficient at this time to support the approx. 150 Class 8 FCETs currently on the road)	Slow rollout, high capital cost of HRS, siting & permitting, reliability of existing stations, "chicken-and-egg" problem with vehicle deployment.	FirstElement Fuel, Iwatani, Air Liquide, Shell, Chevron, utilities (e.g., SoCalGas).	Critical bottleneck. Success heavily dependent on coordinated public-private investment and streamlining of permitting. Corridor-based development likely.
Total Cost of Ownership (TCO) vs. Diesel/BEV	Currently higher than diesel and often BEVs. Hydrogen fuel cost is a major factor.	High cost of hydrogen fuel ($/kg), high vehicle purchase price, uncertain residual values, maintenance costs.	Vehicle manufacturers, fuel providers, fleet operators, government agencies (incentives).	TCO parity with diesel is a key target, requiring lower hydrogen fuel prices ($4-5/kg H_2) and vehicle costs. Policy incentives are crucial in the interim.

Aspect	Current Status (California Focus)	Key Challenges	Major OEMs/ Stakeholders Involved	Outlook
Key CA Deployments/ Projects	Port of LA/LB drayage truck projects (e.g., "Shore-to-Store"), Toyota NAPCC fleet, various transit agency bus deployments.	Scaling up from pilot phase to widespread commercial operation, ensuring project sustainability post-incentives.	CEC, CARB, SCAQMD, ports, private fleet operators, technology providers.	Learnings from current projects will inform future strategy. Focus on high-utilization, return-to-base fleets initially. Success of ARCHES projects will be pivotal.

Source: Guidehouse for CEC (2025)

Aviation

Hydrogen is being increasingly explored as a clean energy solution for the aviation industry, offering the potential to significantly reduce or eliminate carbon emissions from air travel. While direct usage remains largely untested, indirect usage has been commercially tested and verified as a near-future option. Direct usage of hydrogen can be differentiated by two forms: hydrogen combustion and hydrogen fuel cells. In combustion systems, hydrogen replaces conventional jet fuel and is burned in modified gas turbines to power aircraft engines. This method requires changes to the engine design to accommodate hydrogen's high flame temperature and different combustion characteristics. Additionally, the volumetric difference between hydrogen and jet fuel means that aircraft bodies may need redesign. Fuel cell systems use hydrogen to generate electricity through an electrochemical reaction, which then powers electric motors for propulsion. This approach produces only water vapor as a byproduct, making it a true zero-emissions solution.[28] These options are in the early development stages with few demonstrations and a long time until commercial deployment. Due to this, the near-term market will be using hydrogen as a feedstock for sustainable aviation fuel (SAF), a low-carbon alternative that can be used in existing aircraft engines without requiring modifications.

Key Applications

Hydrogen Combustion

Hydrogen combustion aircraft would need larger fuel tanks due to the differing properties between hydrogen and traditional jet fuel. While jet fuel tanks are smaller and able to fit inside the wings of an airplane, hydrogen's larger tanks would have to be placed in the main cabin of a traditional place, thereby taking up space that would normally be used for passengers and cargo.[29] In a shorter-range aircraft, less fuel is needed. This allows tanks to be placed above the passenger cabin. Energy usage for this type of aircraft is estimated to be roughly 18

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[28] Yusaf, Talal, Abu Shadate Faisal Mahamude, Kumaran Kadirgama, Devarajan Ramasamy, Kaniz Farhana, Hayder A. Dhahad, and ABD Rahim Abu Talib. 2024. *Sustainable hydrogen energy in aviation – A narrative review*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/pii/S0360319923009187

[29] Cecere, D., E. Giacomazzi, and A. Ingenito. 2014. *A review on hydrogen industrial aerospace applications*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/abs/pii/S0360319914011847

percent greater than a similar-sized kerosene-powered aircraft.[30] Long-range aircraft, on the other hand, require greater amounts of fuel, thus facilitating a need for larger tanks. These tanks can be placed either behind the cockpit or at the back of the plane and generally exhibit energy usage 12 percent lower than similar kerosene-fueled aircrafts.[31] Due to the precision and minimal range of a long-range aircraft's energy efficiency, leveraging hydrogen can be more beneficial in comparison to a shorter-range aircraft. In addition to fuel tank size, the fuselage of an aircraft must increase for a hydrogen powered aircraft. In fact, a fuselage mass must increase 6 percent to accommodate hydrogen's space demands.[32]

The modifications in the engine and aircraft design to fit these expanded system components of hydrogen, such as fuselage and tank size and placement, is estimated to increase production and maintenance costs by 25 percent.[33] Furthermore, the aircraft engines must be redesigned to address the significant changes in hydrogen's physical properties, such as high flame speed, large diffusivity, and wide range of flammability.

The complete mixture of hydrogen and air is also more difficult to achieve. Due to large diffusive scales and kinetics, high-temperature stoichiometric layers are formed in the combustion chamber, resulting in high NOx pollutant formation. Lowering flame temperature and the time the reactive mixture spends in the combustion chamber are key factors in reducing NOx emissions. Hydrogen’s wider flammability range is greater than that of kerosene. Thus, it is important to modify the fuel to air ratio towards leaner combustion when loading into the engine to prevent blowouts. Additionally, hydrogen's faster flame speed enables a smaller combustion chamber, which reduces the combustion process time and cooling requirements. This technology is in active development and testing.

Fuel cells

Hydrogen is combined with oxygen in an electrochemical reaction that produces electric current, with water as the only byproduct, powering motors to drive aircraft propellers. Fuel cell systems are also equipped with battery systems to handle peak power demands. Some challenges with this technology include the difficulty of storing liquid hydrogen (LH2) with its demanding temperature requirement, technical and operational aspects such as the lack of hydrogen refueling stations at airports and necessity for a larger than normal aircraft, stabilizing fuel cell operations in flight, and high development costs.

Sustainable Aviation Fuel (SAF)

Unlike hydrogen propulsion, SAF is used in existing aircraft engines and fueling infrastructure without requiring modifications. The two primary ways of producing SAF are through standalone methods and co-processing. Standalone units use only sustainable feedstocks to produce synthetic kerosene, which is then blended with conventional jet fuel. Co-processing facilities produce SAF by processing sustainable feedstocks (up to 5 percent) alongside fossil feedstocks, using hydro-processing in an existing refinery. The majority of SAF produced today is made via standalone methods.

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[30] Verstraete, D. 2015. *On the energy efficiency of hydrogen-fuelled transport aircraft*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/pii/S036031991500943X

[31] Ibid.

[32] Verstraete, Dries. 2013. *Long range transport aircraft using hydrogen fuel*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/abs/pii/S036031991302212X

[33] Verstraete, Dires. 2009. *The Potential for Liquid Hydrogen for long range aircraft propulsion*. Cranfield University. https://dspace.lib.cranfield.ac.uk/items/dc023873-db96-4dd6-882b-835ea7cbf3d0

Hydrogen is used in various ways to produce SAF; e.g., via syngas using CO derived from CO_2 (followed by Fischer-Tropsch synthesis), via an alcohol made from combining the hydrogen with CO_2, and for several purposes in the production of hydro-processed esters and fatty acids (HEFA). In all cases, synthetic liquid hydrocarbons are created that mimic the properties of conventional jet fuel. SAF can be blended with conventional fuel at different levels, with limits between 10 percent to 50 percent, depending on the feedstock. Some options for sustainable feedstock include non-petroleum-based renewable feedstocks, including woody biomass; fats, oil and greases (FOGs – oil seeds, industrial waste such as used oil and lard, and cyanobacteria); crop sugars; industrial waste streams (food waste and municipal solid waste); and renewable energy and carbon.

The HEFA pathway is the only commercial option with the ability to produce SAF at scale, however the feedstocks used are more limited than those of other pathways.[34] Production uses waste fats, oils, and greases, much of which can use standard refining unit-process equipment.[35]

Another SAF type is alcohol-to-jet (ATJ), in which an alcohol is converted via oligomerization to generate jet fuel. A disadvantage of this method is that it is not yet commercially ready on a national scale, although the first commercial-scale ATJ plant became operational in 2025 in Georgia, USA (LanzaJet's[36] Pines Fuels facility), the technology is still in the early stages of global deployment and remains characterized by high capital costs and a significant price premium compared to traditional jet fuel.

Gasification Fischer-Tropsch (GFT) converts municipal solid waste and other biomass residues into SAF through syngas processing. While Fischer-Tropsch processing is fully commercialized, its integration with gasification is still in early stages of development.

Toward the end of 2024, Phillips 66 and United Airlines signed an agreement, facilitating the movement of HEFA SAF produced by Phillips 66 to Chicago O'Hare International Airport (ORD) and Los Angeles Internal Airport (LAX); 3 million and 600,000 gallons of SAF were distributed to ORD and LAX in 2024, respectively.[37]

Additionally, Phillips 66's former San Francisco Refinery in Rodeo, California underwent a significant $850 million transformation the same year when the facility was converted to produce renewable fuels such as HEFA SAF.[38] While Phillips 66 has not publicly disclosed customer and airport destinations for the produced SAF, the facility is a likely hub for future considerations for SAF usage in California. Other facilities serving California for renewable fuels include the World Energy Refinery in Paramount, California.[39]

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[34] "Production Pathways and Feedstock." *2025 Global Sustainable Aviation Fuel Report*. Pan American Finance. https://panamericanfinance.com/insights/energy-transition/global-saf-report-2024/production-pathways-and-feedstock-saf24

[35] Calderon, Oscar Rosales, Ling Tao, Zia Abdullah, Michael Talmadge, Anelia Milbrandt, Sharon Smolinski, Kristi Moriarty, et al. 2024. *Sustainable Aviation Fuel State-of-Industry Report: Hydroprocessed Esters and Fatty Acids Pathway*. National Renewable Energy Laboratory. https://docs.nrel.gov/docs/fy24osti/87803.pdf

[36] "Freedom Pines Fuels." Lanzajet. https://www.lanzajet.com/freedom-pines

[37] Van Den Bergh, Yackjaira. 2024. "Phillips 66 and United Airlines sign SAF supply agreement." Phillips 66. https://www.phillips66.com/newsroom/phillips-66-united-airlines-saf-supply-agreement/

[38] "Renewable Fuels at San Francisco Refinery." Phillips 66. https://www.phillips66.com/refining/san-francisco-refinery/

[39] "U.S. sustainable aviation fuel production takes off as new capacity comes online." 2025. U.S. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=65204

Maritime

Maritime transport accounts for 2-3 percent of global greenhouse gas emissions, leading many shipping companies to explore ways to decarbonize their business.[40] The maritime industry is still in very early stages of adopting hydrogen powered vessels. Companies are taking different paths, as some invest in ammonia and methanol, while others directly pursue hydrogen as a fuel. As of now, hydrogen adoption for maritime vessels has mostly been accelerating in pilot projects for short distance shipping, but some large shipping companies are getting involved as well. Some companies are only pursuing ammonia or methanol to offer lower lifecycle emissions as opposed to hydrogen as a direct fuel.

Initial investment in hydrogen or hydrogen-derived fuels for maritime vessels has been increasing, but these vessels are not yet at scale. Many projects are only pilots, initial studies, or have very limited capabilities as of now. There are still many barriers to widescale maritime hydrogen adoption, and many chokepoints in the hydrogen supply chain to support this adoption.

Key Limitations

Regulatory and organizational support

One significant barrier to increased hydrogen maritime adoption is the lack of current regulation and guidelines from national and international organizations. Without certainty in ship rules and standards, it is difficult for companies to significantly invest in a hydrogen supply chain for ships. One promising regulation was established by FuelEU. Effective January 1, 2025, FuelEU set a limit on greenhouse gas intensity of energy used on ships. This should promote the switch to alternative fuels, but this regulation is not hydrogen specific. It only creates a regulatory incentive for hydrogen adoption to lower emissions. FuelEU regulations apply to all ships over 5,000 gross tonnage that call at European Union (EU ports, so this regulation would have the largest impact on shipping in and out of Europe.

Another large organization that would have a large impact on hydrogen adoption is the International Maritime Organization (IMO), which maintains a technology-neutral stance, encouraging the multiple pathways for reducing greenhouse gas emissions. IMO is targeting a 50 percent reduction in total GHG emissions from shipping by 2050, outlining a draft framework with adoption in 2025 that includes a marine fuel standard and a global maritime GHG emissions pricing mechanism, aiming to phase in low-GHG fuels and incentivize green technologies.41 This framework is still in the draft phase and lacks robust details about hydrogen-specific vessels. Lloyd's Register, a maritime classification society in the United Kingdom (UK) issued new classification rules in 2023 specifically for hydrogen as a marine fuel to fill a gap in the IMO, which did not fully cover hydrogen. Its rules outline safety risks, explosion risks, and design standards for hydrogen fuel systems,42 with a gross tonnage of

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[40] Furusaki, Takahiro, and Mette Asmussen. 2024. "The role of maritime fuel projects in decarbonizing shipping." *Climate Action and Waste Reduction*. World Economic Forum. https://www.weforum.org/stories/2024/04/why-reducing-barriers-for-maritime-fuel-projects-is-key-to-progressing-on-decarbonization/

[41] "IMO makes progress on net-zero framework for shipping." 2024. International Maritime Organization. https://www.imo.org/en/MediaCentre/PressBriefings/pages/MEPC-82-makes-progress-IMO-netzero-framework.aspx

[42] Blackmore, Liam. 2023. "LR issues world's first rules for hydrogen fuel." Lloyd's Register. https://www.lr.org/en/knowledge/horizons/june-2023/lr-issues-worlds-first-rules-for-hydrogen-fuel/

500 and above on international voyages and to their 175 member states, so creating standards for hydrogen vessels would be a crucial step in the worldwide scalability of these vessels. There have also been statements of support from other organizations such as leading maritime organizations signing the Joint Statement on Green Hydrogen and Shipping, committing to adoption of hydrogen-based fuels to achieve zero emissions by 2050.43 A direction amenable for maritime hydrogen adoption specifically, there is very little on-the-books regulation that would incentivize ship builders to invest in hydrogen vessels. Many regulations and standards are around lowering emissions, but there are no specific, robust details in the adoption of hydrogen for that purpose.

Cost and Logistics of Infrastructure

In addition to the lack of regulatory guidelines, another key challenge is the cost and logistics of shifting key infrastructure to handle alternative fuels like hydrogen and ammonia. Using alternative fuels is more expensive and capital investment will be needed for wide-scale adoption.44 Hydrogen also has a high production cost and can struggle to compete economically with ammonia or methanol. Converting existing vessels to hydrogen-powered also requires significant capital investment. Using hydrogen aboard a ship has many engineering and design implications, as hydrogen requires energy-intensive compression for storage in vessels. Maritime engineers must consider the specific safety measures for hydrogen use on ships considering hydrogen’s properties such as high flame speed, wide explosion limits, invisible flame, and high gas diffusivity.45 Many ships using hydrogen are still in early pilot stages or have limited deployment, so there is not widespread adoption of a technology optimized for long distance shipping. In addition to the engineering specifications for the vessels themselves, there is also a lack of hydrogen-specific refueling stations at ports. Shifting ports to accommodate hydrogen-powered vessels is a financial and logistics investment, and ports have not been retrofitted to store large quantities of hydrogen. There is a lack of unified, international standards around both ship design and port requirements, leading to uncertainty when commissioning a new vessel.

Value-Chain Implications

Although most ports cannot support hydrogen-powered ships yet, there are a few first-mover ports around the world that are implementing hydrogen technologies. In July 2025, the Kandla port in India will become the country’s first port to have a green hydrogen plant powered by electrolyzers. The plant is starting with a 1 MW electrolyzer producing 18 kg of green hydrogen per hour and will eventually scale up to 10 MW, hydrogen will be used in fuel cells to power ships in the port. The port authority also plans on integrating green ammonia production in the future.[46] Other ports across Europe are investing in hydrogen refueling

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43 El-Sheikh, Sharm. 2022. “Maritime Sector and Green Hydrogen Leaders Agree on Ambitious Targets and Collaboration to Reach Zero-Emissions Global Shipping by 2050.” Rocky Mountain Institute. https://rmi.org/press-release/maritime-sector-green-hydrogen-leaders-agree-on-collaboration-to-reach-zero-emissions-global-shipping-by-2050/

44 “Maritime Industry Advances in Alternative Fuels Amid 2025 Regulatory Shifts.” 2025. Ship Universe. https://www.shipuniverse.com/news/maritime-industry-advances-in-alternative-fuels-amid-2025-regulatory-shifts/

45 Dasgupta, Priyanka. 2025. “Hydrogen ambitions for shipping.” *e-Tech*. International Electrotechnical Commission. https://etech.iec.ch/issue/2025-02/hydrogen-ambitions-for-shipping

46 Mishra, Twesh. 2025. “Kandla Port to start green hydrogen manufacturing in June 2025.” The Economic Times. https://economictimes.indiatimes.com/industry/renewables/kandla-port-to-start-green-hydrogen-manufacturing-in-june-2025/articleshow/119160785.cms

infrastructure to integrate hydrogen into maritime port logistics.[47] The Hydrogen Generator Pilot was just launched in May 2025 in Sweden which will use a hydrogen-powered generator to supply electricity to ships docked at the Stena Line terminal.[48] Another port leading the way with supporting the maritime hydrogen supply chain is the Port of Rotterdam in the Netherlands. This port has a 200 MW green hydrogen plant and a second 200 MW electrolyzer under construction now to support hydrogen usage. The port also has a hydrogen pipeline network through the construction of the national hydrogen network spearheaded from the port itself.[49] A few select ports are slowly adopting hydrogen technology to support the new vessels, but the scale remains low. For worldwide hydrogen vessels, a significant buildout of hydrogen support technology will be required at most ports, and the shift is still in very early stages.

Another barrier is that the cost and value chain implications for maritime adoption are still widely undefined, little information is publicly available about the costs to build out a hydrogen-ship and convert a port to support hydrogen vessels. A DNV whitepaper[50] focusing on ammonia and hydrogen as ship fuels does not provide cost estimates of hydrogen vessels. The paper emphasizes that there are still many challenges to scale hydrogen or hydrogen-derived fuels. There must be more robust safety standards and training programs, new technical competencies for people working on the vessels, cooperation across the value chain, and early engagement with flag states and classification societies. It suggests that hydrogen and ammonia powered ships are still in a demonstration phase and that commercial adoption likely won't be adopted until 2030-2040.

Rail

Hydrogen is being explored as an alternative fuel for replacing diesel and reducing emissions from rail transportation. In recent years, several milestones have been achieved in California advancing the use of hydrogen fuel cell technology for both passenger and freight rail applications. In September 2025, San Bernardino County Transportation Authority (SBCTA) began operating a hybrid hydrogen fuel cell-battery electric zero-emission multiple unit (ZEMU).[51] The ZEMU is a first-of-its-kind hydrogen fuel cell passenger train that meets Federal Railroad Administration requirements for operation in North America. The ZEMU will serve riders on the nine-mile Arrow Corridor of Metrolink's San Bernardino Line. Building on SBCTA's ZEMU project, Caltrans plans to procure additional zero-emission hydrogen-powered trainsets for intercity and regional services.[52] Also in September 2025, Sierra Northern Railway unveiled

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[47] "Hydrogen." Ports Europe. https://www.portseurope.com/category/subject/renewable-energy/hydrogen/

[48] "Hydrogen powers ships with electricity in pilot test at the Port of Gothenburg." 2025. Hellenic Shipping News Worldwide. https://www.hellenicshippingnews.com/hydrogen-powers-ships-with-electricity-in-pilot-test-at-the-port-of-gothenburg/

[49] "Port of Rotterdam: The hydrogen system is taking shape." 2025. Hellenic Shipping News Worldwide. https://www.hellenicshippingnews.com/port-of-rotterdam-the-hydrogen-system-is-taking-shape/

[50] "Safe Introduction of Alternative Fuels: Focus on Ammonia and Hydrogen as Ship Fuels." *Maritime*. Det Norske Veritas group. https://www.dnv.com/maritime/publications/safe-introduction-of-alternative-fuels-focus-on-ammonia-and-hydrogen-as-ship-fuels-download/

[51] "North America's First Hydrogen-Powered ZEMU Passenger Train to Enter Service Sept. 13 in San Bernardino." 2025. San Bernadino County Transportation Authority. https://www.gosbcta.com/north-americas-first-hydrogen-powered-zemu-passenger-train-to-enter-service-sept-13-in-san-bernardino/

[52] "California Continues to Expand Hydrogen-Powered Passenger Rail Fleet." 2024. Caltrans. https://dot.ca.gov/news-releases/news-release-2024-007

a hydrogen fuel cell powered switcher locomotive in West Sacramento that will be demonstrated in a freight rail application.[53] Sierra Northern Railway plans to build on this initial pilot by constructing three additional hydrogen locomotives with support from the California State Transportation Agency's Port and Freight Infrastructure Program.[54]

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[53] Cortez, Denzen. 2025. "Nation's first hydrogen-fueled train unveiled in West Sacramento." KCRA 3. https://www.kcra.com/article/hydrogen-fueled-train-unveiled-west-sacramento/65986830

[54] "Port and Freight Infrastructure Program Selected Projects – Project Detail Summary." 2023. California State Transportation Agency. https://calsta.ca.gov/-/media/calsta-media/documents/pfip-awards-summary-narrative-7-6-23-a11y.pdf

Chapter 3:
Trends and Developments Shaping Clean Hydrogen in California

Key Takeaways

This chapter summarizes the national and international trends shaping clean hydrogen development.

- While clean hydrogen currently represents a small portion of 2023 supply, production is anticipated to accelerate in the latter half of the decade.
- Federal hydrogen policy has created uncertainty that has affected California projects and developers.

Global Hydrogen Market

According to the International Energy Agency (IEA), global hydrogen demand reached 97 million tonnes (MMt) in 2023, an increase of 2.5 percent compared with 2022.[55] Low-emissions hydrogen[56], including hydrogen produced using methane reformation with carbon capture, saw production of less than 1 MMt in 2023. However, low-emissions hydrogen production could reach 49 MMt/yr by 2030 based on announced projects, almost 30 percent more than forecasted the previous year by the IEA. This strong growth has been mostly driven by electrolysis projects.

By the end of 2023, global water electrolyzer capacity reached 1.4 GW, with projections suggesting an increase to 5 GW by the end of 2024. China is the primary driver of this growth, potentially hosting 70 percent of all capacity by year-end 2024. While the total pipeline of announced projects aims for 520 GW by 2030, only 4% is currently under construction or has secured a final investment decision (FID). In contrast, fossil-based hydrogen production with carbon capture shows a higher realization rate, with 14% of planned capacity reaching the FID stage following a recent acceleration in project approvals.[57]

International Policy Developments and Collaborations

Countries experiencing the fastest growth in hydrogen production include Germany, Australia, South Korea, and Morocco. Germany has quickly established itself as a global leader in this field by implementing a clear national strategy that incorporates policy incentives, significant infrastructure investments, and collaboration on an international level.[58] California has numerous bilateral and multilateral agreements with national and subnational entities to

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[55] *IEA Global Hydrogen Review 2024*. 2024. International Energy Agency. https://www.iea.org/reports/global-hydrogen-review-2024

[56] *The IEA defines emissions, in reference to hydrogen production routes, based on emissions intensity*. 2023. International Energy Agency. https://www.iea.org/reports/towards-hydrogen-definitions-based-on-their-emissions-intensity

[57] "Hydrogen production." *Global Hydrogen Review 2024*. 2024. International Energy Agency. https://www.iea.org/reports/global-hydrogen-review-2024/hydrogen-production

[58] "The Countries That Lead the Hydrogen Economy." 2025. HydroLite. https://www.hydrolite-h2.com/the-countries-that-lead-the-hydrogen-economy/

strengthen the global response to climate change, including through collaboration on hydrogen.[59] Hydrogen notably features in agreements with Australia, Canada, Denmark, and Mexico. In the case of Denmark, there's common interest in the development of offshore wind and harnessing that energy resource for clean hydrogen production as part of its "power-to-x" strategy.[60] Denmark is also committed to the development of a hydrogen pipeline with scheduled completion in 2031, after considering technical complexities and regulatory developments.[61] Continued international collaboration and associated information exchanges may provide insights to accelerate the adoption of low carbon hydrogen in California.

Federal Programs and Market Uncertainties

The federal US 2021 Infrastructure Investment and Jobs Act (IIJA) allocated $8 billion dollars for the development of regional clean hydrogen hubs as part of the Regional Clean Hydrogen Hubs Program.[62] The Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) is a public-private partnership awarded up to $1.2 billion[63] from the US Department of Energy to implement a California clean hydrogen hub to accelerate the adoption and production of clean hydrogen technology in the state. However, due to the federal cuts, ARCHES currently has paused full operation and the Governor's Office of Business and Economic Development (GO-Biz) and the University of California have assumed administrative oversight.

Hydrogen Production Tax Credit

Another near-term challenge to building out the market for clean and renewable hydrogen in California is the reduction in available tax credits. In the US, the federal Inflation Reduction Act (IRA) created the Clean Hydrogen Production Tax Credit (PTC) in Section 45V of the Internal Revenue Code, providing qualifying projects with a 10-year incentive for clean hydrogen of up to $3.00/kilogram. Final rules were released in January 2025. For qualifying clean hydrogen plants that commence construction before January 1, 2028, the credit provides four tiers of incentive, between $0.60 and $3.00 per kg of hydrogen produced, depending on the carbon intensity of the hydrogen production process for the first 10 years of a plant's operation. The credit value also depends on whether the project meets prevailing wage and apprenticeship requirements. Emissions are considered through the point of production using the US Department of Energy's 45VH2-GREET model.

The eligible pathways are electrolysis using renewable or grid electricity, SMR with CCS, hydrogen produced from biomethane, and hydrogen produced from waste methane sources. In all cases, the lifecycle emissions must be lower than 4.00 CO_{2e}/kg H_2 using the 45VH2-GREET model. Electrolytic hydrogen may be eligible for the PTC if the lifecycle greenhouse gas

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[59] "Climate Change Partnerships." California Energy Commission. https://www.energy.ca.gov/about/international-cooperation/climate-change-partnerships

[60] *Memorandum of Understanding Between the Danish Energy Agency of the Kingdom of Denmark and the California Energy Commission and California Public Utilities Commission of the State of California of the United States of America*. California Energy Commission. https://www.energy.ca.gov/sites/default/files/2024-09/MOU_DEA_and_CEC_adding_CPUC_ada.pdf

[61] "Denmark's Hydrogen Backbone: Driving Green Energy Transition and Cross-Border Collaboration." 2024. Ministry of Foreign Affairs of Denmark. https://investindk.com/insights/driving-green-energy-transition

[62] "Regional Clean Hydrogen Hubs." US Department of Energy. https://www.energy.gov/oced/regional-clean-hydrogen-hubs-0

[63] "California launches world-leading Hydrogen Hub." 2024. California Governor Newsom's Office. https://www.gov.ca.gov/2024/07/17/california-launches-world-leading-hydrogen-hub/

(GHG) emissions of the electricity used to produce hydrogen, which must be attributed to a specific generator, are sufficiently low. The electricity generation must also meet the three pillars – incrementality, deliverability, and time-matching. Hydrogen produced from SMR with CCS can qualify if a sufficient percentage of carbon dioxide is captured to lower emissions. Hydrogen from biomethane, whether via SMR, gasification, or pyrolysis, is eligible if the biomethane is sourced from landfills, animal manure, wastewater, food waste, or agricultural residues.[64]

Implications for California Analysis

In July 2025, the U.S. Senate approved the budget reconciliation legislation package known as the One Big Beautiful Bill Act (OBBBA) that shortened the end of the construction-commencement eligibility window for the 45V credit from December 31, 2032, to December 31, 2027.[65] Facilities commencing construction after December 31, 2027, are no longer eligible for the credit. This change has affected planning for several large-scale hydrogen projects in California. Given the uncertainty around the credit's duration and implementation, this report acknowledges potential use of the 45V tax credit but does not conduct a full pathway-by-pathway eligibility analysis.

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[64] "E3 Technology Brief 2." 2024.

[65] "2028 Deadline for 45V Hydrogen Tax Credit Approved." 2025. Fuel Cells Works. https://fuelcellsworks.com/2025/07/02/clean-hydrogen/senate-greenlights-2028-deadline-for-45v-hydrogen-tax-credit-as-beautiful-bill-inches-forward

Chapter 4:
Hydrogen Production Pathways

Key Takeaways

This chapter summarizes the characteristics and challenges for current hydrogen production pathways.

- The challenges associated with hydrogen production are not uniform across pathways.
- Although all pathways face cross-cutting barriers such as cost competitiveness, infrastructure needs, and regulatory uncertainty, each also has pathway-specific constraints that affect scalability, emissions performance, and commercial viability.
- As a result, the role of hydrogen in decarbonization will depend not only on expanding production, but on addressing the technical, economic, and policy barriers specific to each pathway.

Chapter Overview

This section examines a range of production technologies, including PEM and Alkaline Electrolysis, Steam Methane Reforming with and without carbon capture, Biomass Gasification, Methane Pyrolysis, and extraction from geological formations. and discusses their technical characteristics, costs, feedstock requirements, and deployment considerations. The pathways described represent analytical options rather than projections or policy preferences, and no single pathway is assumed to dominate future hydrogen production. This section provides technical context for the scenario-based analyses presented in subsequent chapters and highlights key constraints and uncertainties relevant to planning for clean hydrogen development in California.

PEM and Alkaline Electrolysis

Electrolysis, which uses renewable electricity to split water and produce hydrogen and oxygen, accounts for roughly 4 percent of hydrogen produced today.[66] There are two primary electrolyzer types that comprise a large share of the electrolysis hydrogen in California: alkaline and Proton Exchange Membrane (PEM). Both types of electrolyzers are mature, with a technology readiness level (TRL) of 9, and have efficiencies in the range of about 70-80 percent (based on the HHV of hydrogen).

Alkaline electrolyzers, which use an alkaline electrolyte solution, are the most mature electrolyzer technology available today.[67] Alkaline electrolyzers are produced from low-cost materials and have an established manufacturing process, given their maturity and existing deployment. There currently exist alkaline electrolyzer systems that are larger than 100 MW_e.[68]

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[66] "E3 Technology Brief: Task 2." 2024.

[67] "PEM Electrolysers vs. Alkaline Electrolysers." Stargate Hydrogen. https://stargatehydrogen.com/blog/pem-electrolysers/

[68] Hubert, McKenzie, Anne Marie Esposito, David Peterson, Eric Miller, and Joseph Stanford. 2024. *Hydrogen Shot: Water Electrolysis Technology Assessment*. U.S. Department of Energy. https://www.energy.gov/sites/default/files/2024-12/hydrogen-shot-water-electrolysis-technology-assessment.pdf

PEM electrolyzers, which are a newer technology, use a solid polymer electrolyte to facilitate hydrogen production and are more costly than alkaline.[69] They generally can more easily adapt their operating conditions to variable electrical input than alkaline systems. PEM electrolyzer systems are usually found in the size range of 10-100 MW_e[70] and are well suited to supporting intermittent power sources such as solar and wind.[71] PEM electrolyzers are more operationally flexible with faster response to power fluctuations than alkaline electrolyzers. While alkaline electrolyzers have slower response times, the technology is improving in their ability to handle variable loads but lag behind in total dynamic range than PEM electrolyzers. PEM electrolyzers generally have higher efficiency than alkaline electrolyzers and produce high-purity hydrogen at higher output pressures, so there are clear advantages of using PEM electrolyzers; however, alkaline electrolyzers are characterized by their lower costs and longer lifespans (20 – 30 years).

Electrolysis is an energy intensive (about 49-56 kWh/kg H_2) and expensive technology, but improvements in technology could lead to higher efficiencies and lower costs.[72] A critical factor in reducing the levelized cost of hydrogen (LCOH) from electrolyzers will be reducing the price of input electricity, which can account for about 65-85+ percent of LCOH. DOE has estimated the LCOH of hydrogen produced by a PEM electrolyzer to be \$6.00 - \$6.20/kg H_2, versus \$5.00 - \$5.50/kg H_2 for alkaline electrolyzers, assuming grid electricity use.[73] The capital cost (CAPEX) of PEM electrolyzers is expected to become more comparable to that of alkaline units in the future, as economies of manufacturing scale are achieved[74] and a larger workforce of installers and technicians gets developed. Electrolyzers produced in Asia are significantly cheaper than those produced in the Unites States and European Union. This may provide a more cost-effective alternative for hydrogen production in the near-term, while domestic production scales, but some developers have technical and safety concerns. Electrolyzers at Sinopec's Kuqa facility in China, for example, have exhibited a limited operating range due to safety issues.[75]

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69 "PEM Electrolysers vs. Alkaline Electrolysers." Stargate Hydrogen. https://stargatehydrogen.com/blog/pem-electrolysers/

70 Electrolyzer size can be expressed as an amount of hydrogen that can be produced per day (nominally), but it is most common to specify the size of the electrolyzer by the maximum input electric power it can use, typically in kWe or MWe.

71 Hubert, McKenzie, Anne Marie Esposito, David Peterson, Eric Miller, and Joseph Stanford. 2024. *Hydrogen Shot: Water Electrolysis Technology Assessment*. U.S. Department of Energy. https://www.energy.gov/sites/default/files/2024-12/hydrogen-shot-water-electrolysis-technology-assessment.pdf

72 "E3 Technology Brief: Task 2." 2024.

73 Hubert, McKenzie, Anne Marie Esposito, David Peterson, Eric Miller, and Joseph Stanford. 2024. *Hydrogen Shot: Water Electrolysis Technology Assessment*. U.S. Department of Energy. https://www.energy.gov/sites/default/files/2024-12/hydrogen-shot-water-electrolysis-technology-assessment.pdf

74 "E3 Technology Brief: Task 2." 2024.

75 Collins, Leigh. 2023. "World's largest green hydrogen project 'has major problems due to its Chinese electrolysers': BNEF." Hydrogen Insight. https://www.hydrogeninsight.com/production/exclusive-worlds-largest-green-hydrogen-project-has-major-problems-due-to-its-chinese-electrolysers-bnef/2-1-1566679;

Yin, Ivy. 2025. "China's hydrogen electrolyzer industry facing technology, cost challenges." S&P Global. https://www.spglobal.com/commodity-insights/en/news-research/latest-news/energy-transition/021925-chinas-hydrogen-electrolyzer-industry-facing-technology-cost-challenges;

Steam Methane Reforming (SMR)

There are multiple ways to generate hydrogen from hydrocarbons, such as fossil gas and renewable natural gas. In this report, hydrocarbon reforming refers to: (1) steam methane reforming (SMR), which is the reaction of methane or fossil gas with steam to produce hydrogen and carbon dioxide (CO_2) and (2) autothermal reforming (ATR), where some of the steam is replaced by oxygen.[76] Other types of hydrocarbon reforming, such as Partial Oxidation, Catalytic Partial Oxidation, and Dry Reforming exist, but they have non-methane feedstock or require other inputs such as CO_2. This report only addresses SMR because ATR is just now beginning to be deployed commercially.

Steam for Steam Methane Reforming (SMR) is generated by burning fuel (typically fossil gas) in a boiler or capturing waste heat in a heat recovery steam generator (HRSG) to produce steam in the range of 700-1000°C. The reforming process produces CO_2 as a byproduct in two ways: as part of the process stream for creating hydrogen and from the combustion used to heat the process (including any combustion needed for generating steam). Capturing CO_2 from the process stream nets about 55-65 percent of the total CO_2 generated by the plant, but it is the easiest carbon to remove, technically and economically. Carbon capture projects that announce 90 percent or more capture are also removing the CO_2 from the combustion stream, which roughly doubles the cost of the project.[77] This analysis only considers carbon capture and storage (CCS, Capturing CO2 and storing it underground), for SMR using fossil gas feedstock.

SMR creates hydrogen through a high-temperature reaction that produces syngas, which is a mixture composed primarily of hydrogen and carbon monoxide (CO). Additional hydrogen is then produced from reaction of the CO with water. The hydrogen can be used for many applications, including for electricity production and as a transportation fuel.[78] However, in the conversion of syngas to produce hydrogen, trace amounts of CO remain. Thus, for transportation and electric power applications involving CO-sensitive[79] fuel cells (e.g., PEM fuel cells[80]), additional treatment is needed to lower that CO level to parts per billion. Technologies such as preferential oxidation (PrOx), selective methanation (reacting CO into methane), and

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Heyward, Hack. 2022. "Beijing hydrogen body admits that Chinese electrolysers cannot compete with Western machines — yet." Recharge. https://www.rechargenews.com/energy-transition/exclusive-beijing-hydrogen-body-admits-that-chinese-electrolysers-cannot-compete-with-western-machines-yet/2-1-1202835

[76] Despite its name, steam reforming can also be used with other hydrocarbons beside methane, but that use is not common in the U.S.

[77] Collodi, Guido, Giuliana Azzaro, and Noemi Ferrari. 2017. *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant With CCS*. International Energy Agency, GHG Technology Collaboration Programme. https://ieaghg.org/publications/techno-economic-evaluation-of-smr-based-standalone-merchant-hydrogen-plant-with-ccs/

[78] McNaul, Shannon, Charles White, Robert Wallace, Travis Warner, H. Scott Matthews, Jinliang Ma, Massood Ramezan, et al. 2023. *Hydrogen Shot Technology Assessment: Thermal Conversion Approaches*. National Energy Technology Laboratory. https://web.archive.org/web/20240328004116/https:/www.netl.doe.gov/projects/files/HydrogenShotTechnologyAssessmentThermalConversionApproachesRevised_120523.pdf

[79] CO-sensitive fuel cells, such as the Proton Exchange Membrane (PEM) fuel cell, are those in which even trace amounts of carbon monoxide (CO) in the hydrogen fuel significantly degrade the cell's performance and durability.

[80] High-temperature fuel cells, such as the solid oxide type, are not sensitive to the presence of CO.

membrane separation can be used to achieve this reduction in CO.[81]

SMR using fossil gas

SMR with fossil gas feedstock is highly mature (TRL 9) and the most common domestic pathway for hydrogen production today, accounting for 95 percent of production in the US.**[82,83]** CCS is uncommon at SMR plants at this time.[84,85] Several companies have retrofitted, are planning to retrofit, or are building greenfield SMR plants with carbon capture, such as Linde and Air Products in the US,[86] though historically some carbon capture projects have not removed as much carbon as planned.[87] In addition to on-site CO_2 removal, ensuring that upstream fossil gas leakage rates are as low as possible (ideally well below 1 percent) is critical in achieving a satisfactory overall carbon intensity for the hydrogen production.[88]

SMR Using RNG as a feedstock

Renewable natural gas (RNG) is another potential feedstock for steam methane reformers (SMRs). Unlike fossil natural gas, RNG is produced from biogenic sources and upgraded for use as a gaseous fuel. Depending on the source and level of treatment, RNG can be used in existing gas systems and may provide a lower-carbon alternative feedstock for hydrogen production.

RNG is produced when organic wastes decompose under anaerobic conditions to create biogas, which is then upgraded by removing CO2, moisture, and contaminants to increase methane content to pipeline-quality levels. Major RNG sources include landfill gas, wastewater

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[81] Sun, Mingjia, Liqiang Duan, Yufei Zhou, Hanfei Zhang, Licheng Huang, and Nan Zheng. 2025. *Study on a novel hydrogen purification approach base on methane steam reforming process with CO-preferential oxidation and CO2 removal*. Journal of Applied Energy. https://www.sciencedirect.com/science/article/abs/pii/S030626192402110X

[82] "Hydrogen Production: Natural Gas Reforming." U.S. Department of Energy. https://www.energy.gov/eere/fuelcells/hydrogen-production-natural-gas-reforming

[83] "E3 Technology Brief: Task 2." 2024.

[84] Liundgren, Joakim, Berend Vreugdenhil, Yadi Ganjkhanlou, and Robert Baldwin. 2025. *Biomass gasification for hydrogen production*. International Energy Agency, Bioenergy Technology Collaboration Programme. https://www.ieabioenergy.com/wp-content/uploads/2025/03/IEA-Bioenergy_T33_Bio-H2_Final_v2.pdf

[85] "Hydrogen Projects in the US." Clean Energy Group. https://www.cleanegroup.org/initiatives/hydrogen/projects-in-the-us/

[86] "Linde Starts up Supply of Clean Hydrogen and Captured Carbon Dioxide to Celanese." 2024. Linde. https://www.linde.com/news-and-media/2024/linde-starts-up-supply-of-clean-hydrogen-and-captured-carbon-dioxide-to-celanese;

"Port Arthur Fact Sheet: Carbon Capture and Storage Project." Massachusetts Institute of Technology, Carbon Capture and Sequestration Technologies. https://sequestration.mit.edu/tools/projects/port_arthur.html

[87] Juhn, Anika, and David Schlissel. 2025. *Blue Hydrogen's Carbon Capture Boondoggle.* Institute for Energy Economics and Financial Analysis. https://ieefa.org/sites/default/files/2025-03/Blue%20Hydrogen%E2%80%99s%20Carbon%20Capture%20Boondoggle_March%202025.pdf;

McNaul, Shannon, Charles White, Robert Wallace, Travis Warner, H. Scott Matthews, Jinliang Ma, Massood Ramezan, et al. 2023. *Hydrogen Shot Technology Assessment: Thermal Conversion Approaches*. National Energy Technology Laboratory. https://web.archive.org/web/20240328004116/https:/www.netl.doe.gov/projects/files/HydrogenShotTechnologyAssessmentThermalConversionApproachesRevised_120523.pdf

[88] Guidehouse analysis using Argonne National Laboratories' 45VH2-GREET greenhouse gas emissions tool.

treatment plant digesters, dairy and other manure digesters, and anaerobic digestion systems processing food waste and other organic wastes.

The use of RNG in SMRs does present some complications that are important to recognize:

- **Composition variations:** The composition of RNG will vary from source to source; it can also vary over time (e.g., biogas output from a wastewater treatment plant). Industrial processes such as SMRs operate best when the properties of their inputs are kept within a defined range, so feedstock mixes and temporal variations of feedstock properties will need to be properly controlled.
- **Level of CO_2:** An important factor in the acceptability of a biogas-derived feedstock for SMR is the level of CO_2 removal to create RNG. Many biogases are quite high in CO_2 and, if reformed without CO_2 removal, are most suitable for a technology called carbon dioxide reforming or dry reforming.[89] SMR inputs are generally assumed to have CO_2 levels of one or two percent, but pipeline concentrations can be as high as three percent.[90] Note that the dry reforming process converts the methane and CO_2 to an H_2 and CO syngas that is primarily useful for synthesizing hydrocarbon molecules, which is valuable for e-fuels and clean "petrochemicals" production, but it has difficulties that have kept it from commercialization.[91,92]
- **Contaminants:** Also of note is the presence of contaminants in many RNG streams that are not present in fossil gas, such as siloxane, and can cause issues with the catalysts used in steam reforming.[93] SMR plants typically pretreat their gas streams to remove catalyst-damaging components such as sulfur compounds and hydrocarbons,[94] so the key point is to ensure that these pretreatment systems can handle what is in the

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[89] Chiodo, V., S. Maisano, G. Zafarana, and F. Urbani. *Effect of pollutants on biogas steam reforming*. Institute CNR-ITAE. https://publications.cnr.it/api/v1/documents/download/186145

[90] Lewis, Eric, Shannon McNaul, Matthiew Jamieson, Megan S. Henriksen, H. Scott Matthews, John White, Liam Wash, et al. 2022. *Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies*. National Energy Technology Laboratory. https://netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf;

Collodi, Guido, Giuliana Azzaro, and Noemi Ferrari. 2017. *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant With CCS*. International Energy Agency, GHG Technology Collaboration Programme. https://ieaghg.org/publications/techno-economic-evaluation-of-smr-based-standalone-merchant-hydrogen-plant-with-ccs/;

"Natural Gas Composition and Specifications." Pennsylvania State University. https://www.e-education.psu.edu/fsc432/content/natural-gas-composition-and-specifications

[91] "Carbon dioxide reforming." Wikipedia. https://en.wikipedia.org/wiki/Carbon_dioxide_reforming

[92] Nguyen, Dang Le Tri, Anh Vy Tran, Dai-Viet N. Vo, Ha Tran Nguyen, Natarajan Rajamohan, Thanh H. Trinh, Tuan Loi Nguyen, Quyet V. Le, and Tung M. Nguyen. 2024. *Methane dry reforming: A catalyst challenge awaits*. Journal of Industrial and Engineering Chemistry. https://www.sciencedirect.com/science/article/abs/pii/S1226086X24004052

[93] Chiodo, V., S. Maisano, G. Zafarana, and F. Urbani. *Effect of pollutants on biogas steam reforming*. Institute CNR-ITAE. https://publications.cnr.it/api/v1/documents/download/186145

[94] "Steam Methane Reformer: The Heart of Hydrogen Production." Samuel Engineering. https://www.samuelengineering.com/2024/05/14/steam-methane-reformers/

various RNG streams as well. Some RNG producers might remove siloxanes themselves to meet specifications of other customers.[95]

- **Methane content:** Raw biogas *per se* does not generally have a high methane content compared to fossil gas, and what are considered primary and secondary treatment stages to produce RNG result in a product that still does not meet the hydrocarbon energy content level of fossil gas. Thus, conversion of the hydrocarbon from a given volume of this type of RNG will not produce as much hydrogen as the same volume of fossil gas would. RNG producers need to perform an advanced treatment stage to generate a gas that replaces the energy content of fossil gas.[96]
- **Plant scale:** The individual sources of RNG considered here have relatively small production capacities, even in comparison with biomass sources. Landfills have the largest potential capacity of RNG among the four types considered here: the largest landfill in California has the potential to produce more than 20 times the gas output of recently announced very large manure-to-RNG facility in South Dakota, illustrating the scale advantage of landfill-based RNG.[97] That said, Figure 2 shows the level of hydrogen production capacity that Guidehouse estimates for California landfills, using EPA data on landfill gas flow rates.[98]

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95 Nyamukamba, Pardon, Patrick Mukumba, Evernice Shelter Chikukwa, and Golden Makaka. 2020. *Biogas Upgrading Approaches with Special Focus on Siloxane Removal–A Review*. Energies. https://www.mdpi.com/1996-1073/13/22/6088;

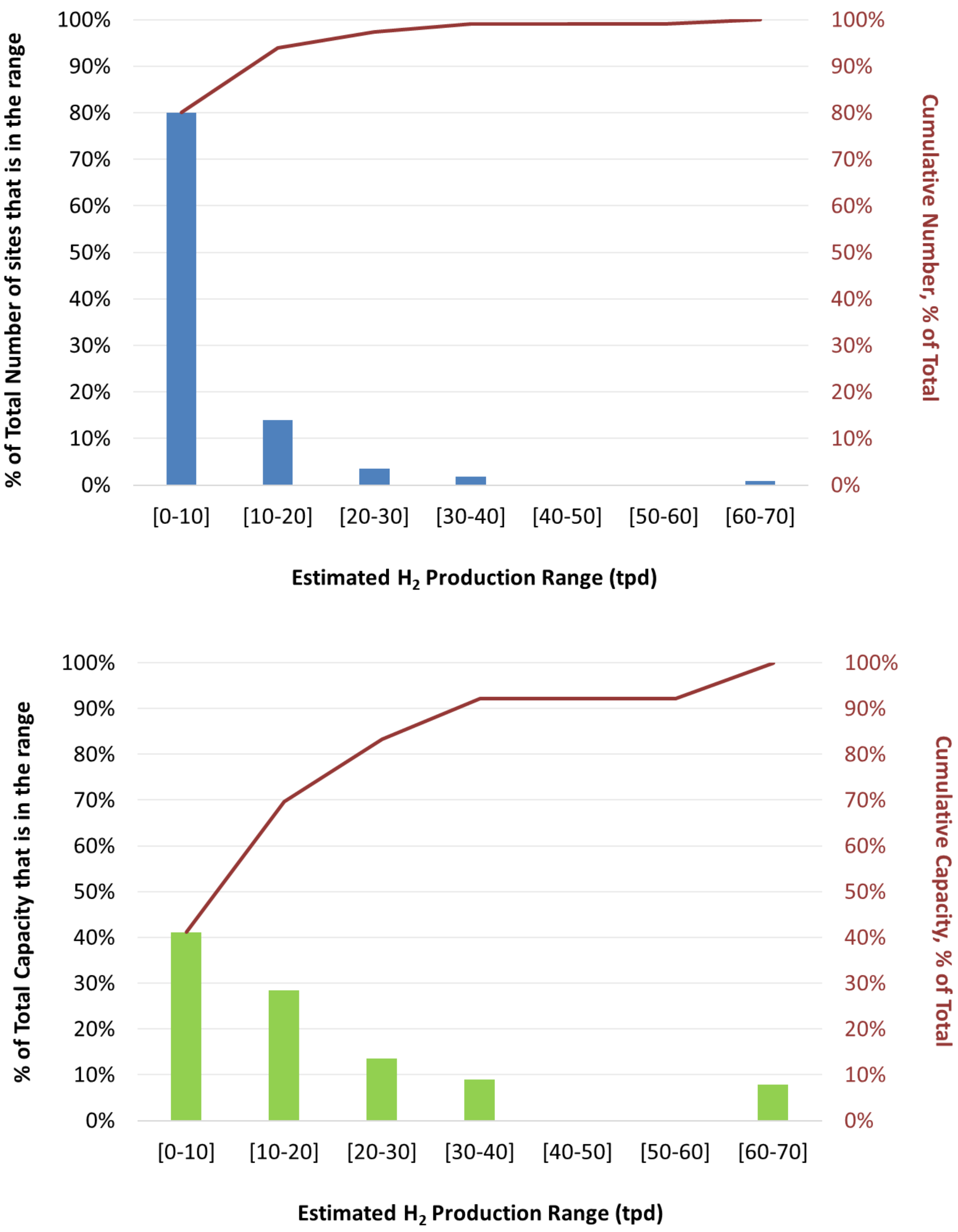
Amaraibi, Rarosue J., Babu Joseph, and John N. Kuhn. 2022. *Techno-economic and sustainability analysis of siloxane removal from landfill gas used for electricity generation*. Journal of Environmental Management. https://www.sciencedirect.com/science/article/abs/pii/S0301479722006430

96 *An Overview of Renewable Natural Gas from* Biogas. 2024. U.S. Environmental Protection Agency. https://www.epa.gov/system/files/documents/2024-01/lmop_rng_document.pdf

97 Envitec Biogas. 2025. "EnviTec Biogas commissions South Dakota RNG project." Biomass Magazine. https://biomassmagazine.com/articles/envitec-biogas-commissions-south-dakota-rng-project

98 EPA identifies landfill gas to be approximately 50 percent methane. See: "LMOP Landfill and Project Database." U.S. Environmental Protection Agency. https://www.epa.gov/lmop/lmop-landfill-and-project-database

Figure 2: Distribution of estimated hydrogen production capacities from California landfills



Top – Distribution of numbers of sites, by site size ranges (estimated tpd of hydrogen). Bottom – Distribution of production capacity, by site size ranges (estimated tpd of hydrogen).

Source: Guidehouse analysis for CEC (2025)

About 90 percent of the 115 landfills that are currently producing landfill gas in the state generate only enough to produce no more than 15.4 tonnes/day of hydrogen. Eighty percent of them could supply 10 tonnes H_2/day or less. Most reach no more than 7.8 tonnes H_2/day. Guidehouse calculates that 15.4 tonnes/day is sufficient to provide 300 MWh of electric power daily for a 50 percent efficient power plant, which is not insignificant. The primary issue with respect to SMR is that – as for nearly all chemical plants – the economics become much more challenging as the scale reduces. Per U.S. EPA greenhouse gas reporting data, only two of the 18 operating SMR plants in California produced less than 20 tonnes of hydrogen per day in 2022.[99]

None of these factors is significant enough to reduce the TRL of operating an SMR when the feedstock is RNG; the TRL for that process should still be considered to be 9.[100] That said, there are very few commercial projects that use RNG reforming to produce hydrogen as of 2025 (the IEA states that there are none[101]). Several planned projects, as well as demonstration-scale projects are listed in Table 2 below).

Table 2: Biomethane/RNG Reforming Projects

Project	Location	Status	Scale	Process
BayoGreen, BayoZero[102]	TBD	Unknown	Not disclosed	SMR operating on a blend of fossil gas and RNG. Currently, BayoTech uses book-and-claim (i.e., environmental attributes are credited separately from physical fuel delivery) to earn RNG credit for SMRs.[103]
H2 SilverSTARS[104]	Thousand Palms, CA	Demonstration project	250 kg/day (~91.3 tonnes/yr)	Inductively-heated biogas reformer for SunLine Transit's hydrogen fueling station
GTI and Department of Defense[105]	Joint Base Lewis-McChord, WA	Demonstration project	50 Kg/day	Steam reforming to convert wastewater treatment biogas into RNG, which is converted into hydrogen for 19 hydrogen-powered military base vehicles

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[99] "Greenhouse Gas Reporting Program Data Sets." U.S. Environmental Protection Agency. https://www.epa.gov/ghgreporting/data-sets

[100] Rosa, Lorenzo and Marco Mazzotti. 2022. *Potential for hydrogen production from sustainable biomass with carbon capture and storage*. Renewable and Sustainable Energy Reviews. https://doi.org/10.1016/j.rser.2022.112123

[101] Liundgren, Joakim, Berend Vreugdenhil, Yadi Ganjkhanlou, and Robert Baldwin. 2025. *Biomass gasification for hydrogen production*. International Energy Agency, Bioenergy Technology Collaboration Programme. https://www.ieabioenergy.com/wp-content/uploads/2025/03/IEA-Bioenergy_T33_Bio-H2_Final_v2.pdf

[102] "Making Hydrogen Easy." BayoTech. https://bayotech.us/bayotech-hydrogen/

[103] "Decarbonizing Hydrogen with Renewable Natural Gas (RNG)." BayoTech. https://blog.bayotech.us/hydrogen-production-from-rng

[104] "Stars Technology Corporation." https://www.starsh2.com/

[105] "Converting Biogas to Hydrogen to Run Military Fuel Cell Vehicles." GTI Energy. https://www.gti.energy/converting-biogas-to-hydrogen-to-run-military-fuel-cell-vehicles/

Project	Location	Status	Scale	Process
Air Liquide's North Las Vegas Liquid Hydrogen Facility[106]	North Las Vegas, NV	Commercial but not yet procuring RNG[107]	30 tonnes/day	Steam methane reformer process coupled with a hydrogen liquefier. RNG will be secured through contractual agreements with fossil gas suppliers to produce renewable hydrogen.

Source: Guidehouse for CEC (2025)

The following is a CEC staff-developed table of hydrogen production projects which include solar (electrolysis) and RNG/SMR.

Table 3: Hydrogen Production Projects

Funder	Supplier	Location	Production (thousand metric tonnes, MT)	Online	End Use	Technology	Notes
CEC (FTD Clean Transportation Program)	StratosFuel	Victorville	10 MT/d 3,600 MT/y	2026	FCV		ARV-17-050 / GFO-20-609
CEC (FTD Clean Transportation Program)	Yosemite Clean Energy	Oroville	18 MT/d 6,600 MT/y	2025	FCV	gasification	GFO-22-608
CEC (FTD Clean Transportation Program)	H2B2 USA	Fresno County	1 MT/d 400 MT/y	2023	FCV	PEM	ARV-21-029
CEC (FTD Clean Transportation Program)	Linde	Ontario	1.7 MT/d 600 MT/y	2025	FCV	PEM	GFO-20-609

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[106] "Air Liquide's North Las Vegas Liquid Hydrogen Production Facility." Air Liquide. https://usa.airliquide.com/sites/al_us/files/2022-07/nlv_facility_one-pager-bracewell_final_5_24_22.pdf

[107] Unnasch, Stefan, Love Goyal, and Anna Redmond (Life Cycle Associates, LLC). 2025. *Messer's Pathway Application for Liquefied Renewable Hydrogen from Biomethane Feedstock*. California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/classic/fuels/lcfs/fuelpathways/comments/tier2/b0772_report.pdf

Funder	Supplier	Location	Production (thousand metric tonnes, MT)	Online	End Use	Technology	Notes
CEC (FTD Clean Transportation Program)	SG H2 Energy	Lancaster	10 MT/d 3,800 MT/y	2025	FCV	paper waste / plasma	GFO-20-609
Air Products	Air Products	Casa Grande, AZ	10 MT/d 3,600 MT/y	2023	FCV	alkaline	ref
Heliogen	Heliogen	Brenda, AZ	55 MT/d 20,000 MT/y	na	na	SOEC	ref
Plug Power	Plug Power	Mendota	30 MT/d 11,000 MT/y	2024	FCV	PEM	ref
Raven SR / Chevron	Raven SR / Chevron	Richmond	5.5 MT/d 2,000 MT/y	2024	FCV	organic waste / gasification	ref

Source: CEC (2025)

Using RNG prices and LCOH estimates[108], Guidehouse estimates that the LCOH would be \$9.06/kg H_2. NETL's 2022 detailed techno-economic estimate of 96 percent carbon capture, without CO_2 transport and storage (T&S), is \$1.64/kg H_2;[109] using a \$37/tonne CO_2 T&S value and the NETL parameters of 2.5 kg CO_2 captured per kg H_2 produced, T&S would add about \$0.97/kg H_2 produced. Thus, an estimate consistent with industry estimates is \$2.61/kg H_2.

In coming years, the hands-on experience gained in hydrogen plant carbon capture at levels of 90 percent or greater is likely to reduce the cost and increase the reliability of that decarbonization technology.

In California, SoCalGas reported that 14 billion cubic feet (Bcf) of renewable natural gas (RNG) was distributed through its pipeline system in 2021. PG&E reported that, as of October 2024, it had received more than 3.4 Bcf of RNG into its pipeline system, primarily from dairy projects, and that it has committed to inject 30 Bcf per year by 2030.

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[108] Wang, Dulles, and Natalia Patterson. 2025. "North America's RNG market set for continued growth in 2025 after historic year." Wood Mackenzie. https://www.woodmac.com/news/opinion/rng-market-set-for-continued-growth-in-2025-after-historic-year/

[109] Lewis, Eric, Matthiew Jamieson, Megan S. Henriksen, H. Scott Matthews, John White, Liam Walsh, et al. 2022. *Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies.* National Energy Technology Laboratory. https://netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf

Under Senate Bill 1440 (Hueso, Chapter 739, Statutes of 2018), the CPUC adopted biomethane procurement targets for the gas utilities it regulates. The CPUC established a short-term 2025 target of 17.6 Bcf/year and a medium-term 2030 target of 72.8 Bcf/year. The agency states that these targets are intended to help displace a portion of the fossil natural gas supplied to customers and support California's methane-reduction goals under Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016).

The CPUC stated that the 2025 target of 17.6 Bcf corresponds to 8 million tons of organic waste diverted annually from landfills, with each utility responsible for procuring a share based on its proportion of natural gas deliveries. The 2030 target of 72.8 Bcf/year is intended to further support the state's methane-reduction goals; the CPUC also notes that dairy biomethane may count toward the medium-term target, subject to certain limits.[110]

RNG Feedstocks: Background

There are four main sources of RNG feedstocks for production of hydrogen via hydrocarbon reforming including animal manure, organic food waste, wastewater treatment, and landfill gas, all of which are commonly available. CARB 2022 Scoping Plan estimates over 90 million MMBtu of available supply across California by 2030. In all cases, raw biogas is generated from its organic source by some process (e.g., digester or decomposition). The biogas is then upgraded to RNG (biomethane) by removal of impurities to concentrate the methane to pipeline-grade levels. A number of upgrading technologies are employed, among them Pressure Swing Adsorption (PSA), membrane separation, and solvent absorption (all common), as well as cryogenic separation, water scrubbing, and physical scrubbing.[111]

The processing steps followed for four main sources are summarized below:

- **Animal manure:** Animal manure is pretreated for feeding into an anaerobic digestor by first removing debris and excess bedding, then diluting and homogenizing it to achieve 8-12 percent total solids. This passes through an anaerobic digestor at temperatures of 35-55°C, where it produces biogas and digestate.[112]
- **Organic food waste:** There are two types of digesters used for organic waste, wet digestors and high-solid digestors. Food waste is processed by first separating any contaminants or plastic packaging. Then it is pulped or liquefied to be turned into either a liquid/slurry with a solids content of up to 15 percent or a cake with 15-25 percent solids, as appropriate to the characteristics of the waste. Slurries are processed in wet digestors, while cake is processed in high-solid digestors.[113]
- **Wastewater treatment**: Primary and/or secondary wastewater treatment sludge gets treated in preparation for anaerobic digestion. The treatment can include thickening,

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110 "CPUC Sets Biomethane Targets for Utilities." California Public Utilities Commission. https://www.cpuc.ca.gov/news-and-updates/all-news/cpuc-sets-biomethane-targets-for-utilities

111 Angelidaki, Irini, Laura Treu, Panagiotis Tsapekos, Gang Luo, Stefano Campanaro, Henrik Wenzel, and Panagiotis G. Kougias. 2018. *Biogas upgrading and utilization: Current status and perspectives*. Biotechnology Advances. https://www.sciencedirect.com/science/article/abs/pii/S0734975018300119?via%3Dihub

112 *Anaerobic Digester / Biogas Operator Guidebook*. 2020. U.S. Environmental Protection Agency. https://www.epa.gov/sites/default/files/2020-11/documents/agstar-operator-guidebook.pdf

113 Miller, Jim, and Craig Coker. 2021. "Facility Design: Food Waste Preprocessing." BioCycle. https://www.biocycle.net/facility-design-food-waste-preprocessing/

sieving out of larger objects or grit, and processing to improve the yield of biogas (e.g., by breaking down cell walls).[114]

- **Landfill gas**: Landfill gas is a product of natural anaerobic decomposition in landfills. The gas naturally contains up to 50 percent methane, as well as nitrogen, oxygen, CO_2, and a variety of impurities. Raw landfill gas undergoes three levels of treatment to reach RNG status: (1) removal of moisture and particulates, (2) further removal of moisture, plus sulfur and siloxane, and (3) removal of other non-methane components (CO_2, air, volatile organic compounds, etc.).[115]

Biomass Gasification

Biomass gasification is the conversion of biomass into hydrogen and other products using heat and either steam, oxygen, or both steam and oxygen.[116] Sources for biomass include forest residue, urban wood waste, and crop residue. Biomass gasification takes place at high temperatures, typically 1300°F or above,[117] generally producing a syngas comprised of H_2, CO, and CO_2. Depending on the feedstock and the process, the syngas can range in composition from dilute to rich in H_2 (H_2:CO ratio of 0.7 to 1.7). As with all syngas, the CO can be converted to CO_2 using water-gas shift reactors. After leaving the water gas-shift reactors, the output gas is usually 65-70 vol percent hydrogen, which is purified by Pressure Swing Adsorption (PSA) to 95+ percent hydrogen. If desired, the CO_2 can be captured using CCS technology to further lower the carbon intensity of the production pathway. There are three main types of gasifiers: fixed bed, fluidized bed, and entrained flow, all of which have energy efficiency in the range of 40-67 percent.[118] All told, there is a large variety of gasification technologies within and among the three types, making a simple characterization of the pathway difficult.

Biomass waste is first pre-processed to make it suitable for processing and production of hydrogen. This varies according to the feedstock's moisture content, bulk density, ash content, and lignin or cellulose composition. The waste is dried to have a moisture content lower than 20 percent, then it is chipped, shredded, or ground to create uniform particles smaller than 50 mm. Any non-biomass contaminants are then removed.[119] In addition, a gasification plant requires a bulk storage area to unload and transport biomass to the process equipment.

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[114] O. S., Joshua, Gbaja I. S., Oluwaseun A. Y., Essein V. E., and Sulaiman F. A. 2017. *Biogas Production Potential of Wastewater*. IOSR Journal of Environmental Science, Toxicology and Food Technology. https://www.iosrjournals.org/iosr-jestft/papers/vol11-issue%2011/Version-1/F1111013336.pdf

[115] *An Overview of Renewable Natural Gas from Biogas*. 2024. U.S. Environmental Protection Agency. https://www.epa.gov/system/files/documents/2024-01/lmop_rng_document.pdf

[116] McNaul, Shannon, Charles White, Robert Wallace, Travis Warner, H. Scott Matthews, Jinliang Ma, Massood Ramezan, et al. 2023. *Hydrogen Shot Technology Assessment: Thermal Conversion Approaches*. National Energy Technology Laboratory. https://web.archive.org/web/20240328004116/https:/www.netl.doe.gov/projects/files/HydrogenShotTechnologyAssessmentThermalConversionApproachesRevised_120523.pdf

[117] "E3 Technology Brief: Task 2." 2024.

[118] Liundgren, Joakim, Berend Vreugdenhil, Yadi Ganjkhanlou, and Robert Baldwin. 2025. *Biomass gasification for hydrogen production*. International Energy Agency, Bioenergy Technology Collaboration Programme. https://www.ieabioenergy.com/wp-content/uploads/2025/03/IEA-Bioenergy_T33_Bio-H2_Final_v2.pdf

[119] Swanson, Ryan M., Justinus A. Satrio, Robert C. Brown, Alexandru Platon, and David D. Hsu. 2010. *Techno-Economic Analysis of Biofuels Production Based on Gasification*. National Renewable Energy Laboratory. https://docs.nrel.gov/docs/fy11osti/46587.pdf

Biomass is usually transported in its waste form and processed at the gasification plant. A solid waste collection and handling system is also necessary to ensure that solid waste can be safely disposed.[120]

A study by Columbia University found that biomass gasification can be used to create low-carbon hydrogen for use in hard-to-abate sectors such as steel and ammonia production.[121] Biomass gasification can produce carbon-negative hydrogen, which has the potential to produce steel with a carbon intensity of -0.61 to 0.39 tonne CO_2 per tonne of steel.[122] According to IEA, there are currently no commercial production plants in operation, however several companies are developing the ability to advance commercial gasification plants. Among these is an early-stage start-up, Mote, that plans to produce 20,000 tonnes per year of hydrogen from wood waste in California.[123] Another example is Torrgas, a 1 MW_{th} gasification pilot plant in the Netherlands which converts wood waste into syngas, biochar, and steam at an efficiency of 80 – 85 percent. The same company is developing a commercial plant to produce 52,000 tonnes of hydrogen per year.[124]

IEA suggests that the TRL for biomass gasification is 6-7 with and without CCS.[125] The analysis considers the TRL of each process step and computes a weighted average, presenting a reliable estimate of the readiness of gasification technology.

As with methane pyrolysis, production of hydrogen via gasification should also see a significant reduction in cost as production plants commercialize and the market scales. Guidehouse estimates that CAPEX costs could drop 25 percent or more by 2045.[126]

A 2023 estimate of LCOH of biomass gasification by NETL was \$3.54/kg H_2. NETL used a cost of feedstock of no more than \$0.45/kg H_2, which roughly corresponds to \$45/bone-dry-tonne – very close to the low end of E3's 2045 forecast (which in turn were taken from the DOE Billion Ton Report's mature-market medium scenario).[127] It is fair to characterize all estimates of costs in 2045 as being quite uncertain.

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120 Liundgren, Joakim, Berend Vreugdenhil, Yadi Ganjkhanlou, and Robert Baldwin. 2025. *Biomass gasification for hydrogen production*. International Energy Agency, Bioenergy Technology Collaboration Programme. https://www.ieabioenergy.com/wp-content/uploads/2025/03/IEA-Bioenergy_T33_Bio-H2_Final_v2.pdf

121 Lou, Yushan, Zhiyuan Fan, Julio Friedmann, Anne-Sophie Carbeau, Mahak Agrawal, and Amit Khatri. 2022. *The Potential Role of Biohydrogen in Creating a Net-Zero World*. Center on Global Energy Policy at Columbia University. https://www.energypolicy.columbia.edu/publications/the-potential-role-of-biohydrogen-in-creating-a-net-zero-world/

122 Liundgren, Joakim, Berend Vreugdenhil, Yadi Ganjkhanlou, and Robert Baldwin. 2025. *Biomass gasification for hydrogen production*. International Energy Agency, Bioenergy Technology Collaboration Programme. https://www.ieabioenergy.com/wp-content/uploads/2025/03/IEA-Bioenergy_T33_Bio-H2_Final_v2.pdf

123 Ibid.

124 "Projects." Torrgas. https://www.torrgas.nl/projects/

125 Liundgren, Joakim, Berend Vreugdenhil, Yadi Ganjkhanlou, and Robert Baldwin. 2025. *Biomass gasification for hydrogen production*. International Energy Agency, Bioenergy Technology Collaboration Programme. https://www.ieabioenergy.com/wp-content/uploads/2025/03/IEA-Bioenergy_T33_Bio-H2_Final_v2.pdf

126 McNaul, Shannon, Charles White, Robert Wallace, Travis Warner, H. Scott Matthews, Jinliang Ma, Massood Ramezan, et al. 2023. *Hydrogen Shot Technology Assessment: Thermal Conversion Approaches*. National Energy Technology Laboratory. https://web.archive.org/web/20240328004116/https:/www.netl.doe.gov/projects/files/HydrogenShotTechnologyAssessmentThermalConversionApproachesRevised_120523.pdf

127 Ibid.

Feedstock availability issues will primarily be driven by two factors: (1) decentralization of some biomass sources (such as food and animal wastes), and (2) seasonality and/or intermittency (such as for crop wastes). Conversely, existing and historical use of wood, mill, forest, and similar waste has been proven across a wide spectrum of one to several thousand dry tonnes per day.

For smaller, decentralized sources of biomass, the economics and logistics will be challenging. Because biomass processing is capital intensive (and more so, the smaller the scale), it is not likely to be economical to process the biomass at each of the many small source locations, yet transporting it to a large central processing facility will create a large transportation and/or logistical expense.

To overcome these barriers the concept of regional biomass hubs is currently being developed by the U.S. Department of Energy (DOE). A biomass aggregation hub would serve as an integrated system designed to more efficiently manage a region's organic waste streams, optimize logistics and utilization, and create localized benefits and economic development. To minimize transportation costs and emissions, a biomass aggregation hub would aim to strategically locate multiple utilization facilities within a maximum economic haul radius for transporting bulky, low-density biomass (approximately 50 to 60 miles).

By centralizing pre-processing and conversion operations, the hub model would improve economy of scale, enabling investment in advanced equipment for drying, grinding, and conversion. It would also support operational resilience through feedstock portfolio management, allowing for blending or switching between biomass types to ensure a stable, year-round supply. Additionally, hubs would stimulate local economies by creating jobs in feedstock collection, transport, and facility operations, while promoting circular economy practices and greater environmental resilience by converting waste material and wildfire fuel into valuable products. Because the hubs would be located in rural communities, community integration would become an important aspect of project development.

Methane Pyrolysis

Methane pyrolysis is the conversion of methane to solid carbon and hydrogen. Pyrolysis reactions take place without the presence of oxygen (or with oxygen in low concentration). The main reactor types used are plasma, thermal, or catalytic and the most common energy inputs are electrical energy, thermal, solar (concentrated solar power), and waste heat from industrial processes. Process conditions vary, but the process is typically performed at near-atmospheric pressure and, for non-catalytic plants, at temperatures in the range of 1100-2200°F (595-1200°C).[128]

Pyrolysis has been used commercially to produce carbon black from methane since at least 1882;[129] however, its use for producing clean hydrogen is much more recent. Because the pyrolysis process does not produce CO_2 from the feedstock, it is considered a promising candidate for low carbon hydrogen production. When the energy source for pyrolysis is low or zero-carbon heat or electricity, total CO_2 emissions can be quite low. It is also possible for

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128 Fromm, Carl. "Hydrogen Production via Methane Pyrolysis: An Overview of 'Turquoise' H2." Chemical Engineering Online. https://www.chemengonline.com/fullscreen/hydrogen-production-via-methane-pyrolysis-an-overview-of-turquoise-h2/

129 Tabler, Dave. 2018. "The world's largest carbon factory." Appalachian History.net. https://www.appalachianhistory.net/2018/04/worlds-largest-carbon-factory.html

biomass to undergo pyrolysis to form hydrogen, although that pathway is not explicitly examined in this report.

The first U.S. commercial biomethane pyrolysis plant was the Monolith Olive Creek Plant in Nebraska, which produces 600 kg H_2/hr that is used to create ammonia fertilizer. It is expecting to expand operations to nearly 8,000 kg H_2/hr.[130] Table 4 summarizes some projects that will or do produce hydrogen via methane pyrolysis.

Table 4: Methane pyrolysis projects announced or in operation.[131,132,133,134]

Company	Location	Status	Scale	Process
Monolith Materials	Olive Creek, NE	Commercial plant	60,000 tonnes H_2/yr 180,000 tonnes carbon 290,000 tonnes ammonia/yr	Plasma
BASF & Linde	Ludwigshafen, Germany	Test plant, with plans for large-scale by 2030	Undisclosed	Non-catalytic thermal
Hazer, FortisBC, Suncor Energy	British Columbia, Canada	Planned	2,500 tonnes H_2/yr	Catalytic
Hazer, Chubu Electric Power, Chiyoda Corporation	Japan	Planned (MOU)	10,000 tonnes H_2/yr, plans to increase to 100,000 tonnes H_2/yr	Catalytic
Hazer	Perth, Australia	Commercial	100 tonnes H_2/yr	Catalytic
C-Zero	Santa Barbara, CA	Pilot	400 kg H_2/day with plans to increase to 1 tonne/day (146→365 tonnes/yr)	Molten salt
VulcanX	Canada	Precommercial	1 tonne H_2/day (365 tonnes/yr)	Molten Salt

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[130] McNaul, Shannon, Charles White, Robert Wallace, Travis Warner, H. Scott Matthews, Jinliang Ma, Massood Ramezan, et al. 2023. *Hydrogen Shot Technology Assessment: Thermal Conversion Approaches*. National Energy Technology Laboratory. https://web.archive.org/web/20240328004116/https:/www.netl.doe.gov/projects/files/HydrogenShotTechnologyAssessmentThermalConversionApproachesRevised_120523.pdf

[131] Moghaddam, Alireza Lotfollahzade, Sohrab Hejazi, Moslem Fattahi, MD Golam Kibria, Murray J. Thompson, Rashed AlEisa, and M. A. Khan. 2025. *Methane pyrolysis for hydrogen production: navigating the path to a net zero future*. Journal of Energy and Environmental Science. https://pubs.rsc.org/en/Content/ArticleLanding/2025/EE/D4EE06191H

[132] "Low-emission Hydrogen and Solid Carbon." VulcanX. https://vulcanx.ca/vulcanx-technology

[133] "Hycamite opens Europe's largest turquoise H2 plant in Finland." Kallanish Commodities. https://www.kallanish.com/en/news/power-materials/market-reports/article-details/hycamite-opens-europes-largest-turquoise-h2-plant-in-finland-0924/

[134] "High-Efficiency Clean Hydrogen Production." Aurora Hydrogen. https://aurorahydrogen.com/

Company	Location	Status	Scale	Process
Hycamite	Kokkola, Finland	Commercial	2,000 tonnes H_2/yr 6,000 tonnes carbon/yr	Catalytic, includes CCUS
Ekona Power	British Columbia, Canada	Pilot, plans for commercial	200 kg H_2/day, with plans to scale to 1 tonne/day (73→365 tonnes/yr)	Non-catalytic
Aurora Hydrogen	Alberta, Canada	Pilot	200 kg H_2/day (73 tonnes/yr)	Microwave technology

Source: Guidehouse for CEC (2025)

The cost of producing hydrogen from RNG[135] pyrolysis is highly dependent on RNG feedstock cost, which can vary depending on competition with alternative end-uses and feedstock availability. The economics of pyrolysis also depend strongly on sale of the co-product, which is mainly carbon black but sometimes may be other carbon products. Carbon black derived from methane pyrolysis can be utilized in sectors such as tire manufacturing, plastics, ink, asphalt and road construction, and coatings. It is also used in electric vehicle batteries and other transportation applications. A byproduct of some pyrolysis processes is carbon nanotubes, a high-value product used in aerospace, medical, batteries & capacitors, and polymers.[136] The sale of the carbon co-product can defray some of the high cost of RNG feedstock. When performing pyrolysis using fossil gas, this revenue could reduce the LCOH to be among the lowest of the various hydrogen production scenarios. [137] The sale of carbon black may be a realistic solution to reduce the cost of hydrogen production using pyrolysis. Carbon black sales are limited by the current market size, which corresponds to only 5.5 Mt of hydrogen production using pyrolysis. [138] Therefore, to keep the cost of hydrogen production low, the market for carbon black will have to grow substantially. The market is poised to grow by 4.8 percent in the coming years, driven by increases in electric vehicle battery and plastics production. Interest in lowering greenhouse gas emissions from the tire manufacturing industry may also further propel the market for carbon black.[139] The University of Victoria found that the LCOH of methane pyrolysis ranged from \$2.30 - 4.30/kg H_2, but focused their analysis on natural gas feedstock.[140] With RNG as the feedstock, the cost would significantly increase.

As an early-stage production pathway, the costs of producing hydrogen via methane pyrolysis will drop as the technology further matures and production plants become more cost-effective

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[135] Note that the sources of RNG are elucidated above in the subsection titled "RNG Feedstocks: Background."

[136] Holler, John, and Doug Vine. 2025. *Methane Pyrolysis for Hydrogen Production*. Center for Climate and Energy Solutions. https://www.c2es.org/wp-content/uploads/2025/09/methane-pyrolysis-for-hydrogen-production.pdf

[137] "E3 Technology Brief: Task 2." 2024.

[138] *Making the Hydrogen Economy Possible: Accelerating Clean Hydrogen in an Electrified Economy*. Energy Transitions Commission. https://energy-transitions.org/wp-content/uploads/2021/04/ETC-Global-Hydrogen-Report.pdf

[139] "Carbon Black Market Size, Share & Forecast 2025 to 2035." Future Market Insights Inc. https://www.futuremarketinsights.com/reports/carbon-black-market

[140] Cost and emissions intensity of hydrogen from thermal pyrolysis of natural gas in BC - University of Victoria

and standardized. Guidehouse estimates the CAPEX cost of pyrolysis plants to be about 68 percent of today's cost by 2045 (see the production modeling section below for details).

Geologically Sourced Hydrogen

Geologically sourced hydrogen, also called "natural" or "white" hydrogen, is molecular hydrogen that occurs naturally in the Earth's subsurface. It is generated by geochemical processes (and perhaps biological processes); e.g., reaction of water with iron-rich rocks and breakdown of water by radiation.[141] It accumulates in porous rock formations and can potentially be extracted via wells. Natural hydrogen has a low carbon intensity because no fossil feedstock or electricity input is required for its primary generation. It also requires no energy inputs for its formation, unlike all other methods of hydrogen production,[142] and similarly eliminates the cost of the chemical production process.

Extraction and use of geologically sourced hydrogen is at an early stage of development. At this time there exists only one, very small-scale, commercial production facility, located in Mali.[143] The ability to extract significant amounts from any formation is not yet proven, as many deposits involve gas seepage and venting associated with volcanos, geysers, mud, and hot springs.

Furthermore, while the concentration of hydrogen in the gas can reach close to 100%, the amount at known sites average between about 25% and 63%. The remainder is some combination of methane, nitrogen, CO_2, oxygen, or helium.[144] Because of this, the extracted gas requires significant purification and, in some cases, utilization or sequestration of byproduct gases with high global warming potential. Processing steps would include separation, drying, compression, and potentially other purification processes.[145]

Although geologically sourced hydrogen is generally considered to be low-cost relative to other clean hydrogen production methods,[146] results from one analysis suggest that this will not be

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[141] Patonia, Aliaksei, Martin Lambert, Ning Lin, and Mark Shuster. 2024. *Natural (geologic) hydrogen and its potential role in a net-zero carbon future*. Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/09/ET38-Natural-geologic-hydrogen-and-its-potential-role-in-a-net-zero-carbon-future.pdf

[142] Hydrogen produced as a byproduct of other industrial products may be considered an exception, but it comprises a small fraction of all commercial hydrogen production.

[143] Everts, Arnout. 2024. "Everything you need to know about natural or geologic hydrogen." Hydrogen Science Coalition. https://h2sciencecoalition.com/blog/everything-you-need-to-know-about-natural-or-geologic-hydrogen/

[144] Patonia, Aliaksei, Martin Lambert, Ning Lin, and Mark Shuster. 2024. *Natural (geologic) hydrogen and its potential role in a net-zero carbon future*. Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/09/ET38-Natural-geologic-hydrogen-and-its-potential-role-in-a-net-zero-carbon-future.pdf

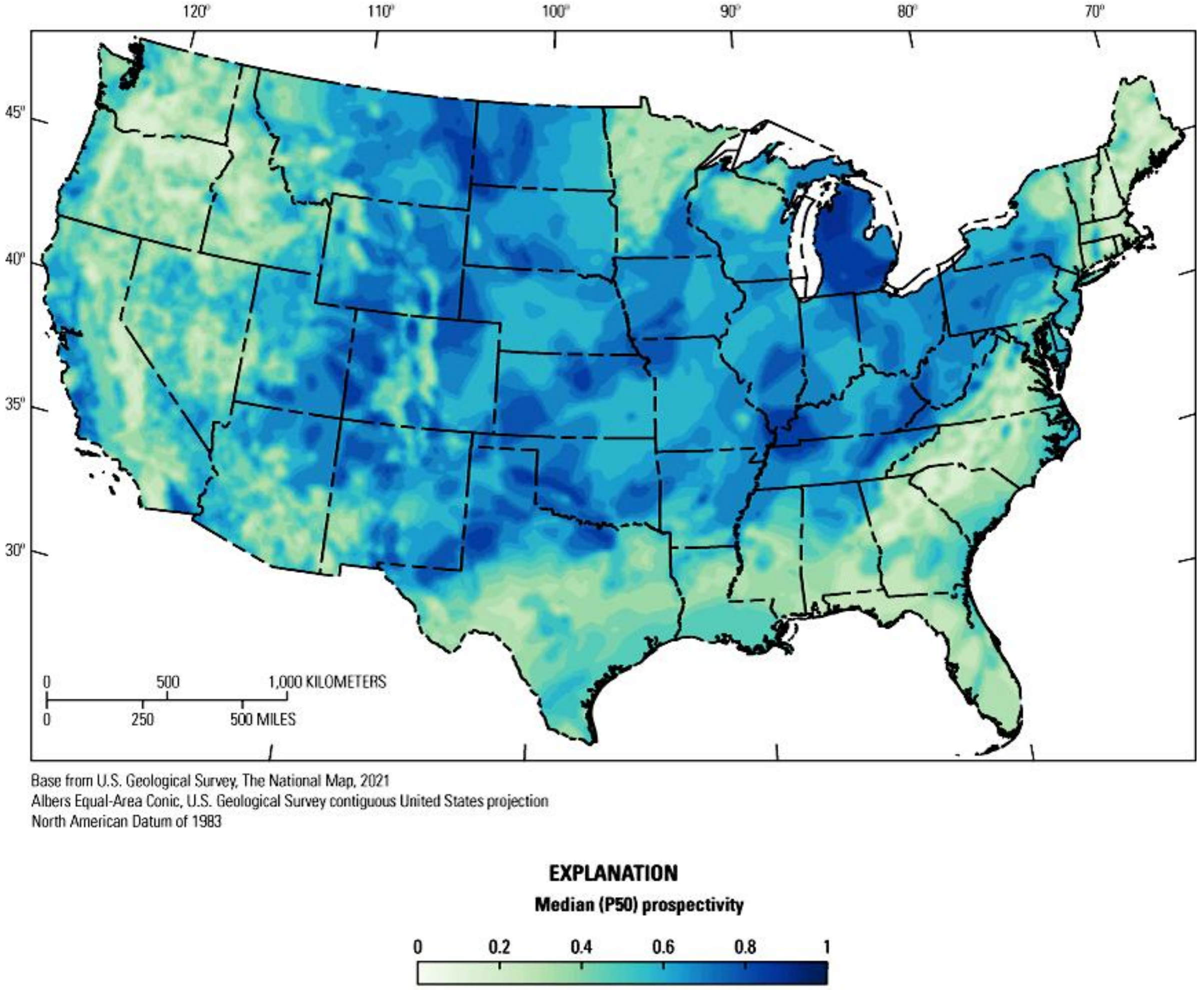
[145] Brandt, Adam R. 2023. *Greenhouse gas intensity of natural hydrogen produced from subsurface geologic accumulations*. CellPress, Joule. https://www.cell.com/joule/pdfExtended/S2542-4351(23)00274-X

[146] *Exploring the Future of Geologic Hydrogen*. 2025. EFI Foundation. https://efifoundation.org/wp-content/uploads/sites/3/2025/10/EFI-Foundation-Report-Geologic-H2-Workshop.pdf;

Flowers, Simon, Gavin Thompson, Kate Adie, and Richard Hood. 2024. "Unlocking the potential of white hydrogen." Wood Mackenzie. https://www.woodmac.com/blogs/the-edge/unlocking-the-potential-white-hydrogen/

possible unless the daily volume of hydrogen produced is at levels of about 10 tonne per day or more, with both CAPEX and OPEX being the largest contributing factors.[147]

Figure 3: Prospectivity of geologically sourced hydrogen in the U.S.



Base from U.S. Geological Survey, The National Map, 2021
Albers Equal-Area Conic, U.S. Geological Survey contiguous United States projection
North American Datum of 1983

Source: USGS (2025)

Extraction is expected to largely mirror natural gas production: drilling wells into hydrogen-bearing formations, managing reservoir pressure, and potentially stimulating flow through fracture generation or fluid injection to enhance permeability.[148] It is still too early, however, to ensure that other production techniques would not be needed for some sites. Also, unlike hydrocarbons, hydrogen's low molecular weight and high diffusivity create additional challenges, including leakage through seals and microbial consumption[149] in the subsurface, both requiring careful reservoir engineering and well design.

The U.S. Geological Survey (USGS) has estimated the likelihood of finding natural hydrogen

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[147] Patonia, Aliaksei, Martin Lambert, Ning Lin, and Mark Shuster. 2024. *Natural (geologic) hydrogen and its potential role in a net-zero carbon future*. Oxford Institute for Energy Studies. https://www.oxfordenergy.org/wpcms/wp-content/uploads/2024/09/ET38-Natural-geologic-hydrogen-and-its-potential-role-in-a-net-zero-carbon-future.pdf

[148] *Energy opportunities through hydrogen geoscience*. Lawrence Berkeley National Laboratory. https://eesa.lbl.gov/wp-content/uploads/sites/2/2025/01/Geological-Hydrogen-Fact-Sheet_compressed-1.pdf

[149] Ibid.

(its “prospectivity”) throughout the continental U.S. As shown in Figure 3, the central and northern coastal zones of California have a high prospectivity; in addition, the concentration of hydrogen in drill-well gas samples in California was typically above 20%, the highest category defined in the USGS report.[150]

In sum, geologically sourced hydrogen has appealing characteristics that make it worthwhile to explore further for development in California. There remain a number of challenges with respect to technological and engineering development, plus the quantification of the production potential of specific geological formations in the state, that could strongly affect the ability of this hydrogen source to be cost-competitive.

Producing Renewable Electrolytic Hydrogen from Curtailed Power

During normal operation, electricity generated from renewable sources is immediately transmitted and delivered into the grid (or local energy storage). However, during periods of curtailment, when there is excess electricity generation or grid congestion, there is an opportunity to use the electricity in an electrolyzer to produce hydrogen on-site. If the hydrogen was stored on-site, it can be used in on-site fuel cells to feed electricity back into the grid later in the day when renewable production is low.

Curtailment is most significant between the months of March and May; in 2024, 66 percent of curtailment occurred during this period.[151] In the large majority of (five-minute) time periods, curtailment represented a small percentage of potential solar electricity production. In fact, the average proportion over all five-minute periods is only 4.3 percent.

At the level of daily curtailment, no days have curtailment over 34 percent of potential solar output; the average over all 366 days is 5.9 percent.[152]

While this data is not granular with respect to individual facilities, it strongly suggests that electrolyzer hydrogen plants that co-locate with renewable assets and limit their electrical input to curtailed power will only be able to produce a relatively small amount of H_2 per day. This is supported by Figure 4, which shows the maximum amount of hydrogen that might have been produced in CAISO in 2024, using every bit of curtailed wind and solar power and no other source of electricity.[153] The maximum total production per year is only 66,800 tonnes of hydrogen. This should be compared against the scenarios considered in the hydrogen economy analysis of Section 7; e.g., the lower scenarios usage of hydrogen for transportation purposes alone is 12 times this quantity.

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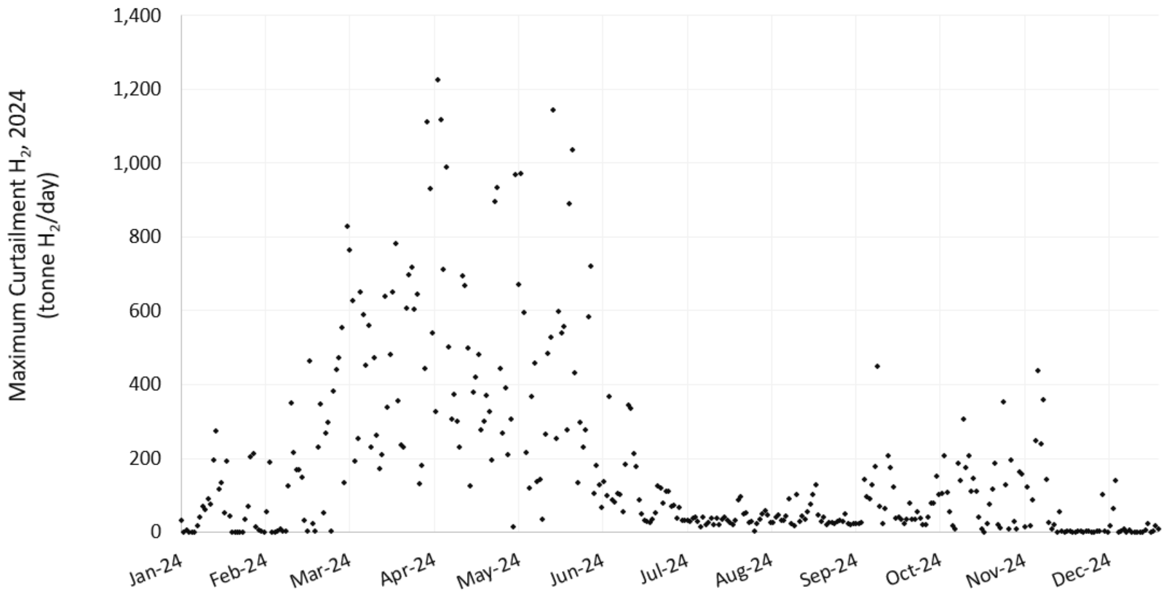
[150] Gelman, Sarah E., Jane S. Hearon, and Geoffrey S. Ellis. 2025. *Prospectivity Mapping for Geologic Hydrogen*. USGS. https://pubs.usgs.gov/pp/1900/pp1900.pdf

[151] “Managing the evolving grid.” California Independent System Operator. https://www.caiso.com/about/our-business/managing-the-evolving-grid

[152] To understand why this percentage differs from the average percentage of five-minute values: (1) the previously given percentage involves taking the average of 105,408 percentages, whereas (2) the 5.9 percent value comes from averaging 366 days in which, for each day, 288 values of curtailment are added and then divided by the sum of 288 values of (curtailment + output). An easy-to-see mathematical analogy is that $\frac{a}{b}+\frac{c}{d}\neq\frac{a+c}{b+d}$.

[153] The maximum hydrogen production was calculated directly from the total solar curtailment energy (MWh) reported for each day, using an electrolyzer energy requirement of 52 kWh/kg H2.

Figure 4: Maximum hydrogen production from solar curtailment in CAISO territory, by day, 2024



Source: Guidehouse analysis for CEC (2025)

The amount of hydrogen that can be produced from curtailment on any given day is distributed among the population of renewable plants with electrolyzers that are actually curtailing. The more renewable power plants curtail, the smaller the average hydrogen production among those plants with electrolyzers. Thus, if a large portion of the renewable portfolio is experiencing curtailment, the amount of hydrogen that any single electrolyzer facility would produce that day (from curtailed energy alone) is likely to be small. Therefore, when estimating an upper bound on the real-life daily production capacity of electrolyzer sites that only use curtailed energy, one should analyze a case with a relatively small population of renewable plants in the state experiencing curtailment – for instance, 10 percent.

According to the U.S. EPA's latest eGRID database, in 2023 there were 695 wind and solar plants in CAISO that produced power and were owned by utilities or independent power producers (IPPs).[154] If only 10 percent of them are ever needed to be curtailed on any given day, that means that the quantity of hydrogen that any specific site might produce is probably not much more than 120 tonnes/day, and that amount would only be possible on a couple of days of the year. Also, if the composition of this set of 10 percent of facilities varies from day-to-day, plants that get to produce this much hydrogen would probably have only one day per year to do so.

In addition to being limited to small quantities on most days, the production schedule for any hydrogen plant that focuses on curtailed power is going to be intermittent and significantly unpredictable. From March through June power is likely to be curtailed every day, but the *amount* of electric power that would be available on any specific day is much less predictable. This can negatively affect a plant's operation and its ability to meet offtake commitments. (Plants that can supplement the curtailed power with non-curtailed power are much less affected.) For the rest of the year, curtailment is comparatively small and often barely occurs.

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[154] "eGRID with 2023 data." U.S. Environmental Protection Agency. https://www.epa.gov/egrid/detailed-data

Developers would have two options to manage the uncertainty of the amount of curtailed electricity: (1) size the hydrogen production plant for the maximum annual available amount of curtailed power (or close to it), or (2) size the plant for a lower amount of input electricity that occurs more frequently over the year. In the former case, a very large amount of plant's daily production capacity would have to sit idle on most days, a highly uneconomical business model.[155] In the latter case (smaller plant size), much of the available potential for producing hydrogen is lost by choosing a reduced production capacity.[156] Neither design option is a good one for hydrogen producers. In both cases, producers will also need on-site hydrogen storage that requires appropriate sizing, which would also be a challenge in light of the variability of input power to produce hydrogen.

Unfortunately, no satisfactory solution exists that would allow electrolysis plants to increase their individual usage of curtailed power – thus achieving a more economical capacity factor and/or a higher production rate – by a proxy such as a Renewable Energy Credit (REC). No RECs can be produced for renewable energy that is not created, i.e., is curtailed. While traditional Renewable Energy Credits (RECs) require the actual generation of energy, the core issue of utilizing otherwise curtailed power may be addressed through emerging mechanisms and regulatory changes designed to provide financial incentives for clean hydrogen production. There are other alternative approaches that lead into the consideration of an REC (or similar) such as Direct State Incentives. An example is California's Clean Hydrogen Program, which offers financial incentives for eligible projects in California demonstrating or scaling up the production, processing, delivery, storage, or end use of clean hydrogen to reduce emissions.[157]

Even if such a proxy system could be developed, there are still many days with too little curtailment to support significant commercial or industrial hydrogen production. For example, if only a *single* 40 tonne/day hydrogen electrolysis plant were assigned all of the curtailed renewable power in CAISO in 2024, that plant would not have been able to produce more than 85 percent of its desired output of hydrogen for 127 days. Furthermore, the proxy scheme could easily end up exacerbating the grid constraints that cause curtailment in the first place as the electrolyzer requires additional electricity that would have to come from some other source than actual curtailment.

The most natural scenario for using curtailed energy is to have an electrolyzer located on-site of a renewable power asset and designed to run off of that asset's regular output. The curtailed energy, when it occurs, would be made available to the electrolyzer at a reduced cost from non-curtailed electricity. This supports the economics of the hydrogen production plant as well as the wind or solar farm, in addition to improving the overall utilization of the power

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[155] The CAPEX of a facility is recouped by sales of product. If the amount of H2 sold is far lower than the plant's production capacity, the levelized cost of hydrogen for each kilogram produced would either exceed what the company can sell the hydrogen for or, if not, greatly reduce (or eliminate) profit. At the statewide level, the maximum amount of H2 production from curtailment is only 15% – just over one-eighth – of what a single plant sized for the most-curtailed day would be capable of producing. With CAPEX representing on the order of 20% of a typical LCOH (i.e., for normally priced electricity), even if the curtailed electricity were free the resulting levelized cost for a plant producing at 15% of its capacity would be roughly 35% higher than the typical LCOH.

[156] In 2024, eighty percent of the time the potential hydrogen production capacity was 300 tonnes/day or less, which is about 25 percent of the annual maximum of 1,184 tonnes/day. The total amount of H2 that could be produced by curtailment, CAISO-wide is reduced by 64 percent if production capacity is limited to that level.

[157] "Clean Hydrogen Program." California Energy Commission. https://www.energy.ca.gov/programs-and-topics/programs/clean-hydrogen-program

grid. This is one of the key assumptions that was considered in the analysis – that by co-locating electrolyzers with renewable energy sources, developers can capture curtailed energy that would otherwise be lost to grid congestion. Utilizing this low-cost, excess electricity improves the hydrogen plant's economics. However, a plant relying solely on intermittent curtailed energy will have a low capacity factor. It is important to note that this analysis applies to 2024, and curtailment will increase over time as SB 100 is implemented.

Challenges for Hydrogen Production Pathways

Although hydrogen offers significant decarbonization potential across multiple sectors, each production pathway faces important constraints that may affect its cost, scalability, and emissions performance. These challenges include cross-cutting issues such as infrastructure, market competitiveness, and policy uncertainty, as well as pathway-specific technical and operational barriers. This section summarizes the key challenges associated with major hydrogen production pathways.

Cross-Cutting Challenges

Cost competitiveness

Clean hydrogen production pathways are currently not cost competitive with traditional fuels. The cost of traditional fossil fuels such as fossil gas, coal, and diesel range from $2.50-$16/MMBtu, which is significantly cheaper than the cost of producing clean hydrogen.[158] Today, traditional hydrogen production – SMR without carbon capture – costs approximately $1.50-2.50/kg H_2 ($11-19/MMBtu), whereas electrolytic hydrogen costs $3.50-$6.00 or more per kg H_2 ($26-45/MMBtu).[159] Market incentives, such as carbon taxes and clean production credits, and technology improvements may narrow this cost differential in the long-term, but at present it is difficult for clean production pathways to compete with traditional fuels.

Storage and delivery constraints

Unless connected to off-site storage, or a buffer such as a pipeline, hydrogen storage is necessary for all production pathways. Storage acts as a buffer against fluctuations in feedstock, production levels, and demand, so that the manufacturer can ensure supply is available as needed. When output is intermittent and/or sufficiently variable, the facility needs significant extra investment in some combination of storage tanks (or space) and higher production capacity than it would otherwise need.

Guidehouse performed an analysis, provided in Chapter 7, of the storage and production capacity requirements – related only to intermittency and variability of electric power input – of an electrolytic hydrogen facility that would be coupled with its variable renewable power source but committed to deliver a constant supply of hydrogen to its customers. The reference point was the amount of hydrogen that could be produced and sold to customers if they *would*, in fact, purchase whatever amount that the plant generated on any given day. This

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[158] "Weighted Average Cost of Fossil Fuels for the Electric Power Industry, 2013 through 2023." U.S. Energy Information Administration. https://www.eia.gov/electricity/annual/html/epa_07_04.html

[159] Curcio, Eliseo. 2025. *Techno-economic analysis of hydrogen production: Costs, policies, and scalability in the transition to net-zero*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/abs/pii/S0360319925016234

unrealistic ideal represents the maximum efficiency of the plant capital, and it requires no storage to compensate for the variability of plant inputs and hydrogen production rate.

Analysis showed that for a given production capacity, various levels of firm hydrogen product commitment (tonnes/day) were possible through the use of storage. However, as output commitments approached the reference/ideal level, the storage requirement for managing production variability ballooned because of the phenomenon described above. The only way to keep storage volumes within reason was to reduce the size of the offtake commitment to the customer.

In the case studied, one possible tradeoff between storage size and offtake commitment was to have storage be about 1.9 days' worth of output, with the firm offtake commitment being about 82 percent of what it might deliver if storage were not needed (an 18 percent overbuild). With a tradeoff like this, a hydrogen electrolytic production plant that could commit to 40 tonnes/day would be losing around 9 tonnes/day of production capacity to maintain an onsite storage capability of 75 tonnes.[160] This volume of storage is very large with respect to current above-ground tank storage facilities, though it will be at least somewhat more manageable in the future.

Regulatory and policy uncertainty

Market incentives, as previously mentioned, are essential to scale and increase the cost competitiveness of clean hydrogen production pathways compared to traditional fuels. However, they can be subject to regulatory headwinds that can increase doubts in the feasibility of production projects. Recent uncertainty in DOE's hydrogen hub funding and changes to production tax credits from the IRA, for instance, has led to the cancellation of several major hydrogen production projects, such as Air Products' green hydrogen facility and Nel's 4 GW electrolyzer facility.[161],[162] Continued doubt in regulatory support for clean hydrogen production will make it difficult for these pathways to be cost competitive with fossil-based alternatives.

Hydrogen is regulated at federal, state, and local levels, and it can be difficult to untangle the web of regulations and policies at every level. Furthermore, inconsistency in regulations and permitting requirements from jurisdiction to jurisdiction is difficult for many project developers.[163] Some companies that have implemented portfolios of projects recommend hiring experts in each project's community who understand the local regulatory and legislative experts.[164] This includes differences across national borders.[165] Complex, slow, or strict

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[160] Guidehouse. 2024.

[161] Parkes, Rachel. 2024. "'Green' hydrogen 'on life support' as major projects canceled." Hydrogen Insight. https://www.hydrogeninsight.com/electrolysers/us-green-hydrogen-developer-cancels-massive-1gw-plus-electrolyser-deal-with-nel/2-1-1717842

[162] Parkes, Rachel. 2024. "US green hydrogen developer cancels massive 1GW-plus electrolyser deal with Nel." Hydrogen Insight. https://www.hydrogeninsight.com/electrolysers/us-green-hydrogen-developer-cancels-massive-1gw-plus-electrolyser-deal-with-nel/2-1-1717842

[163] Wymer, Jess, and Veronica Saltzman. 2025. "Regulatory Framework for Hydrogen in the U.S." Clean Air Task Force. https://www.catf.us/resource/regulatory-framework-hydrogen-us/

[164] Guidehouse. 2025.

[165] Webster, Joseph, and Pau Ruiz Guix. 2024. "Toward harmonizing transatlantic hydrogen policies: Understanding the gaps." Atlantic Council. https://www.atlanticcouncil.org/blogs/energysource/toward-harmonizing-transatlantic-hydrogen-policies-understanding-the-gaps/

regulatory and permitting requirements may lead to delays in project construction, which can slow down potential growth in hydrogen capacity.[166] In general, project developers are advised to work very closely with the set of relevant officials from as early in the process as possible.

In addition to policy matters pertaining to hydrogen itself, such issues also impact the cost and availability of the critical inputs to clean hydrogen production facilities, such as renewable power and biogenic feedstocks. Wind and solar power in particular are experiencing changes to policies in the US, which are affecting both government support and industry investments.[167] A secondary but important effect is the commercial impact on the US manufacturers and deployers of wind and solar technology, as international entities move in quickly to fill market share that the domestic companies lose from policy-related instability.[168]

Supply Chain and Input Constraints

Electrolyzer and critical materials

Each of the hydrogen production pathways is reliant on an extended supply chain to remain feasible. Currently, the majority of electrolyzers are produced in Asia, especially China, with the region accounting for over 60 percent of global manufacturing capacity.[169] Even so, sales have greatly lagged production capacity and the large majority of Chinese electrolyzer sales have occurred within that country.[170]

While the US holds some domestic manufacturing capacity, most of the raw materials required for electrolyzer production, such as platinum, cobalt, and graphite, are imported.[171] The US may be able to expand its domestic electrolyzer manufacturing capacity, but it is expected that Asian electrolyzers will remain a cheaper option than domestically-produced electrolyzers,

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[166] Reed, Jeffrey G., Brendan P. Shaffer, Emily E. Dailey, Blake A. Lane, Robert J. Flores, and G. Scott Samuelsen. 2020. *Renewable Hydrogen Production Roadmap for California*. UC Los Angeles Advanced Power & Energy Program. https://www.apep.uci.edu/PDF_White_Papers/Renewable_Hydrogen_Production_Roadmap_For_California_061920_11am.pdf

[167] Geman, Ben. 2025. "Renewables investors are pulling back from the U.S." Axios. https://www.axios.com/2025/08/26/us-investments-renewable-energy-projects-numbers;

Peters, Keaton. 2025. "Private investment drops as US shifts renewable energy policy." Straight Arrow News. https://san.com/cc/private-investment-drops-as-us-shifts-renewable-energy-policy/

[168] Abrahams, Leslie, and Joseph Majkut. 2025. "U.S. Clean Tech Exports Are the Key to Long-Term U.S. Economic Growth." Center for Strategic & International Studies. https://www.csis.org/analysis/us-clean-tech-exports-are-key-long-term-us-economic-growth

[169] Zhao, Tiantian, and Bridget van Dorsten. 2024. "The competitive edge of China's electrolysers." Wood Mackenzie. https://www.woodmac.com/news/opinion/the-competitive-edge-of-chinas-electrolysers/

[170] Orders for Chinese electrolyzers: "Chinese companies secured orders in January to export 65MW electrolyzers." 2024. Global Hydrogen Hub. https://globalhydrogenhub.com/chinese-companies-secured-orders-in-january-to-export-65mw-electrolyzers.html;

Production statistics: Yin, Ivy. 2025. "China's hydrogen electrolyzer industry facing technology, cost challenges." S&P Global. https://www.spglobal.com/commodity-insights/en/news-research/latest-news/energy-transition/021925-chinas-hydrogen-electrolyzer-industry-facing-technology-cost-challenges

[171] "Water Electrolyzers and Fuel Cells Supply Chain." U.S. Department of Energy. https://www.energy.gov/sites/default/files/2024-12/Fuel percent2520Cells percent2520 percent26 percent2520Electrolyzers percent2520Supply percent2520Chain percent2520Report percent2520-percent2520Final percent5B1 percent5D.pdf

possibly even when considering the impact of tariffs.[172] The effect of tariffs on new solar and wind power will also increase the cost of electrolytic hydrogen production.

Renewable electricity availability

As the assessment discussed below in the hydrogen value chain analysis section shows,[173] a great deal of renewable power generation capacity will need to be present and/or added to the grid to support electrolytic hydrogen generation. Not all this clean power capacity would be dedicated to hydrogen production; on the contrary, to keep equipment capacity factor sufficiently high only about one-sixth of the renewable power capacity would be spoken for by electrolyzers. The addition of renewable power to feed production of electrolytic hydrogen is a multifaceted and somewhat controversial topic. As noted in the Trends and Developments section above, the Treasury Department's regulations implementing the 45V PTC impose strict eligibility requirements on renewable electricity assets and accounting to minimize the induced power grid emissions deriving from production of hydrogen.

However, the actual impacts of hydrogen production's use of renewable electricity on grid emissions are complex and have not yet been definitively measured. Rather, modeling studies on the need for hourly vs. annual temporal matching have led to conflicting conclusions about this issue.[174] Arguments are made on both sides of the incrementality issue as well. While incrementality is generally seen as a necessary condition, some assert that it must be a pre-condition to installing electrolytic hydrogen production capacity while others view that the installation of this production capacity will naturally stimulate new additions of solar and wind power.[175] Delays in new-asset additions due to congested interconnection queues lend some weight to the argument that assets should be in place prior to starting up hydrogen facilities, because otherwise it could be years after hydrogen uses the power before the incremental renewable capacity gets installed. However, as many commented during the 45V regulatory process, this places major constraints on development of the (electrolytic portion of the) hydrogen economy.

Power grid impacts

Where electrolytic hydrogen production draws from the power grid, rather than being co-located with the renewable power sources, a single merchant production facility will increase the load on the grid on the order of 10-100$^+$ MW$_e$. In addition to the local equipment needed

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[172] "E3 Technology Brief: Task 2." 2024.;

Hedreen, Siri. 2025. "China to dominate green hydrogen market as US withdraws subsidies: report." S&P Global. https://www.spglobal.com/commodity-insights/en/news-research/latest-news/electric-power/082725-china-to-dominate-green-hydrogen-market-as-us-withdraws-subsidies-report

[173] See in particular the subsection on Renewable Energy and its Land Requirements for Electrolysis and the following one on Electricity Requirements.

[174] In favor of hourly matching: Esposito, Dan, Eric Gimon, and Mike O'Boyle. 2023. *EPA AVERT Analysis of Upstream Electrolysis Emissions*. Energy Innovation. https://energyinnovation.org/wp-content/uploads/45V-Paper-Appendix-A.pdf;

In favor of annual matching: "Analysis of Hourly & Annual GHG Emissions." 2023. E3 and ACORE. https://acore.org/resources/analysis-of-hourly-annual-ghg-emissions-accounting-for-hydrogen-production

[175] This paper presents both perspectives and the authors' computed consequences of each on grid emissions: Giovanniello, Michael A., Anna N Cybulsky, Tim Schittekatte, and Dharik S. Mallapragada. 2024. *The influence of additionality and time-matching requirements on the emissions from grid-connected hydrogen production*. Nature, Energy. https://www.nature.com/articles/s41560-023-01435-0

for the electrolyzer's offtake, additional transmission and distribution infrastructure, or infrastructure upgrades, will likely be required.[176]

In some cases, more traditional generation capacity may be required, even if it is technically offset by the new renewable energy capacity. DOE estimates that achieving a potential 100 million tonnes of new electrolytic hydrogen per year would require *doubling* the power grid's current annual generation.[177] While that assumes having nearly all of anticipated hydrogen be generated electrolytically, even if one-third of that quantity is generated via electrolyzers the impact on the power grid would be a large increase of about 33 percent from current grid capacity.

Biogenic feedstock competition

The primary challenges for biogenic-sourced hydrogen are the feedstock cost, the ability to gather sufficient quantities in a single location to reach economy of scale for the conversion processes, and competition from alternate end-uses. Large amounts of biogenic feedstock are expected to be produced in California, though estimates of the total amount available vary significantly.[178] Using the 2022 CARB Scoping Plan estimates of available quantities of biomass (agricultural residue, forest waste, and urban waste) and RNG (from livestock, landfill gas, municipal solid waste, and wastewater treatment) feedstock in California,[179] 1.2-1.4 million tonnes of hydrogen could be produced per year,[180] which amounts to 73-87 percent of the Scoping Plan's projected demand by 2045 (which does not include use for producing electric power).[181] However, biogenic feedstocks are valuable for many other applications than producing hydrogen.

Biomass can be directly combusted to produce power or converted into fuel for other uses, such as ethanol for transportation. Currently, direct use of woody biomass to generate power is not very prominent in California, with only 23-25 facilities that account for less than 3 percent of electricity generation capacity in operation today.[182] There was legislation encouraging biomass for electric power in the 1980s and 1990s, but due to high generation

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[176] Distribution substations can vary in size from about 5 MWe (small rural) to 200 MWe (large urban): Short, T. A. 2022. Electric Power Distribution Handbook. Internet Archive. https://archive.org/details/electric-power-distribution-handbook-by-t.-a.-short/page/n33/mode/2up

[177] "Water Electrolyzers and Fuel Cells Supply Chain." U.S. Department of Energy. https://www.energy.gov/sites/default/files/2024-12/Fuel percent2520Cells percent2520 percent26 percent2520Electrolyzers percent2520Supply percent2520Chain percent2520Report percent2520-percent2520Final percent5B1 percent5D.pdf

[178] For example, the 2022 CARB Scoping Plan estimates about 8.1 million tonnes/year of biomass by 2045 but the report "Getting to Neutral" by Lawrence Livermore National Laboratory predicts that 50 million tonnes/year will be available in that time frame:

"Getting to Neutral." Lawrence Livermore National Laboratory. https://gs.llnl.gov/sites/gs/files/2021-08/getting_to_neutral.pdf

[179] Except where noted, this report adopts the estimates for biogenic feedstock availability used in the E3 Technology Brief: Task 2 (December 2024) document. Those derive from the CARB Scoping Plan as follows: (1) 2045 RNG estimates are those in Figure H-3 of Appendix H, (2) biomass estimates also follow Appendix H, except that use of agricultural biomass for electricity is not assumed to increase from 1.1 million tonnes/yr.

[180] The primary uncertainty in this quantity is the conversion efficiency of biomass to hydrogen via gasification.

[181] "E3 Technology Brief: Task 2." 2024.

[182] "Woody Biomass Utilization." UC Agriculture and Natural Resources. https://ucanr.edu/site/woody-biomass-utilization/electricity-generation

costs and competition with other renewables, biomass capacity has shrunk significantly (37 percent) since 2017.[183] An important case of using biomass for electricity is combined heat and power, which biomass is more directly suited to compared to wind and solar power; it is especially prominent in industrial applications.[184]

RNG primarily faces competition for end-use from the transportation market, driven by the Low Carbon Fuel Standard (LCFS), which creates strong incentives for low-carbon transportation fuels. However, there has also been a recent uptick in gas utility RNG offtake, driven by legislation such as California's SB 1440 (Hueso, 2018), which requires major utilities to procure RNG. If these markets continue to generate higher revenue for low-carbon fuels, there will be limited incentive to use RNG to produce hydrogen.

Operational and Pathway Specific Challenges

Electrolytic hydrogen operational issues

Some operational and safety concerns have arisen related to new clean hydrogen facilities. For example, the world's largest green hydrogen project, the 260 MW Sinopec Kuqa facility in China, has faced issues with insufficient hydrogen production and safety.**[185]** The plant was built using alkaline electrolyzers, which do not perform well under low input power conditions (in this case, at nominally <30 percent of nameplate input power) and can present safety issues due to high oxygen levels at the hydrogen electrode.

The string of 52 electrolyzers, with a design capacity factor of 30-50 percent, has an input power rating that is 87 percent of the nameplate capacity of the associated solar facility. The remaining power needed to keep the utilization within the intended range was intended to be acquired via use of the power grid and purchase of clean energy credits. Despite this plan, input power from both sources has been insufficient, and its overall capacity factor has been about 20 percent.[186] In addition, the electrolyzers failed to perform at all at the expected 30 percent level, having a lower operating limit of closer to 50 percent of full capacity. The lower efficiency and smaller operating window has led to a higher levelized cost of hydrogen and a

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[183] "Renewable Energy Consumption: Transportation and Electric Power Sectors." U.S. Energy Information Administration. https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T10.02C#/?f=A&start=1949&end=2024;

Romeo, Jim. 2020. "Is Biomass Dead?" Power. https://www.powermag.com/is-biomass-dead/

[184] "Chapter 02: Biomass Currently Used for Energy and Coproducts." *2023 Billion-Ton Report*. 2024. U.S. Department of Energy. https://www.energy.gov/sites/default/files/2024-03/beto-2023-billion-ton-report_2-current_0.pdf

[185] Collins, Leigh. 2023. "World's largest green hydrogen project 'has major problems due to its Chinese electrolysers': BNEF." Hydrogen Insight. https://www.hydrogeninsight.com/production/exclusive-worlds-largest-green-hydrogen-project-has-major-problems-due-to-its-chinese-electrolysers-bnef/2-1-1566679;

Zhao, Tiantian. 2024. "Hydrogen case study: Sinopec Kuqa project operational efficiency and electrolyser technology." Wood Mackenzie. https://www.woodmac.com/news/opinion/hydrogen-case-study-sinopec-kuqa-project/;

Yin, Ivy, Oceana Zhou, and Eric Yep. 2024. "China's hydrogen ambitions may ride on Sinopec's Kuqa project in Xinjiang." S&P Global. https://www.spglobal.com/commodity-insights/en/news-research/latest-news/energy-transition/011124-chinas-hydrogen-ambitions-may-ride-on-sinopecs-kuqa-project-in-xinjiang

[186] Although this is less than the safe operating range of 30 percent, the company manages this by having a small number of the electrolyzers operate at close to full capacity and shutting down the rest.

significantly slower-than-expected ramp up. These issues are indicative of potential challenges that may be faced as green hydrogen production scales.

Blue hydrogen / SMR with CCS challenges

Fossil Gas Reforming with Carbon Capture (Blue Hydrogen): Production of hydrogen via SMR with carbon capture is not yet widespread. The Guidehouse tracker for carbon capture, utilization, and storage[187] lists five operational blue hydrogen facilities worldwide, with only one of them in the US (Air Products' Port Arthur, Texas facility, a retrofit on an existing production plant). Another 50 facilities are in some stage of commercial development (i.e., beyond planning or a pilot or demonstration plant), with 21 of those in the U.S. and five in California.[188] All of the U.S. projects still in development were announced in 2021 or later.

This production pathway is subject to tradeoffs that must be considered and accounted for in policy and project decision making. Although fossil gas is a well-developed resource that can provide large, steady volumes of affordable feedstock, achieving a very low carbon intensity requires significant investment and effort. In particular, emissions reductions are necessary in the supply chain and production process. The potential for emissions with global warming consequences exists all through the upstream and midstream gas infrastructure, including the point of production, processing, and gas transmission and delivery pipelines. Methane's high global warming potential (GWP) makes leakage of any kind significantly more impactful than release of an equivalent volume of CO_2. Emission rates can range from fractions of a percent to several percent of gas flow, depending on the gas source, how it is developed, and the processing and transportation-related equipment and infrastructure in place. The US EPA has recently promulgated rules to mandate reduction of emissions from production, transmission, and storage (but not distribution), though the compliance date has been extended to January 2027. The DOE's 45VH2-GREET emissions lifecycle assessment model for hydrogen production assumes an upstream emission rate of 1 percent, but a target on the order of 0.20 percent or better is considered to be necessary by many to achieve adequate reduction in emissions, and at least one initiative aims to do better than that.

Emissions from the SMR process stream - SMRs have two main gas flow streams, a process stream where the steam and fossil gas react to form hydrogen and a combustion stream where fuel (usually fossil gas) is burned to produce the heat that drives the chemical reaction. Capturing CO_2 from the process stream can reduce the plant's CO_2 emissions on the order of 55-65 percent.[189] All carbon capture systems installed at SMR plants remove CO_2 from this gas flow. This is usually accomplished at a high percentage – up to 99 percent, thanks to the high concentration of CO_2 and high pressure of the gas stream – but there are some emissions

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[187] Labastida, Roberto Rodriguez, Serkan Birgel, and Petere Marrin. 2025. *Carbon Capture, Utilization, and Storage Tracker 2Q25*. Guidehouse Research. https://www.guidehouseresearch.com/reportaction/TR-CCUS-2Q25/Marketing?SearchTerms=ccus

[188] Two of those are meant to take biogenic feedstocks, rather than fossil gas.

[189] Collodi, Guido, Giuliana Azzaro, and Noemi Ferrari. 2017. *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS*. International Energy Agency, GHG Technology Collaboration Programme. https://ieaghg.org/publications/techno-economic-evaluation-of-smr-based-standalone-merchant-hydrogen-plant-with-ccs/

associated with the removal process[190] unless entirely renewable heat and electricity sources are used.

Emissions from the SMR combustion stream - About 40 percent of the CO_2 generated in an SMR is present in the combustion gas stream. This CO_2 can be removed as well, up to an overall level of removal from both streams of about 90-96 percent,[191] but removal from this low-pressure gas stream with low concentration of CO_2 is quite costly. One study estimated that removing the maximum CO_2 from the process stream alone would increase the cost of a greenfield SMR plant by 34 percent ($1.1 MM per total percentage point of CO_2 removed), but removing the pollutant from both streams would increase the cost by about 79 percent ($1.9 MM per total percentage point of CO_2 removed).[192]

Hydrogen Leakage

As a small molecule with high gas diffusivity, hydrogen is known to leak from equipment at rates that are at least as high as fossil gas, and often higher.[193] Hydrogen leakage is an important consideration for the hydrogen economy, due to safety, economic loss, and the environmental impact of this high-GWP gas (GWP100 $\approx$ 11.6 and GWP20 $\approx$ 37.3)[194].

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[190] "FAQ - What options are there for CO2 capture from a SMR based hydrogen unit?" Axens. https://www.axens.net/resources-events/faq/faq-what-options-are-there-co2-capture-smr-based-hydrogen-unit

[191] Collodi, Guido, Giuliana Azzaro, and Noemi Ferrari. 2017. *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS*. International Energy Agency, GHG Technology Collaboration Programme. https://ieaghg.org/publications/techno-economic-evaluation-of-smr-based-standalone-merchant-hydrogen-plant-with-ccs/;

Lewis, Eric, Shannon McNaul, Matthiew Jamieson, Megan S. Henriksen, H. Scott Matthews, Jorn White, Liam Walsh, et al. 2022. *Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies*. National Energy Technology Laboratory. https://netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf

[192] Collodi, Guido, Giuliana Azzaro, and Noemi Ferrari. 2017. *Techno-Economic Evaluation of SMR Based Standalone (Merchant) Hydrogen Plant with CCS*. International Energy Agency, GHG Technology Collaboration Programme. https://ieaghg.org/publications/techno-economic-evaluation-of-smr-based-standalone-merchant-hydrogen-plant-with-ccs/

[193] Theoretically, hydrogen will leak about 2.8 times as much as methane, but at low pipeline pressures measurements have shown H2 and methane leaking about the same rate.

Barrett, Mark, and Tiziano Gallo Cassrino. 2021. *Heating with Steam Methane Reformed Hydrogen*. Research Square. https://assets-eu.researchsquare.com/files/rs-638496/v1/6f5bc1c2-ff85-4a33-bdea-28a0fedec5ab.pdf?c=1631884868;

Mejia, Alejandra Hormanza, Jacob Brouwer, and Michael Mac Kinnon. 2020. *Hydrogen leaks at the same rate as natural gas in typical low-pressure gas infrastructure*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/abs/pii/S0360319919347275

[194] The GWP of hydrogen is still under study.

A recent paper whose value is used by many: Sand, Maria, Ragnhild Bieltvedt Skeie, Marit Sandstad, Srinath Krishnan, Gunnar Myhre, Hannah Bryant, Richard Derwent, et al. 2023. *A multi-model assessment of the Global Warming Potential of hydrogen*. Nature. https://www.nature.com/articles/s43247-023-00857-8.

Some point out that the typical GWP value used in analyses, the 100-year impact, is not the best one to consider for nearer-term global warming impacts. See reference 1 of this footnote, and: Ocko, Ilissa, and Steven Hamburg. 2022. "For hydrogen to be a climate solution, leaks must be tackled." Environmental Defense Fund. https://www.edf.org/article/hydrogen-be-climate-solution-leaks-must-be-tackled

To assess how leakage could affect hydrogen's decarbonization potential, Guidehouse estimated the impact of hydrogen leakage across the full value chain on hydrogen's ability to displace fossil gas and diesel fuel in electric power, transportation, and industrial applications.

Using 2022 CARB Scoping Plan estimates of fossil gas usage for gas-fired power plants and hydrogen use for transportation and industrial applications, Guidehouse first estimated baseline greenhouse gas emissions for a business-as-usual scenario involving the use of fossil fuels (Appendix E). Leakage of fossil gas through the entire value chain was assumed to be at the same level (1 percent) used in Argonne National Laboratory's 45VH2-GREET model for upstream and midstream leakage of the fuel supply to hydrogen SMR facilities. Greenhouse gas emissions from fossil fuel combustion were assumed to be pure CO_2.

A second, contrasting scenario was considered in which hydrogen fully replaces the fossil fuel for these electric power, transportation, and industrial applications. The splits of hydrogen delivery to the different applications via three modes (pipeline, tube trailer, and on-site delivery) were chosen based on a best judgment of the future state. A sensitivity check was performed with a different set of delivery assumptions, showing little difference in results. The analysis used estimated leakage rates for hydrogen at each point in the value chain from a Columbia University CGEP Study.[195] Two scenarios for hydrogen replacement were analyzed: (1) 100 percent green hydrogen production, which measures emissions only from hydrogen leakage, and (2) 50 percent split between green and blue hydrogen, which accounts for some emissions from blue hydrogen production.

The carbon intensity of the hydrogen scenario with 100 percent green hydrogen was estimated to be 3.4 million tonnes CO_{2eq} per year, whereas a mix of blue and green hydrogen increased the estimated carbon intensity to 8.5 million tonnes CO_{2eq} per year. Comparatively, the baseline scenario estimate was 27.9 million tonnes CO_{2eq} per year. Therefore, due to leakage, replacement of fossil fuels with hydrogen would lead to an 88 percent reduction of CO_{2eq} with 100 percent green hydrogen and 70 percent reduction with 50 percent blue and 50 percent green hydrogen.

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[195] Fan, Zhiyuan, Hadia Sheerazi, Amar Bhardwaj, Anne-Sophie Corbeau, Kathryn Longobardi, Adalberto Castaneda, Ann-Kathrin Merz, et al. 2022. *Hydrogen Leakage: A Potential Risk for the Hydrogen Economy*. Columbia Center on Global Energy Policy. https://www.energypolicy.columbia.edu/sites/default/files/file-uploads/HydrogenLeakageRegulations_CGEP_Commentary_070722_0.pdf

Chapter 5: Storage Pathways

Key Takeaways

This chapter investigates the current and potential future pathways for storing hydrogen. This includes tank storage, pipeline storage, and geological formations.

- For modest hydrogen storage amounts, compressed storage tanks represents a viable storage solution.
- The use of former fossil gas pipelines for hydrogen storage remains untested and presents several technical challenges.
- Feasibility of storing hydrogen in California's depleted oil and gas fields requires additional research and development, but this type of geological formation offers the greatest future opportunity for geological storage.

Chapter Overview

Multiple storage pathways were evaluated as part of this analysis, including the two most common: above-ground storage such as pressurized tanks and pipelines (as a storage option – transport of hydrogen in pipelines is covered in the next section). Staff also evaluated potential future storage options, including underground subsurface storage, such as geological reservoirs. The following sections below provide a detailed analysis of each storage pathway's benefits, disadvantages, and specific implementation challenges.

Compressed Gas Storage Tanks

Compressed gaseous hydrogen storage tanks are a common above ground storage option and are generally classified as Type I, II, III, or IV based on pressure-vessel construction, including the liner material and the extent of composite reinforcement. Type I tanks are all-metal cylinders, while Type II tanks are metal cylinders with hoop-wrapped composite reinforcement. Type III tanks have a non-load-bearing metallic liner with a full composite wrap, and Type IV tanks have a non-load-bearing polymeric liner with a full composite wrap.

Among these options, Type III and Type IV tanks are generally the most suitable for above-ground hydrogen storage applications requiring high pressures. Their liner materials help contain the gas, while the full composite wrap provides the strength needed to withstand elevated internal pressures. This combination of gas containment and structural reinforcement makes Type III and Type IV tanks well suited for high-pressure hydrogen storage applications, including pressures up to 700 bar.[196]

The energy required for compressing hydrogen varies greatly, depending on the initial and final pressure, the efficiency of the compressor employed, and operating parameters. DOE's H2A Delivery Scenario Model (HDSAM), used for techno-economic study of hydrogen delivery,

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[196] Farazmand, Mahgol, Zahra Saadat, and Mohammad Sameti. 2024. *Above-ground hydrogen storage: A state-of-the-art review*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/pii/S036031992404028X

calculates compression energy consumption[197] using an ideal gas thermodynamic formula[198] that is commonly used for engineering estimates, especially early-stage design work. Guidehouse applied that formula to calculate the compression energy, in kWh/kg H_2, as a function of energy for four likely scenarios that are listed in Table 5.

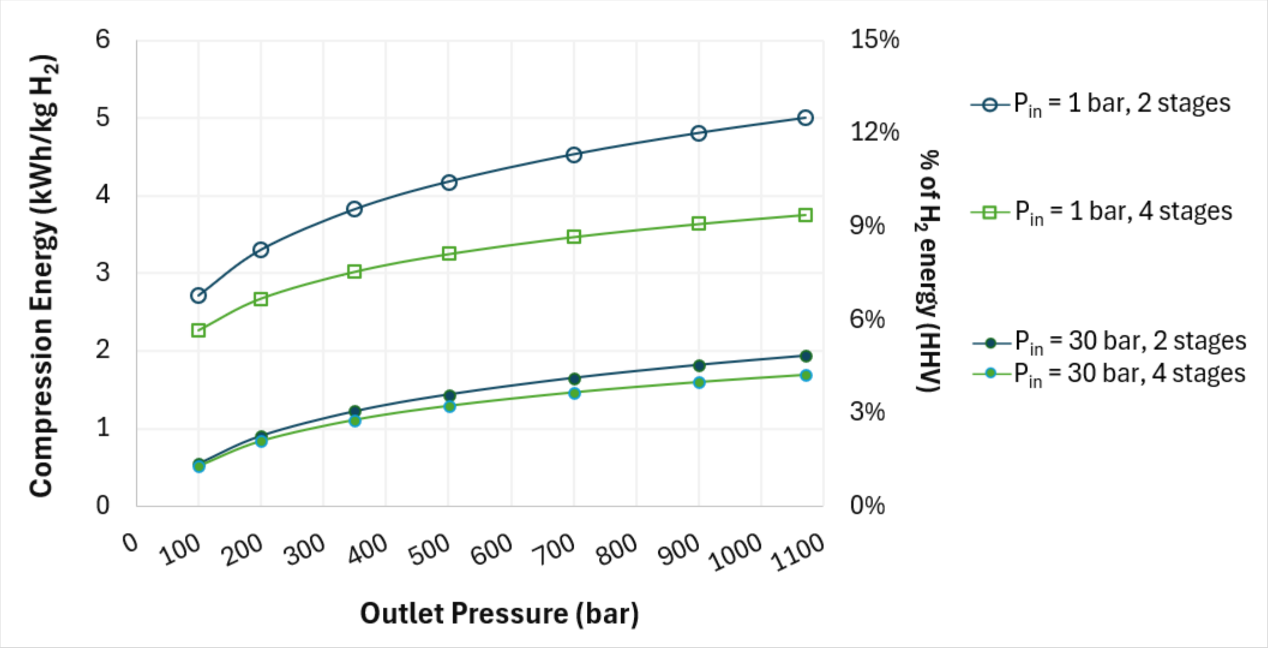
Table 5: Scenarios used to compute compressor energy

Scenario Name	Initial Pressure	# of Stages
P_{in} = 1 bar, 2 stages	1 bar	2
P_{in} = 1 bar, 4 stages	1 bar	4
P_{in} = 30 bar, 2 stages	30 bar	2
P_{in} = 30 bar, 4 stages	30 bar	4

Source: Guidehouse analysis for CEC (2025)

Notes: (1) four-stage compressors are more efficient than two-stage models (all else equal), (2) 30 bar is a common pressure achieved by PEM electrolyzers.

Figure 5: Compressor energy for various inlet and outlet pressures ("Pin" is the inlet/initial pressure)



Source: Guidehouse analysis for CEC (2025)

The results of these computations are shown in Figure 5, where the compressor energy needed to reach outlet pressures from 100 bar to 1,070 bar are shown. Note that most hydrogen transportation application scenarios will use hydrogen at 350 bar or 700 bar, though

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197 Nexant, Inc., Air Liquide, Argonne National Laboratory, Chevron Technology Venture, Gas Technology Institute, National Renewable Energy Laboratory, Pacific Northwest National Laboratory, and TIAX LLC. et al. 2008. *H2A Hydrogen Delivery Infrastructure Analysis Models and Conventional Pathway Options Analysis Results*. EERE. https://www1.eere.energy.gov/hydrogenandfuelcells/pdfs/nexant_h2a.pdf

198 Equation 17 of: Lopez-Paniagua, Ignacio, Javier Radriguez-Martin, Susana Sanchez-Orgaz, and Juan Jose Roncal-Casano. 2020. *Step by Step Derivation of the Optimum Multistage Compression Ratio and an Application Case*. Entropy. https://pmc.ncbi.nlm.nih.gov/articles/PMC7517211/

refueling station storage tanks can reach 900-950 bar. The various scenarios computed here consume significantly different amounts of energy, ranging from about 1.3 percent of hydrogen's fuel energy (higher heating value, HHV) to more than 12 percent. Although the highest case here takes a significant amount out of the net energy, it is a good deal less parasitic than hydrogen liquefaction (30-40 percent energy penalty[199]).

Vehicle-Related Applications

Vehicle related applications fall into three categories: (1) on-board vehicle fuel tanks, (2) refueling station storage tanks, and (3) tube trailer tanks for delivery of hydrogen to end-use locations.

- **On-board vehicle tanks:** Current hydrogen fuel cell electric vehicles (FCEVs) predominantly use compressed gas systems that carry hydrogen at 350 or 700 bar.[200] Tanks can be located at various places on the vehicle, such as behind a truck cab, mounted to the frame, or mounted on the roof.[201] This technology allows drivers to travel considerable distances, thanks to the combination of hydrogen's high energy density (142 MJ/kg, versus about 45 MJ/kg for diesel fuel) and the ability to carry more fuel at the high pressure. The current cost of hydrogen at refueling stations in California varies between \$13-15/kg H_2, though it has reached the \$30-35/kg H_2 range recently.[202]
- **Refueling stations**: Many designs for buffer storage and dispensing of hydrogen at refueling stations exist, depending on types of vehicles served, station design parameters, locality, and other factors. For example, "cascade" systems with various numbers of storage tanks at different intermediate pressure levels are employed, as well as direct systems that do not use a cascade approach. In the cascade system, the main buffer storage is at a higher pressure than the vehicle uses, such as 950 bar storage for a 700-bar vehicle tank. In direct systems, the gas is stored at an intermediate pressure and compressed to the delivery pressure at the time of dispensing.[203]

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[199] *Energy requirements for hydrogen gas compression and liquefaction as related to vehicle storage needs*. 2009. U.S. Department of Energy. https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/9013_energy_requirements_for_hydrogen_gas_compression.pdf

[200] Navinkumar, T.M., and C. Bharatiraja. 2025. *Sustainable hydrogen energy fuel cell electric vehicles: A critical review of system components and innovative development recommendations*. Renewable and Sustainable Energy Reviews. https://www.sciencedirect.com/science/article/abs/pii/S1364032125002746

[201] Ahluwalia, R. K., D. D. Papadias, J-K Peng, and H. S. Roh. 2019. *System Level Analysis of Hydrogen Storage Options*. Argonne National Laboratory. https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/review19/st001_ahluwalia_2019_o.pdf

[202] Weeks, Daniel. 2024. "California hydrogen pump prices climb slightly, remain highest globally." S&P Global. https://www.spglobal.com/commodity-insights/en/news-research/latest-news/energy-transition/060424-california-hydrogen-pump-prices-climb-slightly-remain-highest-globally

[203] Genovese, M., and P. Fragiacomo. 2023. *Hydrogen refueling station: Overview of the technological status and research enhancement*. Journal of Energy Storage. https://www.sciencedirect.com/science/article/pii/S2352152X2300155X;

- **Tube trailer hydrogen transport:** Gaseous hydrogen that is delivered in quantities greater than what cylinders and portable tanks carry but less than a tonne is typically transported in tube trailer trucks. The "tube" in tube trailer refers to long, cylindrical tanks, which are mounted in multiples in the trailer of the truck. The tanks used in this application are discussed later in the Transport Pathways Overview section.

Non-Vehicle Applications

In addition to the automotive sector, hydrogen is being used in many portions of the industrial sector, such as for production of chemicals, glass, and electronics, and as an atmosphere in metals heat treating.

Because there are currently limited hydrogen pipeline networks in California, hydrogen storage tanks play an important and enabling role in applications that consume significant quantities of hydrogen. This option is only practical for consumption levels where above-ground tank storage is feasible (e.g., consumption at facilities such as steel plants can be much too large for tank storage.)[204]

Quantities stored in tanks range from tens of kilograms to several tonnes. Storage pressures for these tanks range from 135-1,000 bar and the hydrogen can be stored for years. In 2017, the U.S. DRIVE Partnership estimated the cost of storage tanks at low (160 bar), medium (430 bar), and high (860 bar) pressure to be \$600/kg H_2, \$1,100/kg H_2, and \$1,450/kg H_2, respectively.[205] Cost escalation since 2016 for tanks used in the chemical industry is approximately 45 percent,[206] so at this time the prices may be on the order of \$870/kg H_2, \$1,600/kg H_2, and \$2,100/kg H_2 for the relevant pressure levels.

Storage Tank Size

Because of hydrogen's very low density, gaseous storage tanks for hydrogen occupy a large volume relative to the amount of material stored. Figure 6 shows what the approximate inner dimensions of a cylindrical hydrogen storage tank would be, assuming an aspect ratio of 2.0 (that is, the height (if vertical) or length (if horizontal) is twice the diameter).[207] Results were calculated for the two common storage pressures of 350 bar and 700 bar.

Li, Xianming Jimmy, Jeffrey D Allen, Jerad A Stager, and Anthony Y K. 2020. *Paths to low-cost hydrogen energy at a scale for transportation applications in the USA and China via liquid-hydrogen distribution networks*. Clean Energy. https://academic.oup.com/ce/article/4/1/26/5812776;

Ahluwalia, R. K., D. D. Papadias, J-K Peng, and H. S. Roh. 2019. *System Level Analysis of Hydrogen Storage Options*. Argonne National Laboratory. https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/review19/st001_ahluwalia_2019_o.pdf

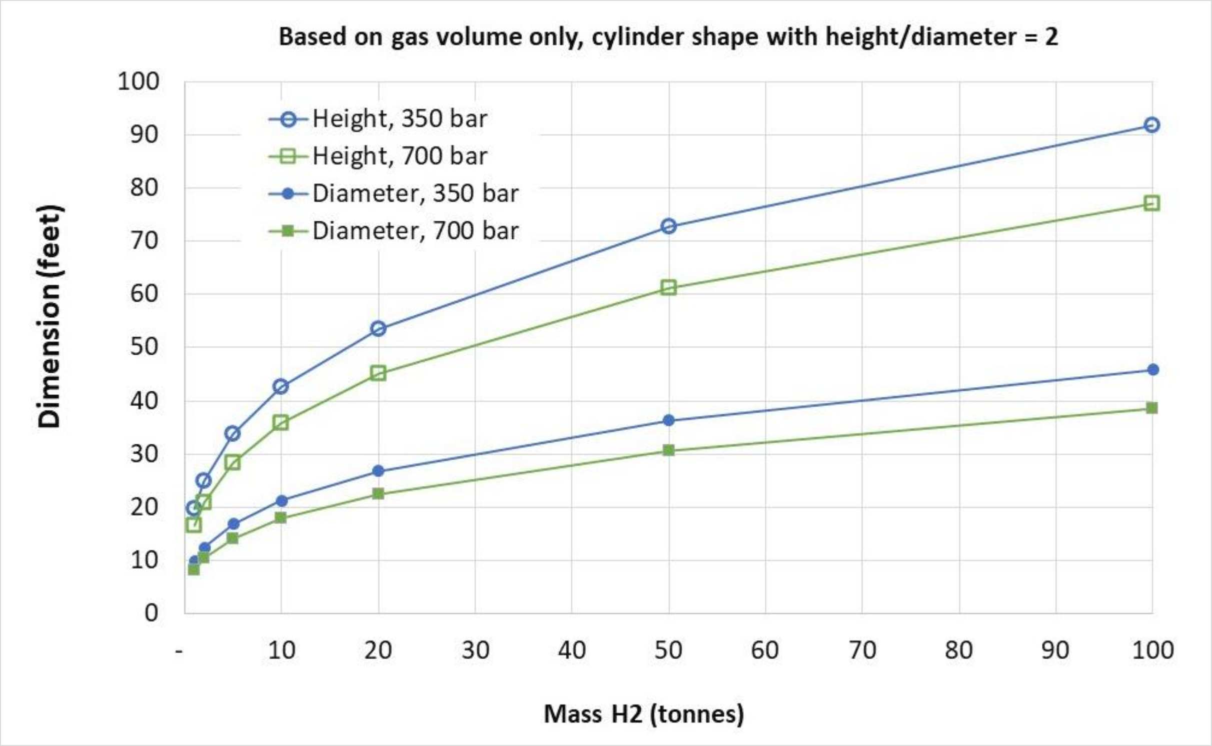
[204] "HYBRIT: Hydrogen storage reduces costs by up to 40 per cent." 2023. Vattenfall. https://group.vattenfall.com/press-and-media/pressreleases/2023/hybrit-hydrogen-storage-reduces-costs-by-up-to-40-per-cent

[205] "Hydrogen Delivery Roadmap." U.S. DRIVE Partnership Hydrogen Delivery Technical Team. https://www.energy.gov/eere/vehicles/articles/us-drive-hydrogen-delivery-technical-team-roadmap

[206] "The Chemical Engineering Plant Cost Index®." Chemical Engineering. http://www.chemengonline.com/pci

[207] The calculation assumes that all of the inner space in the tank is occupied by hydrogen gas; i.e., it ignores any engineered structures or equipment that might be needed for a particular tank technology or design.

Figure 6: Dimensions of tank storage gas volume for various amounts stored



Source: Guidehouse analysis for CEC (2025)

For storage of only 10 tonnes of hydrogen at 700 bar, the tank inner diameter would be 17.9 feet and the inner height (or length) would be 35.7 feet.[208] This is equivalent to 8,960 cubic feet (67,000 gallons). It does not appear that single pressure vessels of anything close to this size have yet been developed that are suitable for hydrogen. For example, Burke et al. list capacities of gaseous storage tanks at 0.5-1 tonne[209] and Hydrogen Tools (a DOE-funded site) notes that compressed gas tank storage is typically done with multiple smaller cylinders loaded into a frame.[210]

Weight

It also needs to be considered that pressure vessels required to hold hydrogen at 350 bar or 700 bar require a large amount of tank material, which is primarily steel for storage volumes on the order of hundreds or more kilograms. The gravimetric storage density (or efficiency) – i.e., the weight of hydrogen that can be stored as a percent of the filled tank weight – varies greatly depending upon the tank size, pressure, and design type (Type I, II, III, or IV). The range of gravimetric storage densities for tanks is roughly 1.0-5.7 percent[211], with Type I

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[208] Liquid hydrogen would only occupy 55.5 percent of this volume, but that is still substantial.

[209] Burke, Andrew, Joan Ogden, and Lewis Fulton. 2024. *Hydrogen Storage and Transport: Technologies and Costs*. UC Davis Institute of Transportation Studies. https://escholarship.org/content/qt83p5k54m/qt83p5k54m_noSplash_8bb1326c13cfb9aa3d0d376ec26d3e06.pdf?t=s9oa2u

[210] "Storage Vessels." Hydrogen Tools. https://h2tools.org/bestpractices/hydrogen-system-components/compressed-gas-storage/storage-vessels

[211] One source (Argonne National Laboratory) cites the existence of Type IV tanks with densities as high as 6.7 percent.

having the worst efficiency and Type IV the best.[212] Most stationary storage tanks are Type I and Type II, whereas vehicles will have Type III or Type IV tanks. Thus, the weight of a stationary hydrogen storage tank containing one tonne of H_2 will be between about 48 tonnes (Type II) and 100 tonnes (Type I).[213]

The use of many small cylinders to reach tonne- or multi-tonne-level storage results in greatly increased aggregate weight of a large storage facility, relative to what might be reached with a single vessel. In sum, facilities that can accommodate very heavy equipment are required to store significant amounts of hydrogen.

Liquid Hydrogen (LH_2) Tanks

The high hydrogen density of LH_2 allows relatively large amounts of hydrogen to be stored in smaller, thinner-walled tanks than are used for gaseous compressed hydrogen. Tank sizes can range from very small (single digit gallons) to over one million gallons (e.g., NASA storage tanks for space vehicles).[214] Very large volumes are stored in spherical tanks, but most LH_2 tanks are cylindrical in form. Their operating pressure tends to be about 8.5 bar, but they can reach 10.35 bar before the pressure relief is activated.[215] Some storage installations have associated active refrigeration units to keep the liquid in that cryogenic state.[216]

The gravimetric storage density of LH_2 is higher than that for storage of hydrogen in gaseous form; i.e., equipment for LH_2 storage is lighter than compressed gas systems. However, values for this in the literature are not fully consistent, possibly due to sources discussing systems with different storage capacities, as small tanks have a much lower gravimetric storage density

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[212] Muthukumar, P., Alok Kumar, Mahvash Afzal, and B. Satya Sekhar. 2023. *Review on large-scale hydrogen storage systems for better sustainability*. International Journal of Hydrogen Energy. https://www.researchgate.net/publication/370989491_Review_on_large-scale_hydrogen_storage_systems_for_better_sustainability;

An overview on the technologies used to store hydrogen. Energy Reports. https://pdf.sciencedirectassets.com/311225/1-s2.0-S2352484723X00110/1-s2.0-S2352484723012143/main.pdf;

Ahluwalia, R. K., D. D. Papadias, J-K Peng, and H. S. Roh. 2019. *System Level Analysis of Hydrogen Storage Options*. Argonne National Laboratory. https://www.hydrogen.energy.gov/docs/hydrogenprogramlibraries/pdfs/review19/st001_ahluwalia_2019_o.pdf;

Rivard, Etienne, Michel Trudeau, and Karim Zaghib. 2019. *Hydrogen Storage for Mobility: A Review*. Materials. https://www.mdpi.com/1996-1944/12/12/1973

[213] Per the source "Hydrogen Storage for Mobility," gravimetric densities by type are as follows: Type I = 1.7 wt. percent, Type II = 2.1 wt. percent, Type III = 4.2 wt. percent and Type IV = 5.7 wt. percent. Other sources indicate that Type I tanks can have a density as low as 1.0 wt. percent, so that value was used in the weight estimate.

[214] Examples: "Liquid Hydrogen Storage Tank." Hylium Industries (13 gallon). https://hylium-industries.com/lh2_tank;

"Storage and transport for liquid hydrogen." Cryolor (5,005 gallon and 13,160 gallon). https://www.cryolor.com/sites/cryolor/files/2023-03/cryolor-lh2-brochure-03.23-sd.pdf;

"DOE/NASA Advances in Liquid Hydrogen Storage Workshop." NASA (1.2 million gallons). https://ntrs.nasa.gov/api/citations/20210020920/downloads/New%20LH2%20Sphere%20Presentation%2017Aug2021.pdf

[215] "Liquid Storage Vessels." h2tools.org. https://h2tools.org/bestpractices/hydrogen-system-components/liquid-storage-vessels

[216] "Hydrogen Loss Mitigation with Active Refrigeration." GenH2. https://www.energy.gov/sites/default/files/2024-11/h2-emissions-workshop-11-hall.pdf

than larger tanks. Commercial products for quantities of LH_2 on the order of tonnes, particularly tanks for LH_2 transport vehicles, have a gravimetric storage density of around 14-18 wt. percent.[217]

With modifications to the vehicle engine and fuel storage system, LH_2 may be used in fuel cell systems and in internal combustion engines due to its high energy content by weight and high efficiency. This makes it an attractive solution[218] for powering different means of transport, from road vehicles to aircraft. It also has a well-established role as a rocket propellent.

At present, a limited number of LH_2 powered vehicles are in operation. In aviation, several pilot projects have demonstrated the ability to use hydrogen as a partial or sole fuel source in small aircraft; technologies include both direct use in combustion engines and in powering fuel cells for an electric powertrain. Similarly, LH_2 is being studied for potential application in the maritime sector, mainly to run fuel cell electric engines. Little attention has been paid thus far to using the fuel in the rail sector.[219]

Various means are used to avoid having vaporized hydrogen result in excessive pressure in the storage tank. These include venting the gaseous hydrogen into the atmosphere, reliquefying it, or compressing and storing it in an auxiliary tank. There is clearly a tradeoff between simplicity and low cost (venting), which results in lost hydrogen and the associated emissions, and the higher-technology solutions (re-liquefaction and compression) that save the hydrogen but require investment and energy to operate**.** Technology that reduces boil-off to zero has been in development and testing for aerospace applications,[220] and is in further development for smaller applications such as refueling stations.[221]

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217 "Storage & transport of liquid hydrogen." Cryolor. https://www.cryolor.com/sites/cryolor/files/2024-06/cryolor-lh2-brochure-01-24.pdf;

"LH2 Transport Trailer ST-18600H 155 Pressure Transfer System." Chart. https://files.chartindustries.com/LH2TransportTrailerSpecSheetST18600H.pdf;

"Liquid Hydrogen Transport." HEIL Trailer. https://heiltrailer.com/wp-content/uploads/2024/09/Heil_LHT_Brochure_091924_HR_-1.pdf.

A consistent non-commercial source is: "An overview on the technologies used to store hydrogen." Energy Reports. https://pdf.sciencedirectassets.com/311225/1-s2.0-S2352484723X00110/1-s2.0-S2352484723012143/main.pdf

218 LH2 is considered an attractive potential solution for powering various future transport means (road, maritime, aviation) due to its high gravimetric energy density and zero-emission potential, however, the widespread future use of LH2 in transport depends on reducing economic and liquefaction penalties (energy penalty and boil-off losses).

219 Schiaroli, A., L. Claussner, A. Campari, D. Cirrone, B. Linseisen, A. Friedrich, E. L. Torres de Ritter, M. Kuznetsov, and F. Ustolin. 2025. *A comprehensive review on liquid hydrogen transfer operations and safety considerations for mobile applications*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/pii/S0360319924054739

220 Notardonato, W. U., A. M. Swanger, J. E. Fesmire, K. M. Jumper, W. L. Johnson, and T. M. Tomsik. *Zero Boil-Off Methods for Large Scale Liquid Hydrogen Tanks using Integrated Refrigeration and Storage*. NASA. https://ntrs.nasa.gov/api/citations/20170006481/downloads/20170006481.pdf

221 Beens, H., and S. Vanapalli. 2025. *Towards Economic Zero Boil-Off Technology for Liquid Hydrogen Storage*. University of Twente. https://indico.cern.ch/event/1431974/contributions/6396983/attachments/3069583/5430167/C1Or4C-04%20Towards%20Economic%20Zero%20Boil-Off%20Technology%20for%20Liquid%20Hydrogen%20Storage.pdf

LH_2 storage tanks are regulated by standards that differ depending on vessel application, size, and operating condition. Compressed Gas Association (CGA) standard H-3-2024 describes the minimum design and performance requirements for vacuum-insulated above-ground LH_2 tanks between 3,785-94,600 L, allowing up to 12.1 bar of maximum pressure. Other regulations and permit requirements for hydrogen storage include:

- FAA 14 CFR §420.66. Specifies separation distance requirements for storage of liquid hydrogen and any incompatible energetic liquids.
- EPA Risk Management Program (RMP), 40 CFR. §68.10. Requires facilities that store more than a threshold amount of a regulated substance to develop a Risk Management Plan and submit that plan to EPA. Hydrogen is listed as a flammable substance and its threshold amount is 10,000 lbs.[222]
- EIGA 06/19. Describes design and operation requirements for fixed storage tanks, enabling safe storage, handling, and distribution of liquid hydrogen. This excludes portable containers and liquid cylinders.
- OSHA Hazardous Materials, 29 CFR §1910.103. Regulate the safety of gaseous and liquid hydrogen systems, installed on consumer premises, where hydrogen is delivered to the facility by mobile equipment. Storage containers are among the types of equipment regulated.
- CA DIR Article 138 §5473. Outlines guidance necessary when storing hydrogen, such as distance from concentrations of people, air ventilation equipment, flammable material, area of location capacity, all based on tank volume.[223]

Former Fossil Gas Pipelines

Some have proposed storing hydrogen in fossil gas pipelines that, in the future, will no longer be used for that purpose due to electrification, hydrogen, and other alternatives. Note that this is different from taking advantage of hydrogen pipelines (that continuously serve the gas) for temporary storage via increases in pipeline pressure, known as "linepack." In the scenario discussed here, the pipeline is *only* used for storage and withdrawal, never as a continuous source of gas.

Table 6 shows Guidehouse's high-level estimate of the amount of hydrogen that could be stored in one mile of pipeline of various diameters and at pressures common in transmission pipelines.

Table 6: Potential for storing hydrogen in former fossil gas pipelines

Pipeline Diameter (in)	P = 200 psia (13.6 bar) (tonne H_2/mile)	P = 800 psia (54.4 bar) (tonne H_2/mile)	P = 1500 psia (102 bar) (tonne H_2/mile)
6	0.03	0.14	0.25
8	0.06	0.24	0.45
12	0.14	0.54	1.0

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[222] *40 CFR Part 68*. U.S. Environmental Protection Agency. https://www.epa.gov/sites/default/files/2013-11/documents/99part68.pdf

[223] *California Code of Regulations, Title 8, Section 5473; Specific Requirements*. California Department of Industrial Relations. https://www.dir.ca.gov/title8/5473.html

Pipeline Diameter (in)	P = 200 psia (13.6 bar) (tonne H_2/mile)	P = 800 psia (54.4 bar) (tonne H_2/mile)	P = 1500 psia (102 bar) (tonne H_2/mile)
24	0.54	2.2	4.1
36	1.2	4.9	9.2
42	1.7	6.7	12.5

Source: Guidehouse analysis for CEC (2025)

Using these estimates, Guidehouse has performed a rough analysis of the maximum order of magnitude of hydrogen storage that might be expected in each county in the state, the results of which are listed in Table 7 below. To produce this estimate, several large simplifying assumptions had to be made, so the results should not be taken as accurate beyond the order-of-magnitude level.

Table 7: Estimated maximum hydrogen storage capacity in fossil gas pipelines using a population-proportional pipeline miles assumption

County	2025 County Pop.	Percent of State	Est. miles of distribution pipeline	Tonnes H_2 at 6" dia. and 13.6 bar in distribution system	Est. miles of transmission pipeline	Tonnes H_2 at 42" dia. and 102 bar in transmission system
Los Angeles	9,550,505	25	27,233	926	2,726	34,063
San Diego	3,255,567	8	9,283	316	929	11,611
Orange	3,106,521	8	8,858	301	887	11,080
Riverside	2,528,844	7	7,211	245	722	9,019
San Bernardino	2,197,017	6	6,265	213	627	7,836
Santa Clara	1,876,106	5	5,350	182	536	6,691
Alameda	1,610,046	4	4,591	156	460	5,742
Sacramento	1,584,104	4	4,517	154	452	5,650
Contra Costa	1,151,037	3	3,282	112	329	4,105
Fresno	1,020,768	3	2,911	99	291	3,641
Kern	907,958	2	2,589	88	259	3,238
Ventura	823,028	2	2,347	80	235	2,935
San Joaquin	814,309	2	2,322	79	232	2,904
San Francisco	811,416	2	2,314	79	232	2,894
San Mateo	721,201	2	2,056	70	206	2,572

Source: Guidehouse analysis for CEC (2025)

The assumptions used for the storage calculations are as follows:

- The total amounts of distribution and transmission pipeline miles in each county were taken from the World Population Review.[224] Miles of distribution pipeline and transmission pipeline were taken from PHMSA.[225]
- A representative or average pipeline in the distribution network has the properties of 6” diameter and 13.6 bar (200 psia) pressure. This should result in a conservative estimate

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[224] “California Counties by Population (2025).” World Population Review. https://worldpopulationreview.com/us-counties/california

[225] “Pipeline Miles and Facilities 2010+.” Pipeline and Hazardous Materials Safety Administration. https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages

(results in higher hydrogen storage) with respect to pressure, but not necessarily so with respect to pipeline diameter. As will be explained below, there is a great deal of discontinuity among pipelines in the distribution network, so hydrogen storage would be very distributed into many small-quantity pockets.

- A representative or average pipeline in the transmission network has the properties of 42" diameter and 102 bar (1,500 psia) pressure. This is conservative (again, in the sense of overestimating hydrogen storage capacity) with respect to both pressure and diameter. This portion of the pipeline system is more aggregated (though not fully so) than the distribution networks, so in many cases a good portion of the transmission system should be available from any given access point.

Chapter 7 defines several scenarios for supplying as much as millions of tonnes of hydrogen annually to electric power plants and medium-to-heavy duty road vehicles. The "upper scenario" for fueling power plants involves producing close to 63 TWh of electric power in gas plants across the state. Guidehouse's analysis of the requirements for matching supply and demand leads to the conclusion that hundreds to thousands of tonnes of hydrogen will need to be stored for every Planning Area, except perhaps IID. Daily withdrawal rates will generally be lower than the storage system capacity, but will still reach the level of hundreds to thousands of tonnes on a number of days. Using underground fossil gas pipelines for bulk hydrogen storage at this order of magnitude presents many challenges, many of which are summarized below.

Table 7 represents a maximum amount (estimated) that the pipeline can hold, but this amount is more than what can be withdrawn in practice, as getting the full amount would require pulling the pressure down to a vacuum. In addition, due to various network complexities, in particular the fact that it consists of many lines of different sizes and desired pressures, there will likely be limits to how low the pressure may be allowed to drop and still have the system work as required. For example, keeping a stable pressure is important to maintaining the system within operating ranges of equipment (such as regulators, valves, meters, and compressors), as well as avoiding large changes in stresses and strains on the pipeline materials and ensuing fatigue and potential cracking.[226]

In fossil gas systems there are pressure regulators in many locations that ensure that pressures are stepped down to desired levels downstream of the regulator. These regulators effectively allow flow in only one direction, so hydrogen that passes a regulator must either be tapped from locations within the lower-pressure portion of the network or it will be trapped and unusable.

Pipelines in residential and commercial areas are often operated at <200 psia (13.6 bar), and even much less than 60 psia (4.1 bar). Diameters in some neighborhoods can be as small as 2 inches.[227] There will be many portions of the full system that operate at substantially equal

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[226] *Interacting Threats to Pipeline Integrity – Defined and Explained*. Interstate Natural Gas Association of America. https://ingaa.org/wp-content/uploads/2013/05/20210.pdf

[227] "PHMSA: Stakeholder Communications: Natural Gas Pipelines Systems." Pipeline and Hazardous Materials Safety Administration. https://primis.phmsa.dot.gov/comm/NaturalGasPipelineSystems.htm;

"Pipeline Basics & Specifics About Natural Gas Pipelines." Pipeline Safety Trust. https://pstrust.org/wp-content/uploads/2015/09/2015-PST-Briefing-Paper-02-NatGasBasics.pdf;

pressure but are not in flow communication with each other because that connection would require "going backwards" through regulators. The amount of hydrogen that can be stored in isolated sections of pipes of these sizes and pressures will often not be large enough to serve customers with usage large enough to merit pipeline delivery or even aggregates of smaller customers.

Because of the pipeline network topologies implied above, hydrogen production sites will typically have to inject their product into the largest diameter pipes, even if their location is closest to smaller diameter pipes in the pipeline network.

It should also be noted that production plants that use gaseous feedstock – fossil gas and/or renewable natural gas (RNG) will generally have to be fed that feedstock from their local fossil gas pipeline (which cannot have been retired), which will likely negate their local access to hydrogen injection into a fossil gas line that is no longer in use.

A large portion of California's fossil gas pipeline network would have to be upgraded to be capable of holding 100 percent hydrogen (or even high concentration blends below 100 percent) safely and sustainably. In a recent study,[228] CPUC concluded that they could not recommend a statewide standard of blending of hydrogen with fossil gas – "at which no or minor modifications are needed for fossil gas infrastructure and end-use systems" – above 5 percent hydrogen. Although a significant factor in this conclusion relates to the capability of the end-use systems, and the perspective of a statewide standard means that they had to make a recommendation for the worst case, it is still well-known that fossil gas systems in place often need significant upgrading, such as material, fittings, flow meters, and compression, to be able to accommodate more than about 20 percent hydrogen by volume.[229] This would result in a large cost, and a great deal of infrastructure work around the state, in upgrading the pipelines and installing proper leakage monitoring, prevention, and maintenance.

Fossil gas pipeline owners currently have sophisticated control systems for maintaining proper pressures, gas velocities, and energy flows throughout the system, as well as systems for performing proper accounting of inflows and outflows. In some locations the pipeline is used as fossil gas storage via "linepack."[230] These systems should be usable as a foundation for an analogous scheme to control and track the pipelines and gas flows if used for hydrogen storage. That said, there are many differences between existing systems and what would be needed for the hydrogen application. For example: (1) the use case is different (the primary function is storage, so there might be days on end when no or minimal gas needs to flow

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California Code of Regulations, Title 8, Section 536. Piping Standards. California Department of Industrial Relations. https://www.dir.ca.gov/title8/536.html;

"Pressure Testing New Gas Distribution Lines." Ralston Instruments. https://www.ralstoninst.com/applications/pressure-testing-new-gas-distribution-lines

[228] Penchev, Miroslav, Taehoon Lim, Michael Todd, Oren Lever, Ernest Lever, Suveen Mathaudhu, Alfredo Martinez-Morales, and Arun S. K. Raju. 2022. *Hydrogen Blending Impacts Study*. UC Riverside for the California Public Utilities Commission. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

[229] *Boosting EU Resilience and Competitiveness*. 2024. European Hydrogen Backbone and Gas Infrastructure Europe. https://ehb.eu/files/downloads/1732103116_EHB-Boosting-EU-Resilience-and-Competitiveness-20-11-VF.pdf

[230] Brockway, Anna. 2021. *Gas Planning and Reliability in California*. California Public Utilities Commission. https://www.cpuc.ca.gov/-/media/cpuc-website/divisions/energy-division/documents/natural-gas/long-term-gas-planning-oir/gasplanning_final_2021-12-27.pdf

through the system in addition to those when maximum flow is required), (2) the properties of hydrogen and consequent operating conditions are quite different than those of fossil gas, and (3) there may be many more injection points (and fewer withdrawal points) and a greater diversity of entities doing the injection.

Different uses of hydrogen have different product specifications, primarily with respect to purity and sometimes focusing specific contaminants (such as carbon monoxide). Unless the end users of pipeline storage have uniform needs, there will be customers who will have to pay for higher-grade hydrogen than they need, or producers who sell premium quality hydrogen for less than that quality could or should command. Alternatively, there could be customers who have to settle for the consequences of using lower-grade hydrogen because it is the only product available during a shortage; some might need to invest in purification plants that get used infrequently, just to protect their equipment from damage or their products from poor quality.

One possible approach to hydrogen storage in former fossil gas pipelines would be to break up the pipelines into local storage "units." This might obviate a number of the issues above. For example, a storage unit could contain hydrogen that is dedicated to a single user or use type (such as refueling stations), eliminating issues with mixed quality needs. A smaller amount of storage would reduce accounting complexities, upgrading costs, and more.

Storage units would have much smaller storage capacities than a more full, interconnected network and would present greater logistical issues regarding filling of the storage space if the hydrogen producer(s) is(are) not located nearby. However, the amounts of hydrogen these units would be capable of storing could well be useful for supplying fuel for transportation uses. The concept is worthy of greater study.

Geological Formations

Large quantities of hydrogen can be stored in underground structures such as salt caverns, lined rock caverns, or depleted oil and gas reservoirs. The following sections provide a more detailed analysis of these primary types of geologic storage, with each storage pathway having distinct advantages and limitations in terms of capacity, recovery efficiency, and safety considerations. . For example, underground geological storage reduces (but does not eliminate) safety concerns relative to tank storage; that is to say, subsurface storage changes the nature of safety risks (compared to aboveground tanks), shifting them from surface-level hazards to subsurface integrity, monitoring, and detection considerations. Additionally, underground storage specifically for hydrogen is not common on a large scale in the United States, the most prevalent geological storage solution being salt caverns in the Gulf Coast and Mountain West.

For some types of geological storage, technical feasibility has not been established. Other barriers to development include lack of specifications for permitting and public perception and acceptance. Once new markets for hydrogen develop on the west coast there will be a greater incentive to develop geological storage.

Table 8 summarizes the three main types of geological formations considered for hydrogen storage and their availability in the U.S. and California. Some examples of underground geological hydrogen storage facilities and pilot storage facilities around the world are listed in Table 9.

Table 8: Overview and availability of geologic underground hydrogen storage pathways

Type	Storage Mechanism	Status
Salt Cavern	• Developed by injecting fresh water into salt formations to dissolve and extract salt, leaving behind a cavernous space. • High sealing capacity and fracture development limiting due to low porosity and permeability. • Able to exist in areas with historically low-lying coastal environments or landlocked saltwater seats, such as along the Gulf Coast and Mountain West regions.	• Currently the only commercially proven method of large-scale hydrogen storage • No salt dome formations currently present in California, preventing salt cavern viability and any near-future projects.
Lined Rock Cavern (LRC)	• A subterranean chamber formed within metamorphic or igneous rock that has been artificially excavated out of rock and lined with concrete and steel, preventing leakage. • Traditionally used for storing liquids such as liquified petroleum, crude oil, and light oil.	• Appropriate rock formations are widespread throughout the U.S, including in the Sierra Nevada Mountains. • Has not yet been deployed in the U.S.; the potential of LRC is being studied.
Depleted Oil and Gas Reservoirs	• Structures containing empty pore space above water-filled reservoir rock with an impermeable cap rock above. • Existing oil and gas fields are very large, with opportunities to store high amounts of hydrogen for a long duration.	• Hundreds of existing oil and gas fields in the U.S. and California can be leveraged, requiring less initial investment.[231] • Viability of reservoirs for hydrogen usage has not yet been fully established, with reports from pilot projects by 2030.

Source: Guidehouse for CEC (2025)

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[231] Depleted oil and gas fields are available for potential reuse, subject to site-specific evaluation and infrastructure upgrades.

Table 9: Examples of geological underground hydrogen storage facilities and pilot projects

Developer(s)	Volume (tonnes)	Type	Status & Location
Conoco Philips[232]	2,400	Salt Cavern	Operational since 1983 in Clemens, TX
Air Liquide[233]	8,230	Salt Cavern	Operational since 2017 in Beaumont, TX
Chevron, Mitsubishi[234,235]	11,000	Salt Cavern	Scheduled for 2025 (30 percent blend) and 2045 (100 percent) in Delta, UT
HYBRIT (SSAB, LKAB, Vattenfall) [236,237,238]	2,540 (if the cited figure uses HHV)	Lined Rock Cavern	Pilot, operational since 2022 in Lulea, Sweden
Underground Sun Storage 2030 (RAG Austria AG) [239]	45	Depleted Gas reservoir	Research phase from 2023-2025. Operational since 2025 in Gampern, Upper Austria

Source: Guidehouse for CEC (2025)

Salt Cavern Storage

Salt caverns are the most common and proven geological storage method for hydrogen. Salt caverns are developed by injecting fresh water into salt formations of sufficient depth and thickness to dissolve and extract salt, leaving behind an open, cavernous space. They are much more effective as a storage solution than structures like aquifers because they are in an open void, and fluid flow is unimpeded by the limited permeability and porosity present in the surrounding rock formations. Salt caverns are widely recognized as favorable underground

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[232] Meeks, Noah D. 2019. *Hydrogen and Energy Storage*. Southern Company. https://www.energy.gov/sites/prod/files/2020/01/f70/fcto-fcs-h2-scale-2019-workshop-19-meeks.pdf

[233] "H2 Storage & Power." Air Liquide USA. https://usa.airliquide.com/sustainability/hydrogen/h2-storage-power

[234] Penrod, Emma. 2023. "Chevron joins Mitsubishi in 300 GWh hydrogen storage project as construction continues." Utility Dive. https://www.utilitydive.com/news/chevron-mitsubishi-hydrogen-storage-aces-delata-utah/693782/

[235] "Mitsubishi Power Welcomes Chevron as Partner in the Advanced Clean Energy Storage Project." 2023. Business Wire. https://www.businesswire.com/news/home/20230912225814/en/Mitsubishi-Power-Welcomes-Chevron-as-Partner-in-the-Advanced-Clean-Energy-Storage-Project

[236] "HYBRIT: Large-scale storage of fossil-free hydrogen gas successfully proven." 2025. HYBRIT Development. https://www.hybritdevelopment.se/en/hybrit-large-scale-storage-of-fossil-free-hydrogen-gas-successfully-proven/

[237] "Fossil-free hydrogen storage in lined rock caverns ready for industrialization." HYBRIT Development. https://www.hybritdevelopment.se/wp-content/uploads/2025/04/broschyr-hybrit-p3-eng.pdf

[238] "HYBRIT: A unique, underground, fossil-free hydrogen gas storage facility is being inaugurated in Luleå – Hybrit." 2022. HYBRIT Development. https://www.hybritdevelopment.se/en/hybrit-a-unique-underground-fossil-free-hydrogen-gas-storage-facility-is-being-inaugurated-in-lulea/

[239] "HYBRIT: Large-scale storage of fossil-free hydrogen gas successfully proven." 2025. HYBRIT Development. https://www.hybritdevelopment.se/en/hybrit-large-scale-storage-of-fossil-free-hydrogen-gas-successfully-proven/

geological spaces for hydrogen storage due to the physical and mechanical properties of salt rocks such as low porosity and permeability, high sealing capacity, and significant deformation potential that limit fracture development.[240,241]

Salt caverns exist in areas with a geological history of low-lying coastal environments or landlocked saltwater seas, where salt was deposited in thick layers over time, creating modern salt formations. They are the most common geological storage method throughout the United States, with the largest ones along the Gulf Coast and Mountain West regions due to their geologic history of marine deposition and ancient saltwater seas. No significant underground salt dome formations are present in California, because the state did not have the same type of marine depositional environment. Frequent tectonic activity prevented any significant underground salt formations from forming anywhere in the state. As a result, salt caverns are not a viable option for hydrogen storage within California.

Some storage projects in the US have been operational for some time, but larger projects are in development phases or plan to kick off soon. Chevron's Advanced Clean Energy Storage (ACES) project in Delta, Utah is currently the largest hydrogen storage initiative under development. This hydrogen facility is planned to provide fuel for the Intermountain Power Project power plant, an 840-MW blended fossil gas/hydrogen power plant. The project targets the plant, expected to begin commercial operation in 2025, using 30 percent hydrogen blend.￼ Chevron’s New Energies Company is in joint venture with Mitsubishi to produce up to 100 tonnes H_2/day via electrolysis, which will be stored in salt caverns. The project intends to use two on-site salt caverns, each capable of storing 150 GWh of energy (3,800 tonnes of H_2 if the cited figure uses the higher heating value of hydrogen).[242] Although salt cavern storage is currently the only commercially proven method of large-scale hydrogen storage, its scalability still has challenges:

- There are no known pilots for salt cavern storage in California because there are no significant salt caverns within the state.
- Hydrogen may be lost during storage due to gas interactions.[243]
- Cavern design specifically for hydrogen storage is still an ongoing concern.
- The dissolution of hydrogen into cavern brine could promote microbial activities that can produce hydrogen sulfide or cause hydrogen loss.[244] Recent advancements in the

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[240] Oni, Babalola Aisosa, Shree Om Bade, Samuel Eshorame Sanni, and Oyinkepreye David Orodu. 2025. *Underground hydrogen storage in salt caverns: Recent advances, modeling approaches, barriers, and future outlook*. Journal of Energy Storage. https://www.sciencedirect.com/science/article/abs/pii/S2352152X24045377

[241] Song, Rui, Yujia Song, Jianjun Liu, and Chunhe Yang. 2024. *Multiscale experimental and numerical study on hydrogen diffusivity in salt rocks and interlayers of salt cavern hydrogen storage*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/abs/pii/S0360319924026570

[242] ”Mitsubishi Power Welcomes Chevron as Partner in the Advanced Clean Energy Storage Project.” 2023. Business Wire. https://www.businesswire.com/news/home/20230912225814/en/Mitsubishi-Power-Welcomes-Chevron-as-Partner-in-the-Advanced-Clean-Energy-Storage-Project

[243] See, for example: Zhao, Qingqi, Yuhang Wang, and Cheng Chen. 2024. “Numerical Simulation of the Impact of Different Cushion Gases on Underground Hydrogen Storage in Aquifers Based on an Experimentally Benchmarked Equation-of-State.” arXiv. https://arxiv.org/pdf/2307.09432 (or https://www.sciencedirect.com/science/article/abs/pii/S0360319923037692)

[244] ”Hydrogen TCP-Task 42 Final Report.” International Energy Agency, Hydrogen Technology Collaboration Programme. https://www.ieahydrogen.org/task/task-42-underground-hydrogen-storage/

study of hydrogen in salt caverns have focused on improving design and construction to increase stability, structural integrity, and limit risks due to hydrogen reactivity.

- Natural impurities such as carbonates and hydrides can exist within salt beds, creating more complex chemical and mechanical storage challenges.[245]

Lined Rock Cavern Storage

A lined rock cavern is a subterranean chamber that has been excavated out of an igneous or metamorphic rock and lined with concrete and steel, structurally supported by the surrounding rock. Because they are artificially excavated from metamorphic or igneous rock, which are very widespread throughout the United States, they offer more geographic flexibility than salt caverns Due to the lining, there is less risk of hydrogen leakage and a lower potential for chemical interaction with the host rock, but there is a risk of hydrogen embrittlement of the steel, as well as potential degradation of the cavern materials due to exposure to hydrogen gas.[246] In addition to the issue of materials compatibility, high excavation and construction costs require larger amounts of capital investment than salt caverns. There are also concerns around thermal management, operational flexibility, leakage potential, and regulations around safety of operations.[247]

Lined rock caverns have traditionally been used for storing liquids such as liquified petroleum, crude oil, and light oil. The host rock must be strong enough to withstand the pressure load, meaning it can only be excavated out of igneous or metamorphic rock, not softer sedimentary formations. Lined rock caverns have not been used for hydrogen storage in the United States. The only current usage for hydrogen storage is in Sweden, with pilot projects beginning in 2022. Sweden's HYBRIT pilot facility leverages a lined rock cavern of 100 m^3 (3,531 ft^3) volume, made from hard amphibolite. The full facility is estimated to have 100,000-120,000 m^3 (3.5-4.2 $MMft^3$) to store up to 100 GWh of energy (2,540 tonnes of H_2 if the cited figure uses the higher heating value of hydrogen).[248] The HYBRIT project has reported successful tests, but it is not yet operating commercially. It will continue testing into 2026.[249]

The United States has many salt caverns throughout the southeast and Mountain West, however, there are no current or announced lined rock cavern pilot projects in the United States. California has extensive granite formations in the Sierra Nevada Mountains that are the appropriate type for lined rock caverns, but no specific pilots have occurred here. Since no

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[245] Oni, Babalola Aisosa, Shree Om Bade, Samuel Eshorame Sanni, and Oyinkepreye David Orodu. 2025. *Underground hydrogen storage in salt caverns: Recent advances, modeling approaches, barriers, and future outlook*. Journal of Energy Storage. https://www.sciencedirect.com/science/article/abs/pii/S2352152X24045377

[246] Patanwar, Yugal Kishor, Hyung-Mok Kim, Debasis Deb, and Yashwanth Kumar Gujjala. 2024. *Underground storage of hydrogen in lined rock caverns: An overview of key components and hydrogen embrittlement challenges*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/abs/pii/S0360319923045378

[247] Masoudi, Mohammad, Aliakbar Hassanpouryouzband, Helge Hellevang, and R. Stuart Haszeldine. 2024. *Lined rock caverns: A hydrogen storage solution*. Journal of Energy Storage. https://www.sciencedirect.com/science/article/pii/S2352152X24005115

[248] "HYBRIT: A unique, underground, fossil-free hydrogen gas storage facility is being inaugurated in Luleå – Hybrit." 2022. HYBRIT Development. https://www.hybritdevelopment.se/en/hybrit-a-unique-underground-fossil-free-hydrogen-gas-storage-facility-is-being-inaugurated-in-lulea/

[249] "HYBRIT: Large-scale storage of fossil-free hydrogen gas successfully proven." 2025. HYBRIT Development. https://www.hybritdevelopment.se/en/hybrit-large-scale-storage-of-fossil-free-hydrogen-gas-successfully-proven/

significant pipeline infrastructure is present in the Sierras, significant delivery infrastructure would be needed to transport hydrogen gas to demand centers.

Oil and Gas Reservoirs

Depleted oil and gas reservoirs are underground geologic structures containing empty pore space above water-filled reservoir rock with an impermeable cap rock above. They are characterized by significant permeability and pore volume and could represent the most prevalent option of the three storage methods in California. Existing oil and gas fields are very large, presenting an opportunity for a large amount of storage for long durations. There are already hundreds of depleted oil and gas fields with existing infrastructure scattered throughout the US and California (much of it in the Central Valley). It is worth mentioning that using existing wells for injection (or withdrawal) can pose challenges associated with mechanical integrity issues, since most wells in depleted oil and gas fields have been in operation for decades and may have to undergo extensive repair or re-completion, which can add to the initial cost.

The viability of using depleted oil and gas reservoirs for geological hydrogen storage has yet to be fully established. An important, recent report from Hydrogen Technology Collaboration Programme (TCP) has expressed uncertainty about when depleted oil and gas reservoirs will be ready for commercial development, though they do note that published reports from ongoing pilots are expected to be published through 2030. According to the report, "Once the pilots provide their performance data, the key focus for industry will be to evaluate, validate, and verify the learnings and set reliable strategies for full-scale commercial deployment and risk management."[250]

Aside from technical maturity issues, the TCP report (which helps address key drivers such as environmental factors, recoverability, and cost) lists eight other focus areas, covering commercial, regulatory, and economic factors. More specifically, they lay out the following as the most important issues remaining to be understood and/or solved:

- Understanding of the processes (geochemical and microbial reactions as well as hydrogeological and thermodynamic factors) involved in hydrogen's mixing, migration, and recoverability.
- Quantification of microbial and geochemical reactions, as well as how they affect hydrogen purity and key performance factors including recovery, storage, and well durability.
- Impacts of health, safety, and environmental hazards on the economics of the project.
- Geomechanical integrity of the reservoir and sealing formation.
- And whether (and how much) exposure to hydrogen affects the properties of sealing formations. The TCP points out that study of these effects on sealing formation can include microcracks that form from the mechanical stresses of injection and withdrawal cycling.

A significant EU research project that focuses on geological hydrogen storage of this type across the continent is the Hydrogen Underground Storage in Porous Reservoirs (HyUSPRe) project. The scope of this effort is rather extensive, involving seven work packages related to

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[250] "Hydrogen TCP - Task 42 Final Report." International Energy Agency, Hydrogen Technology Collaboration Programme. https://www.ieahydrogen.org/task/task-42-underground-hydrogen-storage/

porous reservoir hydrogen storage.[251] HyUSPRe developed a roadmap that shows the relationship between the various work packages.[252]

The work packages in the HyUSPRe program cover the following areas: (1) evaluation of hydrogen storage potential in porous reservoirs in Europe and mapping their location in relation to hydrogen production, demand sites, and transport infrastructure; plus experimental investigation of the effects of (2) geochemistry; (3) microbiology; (4) hydrogen flow behavior, and (5) reservoir integrity in the presence of hydrogen in the reservoir; (6) development and application of integrative multi-scale modeling to establish guidelines for suitability assessment; and finally, (6) performance of a techno-economic assessment of scenarios for hydrogen storage and developing a roadmap towards demonstration and implementation.

The HyUSPRe roadmap was generated to show the anticipated timelines and required actions for upscaling underground storage. Underground Hydrogen Storage (UHS) is projected to advance from its current TRL 6 readiness level (field testing) to full-scale commercial deployment (TRL 8) by 2040, reaching maturity broad EU-wide implementation (TRL 9) by circa 2050. According to the HyUSPRe roadmap, at this time progress is roughly in the phase of in-field demonstrations and technology development.

In summary, UHS in depleted oil and gas reservoirs in certain regions of the world has gained interest as depleted reservoirs offer significantly larger capacity (pore volume) and are more geographically widespread.

Table 10 is a list of current geological hydrogen storage projects involving porous reservoirs, as reported in 2024 and 2025 by the Hydrogen TCP and the Energy Networks Association. The Underground Sun Storage project in Rubensdorf-Gampern Germany was a demonstration that completed in or around May 2025, and is moving into a scale-up phase.[253]

Table 10: Hydrogen storage projects in depleted oil and gas fields[254]

Project Name	Country	Status
Angus+	UK	MOU with Trafigura Group
Aquamarine	Hungary	H2 storage not yet online
Green Hydrogen @Kinsale	Ireland	Pending license and planning approvals
H2RESTORE	Australia	Evaluating feasibility
HyChico	Argentina	Testing phase
HyStorage	Germany	Injection tested successfully (2024)

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[251] "Hydrogen Underground Storage in Porous Reservoirs." HyUSPRe. https://www.hyuspre.eu/

[252] *Roadmap for successful deployment of underground hydrogen storage in porous reservoirs in Europe*. 2024. HyUSPRe. https://www.hyuspre.eu/wp-content/uploads/2024/06/HyUSPRe_D7.5_Roadmap-for-successful-deployment-of-H2-storage_2024.06.11.pdf

[253] "Seasonal electricity storage in the form of hydrogen ready for scale-up." 2025. Underground Sun Storage. https://www.uss-2030.at/en/public-relations/-publications/press/details/article/seasonal-electricity-storage-in-the-form-of-hydrogen-ready-for-scale-up.html

[254] "National Gas SIF B-Linepack+ project, Appendix D7 – Review on Worldwide geological hydrogen storage demonstration projects." Energy Networks Association Innovation Portal. https://smarter.energynetworks.org/projects/10102109/;

"Hydrogen TCP - Task 42 Final Report." International Energy Agency, Hydrogen Technology Collaboration Programme. https://www.ieahydrogen.org/task/task-42-underground-hydrogen-storage/

Project Name	Country	Status
North Adriatic Hydrogen Valley	Italy	Evaluation
Rough Gas Storage Facility	UK	Operational by 2028
UGS Veľké Kapušany (H2I)	Slovakia	Undisclosed
Underground Sun Storage	Austria	Operational
Undergy	Spain	Early stages planning

Source: Guidehouse for CEC (2025)

Five of the projects appear to be in advanced development or the pilot phase but are not completed; those are Aquamarine, HyChico, H2RESTORE, Rough Gas Storage, and UGS Veľké Kapušany. The remaining projects have an unknown status or are likely still in planning or early development.

There are ongoing efforts to study the feasibility of hydrogen storage in depleted oil and gas fields in California, but these studies are still preliminary. A new assessment project called PHySiCa, run by Lawrence Berkeley National Laboratory (LBNL) in coordination with PG&E, SoCalGas, Lawrence Livermore National Laboratory (LLNL), and Sandia Labs (SNL) is studying the viability of McDonald Island in San Joaquin County and Honor Rancho in Los Angeles County as potential sites for hydrogen storage. These sites were selected because they are operational underground gas storage that have demonstrated natural gas containment. Generally, there is a screening process to determine if underground storage is suitable for gas injection, including volumetric considerations such as reservoir capacity and injectivity. The project is still in an early phase and is only conducting laboratory experiments and modeling. Depending on results, future phases could include hydrogen injection testing. There has been no estimate yet of the capacity of these sites for storing hydrogen.[255]

A Stanford study examining 182 depleted underground gas storage fields in Northern California found that only 35 that passed their screening criteria (depth, pressure, pore volume, injectivity) for hydrogen storage. However, the top 10 of their screened sites represent a total storage potential of 203.5 million tonnes (MMt) of hydrogen.[256] Most of the original 182 sites were eliminated after considering criteria such as underground pressure, permeability, porosity, faulting, earthquake record, nearby cities, access to existing pipelines, and landownership.

There are other studies across the country looking at feasibility of oil and gas field storage, including the ongoing SHASTA program,[257] which assesses the viability of geological hydrogen

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255 "State Energy Resources Conservation and Development Commission Resolution." 2025. California Energy Commission. https://www.energy.ca.gov/filebrowser/download/6994?fid=6994

256 Okoroafor, E. R., N. Nazari, T. W. Kim, H. Y. Watkins, S. D. Saltzer, and A. R. Kovscek. 2024. *Assessment of hydrogen storage potential in depleted gas fields and power-to-hydrogen conversion efficiency: A northern California case study*. International Journal of Hydrogen Energy. https://sccs.stanford.edu/sites/g/files/sbiybj17761/files/media/file/assessment-of-hydrogen-storage-potential-in-depleted-gas-fields-and-power-to-hydrogen-conversion-a-northern-california-case-study.pdf

257 "DOE National Laboratories Investigate Subsurface Hydrogen Storage." Subsurface Hydrogen Assessment, Storage, and Technology Acceleration. https://edx.netl.doe.gov/sites/shasta/

storage and is conducting studies in Alaska and Pennsylvania.[258] A study by the University of North Dakota assessed the feasibility of hydrogen storage in oil and gas fields in North Dakota in the Bakken Formation. The study concluded that there is approximately 0.8 MMt of hydrogen storage capacity across three existing wells.[259]

The PHySiCa project will "quantify the potential benefits and costs and assess the technical feasibility and risks of underground hydrogen storage" at the two California sites. This includes the possibility of using the sites to store blends of fossil gas with hydrogen. Among the potential issues that could occur in developing and implementing these sites for hydrogen storage, the investigators will study potential hydrogen loss through mixing with other gases and chemical or biological interactions, changes in rock and caprock strength due to injection of hydrogen, and the risk of well integrity failure.

In general, hydrogen interaction with the *in situ* subsurface materials is less well-known for hydrogen than for oil and gas storage and will need to be studied further. No commercial hydrogen injection in depleted oil and gas fields has occurred yet in the United States, as the current projects are still in research and have not been scaled to commercial levels.

Leakage from Geologic Storage

Leakage of hydrogen from geological storage facilities has not been thoroughly studied to date.

- **Salt caverns**: Studies of leakage of fossil gas from salt caverns report different ranges, but salt cavern storage is generally thought to have a small leakage rate. For example, one study estimated the leakage rate of a 120 bar fossil gas storage salt cavern to be 0.51 percent, 1.63 percent, 1.89 percent, 2.01 percent, 2.24 percent, and 3.61 percent for 1, 10, 15, 20, 25, and 30 years, respectively.[260] A second modeling study estimated the leakage of hydrogen to be 0.36 percent of the storage capacity over 30 years of cyclic storage at that maximum storage capacity (2,955 tonnes of H_2).[261] The leakage rate varies between sites depending on underground depth, pressure, and other factors. The most significant risk for leakage in salt caverns is likely the cement sheaths around the casings. This is an important risk for all geological storage types,

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[258] "DOE Three-Year U.S. Underground Hydrogen Storage Assessment Expands Future Opportunities in the Subsurface." 2024. U.S. Department of Energy. https://www.energy.gov/fecm/articles/doe-three-year-us-underground-hydrogen-storage-assessment-expands-future

[259] Bade, Shree Om, Emmanuel Gyimah, Olusegun Tomomewo, Rachael Josephs, Toluwase Omojiba, and Rockson Aluah. 2024. *Assessing the potential of large-scale geological hydrogen storage in North Dakota's Bakken Formation: A case study integrating wind-powered hydrogen production*. Journal of Renewable Energy. https://www.sciencedirect.com/science/article/abs/pii/S0960148124019748

[260] Chen, Xiang-Sheng, Yin-Ping Li, Ya-Long Jiang, Yuan-Xi Liu, and Tao Zhang. 2022. *Theoretical research on gas seepage in the formations surrounding bedded gas storage salt cavern*. Journal of Petroleum Science. https://www.sciencedirect.com/science/article/pii/S1995822622000279

[261] Ghaedi, Mojtaba, and Raoof Gholami. 2025. *Characterization and assessment of hydrogen leakage mechanisms in salt caverns*. Nature Portfolio Scientific Reports. https://www.researchgate.net/publication/387674597_Characterization_and_assessment_of_hydrogen_leakage_mechanisms_in_salt_caverns

but it may not be as important as integrity of the cap rock in storage types other than salt caverns.[262,263,264]

- **Lined rock caverns:** Leakage rates for lined rock caverns are also not well defined and current studies provide a range of estimates. These storage facilities are designed to be airtight, so leakage would depend on the individual engineering of a given lined rock cavern, which can leak due to degraded steel, poor welding, corrosion, or pressure changes over time.
- **Oil and gas fields:** Some leakage rates from active oil and gas fields have been investigated. A study that remotely sensed methane leakage from the five most productive basins in the United States found that the leakage rate for methane production is between 1.2 percent-1.4 percent for the Permian, Appalachian, Eagle Ford, and Bakken Basins, and is 3.9 percent for the Anadarko Basin.[265] There has been very limited information on potential hydrogen leakage from oil and gas fields, but one study modeled the loss of hydrogen from cap rock via diffusion, estimating it at an average rate of 0.0001 percent but with some reservoirs expected to leak at up to 0.8 percent.[266]

Future Feasibility of Geological Hydrogen Storage in California

A comparison of the three types of geological storage for hydrogen is provided below in Table 11. None of these three methods of geological storage have been robustly tested or proven in California, however, multiple studies are ongoing to determine the feasibility of geologic hydrogen storage in California, as mentioned above (Section 5) Salt cavern storage is not feasible in California due to the absence of salt formations, and there is not a unified consensus on potential storage capacity for the other two methods in the state. Testing of hydrogen storage in lined rock caverns is still in pilot phase and unlikely to be economically viable unless there are large existing mined caverns to be exploited. Feasibility of storing hydrogen in California's depleted oil and gas fields requires additional research and development, but this type of geological formation offers the greatest future opportunity.

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262 Gu, Chenwang, Yongcun Feng, and Xiaorong Li. 2023. "Cement Sheath Integrity in Oil and Gas Wells." *Advances in Oil and Gas Engineering*. IntechOpen. ISBN: 978-1-83768-317-8. https://www.intechopen.com/chapters/88359

263 Aboayanah, Kareem Ramzy, Yunkun Wang, Evangeline L. Eldridge, Ryan Dormer, and Bernhard Mayer. 2020. *Geomechanical assessment of potential gas leak pathways - a numerical modeling study on caprock integrity of natural gas storage site*. Geoconvention 2020. https://geoconvention.com/wp-content/uploads/abstracts/2020/57798-geomechanical-assessment-of-potential-gas-leak-pat.pdf

264 Lemieux, Alexander, Karen Sharp, and Alexi Shkarupin. 2019. *Preliminary assessment of underground hydrogen storage sites in Ontario, Canada*. International Journal of Hydrogen Energy. https://www.researchgate.net/publication/332852268_Preliminary_assessment_of_underground_hydrogen_storage_sites_in_Ontario_Canada

265 Schneising, Oliver, Michael Buchwitz, Maximilian Reuter, Steffen Vanselow, Heinrich Bovensmann, and John P. Burrows. 2020. *ACP - Remote sensing of methane leakage from natural gas and petroleum systems revisited*. European Geosciences Union. https://acp.copernicus.org/articles/20/9169/2020/

266 Ganesh, Priya Ravi, Aubrey Collie, and Derrick James. 2023. *USEA: Underground Hydrogen Storage in Depleted Reservoirs Final Report*. Battelle. https://usea.org/sites/default/files/event-/USEA633-2023-004-01_UHS_Report_FINAL.pdf

Table 11: Comparative overview of geologic storage types

Storage Type	Geology Type	Current Operating Locations	Technology Readiness	Possibility in California
Salt cavern	Salt formations in sedimentary beds	U.S. Gulf Coast, Mountain West	Currently proven and operational	Not possible
Lined rock cavern	Hard metamorphic or igneous	Sweden	Still in research with limited pilot projects	Possible, but not likely
Oil and gas reservoirs	Porous sedimentary formations	Study phase in California	In pilot and research stages	Possible, likely

Source: Guidehouse for CEC (2025)

Chapter 6:
Transport and Delivery Pathways

Key Takeaways

This chapter investigates the benefits and challenges associated with hydrogen transportation through pipelines and on-road transportation.

- The use of pipelines will be essential for large-scale hydrogen demand, but hydrogen pipeline transportation brings increased capital costs, embrittlement challenges, and leakage potential when compared to pipeline transportation of fossil gas.
- Gaseous (CGH2) tube trailers and liquid (LH2) truck transportation are the primary on-road methods to transport hydrogen. LH2 becomes more economical on a $/kg basis than CGH2 trucking for larger quantities and longer distances.

A key challenge in realizing a widespread hydrogen economy lies in efficiently transporting hydrogen from production centers – often located near abundant renewable resources for hydrogen production – to geographically dispersed points of end-use. Various transport modalities are employed or under development, each with specific advantages and limitations. These include pipelines for large, continuous flows; trucks carrying compressed gaseous hydrogen (CGH_2) for smaller volumes or shorter distances; trucks and ships carrying cryogenic liquid hydrogen (LH_2) for larger volumes or longer distances. Chemical carriers like ammonia (NH_3) or Liquid Organic Hydrogen Carriers (LOHCs) that bind hydrogen chemically for transport may also be used but will not be discussed in detail because of the extra cracking processes and associated energy required to extract the hydrogen from the carriers.

Hydrogen Pipelines

The development of a robust pipeline network is essential for connecting large-scale hydrogen production centers with large-scale demand, as pipeline transport of hydrogen is the most efficient and economical solution for transport of large volumes of hydrogen. Truck transport is more efficient for small volumes of hydrogen, regardless of distance.[267] Pipelines offer continuous delivery, economies of scale, and potentially lower long-term operational costs compared to trucking or shipping. Studies suggest that pipelines can, in fact, transmit significantly more energy than equivalent electricity transmission lines, potentially at lower cost.[268]

Dedicated hydrogen pipelines are technologically feasible and have been implemented since at least the 1930s.[269] They leverage established pipeline engineering principles, with specific adaptations for hydrogen's unique properties. Pure hydrogen pipelines typically require lower grade grades of steel (ASME B31.12 recommends X42/X52) but with increased thickness to

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[267] "E3 Technology Brief: Task 3." 2024.

[268] *Boosting EU Resilience and Competitiveness*. 2024. European Hydrogen Backbone and Gas Infrastructure Europe. https://ehb.eu/files/downloads/1732103116_EHB-Boosting-EU-Resilience-and-Competitiveness-20-11-VF.pdf

[269] Topler, J. 2006. *The Technological Steps of Hydrogen Introduction*. STORHY Train-IN 2006. https://web.archive.org/web/20090325154349/https://www.storhy.net/train-in/PDF-TI/03_StorHy-Train-IN-Session-1_3_JToepler.pdf; also, https://de.wikipedia.org/wiki/Pipeline#Wasserstoff-Pipelines

withstand the higher pressures because hydrogen is less dense and needs to be transported at higher pressures than fossil gas for the same energy flow. Pipelines must use steel resistant to hydrogen embrittlement, though fiber-reinforced polymers (FRP) can be used for lower-pressure distribution networks.

Because of hydrogen's lower density with respect to fossil gas, moving it through the pipe requires a high velocity, which can lead to erosion of the inner surface of the pipe. Thus measures, such as increasing pipeline diameter need to be taken to prevent this. Similarly, differences in hydrogen properties relative to fossil gas lead to different needs for pressure management.[4,270] While new hydrogen-dedicated pipeline builds offer optimized design, they involve additional capital investment over fossil gas pipelines due to the increased pipeline thickness and more advanced compressor needs. For smaller-diameter pipelines, the pipeline itself is most of the capital cost, except where higher flow volumes (and thus pressures) than were originally designed for are implemented; in those cases, compressor costs can also be important. For larger diameter pipelines, the compressor expense can make up about half of the total CAPEX.

Repurposing the extensive existing fossil gas pipeline network presents a compelling alternative, offering potentially significant cost savings, estimated at 10-35 percent – and potentially over 60 percent – compared to new construction.[271] This approach could accelerate infrastructure rollout by leveraging existing rights-of-way and assets. However, repurposing entails considerable technical challenges. Hydrogen embrittlement poses a serious threat to the integrity of many existing steel pipelines, especially higher-strength grades used in fossil gas transmission systems. Hydrogen's small molecular size increases the likelihood and rate of leakage compared to fossil gas, demanding advanced detection and mitigation strategies. Furthermore, every specific gas system requires thorough assessment of the compatibility of existing components like compressors, valves, and seals with pure hydrogen or high-concentration blends.

Hydrogen blends above 10 percent also trigger a change of design code from ASME B31.8 to B31.12, which is much more rigorous. The result is that an existing pipeline can get derated (reduced maximum operating pressure), which reduces its capacity. Transitioning an existing pipeline to higher blends of hydrogen is quite challenging because there will be a transition period where the fossil gas pipeline is still needed to serve existing customers, yet those customers can't handle a higher blend of hydrogen. Where there are multiple pipelines delivering fossil gas to the same delivery points, there may be an opportunity to convert one line at a time, shifting the remaining load to the other pipelines. This will be a complex process with contractual, regulatory, and rate impacts, in addition to the engineering challenges. In a recent study for CPUC, UC Riverside and the Gas Technology Institute concluded that any systemwide blending injection standard that might be imposed for the state should not be greater than 5 percent. (This is not to say that it is unsafe to blend hydrogen at a higher level at any given place within the state. Rather, because a *systemwide* standard must account for

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[270] Topolski, Kevin, Evan Reznicek, Burcin Erdener, Chris San Marchi, Joseph Ronevich, Lisa Fring, Kevin Simmons, et al. 2022. *Hydrogen Blending into Natural Gas Pipeline Infrastructure: Review of the State of Technology*. National Laboratory of the Rockies. https://research-hub.nrel.gov/en/publications/hydrogen-blending-into-natural-gas-pipeline-infrastructure-review

[271] *Boosting EU Resilience and Competitiveness*. 2024. European Hydrogen Backbone and Gas Infrastructure Europe. https://ehb.eu/files/downloads/1732103116_EHB-Boosting-EU-Resilience-and-Competitiveness-20-11-VF.pdf

all possible scenarios involving end-uses and the conditions present at any given portion of the gas system, they found 5 percent to be the highest blending ratio that is likely to be safe regardless of all these possible situations and system conditions.)[272]

Some cross-cutting challenges affect both new and repurposed pipelines. Some examples are listed below:

- Hydrogen embrittlement necessitates careful material selection, potential mitigation strategies like coatings or inhibitors, and revised operational protocols.
- Leak detection is also a priority for all hydrogen transport. Leakage monitoring is well established, and detectors have been deployed at sites where hydrogen leaks pose a safety threat. However, leakage detection has been best defined and addressed in the context of its safety risk, i.e., at a much larger scale than small leaks through seals, valves, pipes, and fittings. Development of leakage detection with very low limits will be crucial for quantifying low level leakage levels with the scale of hydrogen networks.[273,274]
- The energy required for hydrogen compression is significantly higher than for fossil gas, impacting operational costs and overall energy efficiency.
- The regulatory landscape, particularly in the United States, remains fragmented, lacking clear federal authority for siting interstate pure hydrogen pipelines and requiring harmonization of codes and standards (such as ASME B31.12) globally.

Blending Modeling Case Study – PG&E's Redwood System

Through the use of gas industry standard hydraulic modeling simulation software, CEC staff, with support from Aspen Environmental Group, assessed the types of modifications along with their associated costs that would be needed to operate an existing fossil gas transmission system with increasing levels of hydrogen blended into the pipeline gas stream while delivering the same energy heat content as provided by 100 percent fossil gas.

For this analysis, CEC staff evaluated the hydraulic model of the PG&E's Redwood System (i.e., the large-diameter and high-pressure pipelines known as Lines 400 and 401 that bring gas from Canada and the Rockies). For purposes of this analysis, it was assumed that the Redwood System would be required to maintain service to all existing customers—in other words, electrification was not analyzed as a potential solution. Figure 7 illustrates the general route and the location of five compressor stations used to push gas through the system. It also illustrates the location of underground gas storage facilities that are connected to the Redwood Path. The red lines in Figure 7 identify "local" transmission, which consists of pipelines of somewhat lower diameter that operate at lower pressures than the backbone

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[272] *Hydrogen Blending Impacts Study*. California Public Utilities Commission. https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M493/K760/493760600.PDF

[273] Fan, Zhiyuan, Hadia Sheerazi, Amar Bhardwaj, Anne-Sophie Corbeau, Kathryn Longobardi, Adalberto Castaneda, Ann-Kathrin Merz, et al. 2022. *Hydrogen Leakage: A Potential Risk for the Hydrogen Economy*. Columbia Center on Global Energy Policy. https://www.energypolicy.columbia.edu/sites/default/files/pictures/Hydrogen%20Leakage%20Regulations,%20designed,%207.21.22.pdf

[274] Aerodyne has developed a technology for hydrogen leak quantification that is being tested under an effort organized by EDF: "Measuring hydrogen emissions: A global research collaboration." Environmental Defense Fund. https://www.edf.org/measuring-hydrogen-emissions-global-research-collaboration

pipeline (trunk pipeline), which move gas from the backbone system to local distribution systems.

Figure 7: PG&E Redwood Path[275]

Source: PG&E (2025)

The analysis shows that considerable new compression must be added. Additionally, above 40 percent or higher hydrogen blending, pipeline capacity must be added to maintain acceptable operating pressures to end-use customers. The additional compression requires larger physical footprints at existing compressor stations and more fuel, regardless of whether natural gas or electricity is used to fuel those additional compressors. The overall result is that up to 10 percent hydrogen can be blended with compression only, costing in the range of $193 million.[276] Forty percent blending (17% of the mixture's energy as hydrogen) can also be

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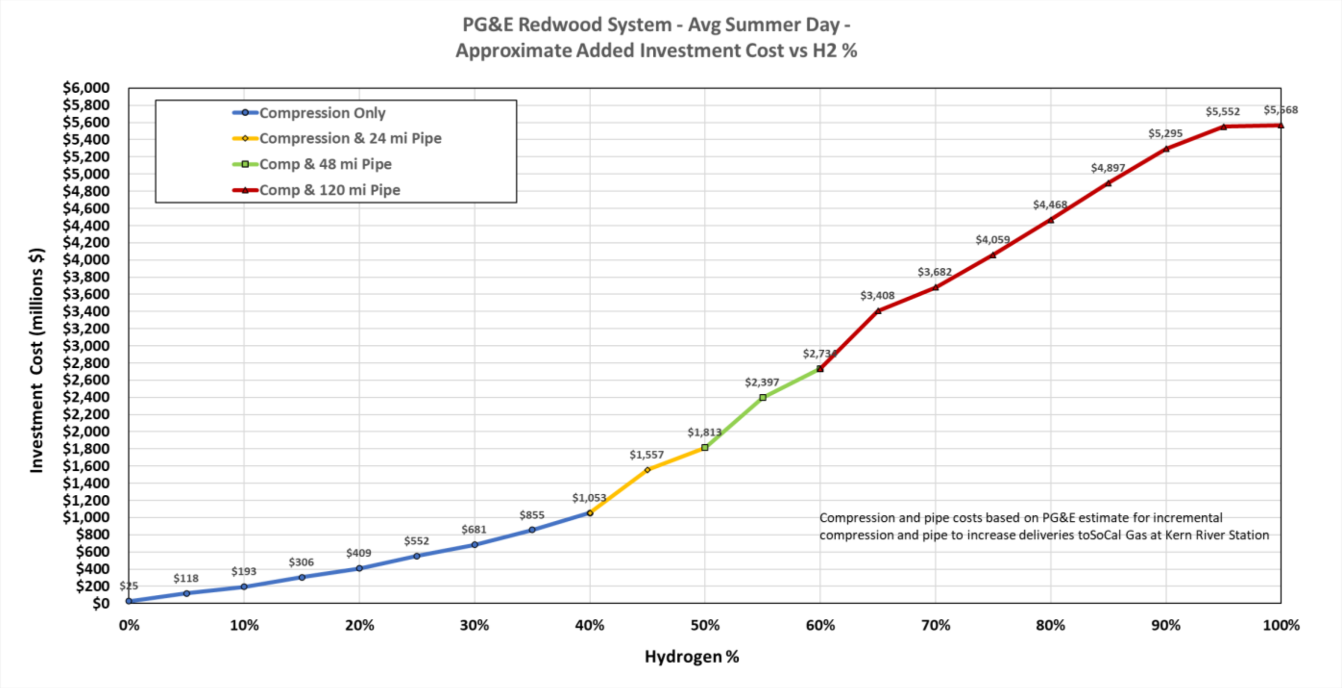
[275] Underlying figure source: "System Map." Pacific Gas and Electric Company. https://www.pge.com/pipeline/en/about-cgt/system-maps/statemap.html

[276] The cost per horsepower of compression added and miles of pipe added come from the CPUC's investigation into what physical assets it might take to retire Sempra's underground gas storage facility at Aliso Canyon. See OII 17-02-002: Pacific Gas and Electric Company's Compliance Filing In Response To Email Ruling Directing Utilities To Evaluate Costs Of Portfolios Presented By FTI And GSC, Filed December 15, 2021. However,

supported with only compression, but at an estimated cost of just over $1 billion. Blending-in more than 45 percent requires both compression and the addition of 24 miles of pipe (Figure 8). Higher levels of blending require more of both, and compressor stations may need significant redesign and replacement, with larger physical footprints and higher fuel requirements.

Figure 8: Redwood Path Cost to Add Additional Compression and Pipe for Hydrogen



Source: CEC (2025)

With no investment to modify existing facilities, the maximum feasible energy that can be delivered falls off about 3 percent for every 5 percent additional hydrogen blended into the pipeline. While further analysis would be necessary, CEC staff estimates that the effects of a 10 percent blend would not be noticeable and that the 12.4 percent drop energy drop at 20 percent blending could be tolerable.[277] By the time the hydrogen blend reaches 40 percent, the reduction in energy delivered drops by 25 percent. For the Redwood System, this amounts to a reduction of nearly 500 million cubic feet per day of today's feasible natural gas deliveries.[278] Higher hydrogen blending levels (above 40 percent) were found to be infeasible: the blades on the centrifugal compressor cannot spin any faster.[279]

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compression cost estimates do not capture any cost for additional gas cooling or the cost of land to expand compressor station footprints nor do they account for changes in compressor design.

277 Before concluding that it is tolerable, one would want to evaluate whether this reduction in energy supply would result in the need to curtail any customer load. It would certainly require some customers to shift their gas purchases towards more expensive supplies.

278 A reduction in energy supply of this magnitude would almost certainly require curtailment of customer load on higher demand days. More refined analyses could assess more precisely those demand conditions.

279 A mechanical engineer may object that this description oversimplifies; but to avoid going into compressor design details, what the CEC team found was that the compressors, as configured in the software, cannot operate at a hydrogen blend above 40 percent, without some modification.

Hydrogen Pipeline Current Status

The global hydrogen pipeline project landscape reflects significant ambition, with initiatives like the European Hydrogen Backbone[280] (ongoing) and the U.S. Regional Clean Hydrogen Hubs (H2Hubs) program planning tens of thousands of kilometers of hydrogen pipelines, often relying heavily on repurposing of fossil gas pipelines. However, it should be emphasized that recent uncertainty in H2Hubs funding has led to the cancellation of several major hydrogen projects.

The SoCalGas Angeles Link project is also set to be one of the largest hydrogen infrastructure endeavors in the United States, aimed at creating a hydrogen distribution system within Southern California. However, for a variety of reasons the number of projects reaching Final Investment Decision (FID) significantly lags announcements.[281] These reasons include challenges in securing offtake agreements; issues with financing; regulatory and incentive uncertainty; permitting issues; negative market reassessment; and project cost and supply chain issues. Overall, the challenges may be seen as involving synchronization of supply, demand, and transportation, each of which requires significant investment that will fail to earn returns without investments in the other two. Even if all of supply, demand, and transportation secure investment, misalignment of in-service dates can lead to high carrying cost of debt before cash flow starts.

Operational experience with existing hydrogen pipelines, particularly the long-standing networks in the US Gulf Coast and Europe, provides valuable data on materials performance (often lower-strength steels at moderate pressures), maintenance practices, and safety management for hydrogen transport. However, this experience is largely confined to industrial users, small diameter pipes, and moderate pressures, offering limited direct precedent for the higher pressures and broader distribution networks envisioned for the future hydrogen economy. Maintenance challenges include managing potential embrittlement over time, ensuring joint integrity, and implementing effective leak detection.

The existing network of dedicated hydrogen pipelines is relatively small compared to the fossil gas network.

- **Global:** Around 4,500-5,000 km (2,485-3,107 miles) of dedicated hydrogen pipelines exist worldwide.
- **United States:** Approximately 1,600 miles (2,575 km) are operational, primarily serving industrial clusters (refineries, chemical plants) in the Gulf Coast region (Texas, Louisiana), Illinois, and California. These pipelines typically operate at pressures below 100 bar (1450 psi). Major operators include industrial gas companies like Air Liquide and Linde (formerly Praxair).

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[280] "The European Hydrogen Backbone (EHB) initiative." European Hydrogen Backbone. https://ehb.eu/

[281] A few examples:

1. Williams, Brett. 2024. "Hydrogen Market Hiccups: Normal Delays Or Cause For Concern?" Hydrogen Fuel News. https://www.hydrogenfuelnews.com/hydrogen-market-hiccups/8567424
2. "Executive summary." *Global Hydrogen Review 2024*. 2024. International Energy Agency. https://www.iea.org/reports/global-hydrogen-review-2024/executive-summary
3. Deconinck, Carl. 2025. "'Almost one in five' European hydrogen projects scrapped in 2024." Brussels Signal. https://brusselssignal.eu/2025/01/almost-one-in-five-european-hydrogen-projects-scrapped-in-2024/

- **Europe:** Around 1,581 km of operational pipelines were reported as of May 2024. Historical examples exist, such as the 240 km Rhine-Ruhr network in Germany, operating since 1938. Other networks serve industrial areas in France, Belgium, and the Netherlands.
- **Asia:** China has approximately 400 km of hydrogen pipelines, mostly serving the petrochemical industry. Other Asian nations are in earlier stages of pipeline development.

Hydrogen Pipeline Design and Technology

Designing dedicated hydrogen pipelines involves specific considerations beyond those for fossil gas pipelines, primarily related to material compatibility, operating parameters, and compression requirements.

Materials

- **Steel:** While steel is the conventional material for pipelines, its use for pure hydrogen requires careful selection and design. Lower-strength carbon steel grades, such as API 5L X42 and X52, are generally considered more resistant to hydrogen embrittlement under typical pipeline operating conditions and are recommended in the prescriptive design option of the key industry standard, ASME B31.12. Higher-strength steels (e.g., X70, X80), common in modern fossil gas transmission lines, are more susceptible to embrittlement, although they may be permissible under ASME B31.12's performance-based design options, which require rigorous fracture mechanics analysis and material testing to demonstrate fitness-for-service. Stainless steels, like grade 316L, exhibit good resistance to hydrogen effects but come at a higher material cost. Ongoing research continues to explore new steel alloys with improved hydrogen resistance.
- **Composites/polymers:** Non-metallic materials offer an alternative to avoid embrittlement issues but mainly for lower pressure pipelines over medium-to-short distances. Fiber-Reinforced Polymer (FRP) pipelines potentially offer installation cost savings of around 20 percent compared to steel due to the availability of longer pipe sections, which minimizes the need for joining (e.g., welding). Polyethylene (PE) pipes (e.g., PE100) are suitable for lower-pressure hydrogen distribution networks. However, a key consideration for polymers is hydrogen permeation; hydrogen permeates through PE at rates significantly higher than methane, necessitating assessment of potential gas loss and safety implications in enclosed spaces. Further testing and standardization for non-metallic materials in hydrogen service are needed.

Operating Pressures and Diameters

- **Pressures:** While transmission pipelines often operate at high pressures (up to about 100 bar), higher pressures are generally considered necessary for hydrogen pipelines to increase volumetric energy density and improve the economics of long-distance transport. Pressures up to 100 bar are common targets in new designs, aligning with or slightly exceeding typical natural gas transmission pressures. The ASME B31.12

standard provides the framework for designing pipelines to safely handle these pressures, considering hydrogen's effects.[282]

- **Diameters:** New hydrogen pipes will need to be larger in diameter than natural gas pipes to transport the volume needed for an equivalent amount of energy.

Compression

- **Energy penalty:** Compressing hydrogen requires substantially more energy than compressing fossil gas to achieve the same pressure ratio or energy throughput. Compressors may need up to three times the driver power compared to fossil gas service for equivalent energy flow.[283] This energy consumption represents a key operational cost and efficiency loss for hydrogen pipelines.
- **Compressor types:** Reciprocating (piston or diaphragm) compressors are well-established for achieving high pressures required in some hydrogen applications but may have limitations in the high flow rates needed for large transmission pipelines.[284] Centrifugal compressors are preferred for high-volume gas transport but require significantly higher rotational speeds for hydrogen due to its low density, pushing material and design limits. Significant advancements are being made in developing specialized centrifugal compressors (e.g., using high-speed impellers, advanced materials, specialized bearings) capable of efficiently handling large volumes of pure hydrogen for pipeline applications. Ionic compressors represent another emerging technology.

Hydrogen Pipeline Challenges

While there is optimism about hydrogen energy, building pipelines has raised concerns about safety, transparency, and environmental justice. The UC Irvine Hydrogen Blending project faced opposition from students and faculty due to safety concerns and a lack of transparency.[285] While proponents argued that it supported California's climate goals, many students and faculty expressed opposition, citing safety concerns and a lack of transparency. Student organizations drafted a resolution in opposition to the project, citing reasons such as ignition concerns and displacing areas vital for students, such as a popular recreation facility and those living near the pipeline.[286] Similar concerns have been raised about Western Pennsylvania's proposed hydrogen hubs, ARCH2 and DNA, which have been criticized for lacking community engagement.[287] Local organizations express concerns about cutting out impacted community members from operation and infrastructure plans, while also raising

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[282] Martin, Paul, Ilissa B. Ocko, Sofia Esquivel-Elizondo, Roland Kupers, David Cebon, Tom Baxter, and Steven P. Hamburg. 2024. *A review of challenges with using the natural gas system for hydrogen.* SCI Journal of Energy Science and Engineering. https://scijournals.onlinelibrary.wiley.com/doi/10.1002/ese3.1861

[283] Ibid.

[284] Melaina, M. W., O. Antonia, and M. Penev. 2013. *Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues*. National Renewable Energy Laboratory. https://docs.nrel.gov/docs/fy13osti/51995.pdf

[285] "Proposed Hydrogen Blending Demonstration Project." UC Irvine. https://uci.edu/hydrogen/

[286] Rios, Hugo. 2025. "Irvine at Odds Over Proposed Hydrogen Pipeline on UCI campus." Voice of OC. https://voiceofoc.org/2025/04/irvine-at-odds-over-proposed-hydrogen-pipeline-on-uci-campus/

[287] Frazier, Reid. 2023. "Groups say 'clean' hydrogen projects lack transparency and fear climate, safety impacts." The Allegheny Front. https://www.alleghenyfront.org/blue-hydrogen-natural-gas-pennsylvania-climate-change

questions about the health impacts of local communities. Additionally, environmental justice concerns are prominent, particularly with projects like the Southern Trails Hydrogen Pipeline, which would impact several Navajo communities.[288] Members of these nations have raised concerns of fuel leaking into surrounding environments and human health impacts, as these areas do not have internet or a way of quickly communicating in the event of an accident.[289]

Ultimately, the development of hydrogen pipeline infrastructure is strategically vital for enabling a large-scale hydrogen economy. The optimal path forward will likely involve a combination of new dedicated pipelines and targeted repurposing of existing assets, dictated by the availability of existing pipelines relative to serving existing customers. Continued research and development, robust policy support, international collaboration, the establishment of clear, harmonized standards, and community engagement are essential to unlock the potential of hydrogen pipelines.

Compressed Hydrogen Tube Trailers

Tube trailers serve an indispensable role in the hydrogen economy, providing a flexible and often economically viable method for transporting compressed gaseous hydrogen (CGH_2). They are particularly crucial for delivering hydrogen over distances where dedicated pipeline infrastructure is either unavailable or not economically justified, and for supplying hydrogen to a diverse range of end-users, including industrial facilities and a growing network of hydrogen refueling stations. Most of the hydrogen moved globally, especially for distances less than 300 km, relies on compressed gas tube trailer trucks.

Gas pressures in tube trailers span a considerable range, from approximately 165 bar in older, steel-cylinder-based systems to over 900 bar in cutting-edge designs utilizing composite materials. A common regulatory baseline, particularly in the United States, has been 250 bar for standard tube trailers.[290] However, the demand for increased efficiency and larger payloads has driven the adoption of higher pressures. Modern composite trailers frequently operate at pressures between 250 bar and 500 bar, often facilitated by regulatory exemptions or special permits.[291] Pressures as high as 700 bar are an emerging target.[292]

This upward trend in operating pressure is intrinsically linked to the fundamental properties of hydrogen; higher pressures result in increased gas density, enabling significantly larger quantities of hydrogen to be transported per trailer. This enhancement in carrying capacity, with recent models capable of transporting 1 metric ton (tonne or MT) or more of hydrogen, directly translates to improved logistical efficiency and reduced transportation costs. Technological advancements, most notably the development and adoption of lightweight,

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[288] "Navajo activists oppose Arizona-New Mexico hydrogen pipeline that could be world's longest." 2025. Oil and Gas Watch. https://news.oilandgaswatch.org/template/brief/navajo-activists-oppose-arizona-new-mexico-hydrogen-pipeline-that-could-be-worlds-longest

[289] Redfern, Jerry. 2023. "Industry Wants New Pipeline on Navajo Land Scarred by Decades of Fossil Fuel Extraction." Inside Climate News. https://insideclimatenews.org/news/14072023/industry-new-pipeline-navajo-land-scarred-by-fossil-fuel-extraction/

[290] "Gaseous Hydrogen Delivery." U.S. Department of Energy. https://www.energy.gov/eere/fuelcells/gaseous-hydrogen-delivery

[291] "Increased hydrogen capacity of GH_2 road trailers." Commissione europea. https://cordis.europa.eu/programme/id/HORIZON_HORIZON-JTI-CLEANH2-2022-02-07/it

[292] Brown, Andy. 2019. "Hydrogen Transport." The Chemical Engineer. https://www.thechemicalengineer.com/features/hydrogen-transport/

high-strength carbon fiber composite cylinders (Type III and Type IV), have been pivotal in safely achieving these higher pressures and capacities, overcoming the weight limitations inherent in traditional steel tube trailers.

Tube Trailer Current Status

The pressures used for transporting hydrogen in tube trailers today cover a spectrum, reflecting the mix of older and newer technologies in service, varying regulatory environments, and different operational requirements. The 200-250 bar pressure range remains relevant, particularly for the legacy fleet of steel tube trailers still in operation and as a baseline regulatory pressure in certain jurisdictions. Federal Department of Transportation (DOT) regulations have historically limited hydrogen tube trailers to a maximum allowable working pressure (MAWP) of 250 bar.[293] Consequently, this pressure serves as a common reference point, and some manufacturers explicitly offer 250 bar systems for various industrial gases, including hydrogen. While this 250 bar limit provides a standard, it often acts as a regulatory baseline from which deviations, typically through exemptions or special permits, are increasingly sought to leverage the higher efficiency offered by modern composite trailer technologies.

Tube Trailer Design and Technology

Tube trailers are currently categorized into four types depending on their material type and fill pressures, with higher type trailers able to hold higher pressures.

Steel Tube Trailers (Type I Cylinders)

Historically, hydrogen tube trailers were constructed using Type I cylinders, which are made entirely of steel. These trailers operated at relatively low pressures compared to modern systems. Typical fill pressures for these older steel tube trailers ranged from 160-200 bar. U.S. Department of Transportation (DOT) regulations eventually led to a common operating limit, often cited around 250 bar, although some manufacturers also list 166 bar as a national requirement option for certain industrial gas tube skids.[294]

The primary constraint on the capacity of these trailers was the substantial weight of the steel tubes themselves. To comply with road weight limitations, the amount of heavy steel that could be used was restricted, which in turn limited both the volume and the pressure of hydrogen that could be transported. The pressure limitations in these early steel tube trailers were not solely due to an inability of steel to withstand higher pressures per se, but rather a complex interplay between the material's strength, the resulting cylinder weight, and overall vehicle gross weight restrictions. Maximizing the hydrogen payload involved a trade-off: increasing pressure would require thicker, heavier steel walls, potentially reducing the net hydrogen carried due to the fixed road weight limits. Thus, an "optimal" pressure for steel trailers was established that balanced hydrogen density with the weight of the containment system itself.

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[293] "Hydrogen Tube Trailers." U.S. Department of Energy. https://www.energy.gov/eere/fuelcells/hydrogen-tube-trailers

[294] Ordin, Paul M. 1997. "Safety Standards for Hydrogen and Hydrogen Systems." NASA Office of Safety and Mission Assurance. https://ntrs.nasa.gov/api/citations/19970033338/downloads/19970033338.pdf

Composite Tube Trailers (Type III and Type IV Cylinders)

A significant leap in hydrogen transport capability came with the development and adoption of composite materials. These materials, primarily carbon fiber composites, offer much higher strength-to-weight ratios than steel, enabling the construction of lighter cylinders capable of withstanding greater pressures. Two main types of composite cylinders are prevalent:[295]

- **Type III cylinders:** These feature a metallic liner, typically aluminum, which is fully wrapped with a carbon fiber composite material. The metal liner acts as a gas barrier.
- **Type IV cylinders:** These consist of a polymeric (plastic) liner, such as high-density polyethylene (HDPE), also fully wrapped with a carbon fiber composite. The composite wrap bears the structural load.[296]

The introduction of these lighter, stronger materials has allowed for a substantial increase in operating pressures. Some Type IV cylinders are designed for pressures up to 700 bar and the European Union's strategic research agenda targets an operating pressure of 700 bar for hydrogen trailers by 2030.[297] These higher pressures directly translate to increased hydrogen carrying capacities. Thus, modern composite tube trailers can transport significantly more hydrogen, with capacities typically ranging from 560-900 kg per trailer. Furthermore, advanced designs are now achieving or exceeding 1000 kg of capacity.[298]

The lighter weight of composite cylinders means that a greater proportion of the trailer's gross vehicle weight can be allocated to the hydrogen payload itself, even at higher pressures that would necessitate prohibitively thick and heavy steel walls. Composites greatly reduce the restrictive linkage between pressure capability and excessive container weight that characterized steel trailers, which is the primary driver behind the substantial increase in hydrogen transport efficiency.

Tube Trailer Challenges

Transporting compressed hydrogen via tube trailer presents a unique set of technical, operational, and economic hurdles.

- **Material stresses:** Technically, the small size of the hydrogen molecule and its capacity to cause hydrogen embrittlement in conventional steel demands more advanced and costly materials. Trailers must utilize specialized composite-lined cylinders or advanced alloys to mitigate the risk of material degradation and catastrophic failure over time. Furthermore, to achieve a practical payload, hydrogen is compressed to extremely high pressures which places immense stress on every valve, fitting, and cylinder in the system.
- **Lower payload:** A CGH2 tube trailer carries a relatively small amount of energy compared to trailers for liquid fuels, requiring more frequent trips to supply a location, which in turn increases transport costs and logistical complexity.

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[295] Mitchell, J. 2024. "The advantages of high-pressure H_2 transport." H2TECH. http://admin.h2-tech.com/articles/2024/july-2024/h2-equipment-and-services/the-advantages-of-high-pressure-h-sub-2-sub-transport/

[296] "Type 4 Storage & Transport." H2Hauler. https://www.H2hauler.com.au/type-4-storage-transport/

[297] "Increased hydrogen capacity of GH_2 road trailers." 2022. Horizon Europe. https://www.horizon-europe.gouv.fr/increased-hydrogen-capacity-gh-2-road-trailers-29672

[298] "CALVERA HYDROGEN develops the largest ever hydrogen transport tube trailer model for Shell Hydrogen." 2023. CALVERA Hydrogen. https://www.calvera.es/calvera-hydrogen-develops-the-largest-ever-hydrogen-transport-tube-trailer-model-for-shell-hydrogen/

- **Lower pressure ranges:** Pressure decay, particularly in older generation trailers, occurs when the trailer is unloaded, the internal pressure drops causing downstream challenges. Applications such as vehicle refueling stations require consistently high inlet pressure. This often results in a portion of the hydrogen not being dispensable without using recompression equipment at the delivery site, which can impact the economic viability of the "virtual pipeline" model.

Table 12: Comparative overview of hydrogen tube trailer pressures and capacities

Trailer generation / cylinder type	Typ. operating pressures (bar)	Common pressures (bar)	Typical H_2 capacity (kg)	Key regulatory context or enabler	Primary application or rationale
Older steel (Type I)	165 - 250	180, 200, 250	200 - 380	Standard DOT limit (US), traditional technology	General industrial, early hydrogen transport
Modern composite (Type III)	200 - 517	250, 350, 450, 517	400-900	DOT exemption/ special permit (US), advanced materials, int'l standards	High-efficiency transport, industrial supply, refueling stations
Advanced composite (Type IV)	350 - 700	350, 500, 517, 700 (design / target)	560-1000+	DOT exemption/ special permit (US), lightweight materials, ISO standards	Very high-capacity transport, emerging direct high-pressure filling
Specialized ultra-high-pressure composite (Type IV)	> 700	875 931	480-1000+ (payload varies)	DOT special permit (US), cutting-edge technology	Direct filling of 700 bar vehicle tanks, max payload density

Source: Guidehouse for CEC (2025)

Gas Compression for Tank Storage Applications

Mechanical compressors are the type most commonly employed at refueling stations; of these, mainly reciprocating piston and diaphragm types are used. Compressors can have a single stage but are often deployed with multiple stages (up to five), depending on required discharge pressure.[299] Their efficiencies range significantly with type and design, from as low as 40-45 percent to as high as 85 percent, with most being somewhere in the middle of this range. One study asserts that mechanical compressor CAPEX accounts for over half of the capital investment required for a hydrogen refueling station, that the operating expenses

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[299] Ibid.

comprise more than 20 percent, and the energy consumed in compression is at least 30 percent of total station energy.[300]

Ionic liquid compressors have been specifically developed to improve the efficiency of hydrogen compression. In these compressors, solid pistons are supplemented with a layer of molten salt[301] with a low melting point. The technology has achieved an energy efficiency of close to 70 percent.[302] Because the liquid does not allow hydrogen gas to pass, seals and bearings can be reduced, which cuts capital and maintenance costs.[303] This type of compressor does have issues with corrosion, liquid leakage, and cavitation, though corrosion can be reduced with the use of AISI 316L stainless steel.[77]

Electrochemical hydrogen compressors (EHCs) are noiseless and vibrationless non-mechanical compressors that can reach pressures as high as 1000 bars and have an efficiency in the range of 60-90 percent. EHCs require very good humidity control to ensure that the electrochemical membrane is sufficiently hydrated. In addition, structural components of the compressor must be very strong so that there is not deformation of the membrane, especially at higher pressures.[304]

Liquid Hydrogen (LH_2) Tankers

One of hydrogen's primary logistical hurdles is its extremely low density under ambient conditions (2.4 kg per 1,000 ft^3 at standard temperature[305] and pressure vs. about 25 kg per 1,000 ft^3 for natural gas[306]). Although hydrogen has a higher energy per unit of mass, this low volumetric density overrides that advantage, leading to hydrogen only having a volumetric energy density of 324 Btu/(standard ft^3) vs. fossil gas' energy density of approximately 1035 Btu/(standard ft^3).[307] Thus, storing and transporting meaningful quantities of hydrogen gas is

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[300] Sdanghi, Giuseppe, Gael Maranzana, Alain Celzard, and Vanessa Fierro. 2020. *Towards Non-Mechanical Hybrid Hydrogen Compression for Decentralized Hydrogen Facilities*. Energies. https://www.mdpi.com/1996-1073/13/12/3145

[301] "Linde standard hydrogen filling station with IC90 compressor." Linde on YouTube. https://www.youtube.com/watch?v=usaQrCDORFY

[302] Sdanghi, Giuseppe, Gael Maranzana, Alain Celzard, and Vanessa Fiero. 2019. *Review of the current technologies and performances of hydrogen compression for stationary and automotive applications*. Renewable and Sustainable Energy Reviews. https://hal.univ-lorraine.fr/hal-02014572/file/Review_H2compression_tohal.pdf;

Sdanghi, Giuseppe, Gael Maranzana, Alain Celzard, and Vanessa Fierro. 2020. *Towards Non-Mechanical Hybrid Hydrogen Compression for Decentralized Hydrogen Facilities*. Energies. https://www.mdpi.com/1996-1073/13/12/3145

[303] "Ionic Liquid Piston Compressor." Wikipedia. https://en.wikipedia.org/wiki/Ionic_liquid_piston_compressor

[304] Sdanghi, Giuseppe, Gael Maranzana, Alain Celzard, and Vanessa Fiero. 2019. *Review of the current technologies and performances of hydrogen compression for stationary and automotive applications*. Renewable and Sustainable Energy Reviews. https://hal.univ-lorraine.fr/hal-02014572/file/Review_H2compression_tohal.pdf

[305] EIA's standard temperature for natural gas is 60°F: "Natural Gas Annual – Glossary." 2024. U.S. Energy Information Administration. https://www.eia.gov/naturalgas/annual/pdf/glossary.pdf

[306] "Natural Gas Density Calculator." UNITROVE. https://www.unitrove.com/engineering/tools/gas/natural-gas-density

[307] "California Heat Content of Natural Gas Deliveries to Consumers." U.S. Energy Information Administration. https://www.eia.gov/dnav/ng/hist/nga_epg0_vgth_sca_btucfa.htm

Note that "Standard cubic foot" is typically abbreviated as "scf."

inefficient without significant volume reduction, which is done by either pressurizing or liquefying the gas.

Liquefaction, the process of cooling hydrogen gas to its boiling point of -253°C (20 K or -423°F), dramatically increases its density to 70.8 kg/m³.[308] This densification allows specialized cryogenic tankers (road, rail, or sea) to carry substantially more hydrogen mass within a given volume compared to compressed gas tube trailers, up to about 4.6 tonnes of H_2.[309]

Consequently, LH_2 transport becomes more economical on a $/kg basis than CGH_2 trucking for larger quantities and longer distances. This improved transport efficiency is a significant part of the motivation for considering LH_2 as a hydrogen delivery vector. A 2024 report from NREL[310] estimated that transporting liquid hydrogen would cost \$0.12/kg H_2 for a 6.2 miles round trip distance and \$0.20/kg H_2 for 120 miles round trip (2022$). This cost is consistent with an IEA report[311] that estimates \$0.25/kg H_2 for 120 miles for liquid H_2. A report[312] by the Hydrogen Council estimates that liquid hydrogen distribution costs will drop from \$0.40/kg H_2 to \$0.20/kg H_2 from 2020-2030 assuming a 186-311-mile distribution.

The standard method for transporting liquid hydrogen over roads involves specialized vehicles commonly referred to as "tanker" trucks or cryogenic semitrailers. These vehicles are equipped with heavily insulated cryogenic tanks (dewars) designed to maintain LH_2 at temperatures below the boiling point of hydrogen. This technology is distinct from "tube trailers," which transport compressed gaseous hydrogen (CGH_2) in high-pressure cylinders.

Efforts are ongoing to maximize payload within the constraints of road weight regulations. Chart Industries has highlighted an "industry first" LH_2 cryogenic trailer with a 10,160-pound (4,608 kg) payload, compliant with US Department of Transportation (DOT) and California bridge laws.[313]

It should be noted that maximum payloads of LH_2 trailers are slightly lower than cited volumetric capacities, most likely to ensure that there is space for liquid boil off, particularly if temperatures should rise.[314]

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[308] *Safety in Storage, Handling and Distribution of Liquid Hydrogen*. 2002. European Industrial Gases Association. https://h2tools.org/sites/default/files/Doc6_02SafetyLiquidHydrogen.pdf

[309] *Heil Liquid Hydrogen Transport Brochure*. HEIL Trailer. https://heiltrailer.com/wp-content/uploads/2024/09/Heil_LHT_Brochure_091924_HR_-1.pdf;

Chart LH2 Transport Trailer ST-18600H 155 brochure. Chart Industries. https://files.chartindustries.com/LH2TransportTrailerSpecSheetST18600H.pdf

[310] Bracci, Justin, Mariya Koleva, and Mark Chung. 2024. *Levelized Cost of Dispensed Hydrogen for Heavy-Duty Vehicles*. National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy24osti/88818.pdf

[311] International Energy Agency. 2019. "The Future of Hydrogen." Organisation for Economic Co-operation and Development. https://doi.org/10.1787/1e0514c4-en

[312] "Path to Hydrogen Competitiveness a Cost Perspective." 2020. Hydrogen Council. https://hydrogencouncil.com/wp-content/uploads/2020/01/Path-to-Hydrogen-Competitiveness_Full-Study-1.pdf

[313] *Chart LH2 Transport Trailer ST-18600H 155 brochure*. Chart Industries. https://files.chartindustries.com/LH2TransportTrailerSpecSheetST18600H.pdf

[314] E.g., the gross capacity of the Chart Model ST-17600H 155 is 17,600 gallons of liquid, but the maximum permissible weight of liquid corresponds to 16,194 gallons of LH2.

LH_2 Design

LH_2 road tankers employ sophisticated insulation systems to minimize heat ingress and subsequent boil-off. The core component is a double-walled tank, typically cylindrical, where a vacuum is maintained in the annular space between the inner vessel holding the LH_2 and the outer jacket. This vacuum effectively minimizes heat transfer via conduction and convection. Additional insulation materials are often used within the vacuum space. Common systems include vacuum jacketing combined with perlite powder fill or multiple layers of reflective material known as multi-layer insulation (MLI). The entire design must adhere to stringent safety regulations governing the transport of hazardous materials, such as those mandated by the US DOT.[315]

LH_2 Operational Considerations

LH_2 tanker trucks are generally considered more economical than CGH_2 tube trailers for longer transport distances, typically cited as being more economic for routes more than 200 miles, although the exact crossover distance depends on specific cost assumptions and volumes.[316] Loading and unloading times are significantly long; one manufacturer estimates approximately four hours to fill a trailer and one hour to off-load the LH_2.[317] A crucial operational factor impacting effective payload is the need to maintain cryogenic temperatures in the trailer during its return journey to the liquefaction plant. This necessitates leaving a residual amount of LH_2 (a "heel") of about 5 percent in the tank,[318] reducing the usable volume delivered to the customer, when combined with free space above the liquid ("ullage") totaling potentially to 90 percent or less of the total tank capacity.[319]

LH_2 Challenges

Despite the density advantage, utilizing LH_2 presents significant technical and economic challenges:

- **Extreme cryogenic temperatures:** Maintaining hydrogen below its boiling point of -253°C necessitates highly specialized, robustly insulated cryogenic containers, commonly known as dewars or cryogenic tanks. These systems typically employ double walls with a vacuum annulus and advanced insulation materials to minimize heat ingress. Handling such extreme temperatures requires specific materials, equipment, and safety protocols.

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[315] "Hazardous Materials Special Permits Search." Pipeline and Hazardous Materials Safety Administration. https://www.phmsa.dot.gov/approvals-and-permits/hazmat/special-permits-search

[316] "E3 Tech Brief 3."

[317] Tamhankar, Satish. 2014. *Terminal Operations for Tube Trailer and Liquid Tanker Filling*. U.S. Department of Energy. https://www.energy.gov/sites/prod/files/2014/07/f17/fcto_2014_h2_trans_dist_wkshp_tamhankar.pdf

[318] Hallett, N. C. 1968. *Study, Cost, and System Analysis of Liquid Hydrogen Production*. NASA. https://ntrs.nasa.gov/api/citations/19680018755/downloads/19680018755.pdf;

Brouzas, Spyridon, Mehdi Zadeh, and Benjamin Lagemann. 2025. *Essentials of hydrogen storage and power systems for green shipping*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/pii/S0360319924054600

[319] Ahluwalia, R. K., H. S. Roh, J-K Peng, and D. Papadias. 2022. *On-board Liquid Hydrogen Storage for Long Haul Trucks*. Argonne National Laboratory. https://www.energy.gov/sites/default/files/2022-03/Liquid%20H2%20Workshop-ANL2.pdf

- **Liquefaction energy penalty:** The process of cooling hydrogen gas to cryogenic temperatures is energy intensive. Current industrial-scale liquefaction technologies consume between 10 and 13 kWh of energy per kilogram of hydrogen liquefied (kWh/kg LH_2). Some sources cite ranges up to 15 kWh/kg or even 20 kWh/kg, depending on scale and technology. This energy consumption represents a substantial fraction (approximately 30-40 percent) of the hydrogen's own lower heating value (LHV) of ~33.3 kWh/kg.[320] This energy penalty significantly impacts on the overall energy efficiency and cost-effectiveness of the LH_2 pathway.
- **Boil-off losses:** Despite advanced insulation, some heat inevitably leaks into cryogenic containers from the warmer environment. This heat input causes a continuous evaporation of the LH_2, generating hydrogen gas known as boil-off gas (BOG). If the tank is sealed, BOG generation causes pressure to rise; if vented or combusted to maintain safe pressure, it results in a loss of valuable hydrogen product. This phenomenon occurs during storage, transport, loading, and unloading operations.[321]
- **Material considerations:** Materials used in LH_2 systems must maintain structural integrity and appropriate mechanical properties at extremely low temperatures. While LH_2 itself is non-corrosive, it is essential that material properties be able to handle cryogenic conditions. For example, certain materials transition from being ductile to being brittle under such conditions.[322] Additionally, while less of a concern for LH_2 compared to high-pressure gaseous hydrogen, potential hydrogen embrittlement effects in certain materials under specific conditions must still be considered in system design.[323]

CGH_2 vs. LH_2 for On-Road Delivery of Hydrogen

The physical state of hydrogen chosen for a given application – gaseous (CGH_2) or liquid (LH_2) – depends on a number of factors, the most important of these being the economics and the best technical fit to the application. The overall economics of using H_2 in a given form involve the following factors as the material flows through the value chain: (1) the cost of conversion from produced hydrogen (compression vs. liquefaction), (2) the cost of transport from production to delivery points, (3) the cost of storage in the given form, and (4) costs associated with any material losses (e.g., boil-off or blowoff) anywhere in the value chain. All of these factors involve significant trade-offs in logistics, on-site infrastructure, and demand volume.

The following discussion addresses these trade-offs and applies them to a case where there are no deciding technical factors that mandate a choice of one option over the other. Because

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[320] "Liquid Hydrogen Delivery." U.S. Department of Energy. https://www.energy.gov/eere/fuelcells/liquid-hydrogen-delivery

[321] Notardonato, W. U., A. M. Swanger, J. E. Fesmire, K. M. Jumper, W. L. Johnson, and T. M. Tomsik. *Zero Boil-Off Methods for Large Scale Liquid Hydrogen Tanks using Integrated Refrigeration and Storage*. NASA. https://ntrs.nasa.gov/api/citations/20170006481/downloads/20170006481.pdf

[322] Brouzas, Spyridon, Mehdi Zadeh, and Benjamin Lagemann. 2025. *Essentials of hydrogen storage and power systems for green shipping*. International Journal of Hydrogen Energy. https://www.sciencedirect.com/science/article/pii/S0360319924054600

[323] "Hydrogen transportation." *The ANZ Hydrogen Handbook Vol II*. ANZ. https://www.anz.com/content/dam/anzcom/pdf/institutional/reports/hydrogen-transportation.pdf

this is currently most relevant for transportation end use, the discussion focuses on that application in this section.

While liquid hydrogen has historically been viewed as the more scalable option for refueling stations in the U.S., recent technological and regulatory advancements in Class IV high-capacity gaseous transport are fundamentally altering the economic calculus. Class IV tanks make CGH_2 a more viable solution than before for many emerging applications, particularly those with small-to-medium scale demand. A nuanced understanding of the pros and cons of each delivery pathway is critical.

Logistics: Payload

A primary logistical advantage of LH_2 is its superior energy density by volume, which allows a single cryogenic tanker to transport a larger quantity of hydrogen (up to 4,500-5,000 kg) compared to about 1000 kg in a Type IV composite CGH_2 tube trailer. This translates to fewer required delivery trips for the same amount of hydrogen, which can be a critical advantage in regions with shortages of qualified hazardous materials drivers or where minimizing traffic to a site is a priority.

However, this payload advantage comes at a steep price, as would be expected when considering the technical and economic factors discussed in the previous section. The total delivered cost of LH_2 is significantly inflated by several factors:

- **High capital costs:** Liquefaction plants are large, capital-intensive facilities, costing hundreds of millions of dollars.
- **High energy consumption:** The process of liquefying hydrogen is extremely energy-intensive, consuming at a level of 30-40 percent of hydrogen’s own energy content.
- **Boil-off losses:** During transit and transfer, a portion of the liquid hydrogen naturally evaporates or "boils off," resulting in direct product loss. Without extra measures to reduce boil-off, it can amount to 15 percent or more of the cargo.

Consequently, while CGH_2 delivery requires more frequent trips, its dramatically lower capital and energy overhead can result in a delivered fuel cost as much as \$5/kg H_2 lower than LH_2.[54] For a fleet operator, the trade-off becomes a decision between fewer, more expensive LH_2 deliveries and more frequent CGH_2 deliveries.

Refueling Operations and On-Site Infrastructure

The form of delivered hydrogen directly impacts the complexity and cost of the on-site equipment needed to dispense the product into a vehicle. To refuel a vehicle, hydrogen must be delivered from a station's storage into the vehicle's tank at a specific target pressure, typically 350 bar or 700 bar.

As a comparison to some of EU’s refueling stations, Switzerland has less than 1000 Hyundai FCE trucks, mostly operated by two large grocery chains. Delivered hydrogen has a distribution cost of about \$1.12/kg (mostly small startups with low management overhead compared to the bigger companies) and \$8-10/kg total pump costs for a green/grey combination (electrolytic hydrogen is much more expensive than anticipated) compared to \$4-6/kg grey H_2.

The European Union Light-Duty vehicle infrastructure is in expansion and has approximately 60 Light Duty / 700 bar stations using the new Maximator hardware with less than \$2M total station cost and 96 percent uptime. As of January, 2026, there are at least 186 hydrogen refueling stations in the EU,[324] and new projects for H_2-fueled road vehicle infrastructure are in planning or underway. For example, JET H2 Energy is planning the construction of its first 10 refueling stations across Germany and Denmark. These sites will provide gaseous hydrogen at 350 and 700 bar to power light and heavy commercial vehicles and busses.[325]

LH_2 station dynamics

An LH_2-supplied station requires a cryogenic storage tank, equipment to vaporize the liquid back into a gas, and a high-pressure compressor to bring the gas to dispensing pressure. Compressing cold, dense gas from a vaporized liquid can be more efficient than compressing ultra-low density ambient-temperature gas, however this still represents a complex and costly on-site system.

CGH_2 station dynamics

- **Traditional cascade filling:** Historically, CGH_2 stations relied on a 'cascade' system, where hydrogen is transferred from the delivery trailer into multiple banks of permanent, on-site storage tanks. This approach incurs significant upfront capital cost for the fixed storage vessels. Furthermore, to extract the maximum amount of hydrogen from the trailer and reach final dispensing pressure, these stations often require an on-site 'booster' compressor. The booster compressor represents an additional capital expense and increases operational costs via electricity consumption and maintenance.
- **"Drop-and-swap" model:** The "drop-and-swap" model, an emerging method for gaseous hydrogen delivery, significantly alters the economics of delivery. In this approach, the high-pressure tube trailer itself serves as the station's storage. Modern Type IV CGH_2 trailers can deliver hydrogen at a pressure of 500 bar. While this direct-fill method may be slower than refueling from a higher-pressure buffer system, it offers a balanced, low-capital option when speed is not the primary concern. A full trailer is delivered and connected directly to the dispenser, while the empty trailer is removed. This method can reduce or eliminate the need for expensive, permanent on-site high-pressure storage vessels and the associated booster compressors typically required to fully utilize the gas from a delivery trailer.

Application Scale and Demand Volume

The daily hydrogen demand of an application is another decisive factor in determining the most economical form of hydrogen. Different solutions are best suited for different scales of operation.

- **Small-to-medium demand (< 1 to 2 tonnes/day):** This range, typical for material handling fleets, small-to-medium bus depots, and initial heavy-duty truck fleet deployments, is the current economic sweet spot for CGH_2 delivery. Gaseous systems can be economically scaled down to 1-2 tonnes per day. This crucial flexibility allows projects to launch and scale incrementally without the prerequisite of massive initial demand. It solves the "chicken-and-egg" problem created by LH_2, whose economics

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[324] "Hydrogen Refuelling Stations." European Hydrogen Observatory. https://observatory.clean-hydrogen.europa.eu/hydrogen-landscape/distribution-and-storage/hydrogen-refuelling-stations

[325] "JET H2 Energy plans to build ten hydrogen filling stations in Germany and Denmark." 2023. Maximator Hydrogen. https://www.maximator-hydrogen.de/en/newsroom/jet-h2-energy-plans-to-build-ten-hydrogen-filling-stations-in-germany-and-denmark

rely on large, centralized liquefiers (e.g., 30 tonnes/day minimum) that require hundreds of vehicles to be operational from day one to be viable.

- **Large demand (~4 to 10+ tonnes/day):** As demand grows to the level of a large municipal bus depot or a high-throughput public refueling station, the logistics of trucked delivery intensify. For example, an eight-tonne/day station would require approximately six CGH_2 trailer swaps per day, versus two LH_2 deliveries. At this scale, end-users must weigh the cost savings of CGH_2 systems against the increased truck traffic and logistical management. Importantly, as demand reaches this level, both trucked CGH_2 and LH_2 become less economical than permanent solutions like pipelines.
- **Very large industrial demand (>10 tonnes/day):** For full-scale industrial processes such as fuel refining, ammonia production, steel manufacturing, and power generation, mobile delivery of any kind is not feasible. The sheer volume of hydrogen required can only be met by co-located, dedicated on-site production or a direct industrial pipeline.

Conclusions Regarding On-Road Delivery

In conclusion, the decision between liquid (LH_2) and compressed gaseous hydrogen (CGH_2) is not a simple one; it is a complex, multi-faceted trade-off where the optimal choice depends heavily on a project's specific goals, constraints, and long-term strategy.

The drop-and-swap model for CGH_2 is highly efficient but requires additional physical footprint. A 53-foot trailer needs a large, dedicated horizontal space for parking and maneuvering, which can be a non-starter for existing, space-constrained sites like urban gas stations. In these dense environments, the smaller footprint of a vertical LH_2 storage tank may be the only physically viable option to add hydrogen fueling (unless and until a cost-effective and safe technology for hoisting the payload of a tube trailer to a vertical position gets developed).

The two pathways also present fundamentally different business models and risk profiles. LH_2 bears higher upfront CAPEX and financial risk, where the primary risk is *stranded capital*. Committing to a multi-hundred-million-dollar liquefaction plant requires guaranteed, large-scale demand, ideally being fully in place when the plant is put in service. If this demand fails to materialize, the financial losses can be large, depending on how much the asset is underutilized. On the other hand, CGH_2 is a high *operational risk* model. The financial barrier to entry is much lower, making it easier to initiate projects. The risk shifts from finance to the supply chain. A drop-and-swap model relies on "just-in-time" logistics. Any disruption – from traffic and road closures to driver shortages or mechanical issues with the truck fleet – can have an immediate impact on fuel availability at the station. A site with a large LH_2 tank, by contrast, may hold several days of supply, providing a buffer against these short-term disruptions.

In terms of scalability and future-proofing, CGH_2 offers better initial scalability, allowing projects to start small and grow. However, scaling up at a single, high-volume site means a linear increase in required space and truck delivery traffic. Once the high capital cost is paid, an LH_2 system can more gracefully handle a ramp-up in demand without a corresponding increase in logistical complexity.

For future-proofing, the consensus is that for hydrogen to reach true scale, regional pipelines will be essential, as they offer the lowest cost of transport by an order of magnitude. In this context, CGH_2 infrastructure serves as a more logical "bridge" to that future. The on-site equipment used for dispensing gaseous hydrogen from a trailer is largely compatible with a future gaseous pipeline connection. In contrast, the expensive cryogenic tanks, pumps, and vaporizers at an LH_2 station would become obsolete for that site, making the initial investment less adaptable to the industry's ultimate trajectory.

Chapter 7: Hydrogen Future Scenario Analysis

Key Takeaways

This chapter evaluates high-adoption hydrogen futures for California in 2045 across electric power and transportation applications. For the scenarios analyzed:

- The analysis shows that meeting hydrogen demand without storage can require substantial overbuilding of production capacity and can lead to significant underutilization.
- Hydrogen storage is a major lever for reducing production requirements and improving supply-demand matching, though highly variable demand profiles can still create infrastructure challenges.
- Production-storage tradeoffs are broadly similar across many planning areas, suggesting that some infrastructure sizing relationships may apply across regions.
- Production portfolio choice materially affects resource requirements, land use, and capital investment, underscoring the importance of evaluating hydrogen deployment as an integrated system.

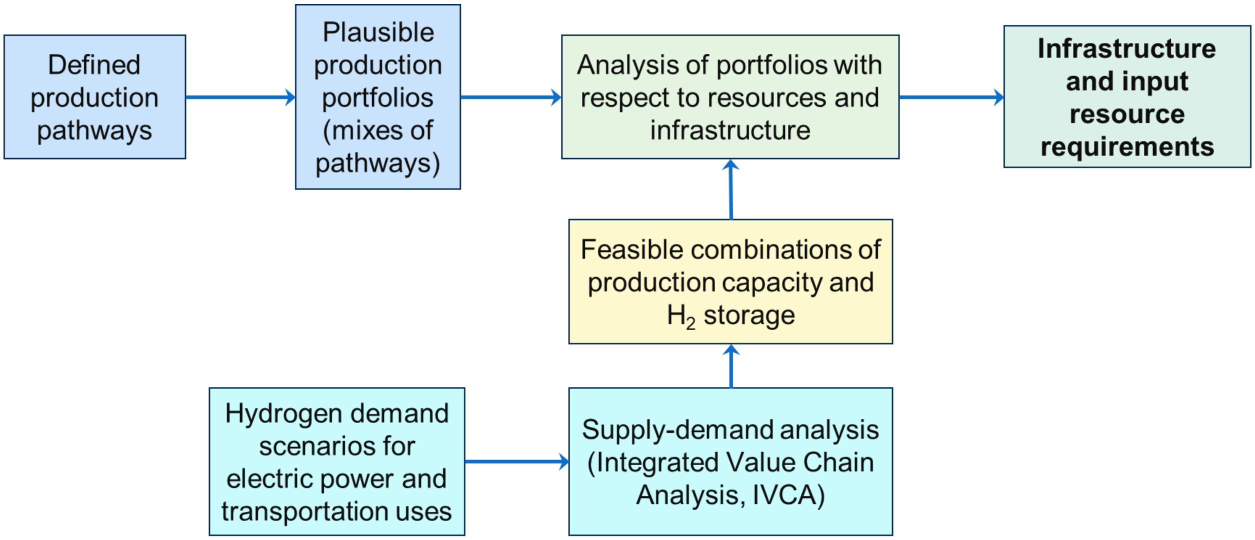
Chapter Overview

The purpose of this analysis is to (1) explore the feasibility of several scenarios for the use of hydrogen to support decarbonization of the electric power and transportation fuel industries, and (2) to address the impacts of utilizing hydrogen on a large scale for these purposes. The timeframe considered in the analysis is 2045, using the following approach:

1. Develop three representative hydrogen production portfolios that reflect different pathway mixes (e.g., electrolysis-heavy, balanced, and biogenic-max) and provide a consistent basis for comparing resource needs and constraints.
2. Model daily hydrogen supply–demand matching using an integrated value chain (IVCA) framework to quantify the production and storage combinations needed to reliably serve variable end-use demand profiles across regions and sectors.
3. Estimate upstream resource requirements (e.g., electricity, biomass, natural gas with CCS, and associated inputs) implied by the portfolios and scenario demands, and summarize key implications for planning and implementation.

The full analysis process is shown schematically in Figure 9.

Figure 9: Schematic of 2025 Hydrogen Analysis for the IEPR



Source: Guidehouse for CEC (2025)

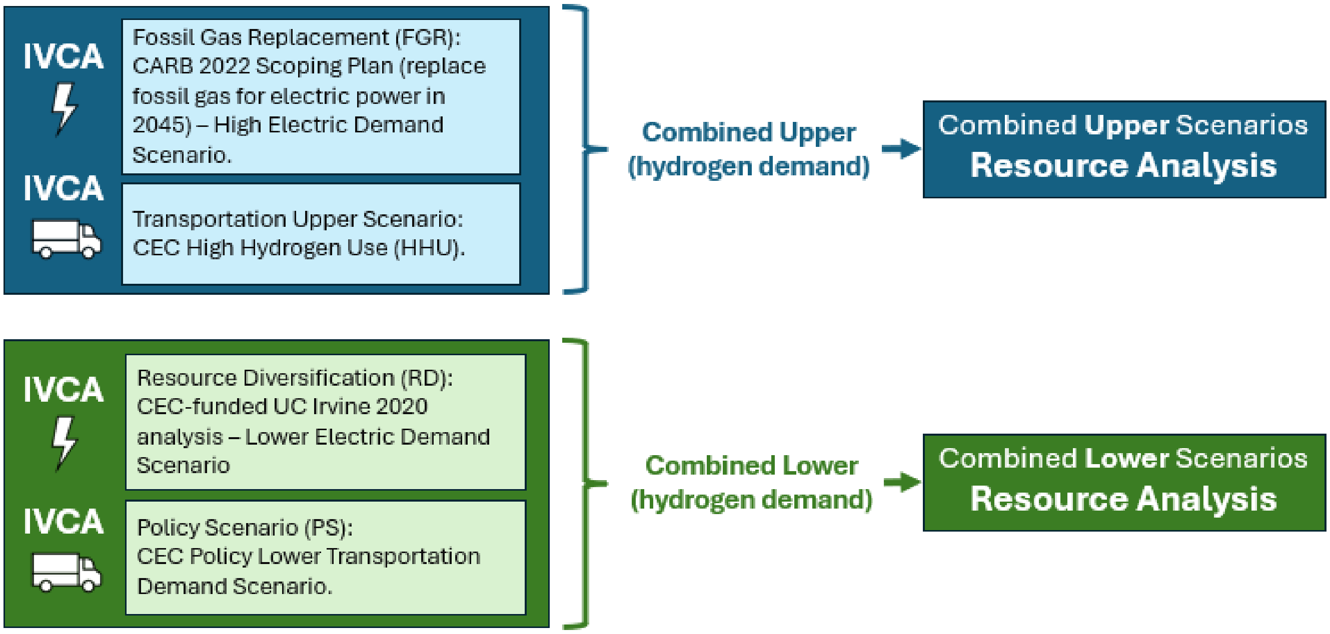
Figure 9 shows how the hydrogen demand (end-use) scenarios are initially introduced to the analysis as direct inputs to the IVCA. Note that the end-use scenarios are not used only in the IVCA step but are also carried through every analysis downstream of the IVCA.

End-Use Scenarios

In this analysis, the scenarios analyzed reflect a limit in the quantity of hydrogen evaluated. The upper scenarios in electric power and transportation are considered to be on the very high side of potential hydrogen usage for the application. However, the lower scenarios do not represent a known or assumed lower constraint on how much hydrogen usage might be adopted. Rather, they represent the lower limit of hydrogen *considered for this analysis*. They are based on plausible assumptions of partial adoption of hydrogen in the sectors.

Figure 10 shows a schematic of how the scenarios relate to each other and the various portions of the overall analysis. The specific definitions of each scenario follow below.

Figure 10: Scenarios and their use in the IVCA analysis



Source: CEC (2025)

Electric Power Sector Scenarios

The electric power generation scenarios are the same as those used in the 2023 IEPR:

1. **Fossil Gas Replacement (FGR):** This scenario (upper) assumes hydrogen is used to replace all the fossil gas that CARB's *2022 Scoping Plan Update* estimated would be used to produce electricity in 2045. This amounts to 1.59 million tonnes of hydrogen fuel per year.[326]
2. **Resource Diversification (RD):** This scenario (lower) assumes hydrogen is used to diversify the portfolio of low carbon energy resources. This included replacing half of the long-duration energy storage and half of the grid power from geothermal resources, as forecast by the CPUC's 2018 RESOLVE resource planning model. This scenario is based on a 2020 report developed for the CEC by the University of California at Irvine (UCI).[327] . It amounts to 0.350 million tonnes of hydrogen per year in 2045. The power generation assets assumed by UCI, and adopted as an assumption here, are fuel cells and new advanced hydrogen turbines. Molten Carbonate Fuel Cells (MCFCs), for example, offer more fuel flexibility and higher fuel-to-electricity efficiencies than lower temperature fuel cells. Fuel to electricity efficiencies in MCFCs can reach up to 60%.[328]

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[326] This amount differs from the 1.88 million tonnes specified in the 2023 IEPR because that analysis used a different thermodynamic basis for hydrogen — lower heating value — versus the current basis of higher heating.

[327] Reed, Jeffrey G., Emily E. Daily, Brendan P. Shaffer, Blake A. Lane, Robert J. Flores, Amber A. Fong, and G. Scott Samuelsen. 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*. California Energy Commission. Publication Number: CEC-600-2020-002. https://efiling.energy.ca.gov/getdocument.aspx?tn=233292

[328] "Fuel Cells." National Fuel Cell Research Center. https://www.nfcrc.uci.edu/Fuel_Cells_Types.html

Transportation Sector Scenarios

The transportation hydrogen scenarios are similar to, though not exactly the same as, those used in the 2023 IEPR.[329] Both hydrogen demand scenarios involve greater usage of hydrogen than was previously considered and are derived from the energy demand scenarios in the SB 100 analysis.

- **High Hydrogen Use Transportation Demand Scenario (HHU):** Hydrogen demand in this scenario is 1.4 million tonnes per year in 2045, which approximates the amount that CARB attributes to transportation applications in the 2022 Scoping Plan.
- **Policy Scenario (PS) Transportation Hydrogen Demand:** This is the lower end of the transportation scenario. The hydrogen demand in this scenario is 0.81 million tonnes per year in 2045.

Production Portfolio Analysis

Since there is no single best pathway to produce clean and renewable hydrogen, a mix of production pathways is likely to be what the market achieves. In order to compare different mixes of production pathways, the staff created three hypothetical portfolios to illustrate differences in approaches. The production portfolios are comprised of mixes of individual production pathways. The first subsection describes how the pathways are unique combinations of production technologies, feedstocks, and energy sources. This is followed by a discussion of the factors affecting the likelihood of adoption of the production pathways, which have an impact on the composition of plausible portfolios. Finally, the development of the production portfolios themselves is summarized.

Production Pathways

This analysis considered four main hydrogen *technology* types – electrolysis, reforming, gasification, and pyrolysis. Each of these requires both material feedstocks (molecules to be converted into hydrogen and byproducts) and energy. The technology types were previously documented in Chapter 4 (Hydrogen Production Pathways). The present analysis encompasses nine production pathways, each of which uniquely combines a technology type with a feedstock and energy supply:

1. PEM water electrolysis with renewable electricity (PEM)
2. Alkaline water electrolysis with renewable electricity (ALK)
3. Steam reforming with fossil gas and carbon capture (SMR NG CC)
4. Steam reforming with renewable natural gas, with or without carbon capture (SMR RNG)
5. Biomass gasification using forest residue feedstock (Biomass FR)
6. Biomass gasification using urban waste feedstock (Biomass UW)
7. Biomass gasification using crop residue feedstock (Biomass CR)
8. Pyrolysis of fossil gas (Pyrolysis NG)
9. Pyrolysis of renewable natural gas (Pyrolysis RNG)

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[329] Per the 2023 IPER report, scenarios of transportation hydrogen demand are based on the 2022 Scoping Plan Update and modified AATE 3 (Additional Achievable Transportation Electrification) scenarios of clean and renewable hydrogen consumption in transportation applications. The greatest hydrogen demand was projected for medium and heavy-duty transport applications.

Production Pathway Adoption Factors

The mix of pathways that will participate in supplying hydrogen in California between now and 2045 is uncertain. Even so, a number of drivers and constraints are expected to impact the evolution of the various hydrogen pathways, several of which are described below.

- **Electrolysis pathways** are currently in great favor, due to their very low carbon emissions and the presence and expected continued growth of renewable electricity sources. In many places the water feedstock supply is reliable, though that is not true everywhere in the state. Generally speaking, the electricity resources used for electrolysis are intermittent and, when producing electricity, they can have high temporal variability. A critical factor impacting the viability of electrolysis pathways is their economics, which depend heavily (~70-85 percent) on the price of electricity, and additionally on electrolyzer CAPEX. Both of these costs are currently high, though CAPEX is likely to go down over time as production quantities increase and learning curves are scaled.
- **Renewable natural gas** is an existing feedstock whose use will continue to grow, not least because it is a drop-in replacement for fossil gas that helps in meeting decarbonization goals. Furthermore, sources of RNG continue to grow;[330,331] in addition to landfill facilities, other sources for RNG include dairy & livestock waste, wastewater treatment plants, and food and forest waste. Another factor is the existence of financial incentives, such as the Low Carbon Fuel Standard (LCFS).
- A number of the sources of RNG can provide a reasonably steady stream of feedstock, but a large portion of the RNG supply comes from many small and distributed sources that make it challenging to process in a way that achieves significant economies of scale. There is also competition for this fuel in other sectors: the 2022 CARB Scoping Plan estimates that about two-thirds of the available RNG will be used by 2045 in a variety of non-hydrogen applications, including industrial, residential, transportation, oil and gas extraction, petroleum refining, and telecommunications/utility infrastructure purposes.
- **Biomass feedstocks** are growing in volume in California,[332] especially those related to forest residue and urban waste (woody biomass in particular). There will be a need to find valuable uses for these feedstocks. Their supply can be subject to significant intermittency and other temporal variability, and the feedstock costs are high relative to fossil gas and water. Processing can require more steps than the other pathways; for

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[330] "Renewable Natural Gas Industry Drives $7.2 Billion Boost to U.S. Economy." 2024. CNG Delivery. https://cngdelivery.com/renewable-natural-gas-economic-impact-2024/

[331] *Renewable Natural Gas Supply Assessment*. 2025. American Gas Foundation. https://gasfoundation.org/wp-content/uploads/2025/07/AGF-RNG-Study_FINAL-09022025.pdf

[332] "Capacity Planning for Organic Waste Recycling." CalRecycle. https://calrecycle.ca.gov/organics/slcp/capacityplanning/recycling/;

Strategic Biomass Utilization at Multiple Scales. 2025. North Coast Resource Partnership. https://northcoastresourcepartnership.org/site/assets/uploads/2025/04/Forest_Biomass_Report_V6.pdf;

Uden, Sam, and Amanda DeMarco. "State and federal agencies release first-of-its-kind biomass utilization strategy." Net-Zero California. https://www.netzerocalifornia.org/blog/state-and-federal-agencies-release-first-of-its-kind-biomass-utilization-strategy;

Note, however, that there is year-to-year fluctuation in biomass volume, for example temporary reductions due to logistical constraints.

example, in addition to the syngas treatment that SMRs perform, solids preparation and the multiple stages involved in gasification and syngas cleaning.[333]

- **Pathways involving fossil gas** are the only one of these feedstocks that currently can support a high-volume hydrogen supply chain without intermittency or time-based variation of the process inputs. However, fossil gas SMR pathways will require a high level of carbon capture (and offtake options for the CO_2).
- **Pyrolysis technologies** for hydrogen production are not as well developed as most of the other pathways, but they appear to have good potential for future growth and are being pursued by a number of parties. When the solid carbon co-product is marketable, that will support the economics of these pathways.

Production Portfolios and Their Evolution

Portfolio Definitions: Because there are many ways in which the hydrogen production landscape can develop, analysis required narrowing down the possibilities to three hypothetical yet representative portfolios. Educated hypotheses about how the production pathways might grow over time were made (see Portfolio Evolution section below) to ensure that the end states are reasonably achievable.

The nature of the three portfolios and the factors involved in their design are described below.

- **Electrolytic-Heavy portfolio:** As the name implies, this portfolio focuses on electrolysis, which has been widely discussed as a front-runner in the options to generate hydrogen. Electrolysis makes up the large majority of this mix, whereas fossil gas pathways are de-emphasized, and biogenic sources are used to provide generation diversity. Biomass resources are used at a level of 10-35 percent of their statewide potential, and 65-100 percent of available RNG[334] is employed to produce hydrogen.
- **Balanced portfolio:** This portfolio is based on the premise that all major pathways, fuels, and feedstocks will contribute to hydrogen production. The use of fossil gas to produce hydrogen grows steadily because of the following two factors: (1) having a high-volume, reliable hydrogen source that is not affected by fluctuating energy input or feedstocks is found to be necessary to growth and maintenance of hydrogen demand, and (2) the carbon intensity of the supply chain is sufficiently well managed to ensure that the hydrogen has satisfactory (though not optimum) decarbonization potential – including reduced or eliminated upstream fossil gas release, carbon capture for SMRs, and significant use of NG pyrolysis. Biomass resource usage is between 20-50 percent of the estimated total resources (note that there are other anticipated uses of the feedstock, such as liquid biofuels and industrial chemicals) and all available RNG is used for hydrogen production. Electrolysis makes up the remaining production and approximately equals the level of production from fossil gas pathways.
- **Biogenic Full portfolio:** Biogenic feedstocks are deployed at 100 percent of an estimated statewide potential.[335] While this portfolio makes maximal use of biogenic

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[333] For example, see Figure 2 of: Spath, P., A. Aden, T. Eggeman, M. Ringr, B. Wallace, and J. Jechura. 2005. *Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier*. National Renewable Energy Laboratory. https://www.osti.gov/biblio/15016221

[334] The "available RNG" is determined by subtracting the levels of RNG usage targeted in the 2022 CARB Scoping Plan Update from the total estimated RNG production in the state.

[335] The biomass potential used was that specified in the 2022 CARB Scoping Plan.

feedstocks, their limited availability still results in a high dependence on the other pathways in the upper scenarios. Electrolysis assumes a large portion of the remaining hydrogen supply, with pathways involving fossil gas providing moderate support.

The mixes of various feedstocks in each portfolio are summarized in Table 13.

Table 13: Production portfolio mixes in 2045 for the two combined (electric power and transportation) scenarios

Scenario	Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Water (electrolysis)	72%	40%	44%
Combined Upper	Fossil gas (SMR+CC and pyrolysis)	12%	40%	22%
Combined Upper	Biomass (gasification)	9%	14%	28%
Combined Upper	RNG (SMR and pyrolysis)	6%	6%	6%
Combined Upper	**Total**	**100%**	**100%**	**100%**
Combined Lower	Water (electrolysis)	75%	34%	6%
Combined Lower	Fossil gas (SMR+CC and pyrolysis)	5%	33%	5%
Combined Lower	Biomass (gasification)	10%	18%	74%
Combined Lower	RNG (SMR and pyrolysis)	10%	15%	15%
Combined Lower	**Total**	**100%**	**100%**	**100%**

Source: Guidehouse analysis for CEC (2025)

The calculations that went into establishing these mixes assume that the amount of hydrogen produced each year is just equal to the annual demand of the associated scenarios (the combined upper scenario case and the combined lower scenario case). As discussed in the IVCA section below, the plants supplying hydrogen can be sized to exactly produce and deliver at the level of average daily demand (i.e., annual demand/365), but only if there is adequate hydrogen storage available to help those plants meet commitments on days when demand exceeds production capacity.

If there is insufficient hydrogen storage capacity, then the production plants will need to be larger so that they can directly meet the demand themselves without having to rely on product storage. When there is such excess production capacity, limitations on biogenic feedstock availability may prevent facilities that use that type of feedstock from putting their excess production capacity to use supplying additional offtakers. This is particularly true for the Biogenic Full portfolio, as all the available biomass is being used already to supply the electric power and transportation demand.

Portfolio Evolution: Educated hypotheses about how the production pathways would grow over time were made to ensure that the end states are reasonably achievable. The growth assumptions included the following:

- All of the portfolios involve production of enough hydrogen to meet the expected trajectory of CARB demand targets. The 2022 CARB Scoping Plan projects the growth of adoption for non-power applications between 2025 and 2045.336 The hydrogen use for electric power production was assumed to grow linearly over time and can be overlaid upon the non-power applications profile to produce the final trajectory assumed for hydrogen adoption.[337]
- The initial state of each portfolio is dominated by fossil gas SMR production, which reflects the current situation regarding hydrogen production in California. It is assumed that these production plants will be retrofitted to include CCS or CCUS over the early part of the 2025-2045 timeframe with minimal lag time.
- Except for the Balanced portfolio, the percentage of SMR participation drops as rapidly as reasonably possible. This does not mean that existing fossil gas SMR facilities shut down during the early and mid-term years; rather, hydrogen demand increases so rapidly that volumetric growth in SMR supply is still needed to meet its reduced role. The analysis leads to a turning point for fossil SMR – when no new plants go into service and/or existing ones start to close – taking place in the 2035-2040 time frame.
- The non-SMR technologies – electrolysis, gasification, and pyrolysis – are assumed to ramp up as quickly as possible. However, the analysis avoids the unrealistic situation of large numbers of these plants being put in service immediately. After an initial rapid rise in plant installations, additional units are put into place at a somewhat slower rate. Sublinear power law functions (the form axb, where b < 1) have this property, so the rise in percentage share of the non-SMR pathways were modeled using that functional form, most often with $b = 0.5$:

$$\text{Percent of pathway in production mix} = a \cdot (\text{year} - 2025)^{b}$$

It needs to be emphasized that this is not a detailed model, nor has it been checked for internal consistency with respect to practical matters such as times for new plants to ramp up and obsolete plants to ramp down (e.g., decreasing SMR use near the end of the Electrolysis-heavy and Biogenic Full trajectories). Rather, it is intended to serve as a notional and illustrative picture to outline several possible courses of production market development in a broad and approximate way.

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[336] In keeping with the philosophy of being as consistent as possible with the CARB scoping plan, <u>all</u> hydrogen applications listed there were included, not just transportation. Transportation usage comprises 87 percent of CARB's estimated hydrogen adoption; other uses add another 205,000 tonnes H_2/year.

[337] In the Scoping Plan pathways, combustion-based electric power decreases between 2025 and 2045, from 0.52 to 0.23 exajoule/yr, and the Plan does not envision replacing fossil gas with hydrogen for gas-fired plants. Therefore, there is no guiding metric within the Plan upon which to base a schedule for development of this pathway. In light of recent backlogs of, and demand for, fossil gas turbine equipment for power production, it might be expected that development efforts on hydrogen-based turbines could slow down in the near-term. This would preclude a rapid increase in deployments in the early years of the time frame.

Integrated Value Chain Analysis (IVCA)

Background and Purpose

In prior CEC analysis, the focus was on a simple analysis of the quantity of electrolyzers required to generate a particular amount of hydrogen and the land use required for storage. The 2023 Integrated Energy Policy Report (IEPR) discussed speeding connection of clean resources to the electricity grid and the potential of renewable hydrogen in the electric power generation and transportation sectors. The 2023 analysis used two hydrogen demand scenarios with high and low cases, similar to this report (2025 analysis). The focus was on Proton Exchange Membrane (PEM) electrolysis for producing hydrogen. However, the 2025 analysis broadened this scope to account for more diverse hydrogen production pathways. Hence, the purpose of the analysis in this report is to better describe the relationship among production equipment type and sizing, variable demand, and the storage requirements to support both.

Hydrogen is subject to the same requirements and constraints that apply to all supply chains, namely that producers be able to reliably meet demand and to do so with an affordable product. However attractive the benefits of decarbonization, parties will not be able to participate in a hydrogen economy if they cannot be certain that the hydrogen will reliably be available when they need it. As with most commodities, supply and demand of hydrogen can ebb and flow, a condition that typically requires a means of storing the product. A lesson learned by the electric power industry was that, without any storage, the infrastructure had to be built to manage peak power at any given moment. As the IVCA will show, a build out designed for peak demand can be accomplished for hydrogen, but under many circumstances this would extract a high economic cost. This is not likely to be feasible for a commodity like clean hydrogen that is already significantly more expensive than existing fuels and many, if not all, of the alternatives for decarbonization.

The IVCA was developed to enable a realistic better assessment of the amount, nature, and cost of the hydrogen production infrastructure needed under the various end-use scenarios considered in the IEPR analysis.

Supply-Demand Matching and the Need for hydrogen Storage: One could specify a configuration of hydrogen production that would always match supply and demand by simply ensuring that the available daily production capacity is equal to or greater than the maximum demand ever expected from customers. However, under conditions of highly varying demand, this can lead to massive underutilization of the production plants. The upper electric power scenario is an excellent example of this phenomenon, as described below.

Figure 11 shows a profile of grid-level demand from gas-fired power plants (i.e., the upper electric power scenario) in the LADWP territory in 2045.[338]

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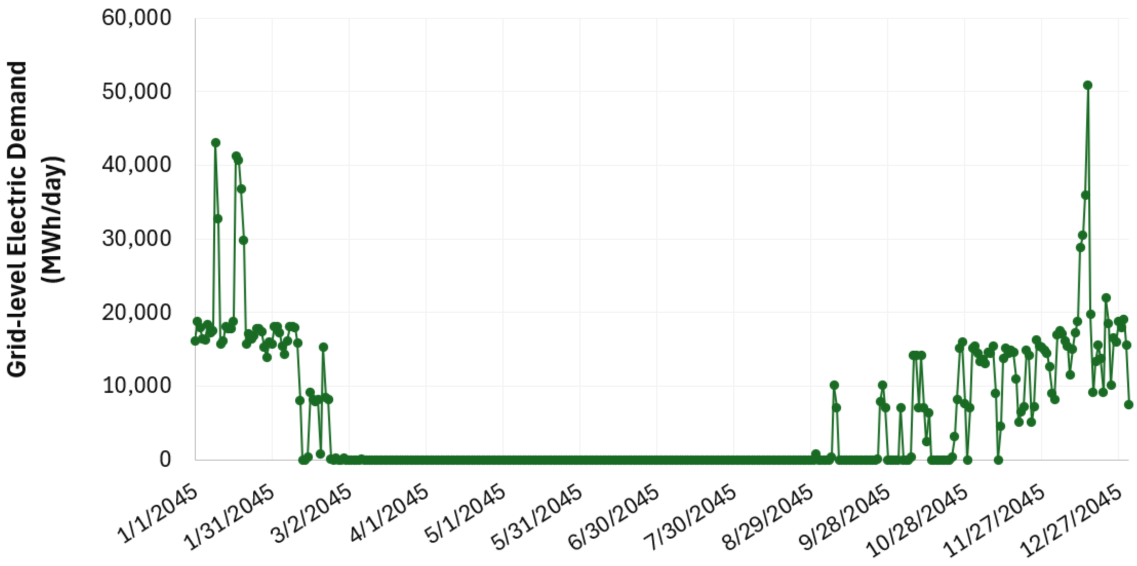
[338] The term "demand" can be confusing here, as the gas-fired power plants are supplying power to meet their customers' demand. However, this creates a demand for fuel to the power plants, i.e., the chart also tracks the demand for hydrogen. To convert the MWh of power plant output to a fuel demand, one simply needs to divide the output energy by the fuel efficiency of the plant.

Figure 11: Scaled grid-level electric power demand from gas-fired power plants (upper scenario) in LADWP in 2045



Source: Guidehouse analysis for CEC (2025)

The profile was based on the SB 100 Reference Scenario, but is scaled so that the 2045 use of fossil gas in gas-fired plants across the state is equal to the CARB 2022 Scoping Plan target:[339] i.e., to the upper electric power scenario level of output.

Through most of the winter, the hydrogen demand to power these plants is fairly consistent, though it does have daily variation. The hydrogen demand is zero through most of spring and summer, and it is intermittently called for during the fall.

Installing enough hydrogen production to be able to provide the plant its annual maximum daily output of 50,872 MWh/day at any time will completely cover the associated power plants' need for fuel without the need for hydrogen storage. However, during every other day of the year the hydrogen production *capacity* far exceeds what is being supplied. In fact, enough capacity is present over the course of a single year to supply the same power plants for 8.3 years.

Such a situation is highly unrealistic and economically untenable, so large-scale hydrogen storage will be needed to reduce the amount of instantaneous production capacity needed by the system. The LADWP region is not the only one with a demand profile of this shape in the upper electric power scenario; Figure 12 shows that the pattern is the same for all Planning Areas (PAs) except for IID, which is flat.

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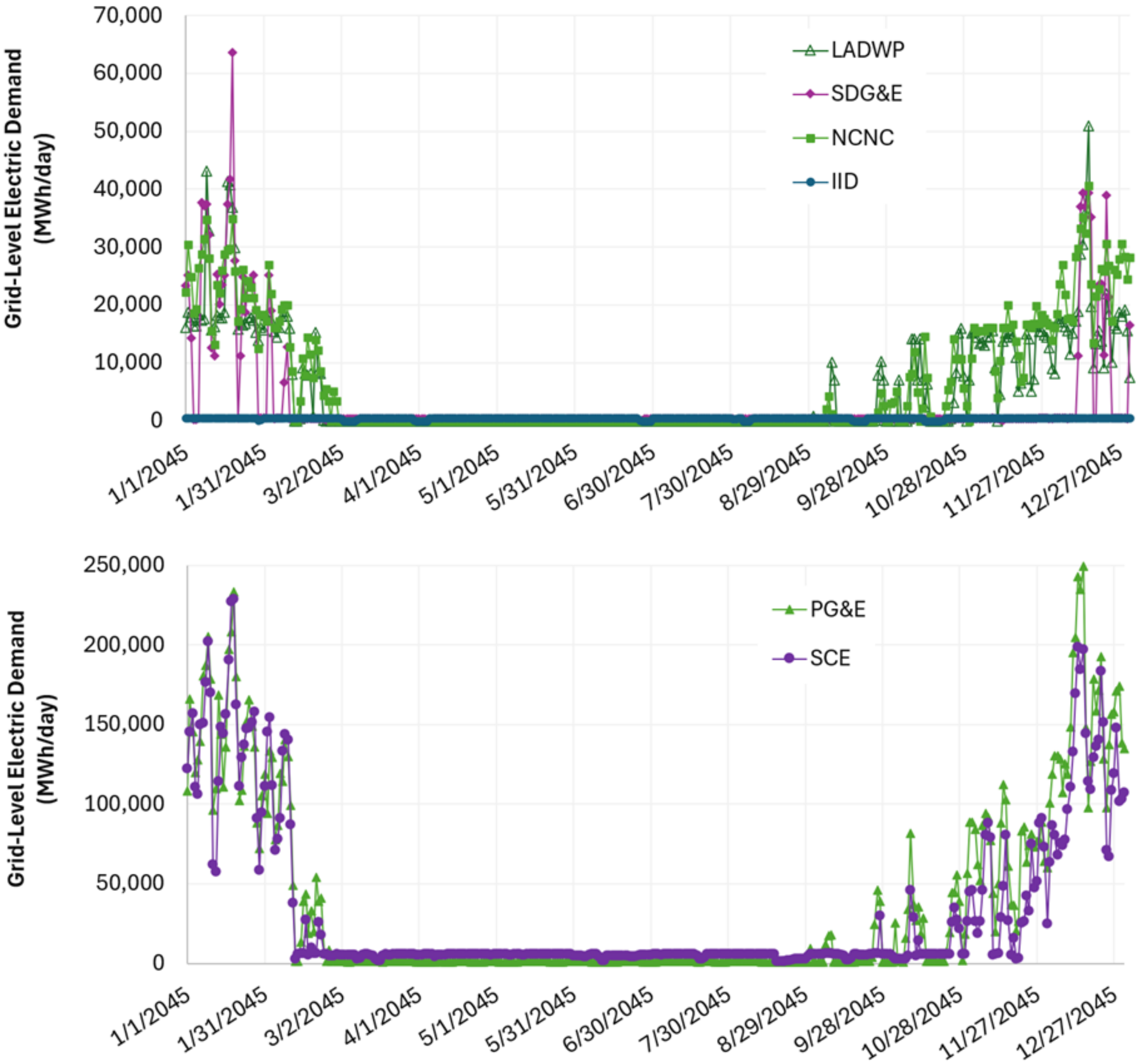
[339] The average power plant efficiency was assumed to be 50 percent, which is approximately midway between the current average efficiency of gas-fired power plants and that of a new combined cycle gas plant. The average efficiency value (44%) was reported in a CEC Staff Report. See: Nyberg, Michael. 2019. *Thermal Efficiency of Natural Gas-Fired Generation in California: 2019 Update*. California Energy Commission. Publication Number: CEC-200-2020-03. https://www.energy.ca.gov/publications/2020/thermal-efficiency-natural-gas-fired-generation-california-2019-update-staff

Figure 12: 2045 scaled, grid-level electric power demand profiles for gas-fired plants (upper scenario) in all PAs



Source: Guidehouse analysis for CEC (2025)

Much less seasonal variability is observed in the demand profiles for the lower scenario of electric power, and the demand is close to zero on many fewer days; however, there is still considerable daily fluctuation in demand. This leads to a smaller but not insignificant requirement for hydrogen storage. For the transportation application, the demand profiles exhibit a regular weekday-weekend pattern (higher demand during the weekday with peaks in the morning or evening and lower demand on the weekend) with an overlay of small monthly variations and moderate seasonal differences. Overall, the level of demand stays within a fairly small band, at least in comparison to electric power profiles. The need for storage is more complicated to define and is discussed in detail in the subsections below.

Methodology and Key Assumptions

The analysis focused on the core value chain components needed to match supply and demand: production facilities, hydrogen storage, and end-use demand.

Delivery Mode to Supply-Demand Matching

The question of whether delivery of hydrogen should also be included in a supply-demand analysis is nuanced. As noted earlier in the report, on-road delivery is currently limited to quantities of about one tonne H_2 per trailer (gaseous hydrogen) to five tonnes per truck (LH_2). Delivery of hydrogen to electric power plants will require pipeline transport[340] but delivery to refueling stations will more likely be done via a mix of tube trailers, liquid H_2 trucks, and some pipeline transport.

The cost and logistics of installing a hydrogen pipeline network to serve the gas-fired power plants in any region (let alone the whole state) are significant factors in the viability of the electric power scenarios, especially the upper scenario in which the pipelines would be delivering no hydrogen to power plants for a large portion of the year. However, assuming that an adequate, well-designed, and functioning pipeline network is in place, there is nothing about its daily operation that would affect the ability of supply to match demand. Hence, the electric power IVCA did not include any calculations related to delivery.

On the other hand, for transportation end uses, the need for storage could create issues with respect to the availability, logistics, and cost of additional delivery trucks and drivers. Two factors create situations in which complete matching of supply and demand would involve partial delivery loads (which are unlikely to be permitted in most cases):

1. the discrete nature of truckload quantities may not match well with the typical daily demand (say, a refueling station that needs 4.3 tonnes of hydrogen per day), and
2. day-to-day variability in demand will add another layer of logistical complexity.

Incorporating the effects of storage deliveries and avoidance of partial loads into the treatment of multiple producers and refueling stations would require many new assumptions and a level of complexity beyond the scope of the IEPR analysis. Instead, these factors were considered via a semi-quantitative *post facto* assessment, once the main analysis of supply vs. demand was completed.

Type of Analysis

The present study goes much deeper than the 2023 IEPR in two respects: (1) by considering the ability to use hydrogen storage to avoid overbuilding of production assets, and (2) by allowing for multiple types of production pathways for low-carbon hydrogen, instead of just electrolysis. IVCA addresses the first of these, and the *output* of the IVCA is used for the resource analysis of the nine production pathways.

IVCA analysis is <u>not</u> intended to spell out or simulate the full 2045 hydrogen market (hydrogen economy). A full modeling simulation would involve many additional assumptions about the amounts, types, and locations of hydrogen production and storage facilities, plus all their major interactions with end users. Such assumptions could be based on what is essentially educated guesswork, or they could be derived from an attempt to model the economy from

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[340] For example, the demand profile of Figure 11 has many days in which the grid-scale daily power production is on the order of 17,000 MWh (one-third of the annual maximum demand). Assuming again an average plant efficiency of 50 percent, 863 tonnes of H_2 would have to be delivered. According to U.S. EPA power plant database eGRID, in 2023 90 percent of LADWP gas-fired electric power was delivered by four plants with nameplate capacities between 388 MW_e and 1,739 MW_e. If a similar generation distribution holds in 2045, the four plants would each receive between 153 and 287 tonnes of H_2 per day. Daily truck delivery of such quantities is not practical.

first principles. Either way, the effort and uncertainties involved in the analysis would be substantial.

Rather, the IVCA focuses on the larger, more fundamental, and simpler-to-explore issue of supply-demand balance and matching. In place of a bottom-up approach that forecasts the full hydrogen economy, the analysis starts in the same place as the investigations performed for the 2023 IEPR, i.e., with scenarios that define the level of demand for the electric power and transportation fuel applications. The supply-demand analysis gives a good zeroth-order estimate of the amounts of both production and storage capability needed, as well as the capital investment involved in production[341] It also enables estimates of the amount of renewable energy assets needed to support hydrogen production via electrolysis.[342]

Three important high-level simplifying assumptions were made in the IVCA analyses:

1. All of the transportation hydrogen is treated as being delivered to refueling facilities in quantities similar to those expected for refueling stations for medium- and heavy-duty (MDHD) vehicles, about five tonnes per day.
2. Different sources of hydrogen that will be deployed in 2045 will have complementary production profiles across the year, so that the total capacity for producing hydrogen is constant on a day-to-day basis. Thus, when one type of asset (say an electrolyzer facility) is experiencing low production, it is assumed that another asset (say, a biomass gasification facility) is assumed to have an excess capacity that makes up the difference.
3. The hydrogen markets for electric power and transportation are initially analyzed independently. The analyses did not quantitatively address the fact that hydrogen production and storage facilities for one sector can be made available to the other sector. Therefore, some post facto semiquantitative analysis was performed to preliminarily explore a combined market.

Electric Power IVCA Analysis

Figure shows the full value chain for the electric power scenarios, including the three core components (production, storage, distribution). The figure illustrates hydrogen production from electrolysis using renewable energy, but all nine production pathways were evaluated in the resource assessment portion of this analysis that was completed after the IVCA.

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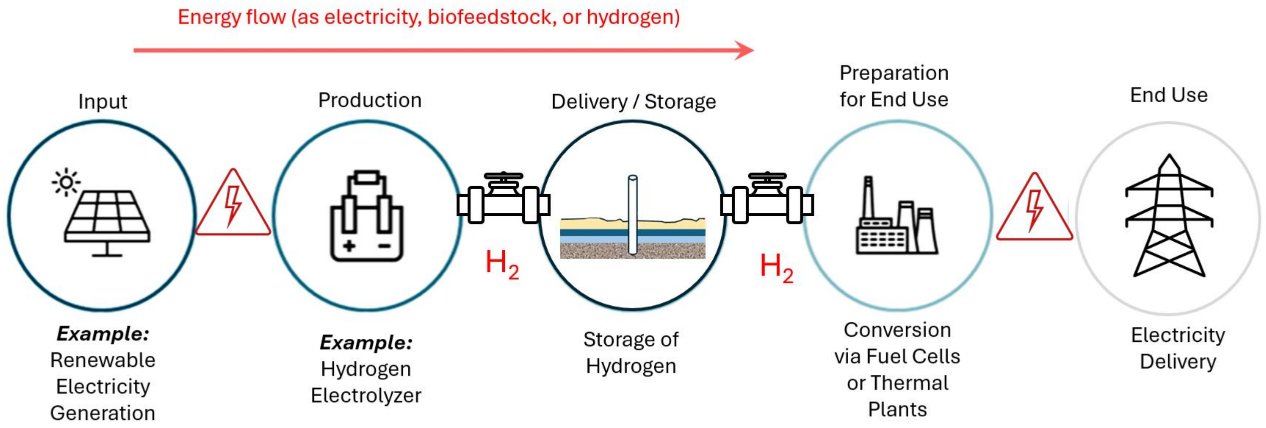
[341] Capital costs for the large amounts of hydrogen storage that can be required are too uncertain to estimate with a reasonable amount of certainty at this time.

[342] Technically, IVCA can estimate the infrastructure that would be needed for the maximum daily supply of all of the energy and material inputs of all nine production pathways. However, the renewable energy infrastructure likely involves much more investment, permitting, land use, and project development effort than the other resources (e.g., biomass storage). Therefore, the only input whose infrastructure capacity was estimated in this analysis was renewable energy for electrolysis.

Figure 13: IVCA value chain configuration for electric power scenarios



Only production, storage, and electric generation are modeled to find configurations that match H_2 supply with demand; input energy and feedstocks are computed as a later step. Because of gas volumes, all storage in the Delivery/Storage part of the value chain is assumed to be geologic.

Source: Guidehouse for CEC (2025)

The multiple production and end use facilities are each aggregated together into single values in the electric power IVCA, for the following reasons: (1) all of the hydrogen from production plants that is meant for electric power production will flow into pipelines that go to the large underground geological storage facility (or multiple facilities, though likely no more than two or three located near each other), (2) all of the thermal power plants must have pipeline access from the central storage facility or facilities, and (3) modeling is done at the grid level, with a grid-level demand input profile, and there is no clearly applicable reference point from which to make reasonable assumptions involving the many producers and end-users that will make up the hydrogen economy in 2045.

The analysis computes a daily mass balance of fuel flows among the production, storage, and end use components of the value chain. It keeps track of key metrics – percent of demand met, storage level, and unused production capacity – for each of these over the course of both one year (2045) and two years (2045 and 2046).[343] There are two main branches of possibility on any given day:

1. Available production capacity is greater than or equal to the demand. After meeting demand, the excess capacity is used to refill storage to the extent that storage space is available – the model seeks to keep storage as full as possible. Should there still be capacity left over after this, that excess production capability is chalked up as potentially unused capacity.
2. Available production capacity is less than the demand. If there is enough hydrogen in storage to fill the gap, that hydrogen is removed from storage and demand is considered satisfied. If there is not enough stored hydrogen to fill the gap, what is left in storage is removed, leaving an empty storage facility, and the amount of unmet demand is calculated. In either case, there is no waste of production capacity.

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[343] The two-year analysis was done to understand the implications of having a low storage level at the end of the first year.

Electric Power Supply and Demand Assumptions

As mentioned, the IVCA tool does not currently allow specifying the variability in the daily amount of production capacity, which is equivalent to assuming that any variations among the fleet of producers offset each other. A different implicit assumption for constant supply that one might consider is if each production facility with variable output has its own local storage of sufficient magnitude to "smooth out" the variations and interruptions to its output. However, that assumption is not compatible with the IVCA tool as currently constructed, for the following two reasons:

1. The "smoothing out" storage capacity would need to be accounted for as part of the supply-demand analysis, i.e., added to any systemwide storage that the IVCA identifies as necessary because of demand fluctuations. This requires a computation of the amount of onsite storage needed, which the IVCA is not capable of doing.
2. To maintain an onsite storage capability at a production facility with an otherwise variable production level, the *production capacity* would need to be increased from the nominal value – the amount that IVCA is counting on that facility to provide – to something notably larger.[344] This again would need to be incorporated into the supply-demand equation of the IVCA, and it also requires computations that are not in the IVCA: (a) an estimation of the amount of onsite storage required (as above), and (b) an estimate the nameplate capacity needed to be able to both properly fill the storage and reliably deliver the stated quantity of hydrogen each day.

All of the upper scenario demand profiles were constructed in a similar manner to the LADWP gas-fired plant demand profile described in the Supply-Demand Matching section. That is, the relevant SB 100 Reference Scenario profiles provide the day-to-day variability within a Planning Area (PA), but the total demand is defined by the IEPR scenario definitions given above.

The demand profiles for the lower scenario were also constructed using SB 100 Reference Scenario profiles, in this case the profiles for long duration energy storage (LDES) – discharge only – and geothermal electric power that are replaced by hydrogen-fueled equipment. Consistent with the UCI Roadmap study, for the low scenario the conversion of hydrogen to electric power in 2045 was assumed to occur via high-efficiency equipment such as advanced fuel cells and hydrogen turbines.[345] Note that LDES is not deployed by the model in LADWP and IID in the SB 100 Reference Scenario. In any case, for each region a demand profile was constructed that represented the combined contributions of both power generation/dispatch methods. All of these demand profiles were then adjusted by a uniform factor that ensured that the total hydrogen produced in 2045 matched UCI's estimate of 350,000 tonnes of H_2 per year.

The IVCA assumes that the majority of hydrogen is produced offsite of the place of consumption, although it is possible to be produced onsite (such as case of the Lodi Energy Center) if key components are available, such as land space and renewable energy sources. Electrolytic hydrogen would require far more land space for renewable energy than any power

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[344] See the "Need for On-site Hydrogen Storage" subsection in the "Hydrogen Production Pathways" section.

[345] Reed, Jeffrey G., Emily E. Daily, Brendan P. Shaffer, Blake A. Lane, Robert J. Flores, Amber A. Fong, and G. Scott Samuelsen. 2020. *Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California*. California Energy Commission. Publication Number: CEC-600-2020-002. https://efiling.energy.ca.gov/getdocument.aspx?tn=233292

plant is likely to have (solar-derived hydrogen needs about 51 acres per tonne of H_2 production per day). Other types of production could be considered; resource requirements including delivery infrastructure for feedstock, land area for feedstock storage and processing facilities,[346] and the processing plants themselves. Assessment of non-electrolytic onsite scenarios was not performed in this analysis.

Electric Power Analysis Parameters

As mentioned, pipeline parameters are not included in the analysis, reflecting the assumption that the pipeline infrastructure will be built as needed to accommodate all flows without putting constraints on them. Similarly, the only characteristic of the underground, geological storage facility specified was the storage capacity. Any limitations on the rate of injection or withdrawal of hydrogen from a reservoir were assumed to be overcome by having as many separate wells as needed to ensure that the requirements are met.

Given the assumption of constant hydrogen supply capacity, the different mixes of production pathways have no effect on the supply-demand matching of the IVCA analysis.

Finally, the amount of hydrogen in storage at the start of 2045 was always set to the maximum storage capacity.

Electrolysis Parameters and Associated Facility Size Constraints

To produce a result that can be directly compared to the 2023 IEPR results (with appropriate correction for difference in assumptions about hydrogen's energy content), the IVCA for electric power production includes a calculation of the total nameplate capacity of electrolyzer plants (in MW_e) that would be used if all hydrogen production were to be done via electrolysis powered by renewable energy.

- **Process parameters:** For the calculation of nameplate electrolyzer capacity, two electrolysis process parameters were used, namely the electrolyzer energy requirement of 52 $kWh_e/kg\ H_2$[347] and the capacity factor, which was assumed to be 45 percent. Note that these differ from the 2023 IEPR's assumptions of 65 percent capacity factor and 51 $kWh_e/kg\ H_2$. The basis for the lower capacity factor is the assumption that electrolyzers will exclusively be powered by variable renewable energy to ensure the cleanest possible resulting hydrogen.

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[346] Two data points on the land footprint of a processing plants are:

1. The ARBRE biomass gasification plant in England, which supplied biomass to a 10 MWe power plant and occupied approximately 11 acres. See: Cheng, Vincent K. M., and Geoffrey P. Hammond. 2017. Life-cycle energy densities and land-take requirements of various power generators: A UK perspective. Journal of the Energy Institute. https://www.sciencedirect.com/science/article/pii/S1743967115300921
2. A NETL estimate of the land footprint of a large-scale gasification plant that can handle either biomass or coal to produce 660 tonnes of hydrogen per day. Their estimate was 30 acres, with an additional 270 acres for a buffer to the fence line. See: Lewis, Eric, Shannon McNaul, Matthew Jamieson, Megan S. Henriksen, H. Scott Matthews, John White, Liam Walsh, et al. Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies. National Energy Technology Laboratory. https://netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf

[347] This is a very common assumption in the industry and was reported to be used by E3 in their February 25, 2025 presentation at the CARB SB 1075 Technical Analysis Workshop: Gangelhoff, Gregory, and Vignesh Venugopal. 2025. Analysis of Hydrogen in California for Senate Bill 1075 Report. California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/2025-02/sb-1075-workshop-022525-presentation-e3.pdf

- **Achieving 45 percent capacity factor:** Per data from the CEC's Energy Assessments Division,[348] realized solar and wind capacity factors (i.e., including curtailment) in 2023 were 22.6 percent and 25.3 percent, respectively.[349] Capturing curtailed energy should add about 1.2 percent to the capacity factor, which still results in only 23.8-26.5 percent.[350] However, analysis shows that capacity factors for the electrolyzers powered by renewable assets can be significantly increased relative to the capacity factor of the renewable itself by under-sizing the hydrogen production relative to the maximum renewable generation output – provided that all the electricity produced at low output levels is dedicated to hydrogen production. A trade-off that yielded an average capacity factor of 44 percent was achieved for the assets in the study by choosing an electrolyzer with a nameplate capacity about one-sixth that of the renewable generation capacity.[351]
- **Electrolyzer facility size:** Almost all of the solar plants of 50 MW_e capacity or greater in California are smaller than 350 MW_e; similarly, with one exception wind plants are 220 MW_e or smaller.[352] Thus, if the "one-sixth" rule of thumb were applied, along with a 45 percent capacity factor, the associated electrolytic hydrogen production facilities would be at most 56 MW_e (12 tonne H_2/day) and 37 MW_e (7.6 tonne H_2/day) for solar and wind, respectively.

Transportation IVCA Analysis

The structure of the value chain for transportation scenarios is shown in Figure 14 below, in this case showing only the three core components of the value chain and their connectivity. The transportation IVCA tool covers more production nodes (currently five) and more refueling stations (currently 55-75). Instead of aggregating or bundling the production and end use into a single component each, the model computes the production and delivery for every facility.

Managing the multiplicity of producers and offtakers

The future transportation hydrogen economy could develop in a large variety of ways, three of

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[348] "2023 Total System Electric Generation." California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2023-total-system-electric-generation

[349] Wind capacity factors are much higher along the coast, especially in far northern and far southern California.

See: "CEC seasonal wind variation tool." California Energy Commission. https://repository.energy.ca.gov/3D_Visualizations/2014-2022_Monthly_Visualization/2014-2022_monthly.html

This study assumes that the renewable power assets used for hydrogen are solar power or lower-capacity-factor wind farms.

[350] Guidehouse calculation, based on May 31, 2025 curtailment data (see: "Wind and Solar Curtailment May 31, 2025." California Independent System Operator. https://www.caiso.com/documents/windsolarcurtailmentreport.pdf) and the installed capacities listed at: "2023 Total System Electric Generation." California Energy Commission. https://www.energy.ca.gov/data-reports/energy-almanac/california-electricity-data/2023-total-system-electric-generation

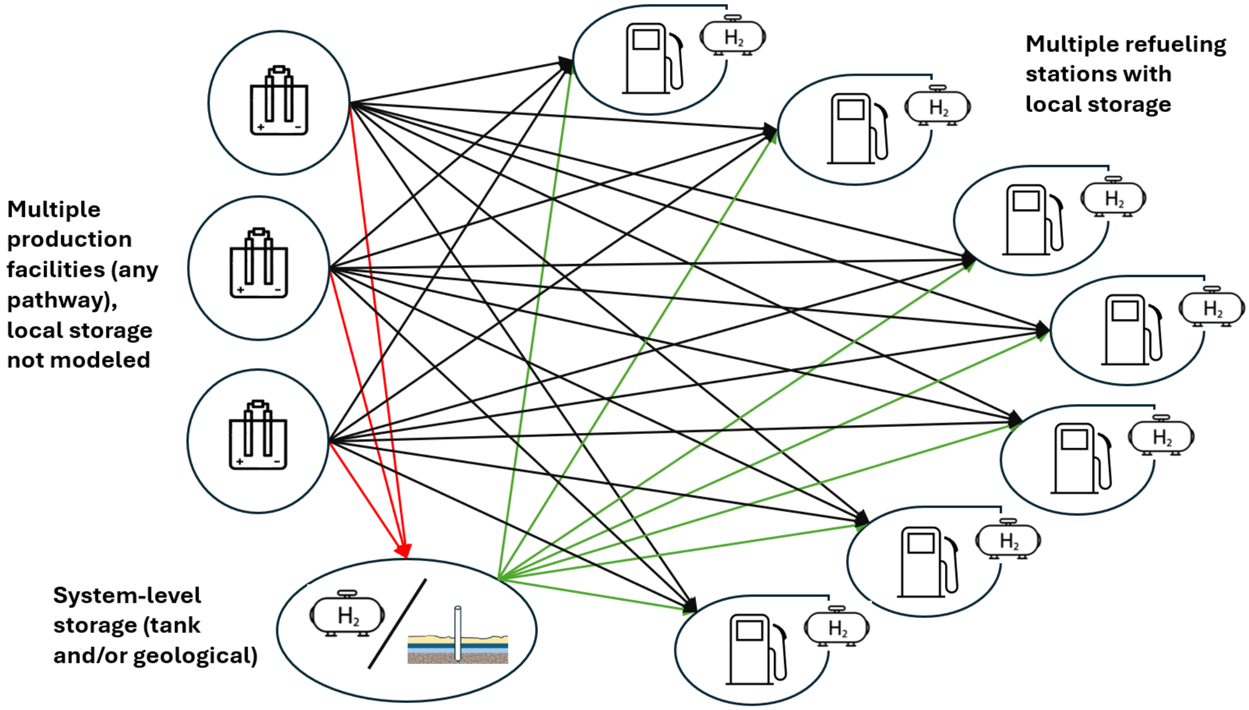
[351] Guidehouse analysis. For example, the shape of a PV unit's output power over the course of a day resembles a Gaussian distribution (see: "Solar photovoltaic output depends on orientation, tilt, and tracking." 2014. U.S. Energy Information Administration. https://www.eia.gov/todayinenergy/detail.php?id=18871). If an electrolyzer is sized to accept peak PV output power, it will only receive that much power for a few hours a day, leaving its capacity factor too low for economic viability. The lower the electrolyzer input power requirement, the more hours per day that the solar panel can utilize that much power. Guidehouse judges sizing the electrolyzer at one-sixth of peak PV power output to be a reasonable starting point for detailed site analysis.

[352] "WebQFER Source Files." California Energy Commission. https://www.energy.ca.gov/files/webqfer-source-files

which are described below:

- One trajectory could be for every production facility to have separate supply contracts with a subset of the refueling stations, with some exclusivity involved. At the same time, all of the producers and all of the refueling stations may use the storage facility as a service. This configuration, while entirely possible, could be quite inefficient as some of the producers might at times have excesses of hydrogen that they can't sell to some of the refueling stations. Likewise, some of the refueling stations might have shortages that they can't cover with a different producer. In addition to this inefficiency, modeling such a marketplace is highly complex and would likely involve having to explore many of the permutations of bilateral agreements between supply and demand.

Figure 14: IVCA value chain architecture for the upper and lower transportation (MDHD vehicle) scenarios



Feedstocks and energy sources of production, as well as the end-use vehicles, are not shown; only the modeled components of production, storage, and refueling stations are illustrated in the diagram.

Source: Guidehouse for CEC (2025)

- A different case might occur in a region in which a single company owns all of the production facilities, and another company owns all of the refueling stations (or even one company owning the whole market in that region). If the size of the region is not too large, all the production facilities would supply all of the refueling stations and all of the refueling stations could receive their hydrogen from any of the suppliers. This arrangement would be much more efficient, as every party on the supply side is incentivized to ensure that all the end users get as much hydrogen as possible every day.
- A third possibility is to have a variety of different entities on both the supply and demand side, but all participate in a cooperative marketplace designed to ensure the

least waste of production capacity and the most parity in coping with supply chain issues among the refueling stations. Although there would be multiple parties involved, the collaboration behavior would be like that of the single-owners scenario of the previous paragraph.

The transportation IVCA has adopted a pattern of relationships that follows the more efficient and simpler structure outlined in the last two trajectories described above, as opposed to the complex and uncertain approach of trying to predict and account for the myriad ways in which the first-describe marketplace could play out. The fully cooperative marketplace is assumed to be implemented with the following rules:

- **When supply exceeds demand:** Every producer sells an amount of hydrogen proportional to its share of the total supply.
- **When demand exceeds supply:** Every refueling station receives an amount of hydrogen proportional to its share of the total demand.

The net effect of this cooperation is that supply-demand matching step of the analysis of these multiple suppliers and multiple end users can aggregate those parties into a single total supply and a single total demand. The interaction between the aggregated supplier group, the systemwide storage, and the aggregated refueling station group takes place according to the same daily mass balance rules that the electric power sector IVCA follows. To determine the amount of hydrogen associated with each party, each production facility is assigned a share of the total supply according to the rule of proportionality; apportionment of the amount of hydrogen delivered to the set of refueling stations is performed likewise.

Many more market structures are possible, of course, but all would be more complex, and probably more inefficient, than the one chosen. In that sense, the current transportation IVCA analysis appears to embody a best-case assumption regarding a marketplace structure for supply-demand matching.

Differences from the electricity sector approach

Given how much of the complexity of the multiparty structure of the transportation IVCA is simplified into a matching algorithm that is at its core identical to that of the electric power sector IVCA, it might seem that little or nothing is gained by allowing for and tracking multiple producers and multiple refueling stations. However, several distinct features of the transportation IVCA were implemented that distinguish its analysis from the electric power sector version:

- Rather than splitting the regional demand equally between refueling stations, several types of demand variation were imposed on each station, while keeping the overall regional demand constant. This better reflects the reality of the marketplace, where refueling stations do not behave in an identical way. Furthermore, real-life variability has the potential to affect the matching of supply and demand and the need for systemwide storage.
- There is a potential for constraints on delivery between the various parties in each region, including transfer of hydrogen to and from storage. As mentioned in the Importance of Delivery Mode to Supply-Demand Matching section, several factors could impose constraints, but a critical one is the availability of trucks and drivers. (Road transport is assumed to be the only mode of delivery in the IVCA, though if any pipelines are available, they would likely be used preferentially.) A refueling station that sells 4.56 tonnes of H_2 in each day is not going to be dealing with a

0.56-tonne delivery but rather will receive either four or five trucks per day. A delivery constraint analysis was therefore performed to assess truck constraints, and the reality that partial-vehicle deliveries are generally unlikely.

- The practical solution to the partial truck issue is having some station-site tank storage. As part of the IVCA, a refueling station was modeled with various sizes of onsite storage to see whether and how the local storage buffer could eliminate extra trips that would exceed the capability of the delivery system. The bottom line is that reasonably sized onsite storage does in fact accomplish this; the results are discussed in the Transportation Sector IVCA Results section. Without the granularity of the analysis setup, the delivery constraint analysis could not have been performed to confirm that transport to refueling stations does not seem to affect the amount of production and storage needed for supply-demand matching.

Transportation Supply and Demand Assumptions

As was done for the electricity sector IVCA, and for the same reasons, production capacity was assumed to be constant.

The 2045 MDHD hydrogen demand profiles for each PA were constructed from two sources:

1. **Day-to-day variability of transportation demand for hydrogen:** For both upper and lower scenarios, this was assumed to be the same as that of MDHD electric vehicles for that PA in 2045, as reflected in their load shape profiles in the CEC SB 100 Transportation Energy Demand Scenario.
2. **Magnitude of hydrogen consumption:** This was also sourced from the SB 100 Transportation Energy Demand Scenarios, though it was only available with monthly granularity. The quantity of hydrogen analyzed was set equal to the total transportation-related hydrogen use by all modes except for ocean-going vessels (which comprise about 6.6 percent of total estimated hydrogen use). For simplicity, in the IVCA the end-use facilities were all assumed to consume about as much hydrogen per day as a refueling station for MDHD vehicles, with is 4-6 tonnes.[353]

The day-to-day variability of MDHD fuel demand was used to produce daily hydrogen demand values from the monthly transportation hydrogen demand. This was done by first normalizing the daily demand; for each month, each day's value was divided by the total demand of the month. Since all the daily factors in a month add up to 1.00, this resulted in a weighting factor for each day in that month. Each day's weighting factor was then multiplied by that month's total hydrogen consumption, resulting in daily usage values. A resulting preliminary hydrogen demand profile for the LADWP region is shown in Figure 15, below. As in the electric power analysis, it was assumed that no onsite hydrogen production takes place at the end-use facilities (i.e., refueling stations).

Note that the upper scenario's projected demand for transportation hydrogen in the LADWP region in 2045 is as high as 744 tonnes of hydrogen per day. This was considered too large for a single, integrated supply network with system-level storage, because of the extra cost and potential time delays that might occur if producers had to deliver their hydrogen, via road vehicles, to more distant stations. Considering that a demand of half of that size could serve 75 refueling stations of an average 5 tonnes H_2/day capacity, analyses were performed on a

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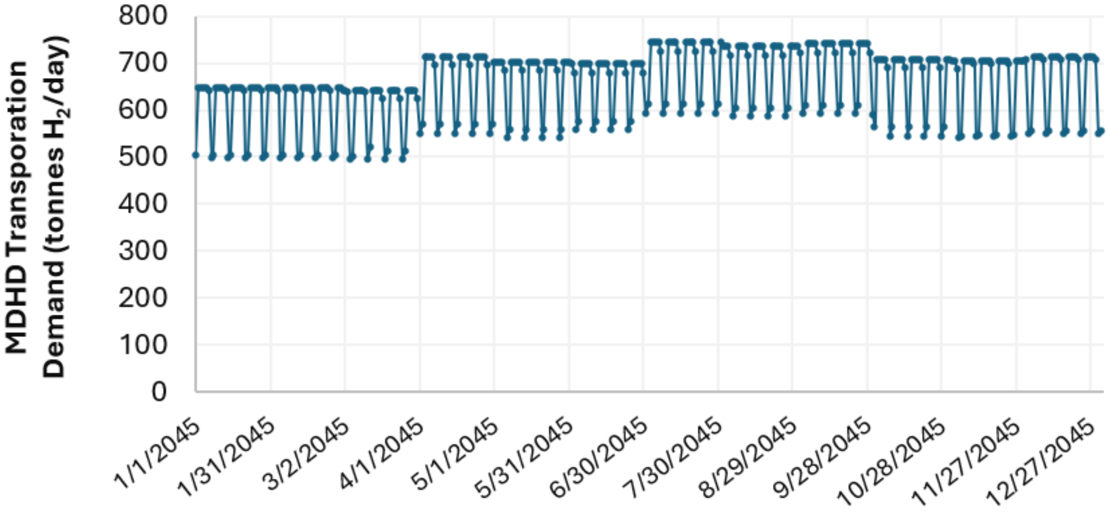
[353] Note that MDHD-vehicle hydrogen use comprises about 76 percent of the non-oceangoing-vessel transportation hydrogen estimated for 2045 in the SB 100 Demand Scenario modeling.

hypothetical "region" having about 370 tonnes/day of hydrogen demand.

Figure 15: 2045 preliminary daily hydrogen demand profile for LADWP in the HHU scenario of SB 100 transportation hydrogen demand



Source: Guidehouse analysis for CEC (2025)

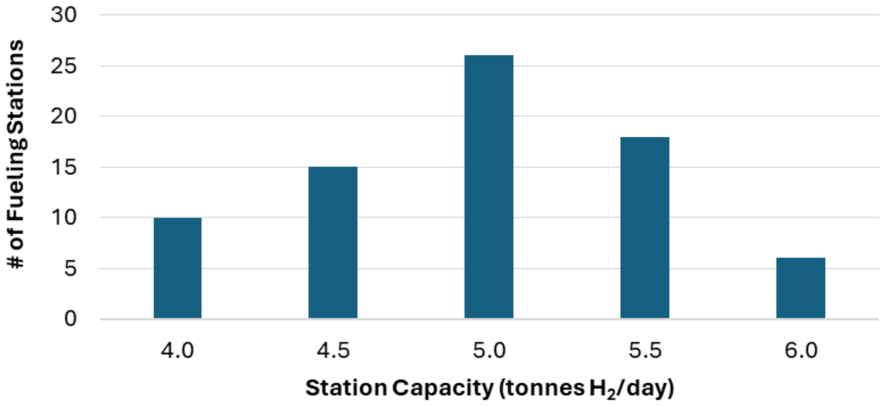
LADWP has two such regions, whereas SCE was split into four regions of 335 tonnes of daily demand each. The analysis of SDG&E, which is a much smaller PA with respect to transportation hydrogen demand, used a single region of 270 tonnes of daily hydrogen demand and accordingly was assumed to serve only 55 refueling stations. These are rough working assumptions that are not based on detailed analysis of viable region sizes and characteristics in California.

As noted, additional layers of refueling station variability were programmed into the analysis. The first of these is the capacities of the many refueling stations. At-scale hydrogen refueling stations for MDHD vehicles are assumed to have capacities between 4-6 tonnes/day. The population of stations was thus split into batches of stations of different sizes and capacities of 4.0, 4.5, 5.0, 5.5, and 6.0 tonnes H_2/day.

The numbers of stations in each batch were adjusted so that their total hydrogen consumption would equal the specified demand for the multi-station marketplace; Figure shows an example of the resulting distribution of refueling stations of the various sizes.

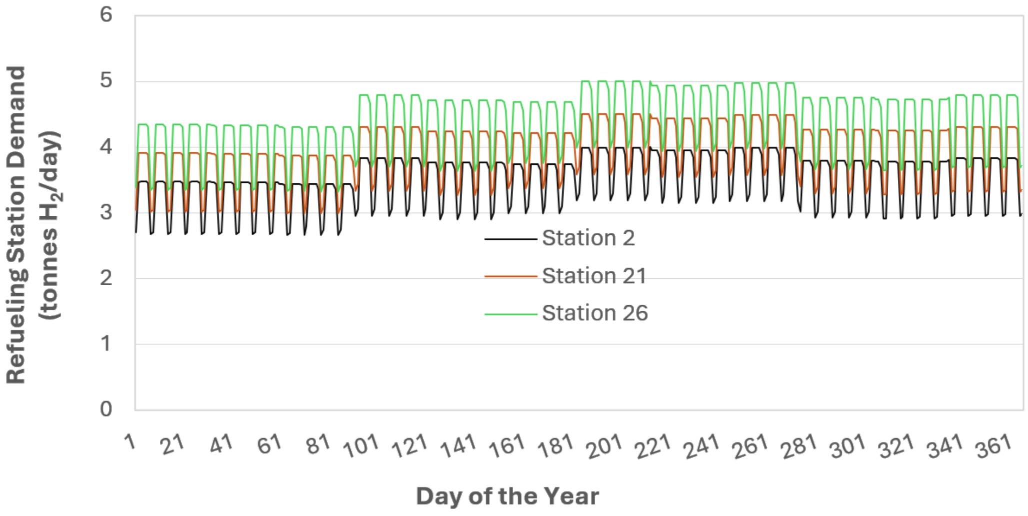
Station-specific and day-to-day random variability was also added, by multiplying each refueling station's daily demand by a randomized factor between 0.9 and 1.1. Thus, there was ±10 percent random variation from the otherwise uniform and synchronized daily variability among the stations. Daily demand profiles for three such stations are shown in their original and modified forms in Figure 17 and Figure 18.

Figure 16: Assumed hydrogen refueling station size distribution for each (of the two) assumed LADWP marketplaces, HHU (upper scenario) scenario



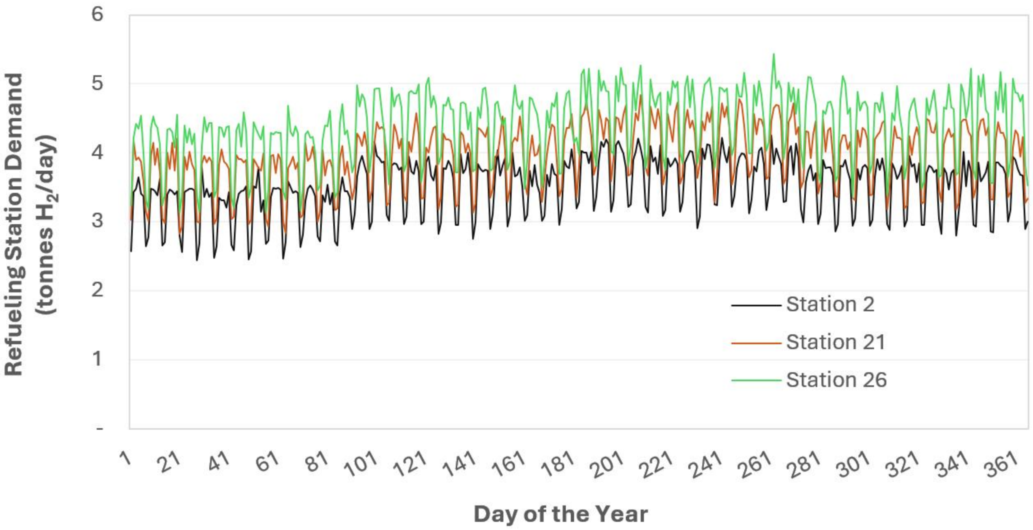
Source: Guidehouse analysis for CEC (2025)

Figure 17: Refueling station demand profiles for three different sizes of stations, before daily random variability was added



Source: Guidehouse analysis for CEC (2025)

Figure 18: Final refueling station demand profiles after station-specific daily random variability was added



Source: Guidehouse analysis for CEC (2025)

The net effect on level of demand due to these random variations across 55-75 stations was minimal, with each modified daily demand staying within ±1.3 percent of the demand specified by the SB 100 profile and within ±0.5 percent on 78 percent of the days. Total demand for the year was within 0.015 percent of the SB 100 value.

As mentioned above, the use of storage tanks of reasonable size at refueling stations eliminates concerns about assuming daily hydrogen consumption quantities that would appear to require unrealistic partial deliveries.[354] This provided some assurance that the IVCA calculations could be greatly simplified by allowing the analysis to assign consumption that would seem to require partial truck loads. Even so, a slightly unrealistic feature of the transportation IVCA is that it assumes that there is pre-knowledge of the amount of hydrogen to be sold each day: unlike the case of pipeline delivery with systemwide storage, delivery – truck rolls – needs to be scheduled. This assumption appears to not affect the outcome of the analysis, due to the small amount of day-to-day variation in demand across the year: the coefficient of variation in the demand profile is only 11-13 percent, depending on PA.[355]

Specifically, the on-site storage analysis shows that for a 4.0 tpd refueling station whose average annual demand is 3.5 tpd, the number of trucks that would be scheduled with pre-knowledge of the demand is either three or four trucks for most days. This is very similar to what one would do without such advanced knowledge. Under pre-knowledge, the station would only call for two or five trucks on 30 days of the year, and those days are during the known seasons of higher and lower demand than average. During those times, increasing or reducing deliveries is expected and without pre-knowledge would be incorporated into the schedule via some well-developed logistics algorithm. In sum, it’s likely that knowing the typical levels of demand for each season, combined with a small amount of extra storage beyond what the analysis would recommend, would compensate for not knowing what the

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[354] See the section below titled Analysis of On-Site Storage and Trucking Requirements for details.

[355] Coefficient of variation, or COV, is the ratio of the standard deviation of a data set to its average. It provides a good measure of the spread of data points around the mean value. A COV value around 12 percent means that the band of variation is a small fraction of the average value itself. This is evident from the demand profile chart.

current or next day's demand will be.

Transportation Analysis Parameters

Due to the number of participants involved in the value chain analysis, the computations were coded into Excel VBA.

Since no explicit assumptions about the production pathways of the various producers were made, there are no production parameters specified (such as nameplate capacity, efficiency, or capacity factor). This keeps the production generic so that the computation workbook is not cluttered with parameters for the multiple producers.

As in the electric power sector IVCA, the storage level is set to full at the start of 2045.

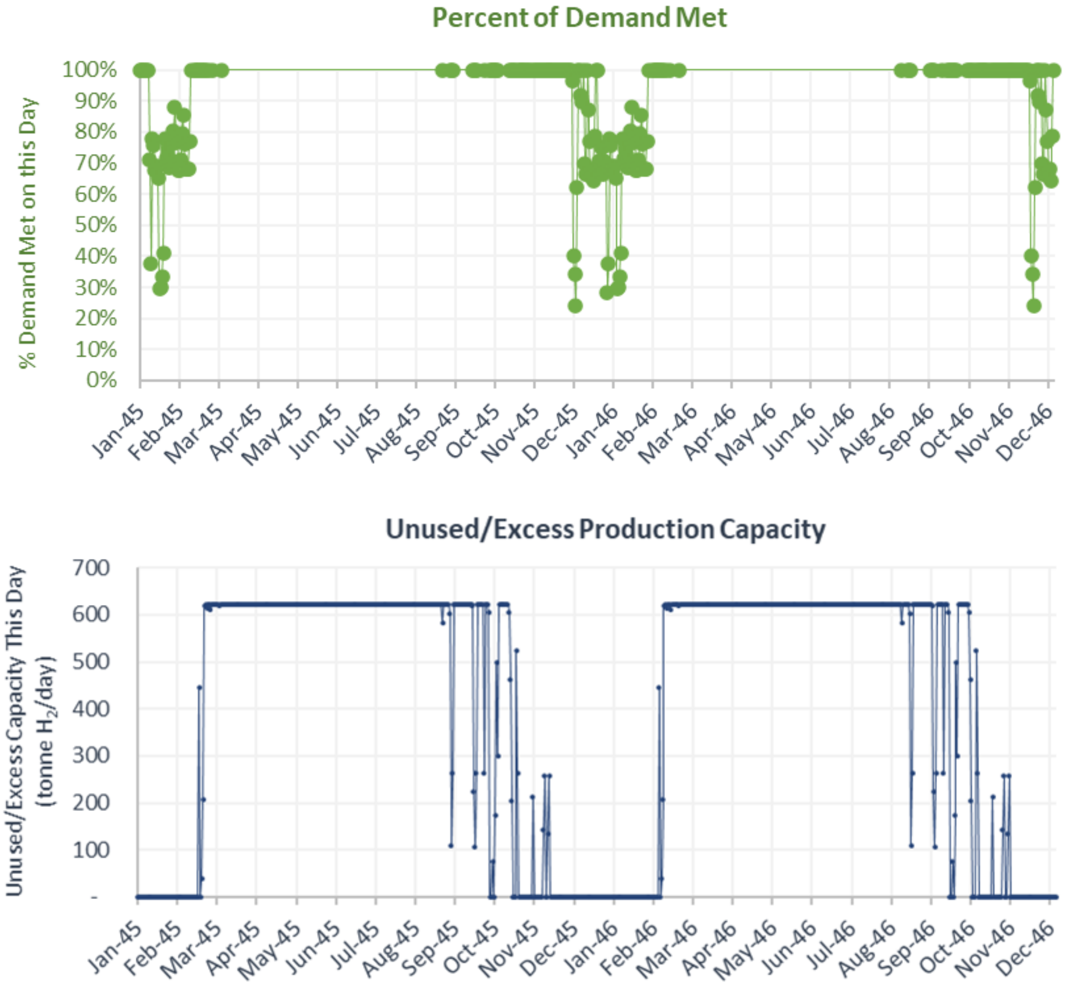
Electricity Power Sector IVCA Results

Upper Electric Demand Scenario

Model Output

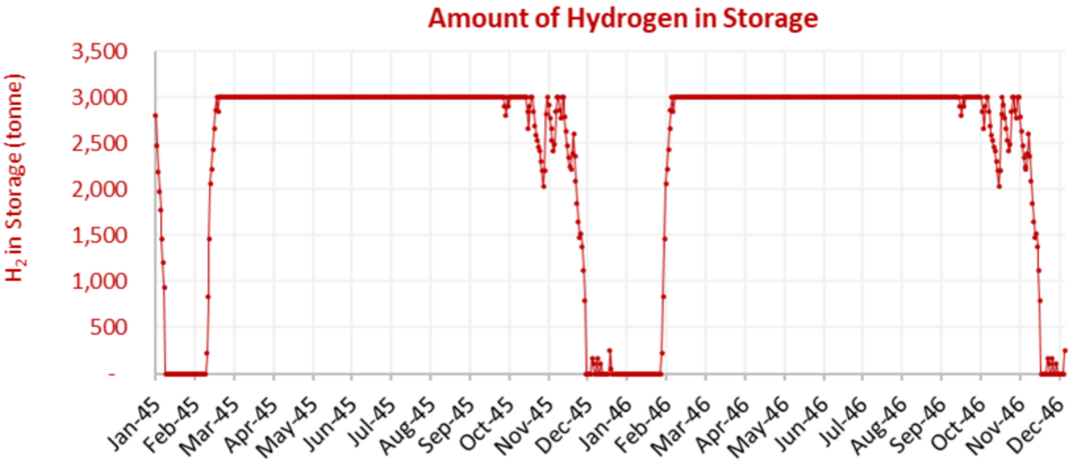
As mentioned earlier, the IVCA tool tracks how much of the specified hydrogen demand is met each day, how much is in storage, and how much (if any) production capacity would potentially go unutilized because demand was more than met but storage was full. The main output charts produced by the IVCA tool are shown in Figure 19 and Figure 20 for the LADWP upper scenario analysis for 2045 and 2046, where the 2046 demand profile is identical to that of 2045.

Figure 19: Two of three output charts for upper electric scenario for LADWP, production = 623 tonne H_2/day, storage = 3,000 tonnes H_2 (two years)



Source: Guidehouse analysis for CEC (2025)

Figure 20: Third output chart for upper electric scenario for LADWP, production = 623 tonne H2/day, storage = 3,000 tonnes H2 (two years)



Source: Guidehouse analysis for CEC (2025)

Analyzing two years enables any effects of having a different start-of-year storage level to be determined and accounted for. The production capacity modeled is 623 tonnes H_2/day (corresponding to 3,000 MW_e (3 GW_e) of electrolyzer capacity in a fully electrolytic framework), paired with 3,000 tonnes of H_2 storage. Despite these large capacities, the hydrogen plants fail to deliver enough fuel to power the LADWP gas generation plants 52 times each year.

Chart Interpretation

The three charts together help to explain how supply, storage, and demand interact. Recall that the demand underlying this case is the profile shown in Figure 11 (also shown in blue in Figure 21 below), in which demand occurs at an overall high level between mid-October and mid-February, but in the period between March and October is usually zero. For a small handful of days in January and December, the demand spikes to 2-3 times its winter average. The interactions between the core supply-demand components are best explained as follows:

- Starting in the middle of February, which is the end of the winter stretch of high demand, the demand drops greatly, allowing the production that is no longer needed to supply offtakers to refill the storage reservoir. See the red "Amount of Hydrogen in Storage" chart. The storage reservoir gets filled in a little over a week, by the 20th of February.
- At that point, the supply can no longer be used to fill storage. There's a little demand through the end of February, but starting in March essentially all of the production capacity is not used for either meeting offtaker demand or filling storage. The dark blue "Unused/Excess Production Capacity" chart shows this occurrence.
- This remains the status quo for the summer and early fall, which can be identified by completely full storage and full unused production capacity.
- Starting around September, there are some days with hydrogen demand that the production and storage can fully meet. The green "Percent of Demand Met" chart shows 100 percent during that time. Storage starts to be used around the start of October, but can get refilled again several times, the last of these being November 24, 2045.
- By November 24, demand has kicked in at a high enough and constant enough level to drain storage by the second week of December, and after that demand can no longer be met on many days.
- For the rest of the winter high-demand season, going into January and February of 2046, demand is only met on a small number of days. There is no unused production capacity because 100 percent of it is needed to meet demand.
- The cycle repeats itself throughout the rest of 2046. (Note that not all cases analyzed have close-to-identical second-year behavior; sometimes the storage level at the start of the second year differs from that at the start of 2045.[356])

Supply-Demand-Storage Dynamics

To understand the implications of these connections between demand, supply, and storage, it helps to define the limits that dictate the amount of installed production capacity necessary to have a sustainable and economically efficient supply chain. Referencing Figure below, the total hydrogen required to supply the LADWP PA in 2045 is the area under the demand profile,

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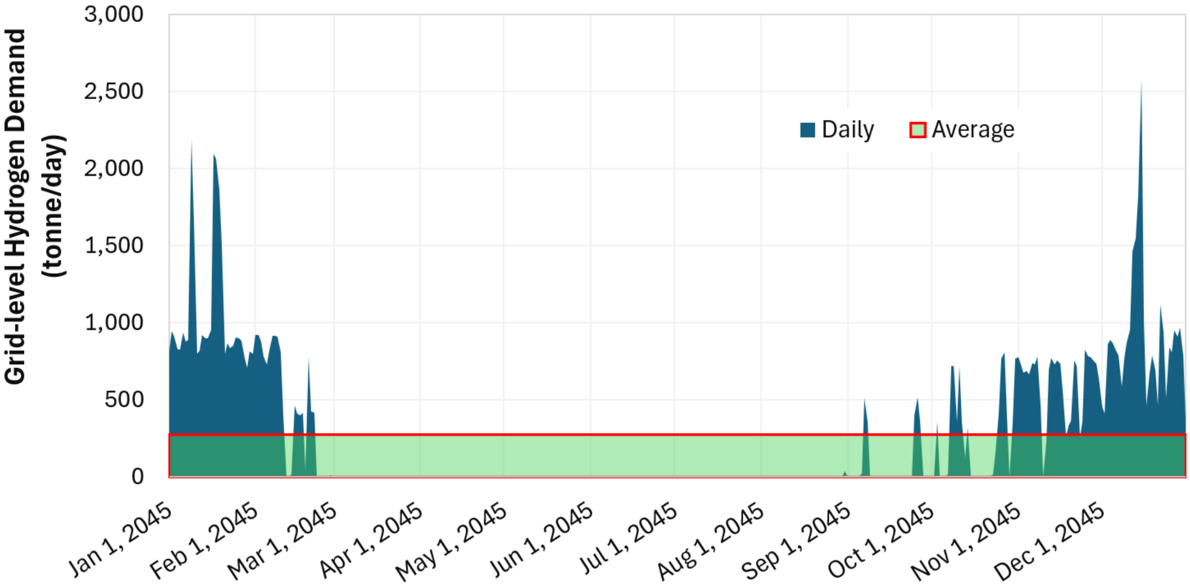
[356] Also, of course, one wouldn't expect real-life demand to be exactly identical from year to year, but this

shown in blue. The horizontal red line at 277 kg H_2/day represents the average demand over the course of the year, which means that the green area below it is also equal to the total hydrogen required in 2045. Clearly, no set of hydrogen production facilities could possibly serve this demand unless they produce at least this much fuel per day.

Figure 21: Upper scenario hydrogen demand profile for LADWP, showing elements to help visualize production vs. demand



Source: Guidehouse analysis for CEC (2025)

From the standpoint of the hydrogen producer, the ideal situation would be to operate their facility at the highest possible capacity factor so that their capital investment leads to the maximum amount of product. If the timing of the demand were not an impediment, that would look like sizing the production plant to be at full capacity when producing and delivering the average level of demand, 277 tonnes H_2/day, as that exactly supplies the gas plants with their annual fuel consumption while keeping the plant fully utilized. However, this does not provide customers enough hydrogen on days where demand is larger than average, unless there is sufficient hydrogen storage to be able to bridge the supply gap on any day of the year.

Unfortunately, the IVCA analysis shows that for a hydrogen production capacity of 277 tonnes/day and the demand profile in Figure 21, the level of storage required to ensure no shortfalls for the year would be massive at 31,016 tonnes H_2, assuming that the storage reservoir starts the year at full capacity. Even then, this configuration of production and storage is not sustainable beyond the first year, as the high consumption at the end of the year fully depletes the storage facility of hydrogen and the demand stays high until mid-to-late February 2046. IVCA shows that the storage facility would have to be almost double the size, or 61,625 tonnes H_2, to sustainably support the minimal production capacity (and it needs to be at least half full at the start of the year). The takeaway from this analysis is that, for the upper electric power scenario, planning hydrogen production for the minimum viable amount needed to provide adequate fuel is technically feasible, but it is not a practical approach.

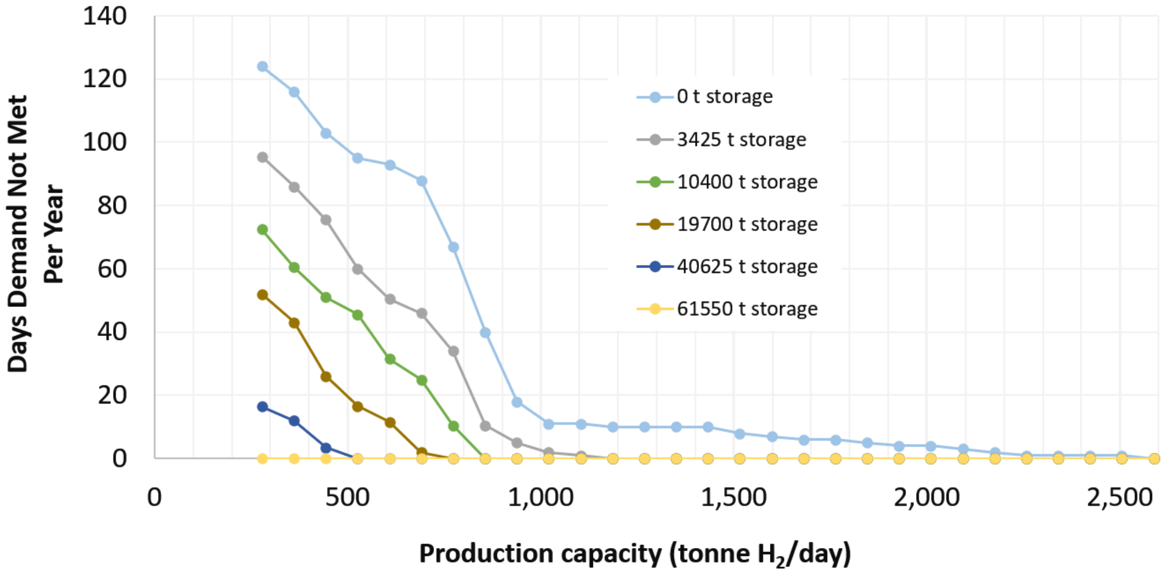
With this understood, the results shown in Figure 19 can be interpreted better. The amount of hydrogen production specified there is more than twice the minimum viable rate. IVCA analysis shows that there would have to be about 25,500 tonnes of H_2 storage to sustainably avoid shortfalls to the customers. Clearly, the amount of hydrogen production needed to supply the upper electric power scenario's highly variable demand is going to be far larger than the minimum technically viable amount.

Feasible Production-Storage Combinations

The IVCA explored the production-storage capacity space via the use of Excel's two-way data tables. The metric used to evaluate the suitability of any combination of production and storage was the number of days per year that demand could not be met.

In Figure 22, the days of unmet demand are plotted against the production capacity for several levels of hydrogen storage capacity. For context on storage volume, note that hydrogen storage in the three salt dome facilities in the U.S. Gulf Coast is estimated to be 12,000-19,000 tonnes altogether.[357] Multiple reservoirs might be needed in some locations in California.

Figure 22: Days of unmet demand for several levels of storage capacity, as a function of production capacity, 2045 LADWP electric power upper scenario



Source: Guidehouse analysis for CEC (2025)

As mentioned previously, the minimum viable production capacity for the LADWP PA in the upper electric power scenario is 277 tonnes H_2/day (yellow line), but almost 62,000 tonnes of hydrogen storage must accompany it to meet demand. The dark blue curve just above the yellow line represents 40,625 tonnes of H_2 storage, and it reaches the level of zero unmet days of demand at 526 tonnes of H_2 production per day. The trend for decreasing levels of storage capacity follows as expected, finally reaching the light blue line representing no storage at all, which requires a minimum of 2,587 tonnes of H_2 production per day, slightly above the highest demand expected during the year. The boundary condition of just achieving zero days of unmet demand, referred to henceforth as the "efficient frontier," is the critical

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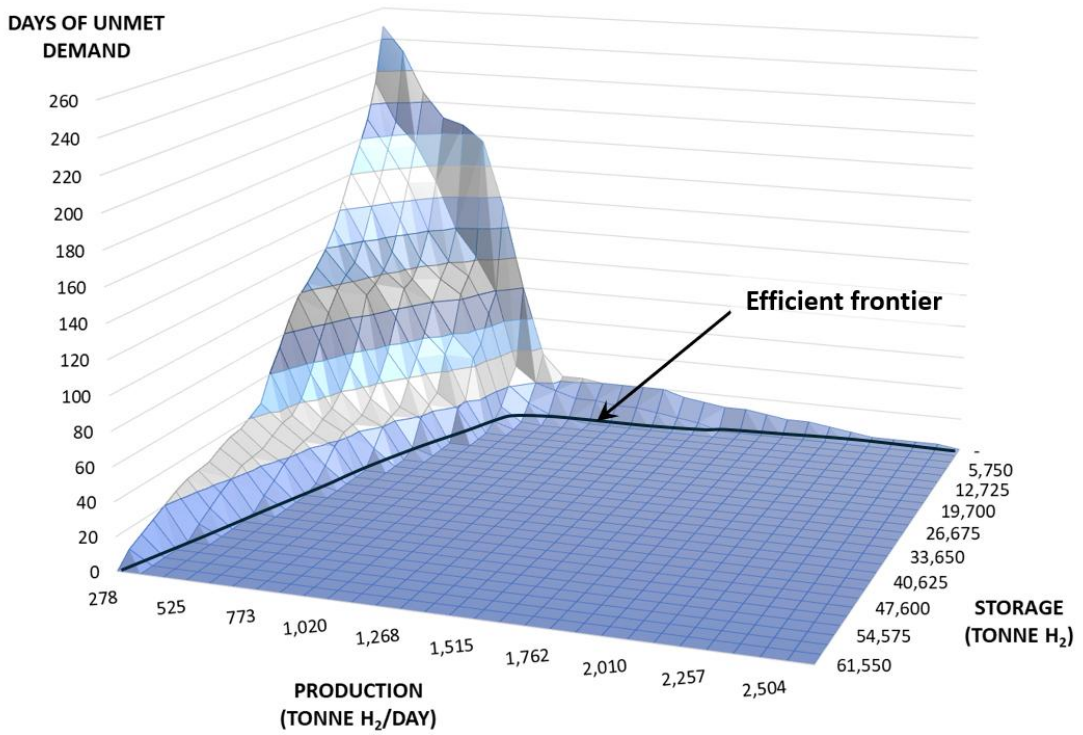
[357] Jacobs, Trent. 2023. "Digging Into the US Gulf Coast's 'Salt Real Estate' for Hydrogen Storage." Journal of Petroleum Technology. https://jpt.spe.org/digging-into-the-us-gulf-coasts-salt-real-estate-for-hydrogen-storage

one to explore in order to optimize the balance between production and storage capacities.[358]

The results of the computations performed for multiple combinations of production capacity and storage capacity are plotted as a surface in Figure 23, for the LADWP PA in the electric power upper scenario. Where combinations of hydrogen production capacity and storage result in being unable to fully satisfy the demand for hydrogen, the surface lies above the blue-grey X-Y plane. For a given amount of production capacity, though, when the storage capability gets high enough there are no more days of unmet demand. Increasing the storage capacity further provides no further benefit; thus, "efficient frontier" is an apt name for the line demarcating where the surface just touches the X-Y plane.

Figure 23: Full space of production, storage, and days of unmet demand, 2045 LADWP electric power upper scenario



Source: Guidehouse analysis for CEC (2025)

Figure shows the efficient frontier for LADWP in a simpler format, where only production and storage capacities are shown, as there is no need to include days of unmet demand (it is always zero at the efficient frontier). For any given point on this line, there is no further reduction in shortfall days achieved by either raising the production level or the storage level. In practice, one would design in a safety factor or margin of error for both production and storge, especially in light of the uncertainty inherent in predicting both supply and demand.

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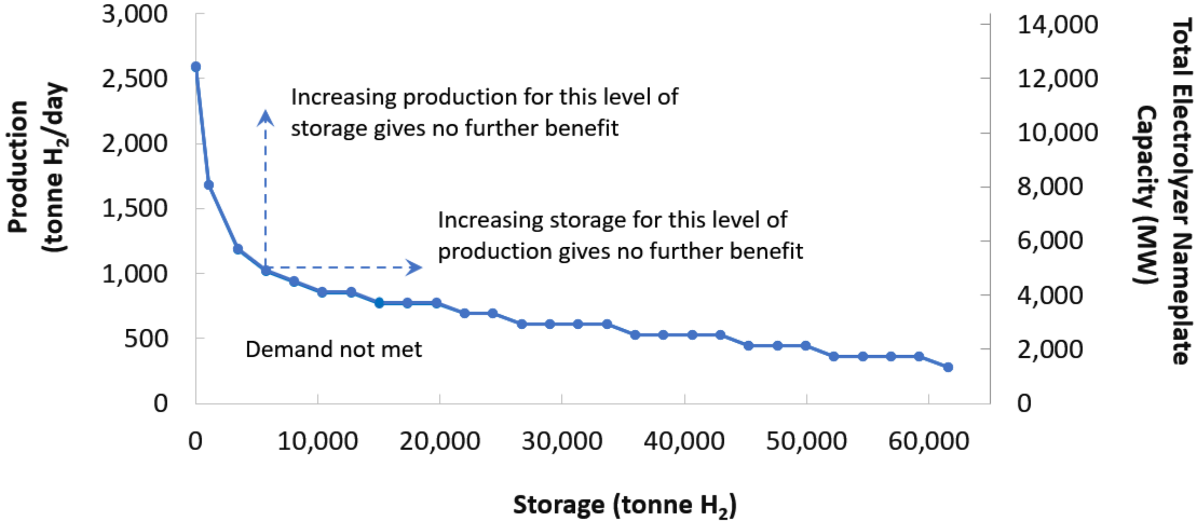
[358] "Efficient frontier" is a term of art in financial analysis of investment portfolios that applies well to the key results of this analysis. Per Wikipedia, it is "the set of portfolios which satisfy the condition that no other portfolio exists with a higher expected return but with the same standard deviation of return (i.e., the risk)." In the present analysis, the analogy of risk is the ability to meet hydrogen demand.

Figure 24: Efficient frontier for LADWP in the electric power upper scenario. Based on modeling of two years.



Source: Guidehouse analysis for CEC (2025)

For comparison against the results of the 2023 IEPR analysis, the right vertical axis in Figure 24 shows the efficient frontier for LADWP in a simpler format, where only production and storage capacities are shown, as there is no need to include days of unmet demand (it is always zero at the efficient frontier). For any given point on this line, there is no further reduction in shortfall days achieved by either raising the production level or the storage level. In practice, one would design in a safety factor or margin of error for both production and storge, especially in light of the uncertainty inherent in predicting both supply and demand.

Figure 24 shows what the nameplate capacity would be if all the production were accomplished via electrolyzers,[359] given the efficiency and capacity factor assumptions used for the IVCA analysis. The condition chosen in that analysis was a production capacity equal to the average demand, which is the lowest amount of production plotted in the figure.

The IVCA also calculates the critically important characteristic of unused or excess production capacity, plotted in Figure 25 along with the efficient frontier. With no storage at all, this potential loss of production capacity is very high, but it gets lower with larger amounts of storage until it finally reaches zero at the point where production capacity is equal to average demand.

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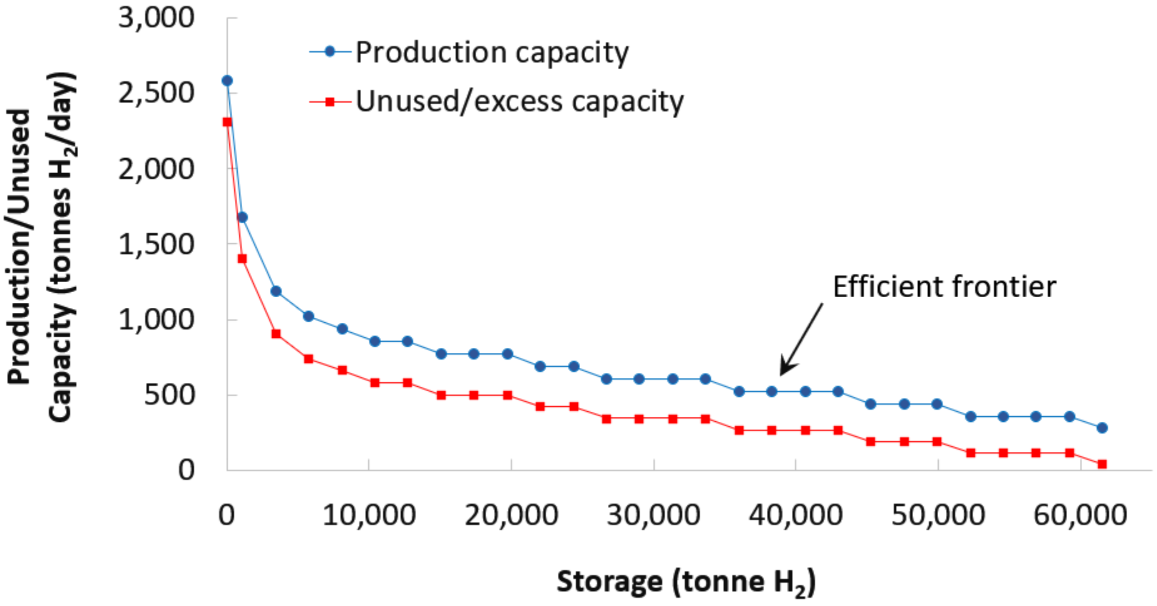
[359] As also noted, this assumption did not have any effect on the matching of supply and demand performed in the IVCA.

Figure 25: Production capacity and unused/excess capacity, LADWP upper electric power scenario, based on modeling for two years



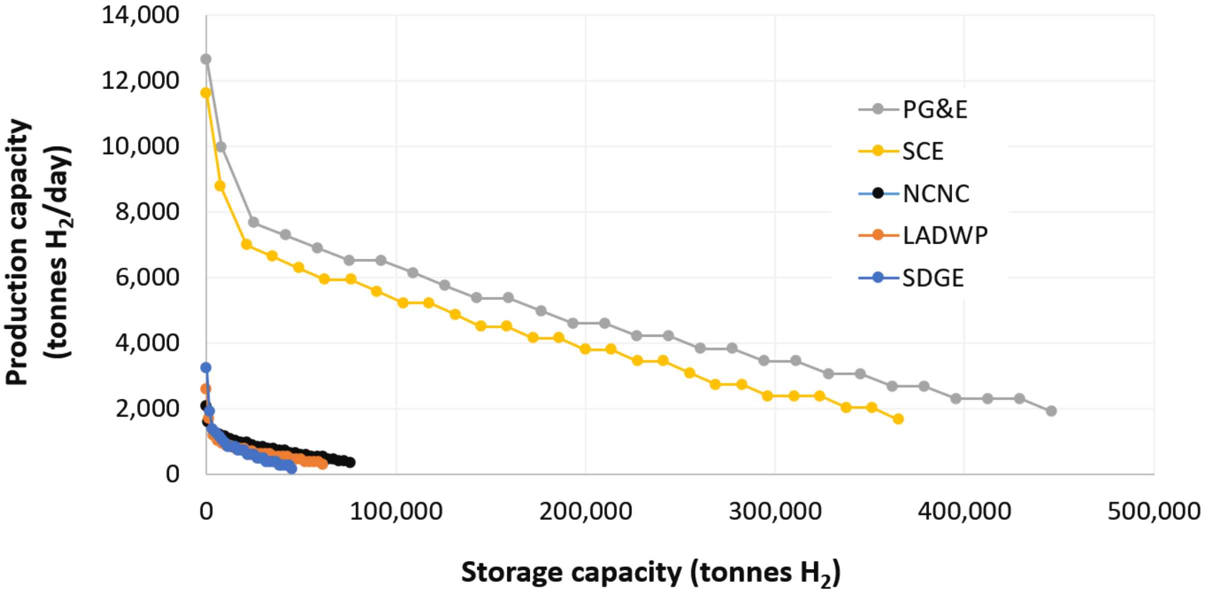
Source: Guidehouse analysis for CEC (2025)

Statewide Supply-Demand Curves

The efficient frontier was then computed for all of the PAs except IID, which has a demand curve that is both very small and perfectly flat except for a few days of low-to-zero demand. These are shown in Figure 26.

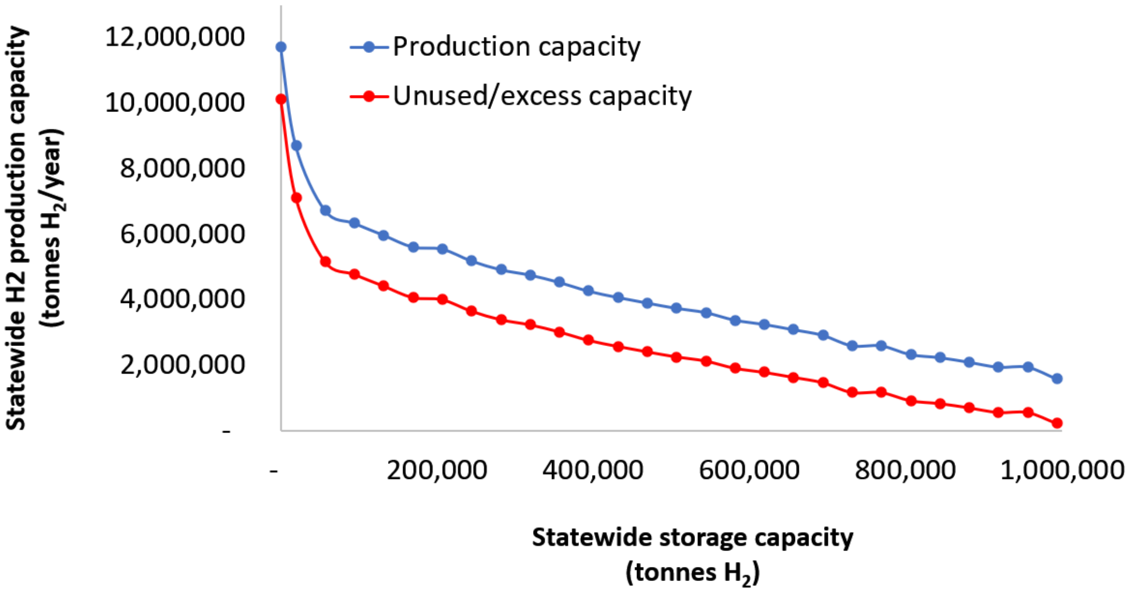
Figure 27 illustrates the statewide tradeoffs of hydrogen production capacity and potentially unused production capacity versus available storage for the upper electric power scenario. The chart assumes that storage would (and could) be implemented in a distributed way according to PA-level needs across the state.

Figure 26: Efficient frontier curves for all PAs except IID, electric power upper scenario



Source: Guidehouse analysis for CEC (2025)

Figure 27: Statewide tradeoffs of hydrogen production capacity and potentially unused production capacity vs. available storage, upper electric power scenario



Source: Guidehouse analysis for CEC (2025)

The difference between the production capacity and the unused/excess capacity is equal to the actual amount of hydrogen delivered to the power plants (1.59 million tonnes/yr) when there is no storage. However, as the storage level increases the difference between the two curves becomes lower than this amount, due to the IVCA assumption of a full storage facility on the first day of the analysis.[360] Statewide, the difference between required production

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[360] To see why this is so, imagine that the storage facility were considered to be empty or half full at the start of the analysis. The high demand in January and February is met by a combination of what can be produced daily

capacity and unused capacity is only 1.36 million tonnes H_2/yr at the full-storage condition; that is, the IVCA estimates a "residual unused production capacity" for full storage of about 235,000 tonnes, even though it would not be expected that there is excess production capacity. This is a condition that could occur in real life, so it is not an artifact of the analysis; rather, it means that the IVCA is a somewhat conservative estimate. However, it may not be a highly likely event, as infrastructure and demand scale up gradually rather than being dropped in place fully formed. In any case, the effect is small and does not affect the conclusions of the analysis.

Comparison to 2023 IEPR Estimate

The 2023 IEPR report estimated the amount of electrolyzer capacity needed for the upper scenario to be just that amount needed to generate the hydrogen to be consumed by gas-fired plants in 2045. Using the technical assumptions adopted in this IEPR analysis, the 0.226 exajoules of fuel (214 million MMBtu) per year to be replaced by hydrogen in the upper scenario translate to 1,593,757 tonnes of H_2 per year. Using the electrolysis parameters described above, producing hydrogen entirely by electrolyzers would require a minimum of 21.02 GW_e of installed electrolysis capacity.

Table 32 in the Ancillary Material Appendix shows the level of electrolyzer capacity that would be needed at each of the efficient frontier conditions, for each PA, in the event that all hydrogen production is done via renewable energy and electrolysis. The last line of the table gives the best-case scenario, where installed production is at the average demand level and very large storage facilities provide the necessary buffer to distribute it in a way that meets demand.[361] At the top of the table is the worst case, representing either a complete lack of storage capacity or an inability to economically use hydrogen storage facilities because of their cost. The worst-case situation requires 154.7 GW_e of nameplate electrolyzer capacity to be installed, which is 7.4 times as much as the level calculated when using 2023 IEPR assumptions (21.02 GW_e).

Summary of Electric Power Upper Scenario IVCA

Should the state pursue major replacement of fossil gas with hydrogen for gas-fired power plants, the infrastructure requirements of that future hydrogen economy could span a large range of possibilities. Where California will land by 2045 on the spectrum between best and worst cases will depend strongly on both the success of development of technology for storing hydrogen in depleted oil and gas reservoirs and the level of adoption of such storage in the state.

Shifting back to a perspective independent of the choice of hydrogen production pathway, the quantitative infrastructure impacts estimated by the IVCA are summarized below:

- **If no hydrogen storage is available**, the dedicated hydrogen production capacity would need to be 11.7 million tonnes/yr, which is 7.4 times what the gas-fired plants in

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and what may exist in storage. By the time the summer lull in demand arrives, storage is very low or (just) fully depleted. Refiling the storage takes a certain amount time during the summer days with low or zero demand. However, when storage starts out 100 percent full, as is assumed, the storage facility is more full when the summer lull arrives and fills up more quickly. Having more summer days with no demand results in a higher estimate of unused production capacity.

[361] The electrolyzer capacity figures in the bottom row add up to 20.91 GW_e, which is 0.5 percent below the exact number of 21.02 GW_e. This is an artifact of the granularity of the binning built into the data table method used to construct Table 30.

the upper scenario would be using.

- **If limited storage is available**, the dedicated hydrogen production capacity would depend on just how limited storage may be, with the tradeoffs being as shown in Figure 27, for the assumption that storage could and would be implemented in a distributed way according to need across the state.
- **If ample hydrogen storage is available**, the dedicated hydrogen production capacity for the electric power sector could be the minimum value of 1.59 million tonnes/year.

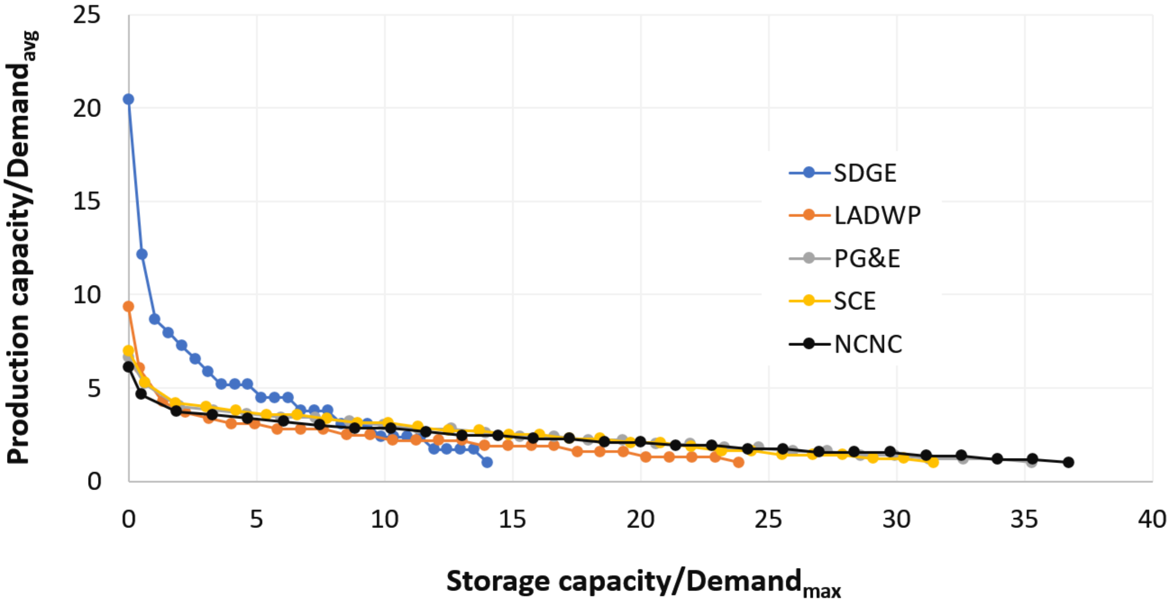
Similarity of Production-Storage Tradeoffs Among the Pas

It is helpful to understand how similar or different each of the efficient frontier spaces are for the different PAs. A visual examination of the demand profiles in Figure 26 shows that all of the regions except IID (which has a fully flat profile) have no demand, or close to no demand, in the summer. Demand picks up in the fall for all (non-IID) regions except for SDG&E, and the demand peaks through the winter for all of the non-IID regions.

One factor that should contribute to having similar efficient frontiers among the regions is how much day-to-day variation each demand curve has. A common measure of variation of a population that allows comparison against other populations is the *coefficient of variation* (COV), which is the standard deviation of the data divided by its average. Dividing the standard deviation by the average gives a sense of scale of the variations with respect to the profile as a whole.

Excluding IID, the demand curves have very similar COVs that lie between 1.49 and 1.59 for every PA except SDGE (COV of 2.85). This similarity lends credence to the possibility that the optimization of storage and production might be very similar for all the PAs, even though the absolute demand levels are widely different among them. After some exploratory analysis, it was determined that the average and maximum of the demand curves could be used to scale production and storage, respectively, so that when these scaled quantities are plotted against each other the efficient frontier curves are quite similar (Figure 28).

Figure 28: Normalized storage vs. production curves for all major California regions, upper scenario.



Source: Guidehouse analysis for CEC (2025)

Scaling the production capacity by the average demand makes sense because the average demand is the true amount of hydrogen delivered to the customers, regardless of production capacity. The maximum demand is a logical choice for scaling storage capacity because that is the most that the storage facilities could ever need to deliver on a single day.

Visually, the curves all stay within a limited band, the only real deviation being for SDGE. This may be due to that PA's higher COV, which is a consequence of its demand being lower for more days of the years than the other PAs.[362] Because the amount of hydrogen delivered to the electric power system is constant, regardless of total production capacity, amount of unused production capacity scales with storage capacity identically.

Ability to Utilize "Unused" Production Capacity

Figure shows that without hundreds of thousands of tonnes of H_2 storage throughout the state, the challenge of using hydrogen to provide 100 percent of gas-fired plant demand on a daily basis lead to only a fraction of the installed production capacity being used to support electric power generation. The logical question to consider is whether the hydrogen production facilities have other offtakers to which they can provide hydrogen and increase utilization of their plants. If that is not possible, it would lead to a greatly increased levelized cost of hydrogen, especially for the capital-intensive pathways of gasification and pyrolysis.

CARB has given estimates of hydrogen usage in various sectors[363] that show that the transportation sector dominates the expected hydrogen consumption in the non-electric power sectors in 2045, using 87 percent of the forecasted ~1.63 million tonnes per year of H_2. Thus,

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[362] The SDGE demand is less than 20 percent of the annual average for about 38 percent of the time more than the other PAs.

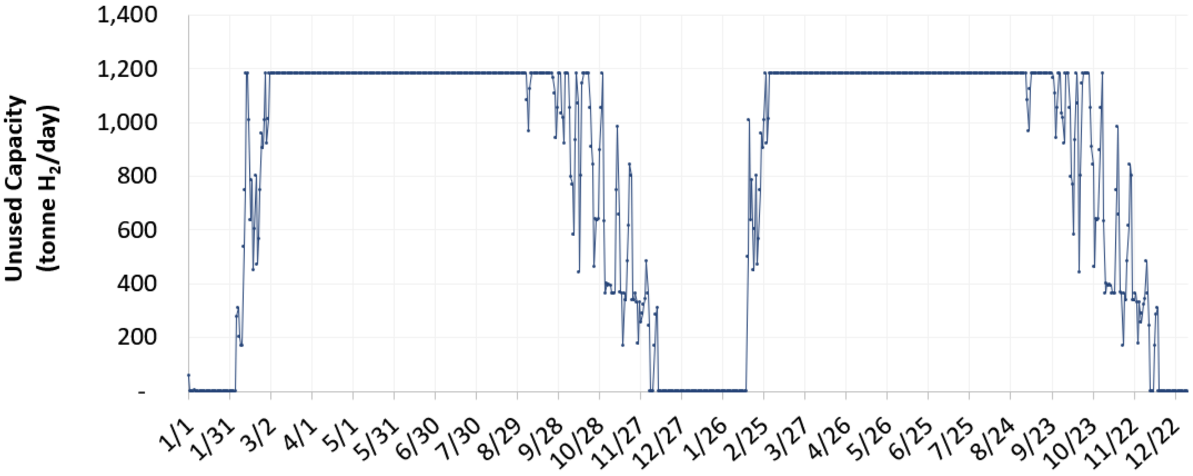
[363] Gangelhoff, Gregory, and Vignesh Venugopal. 2025. *Analysis of Hydrogen in California for Senate Bill 1075 Report*. California Air Resources Board. https://ww2.arb.ca.gov/sites/default/files/2025-02/sb-1075-workshop-022525-presentation-e3.pdf

large amounts of hydrogen consumption beyond the amount considered in the two upper scenarios of this IEPR would not be expected unless usage by other sectors such as industrial, commercial, or residential ends up being much greater than CARB anticipated. Of those three, the industrial sector has the greatest potential for adopting hydrogen; for example, a situation where grid constraints reduce the feasibility of complete industrial electrification might lead to more use of hydrogen as a heating fuel for otherwise easy-to-electrify applications. CARB considered that industrial uses would represent about 8 percent of non-electric end uses; even if it tripled relative to expectations it would not use more than about 400,000 tonnes of H_2 per year.

The best-case situation for putting the "unused" production capacity to use would be for it to supply all of the non-electric power hydrogen demand that CARB forecast. Assuming that to be true, and that industrial usage is triple the CARB expectation, that would remove about 1.9 million tonnes/yr of excess hydrogen capacity[364] However, from a practical standpoint, it may be difficult to source all of the hydrogen from the production facilities built to supply the electric power sector. Figure 29 shows how excess capacity varies over the course of a two-year period in the NCNC PA for a given amount of storage that is roughly half the amount of hydrogen storage presently available in the U.S. Gulf Coast.

There is no extra hydrogen production available to serve other sectors for 68 of the 71 days between 12/4/45 and 2/12/46. This pattern of spring and summer excess capacity, with no unused capacity in mid-winter, is typical of all of the PAs.

Figure 29: Daily unused capacity profile over two years at the minimum production capacity level; NCNC region, electric power upper scenario.



Production = 1,184 tonnes H_2/day, storage = 6,770 tonnes H_2

Source: Guidehouse analysis for CEC (2025)

Focusing in on the biggest hydrogen user, transportation, the CEC estimates the hydrogen usage for transportation in NCNC during those weeks to be about 9,948 tonnes (roughly 146 tonnes H_2/day). Some hydrogen could be supplied to transportation during this period, but there would still need to be about 8,700 tonnes of H_2 storage for transportation purposes –

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[364] There will be only be that much excess production capacity available if less than 591,000 tonnes of H_2 storage can be developed and put to use for hydrogen use for electric power (Figure 48).

above and beyond the 6,900 tonnes of storage planned for supporting the electric power sector.[365]

Lower *Electric Demand Scenario*

Demand Profiles for the Lower Scenario

As described above, the lower electric power scenario is defined by two features of the 2020 UCI renewable hydrogen deployment roadmap:[366] (1) the hydrogen demand is based on the combination of the demand of geothermal power plants and the dispatch of long-duration energy storage (LDES), both in 2045, which defines the day-to-day variability in the profile, and (2) the total amount of hydrogen to be produced in 2045 is estimated to be 350,000 tonnes. As with the upper scenario, the power grid demand profiles used were those of the SB 100 Reference Scenario (dispatch only, and not charging, in the case of LDES), and a universal scaling factor was applied to each day's MWh demand to ensure the desired level of hydrogen production.

The efficiency of conversion from hydrogen to electric power was assumed to have the same high value of 70 percent that UCI used. This value assumes that the equipment used in 2045 would be high-efficiency fuel cells and turbines, rather than retrofitted fossil gas plants.

The adjusted electric demand profiles used in IVCA calculations are shown in Figure 30 and Figure 31. The first figure covers the three PAs with the smallest demand and the second shows the highest three PAs.

- Three of four regions with both geothermal and LDES power – SDG&E, SCE, and PG&E – have demand profiles with a fairly uniform level of variability, all having a COV in the range of 0.37-0.45.
- NCNC, with a COV of 0.49, also has both types of power production, but it shows clear seasonality overlaid upon an otherwise uniform level of variation. That said, it has few days with close to zero demand.
- The two regions with geothermal power only, LADWP and IID, have COVs of 0.29 and 0.66 respectively. LADWP's demand profile is similar to that of NCNC, though its several days of lowest demand are bunched together into about 1.5 weeks. IID's demand experiences a late-spring-through-summer lull that's reminiscent of the gas-fired plants

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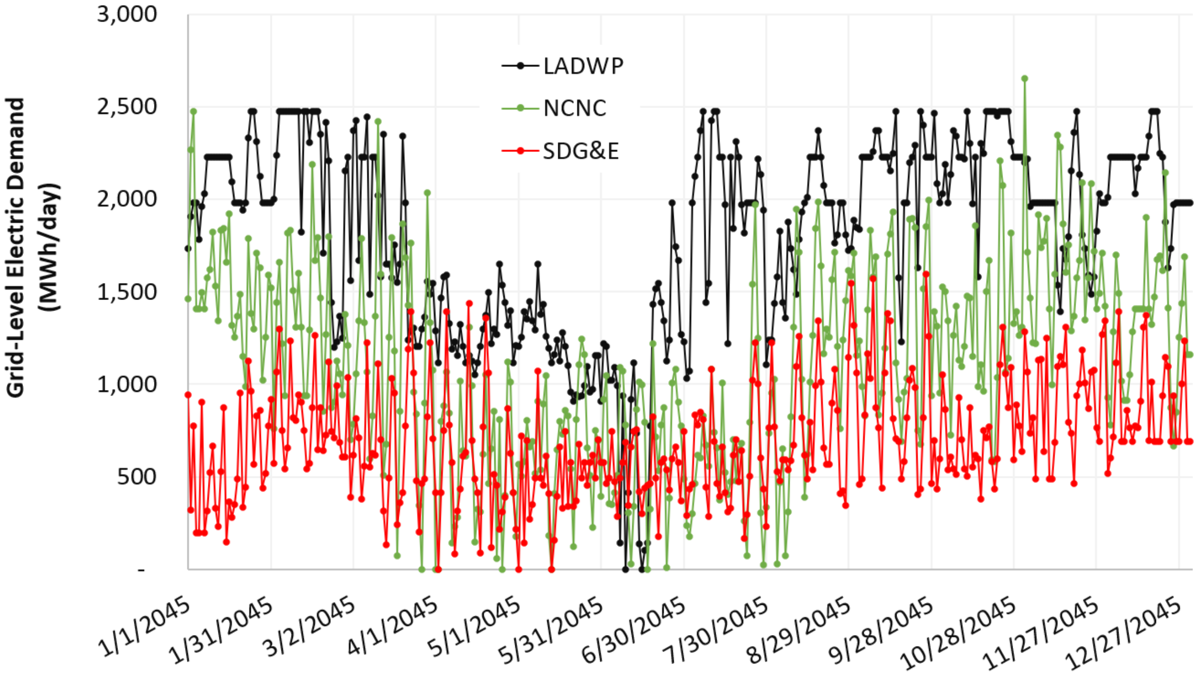
[365] During that period, the storage facility serving the electricity sector starts at 6,886 tonnes H_2 and is drawn down to only 132 tonnes by 1/20/46. None of the original 6,886 tonnes of stored hydrogen would be available for transportation, because the electricity sector is using it. Between 1/21/46 and 2/9/46 production exceeds demand enough that 3,617 tonnes of H_2 get added to storage, but at an erratic rate that's less than transportation demand, or negative, for one-third of the days. Between 2/10 and 2/12, another 2,468 tonnes get added to storage, ample for transportation in those three days.

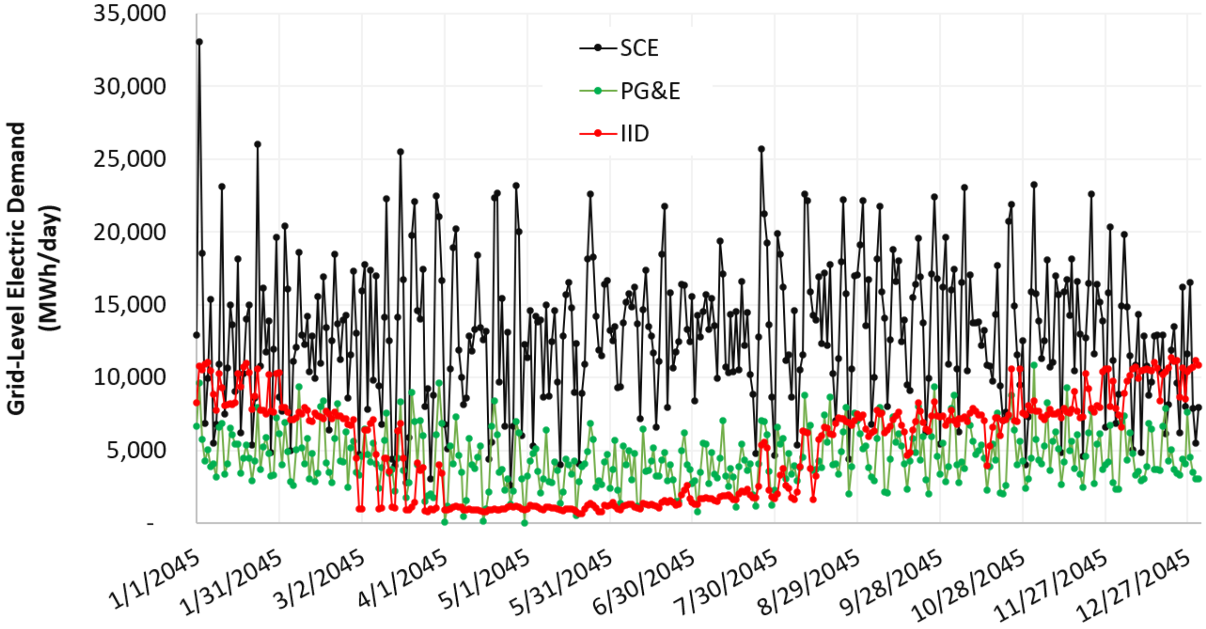
[366] Reed, Jeffrey G., Eily E. Dailey, Brendan P. Shaffer, Blake A. Lane, Robert J. Flores, Amber A. Fong, and G. Scott Samuelsen. 2020. Roadmap for the Deployment and Buildout of Renewable Hydrogen Production Plants in California. California Energy Commission. Publication Number: CEC-600-2020-02. https://efiling.energy.ca.gov/getdocument.aspx?tn=233292

Figure 30: Smaller-magnitude lower scenario electric demand profiles – LADWP, NCNC, and SDG&E



Source: Guidehouse analysis for CEC (2025)

Figure 31: Larger-magnitude lower scenario electric demand profiles - SCE, PG&E, and IID



Source: Guidehouse analysis for CEC (2025)

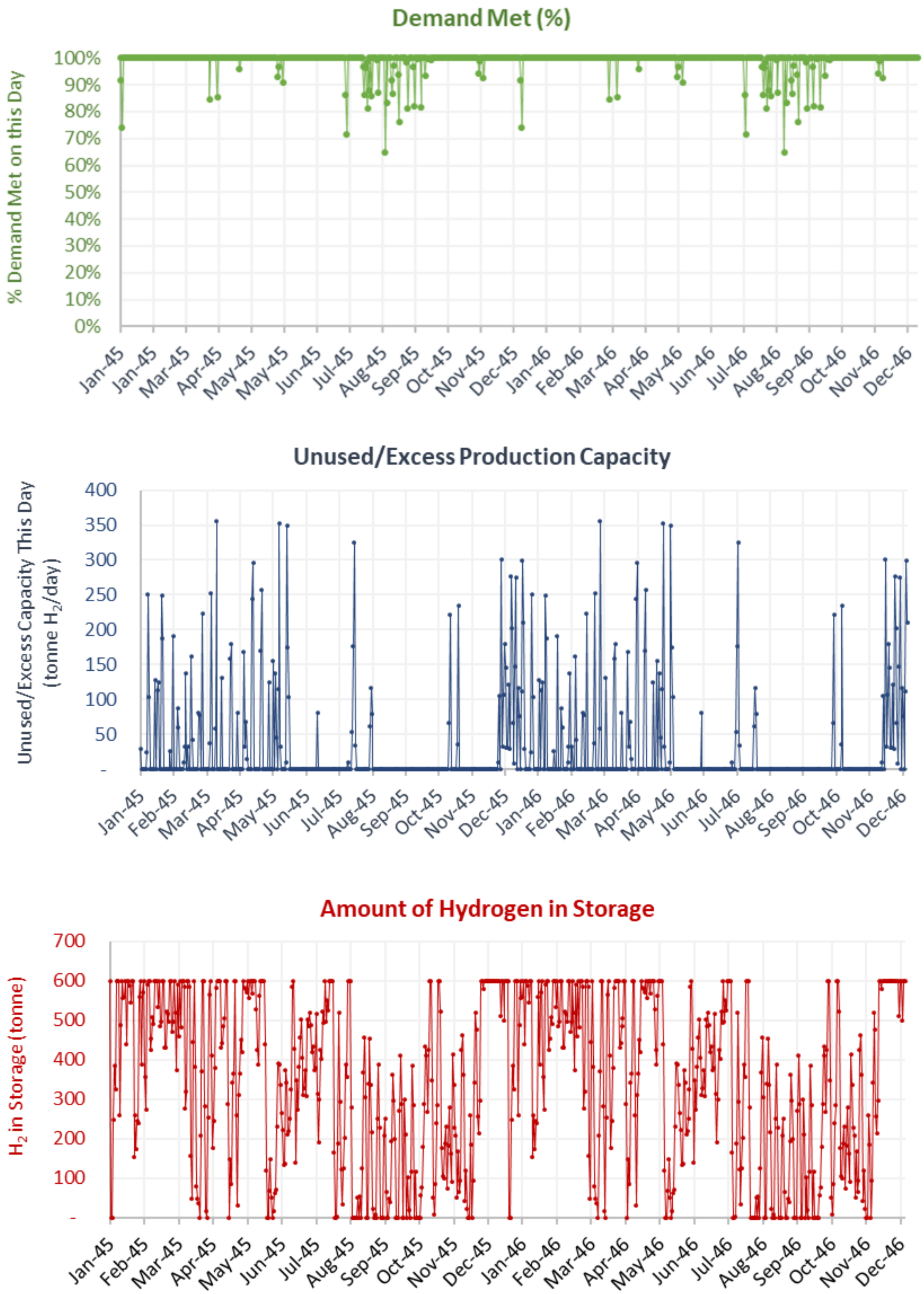
Overall, except for IID the demand profiles for the low scenario are not as “peaky” as those used for the upper scenario analysis.

Model Output and Its Interpretation

The structure of the lower scenario demand profiles ranges from having a fairly uniform average level over the year (SCE and PG&E) to having moderate season-length dips once or twice a year (LADWP and SDG&E) to having major dips for close to half of the year (NCNC and IID). IVCA output charts for the three types of profile are shown below for a two-year period in Figure 32 (SCE), Figure 33 (LADWP), and Figure 34 (NCNC), all located below. For all of these examples, the combination of production capacity and storage capacity is insufficient to eliminate the presence of days in which demand cannot be met, i.e., the conditions are shy of the efficient frontier. The purpose of showing these conditions is to allow the reader to see the different behaviors of the storage level under conditions of not-quite-sufficient storage capacity, for the three different types of demand profile. The differences in unused/excess capacity are worth examining as well.

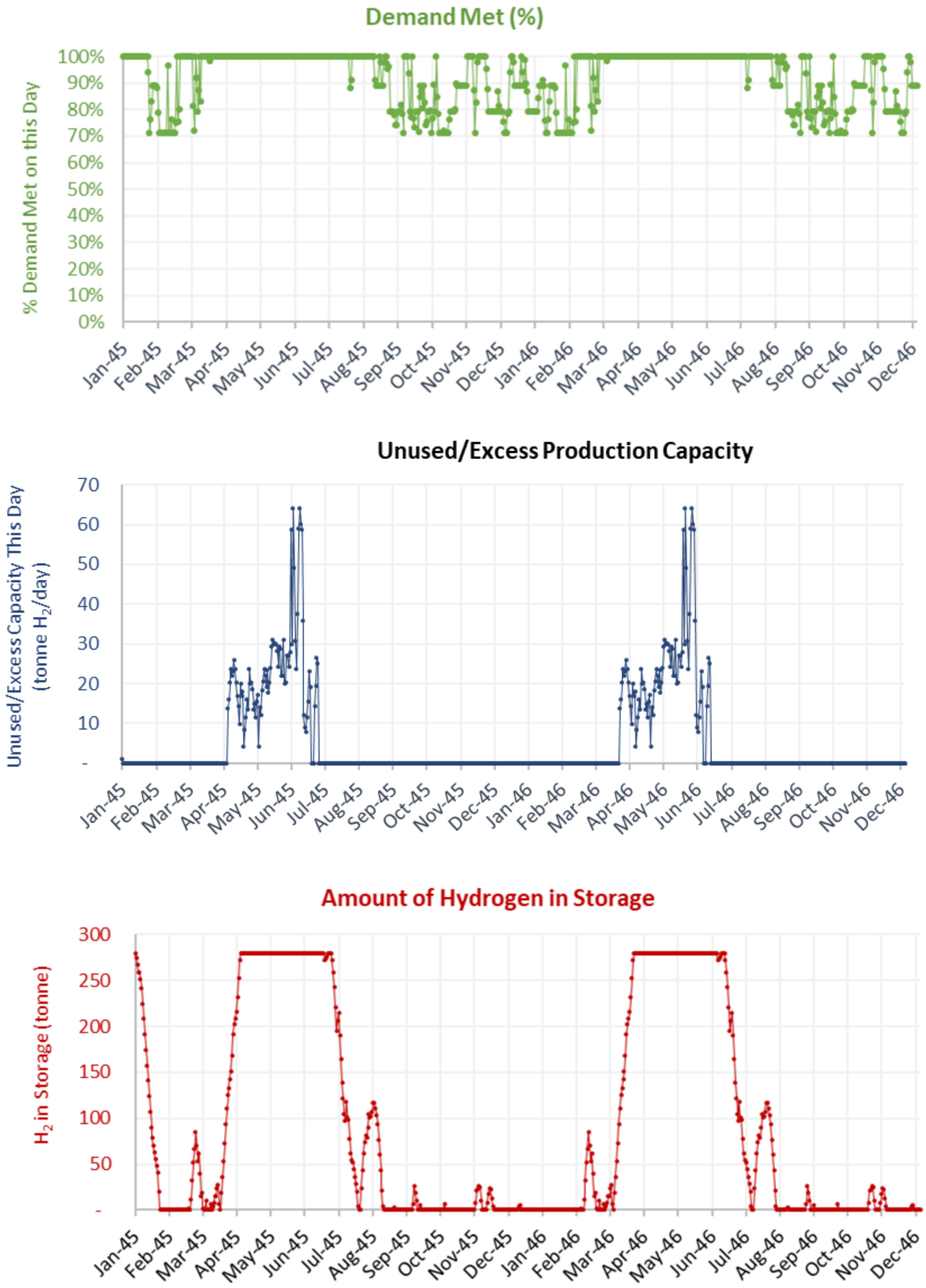
1. With a demand profile like that of SCE, having no significant seasonality and a day-to-day variation that stays within a well-defined distance of a constant average, the level of hydrogen storage shows no significant – or at least obvious – pattern over time. In addition, whatever amount of unused capacity there may be is randomly distributed across the year. Despite the lack or large patterns in both profiles, the two are related in that there is never unused capacity if the storage facilities are not full.
2. The more the demand profile has defined periods of lower electric power production, e.g., seasonal variations, the more that clear peaks appear in the storage level and unused/excess production capacity profile. The seasonality of the LADWP demand, while far less drastic than the same PA in the upper electric power scenario, shows up as peaks in the storage level and unused capacity profile.
3. With the most seasonality of all three examples, the periods of full storage and large excess capacity are the greatest for the NCNC PA.

Figure 32: Output charts for lower electric scenario for SCE, production = 498 tonne H_2/day, storage = 600 tonnes H_2 (two years)



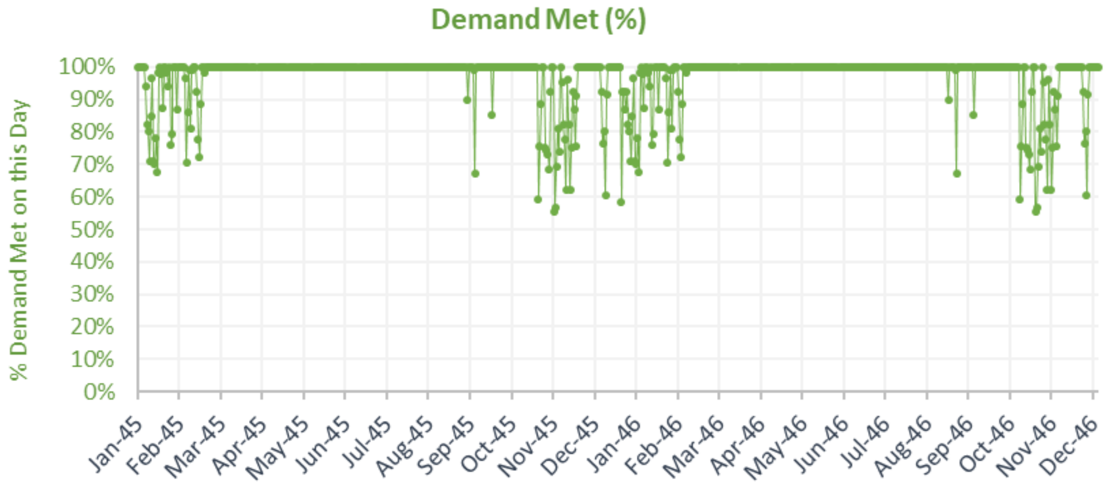
Source: Guidehouse analysis for CEC (2025)

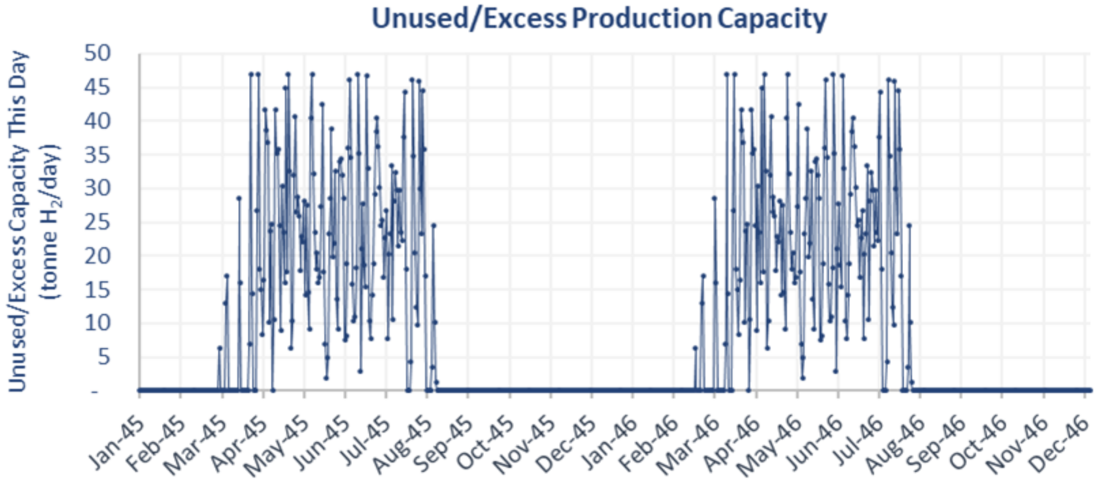
Figure 33: Output charts for lower electric scenario for LADWP, production = 64 tonne H_2/day, storage = 280 tonnes H_2 (two years)

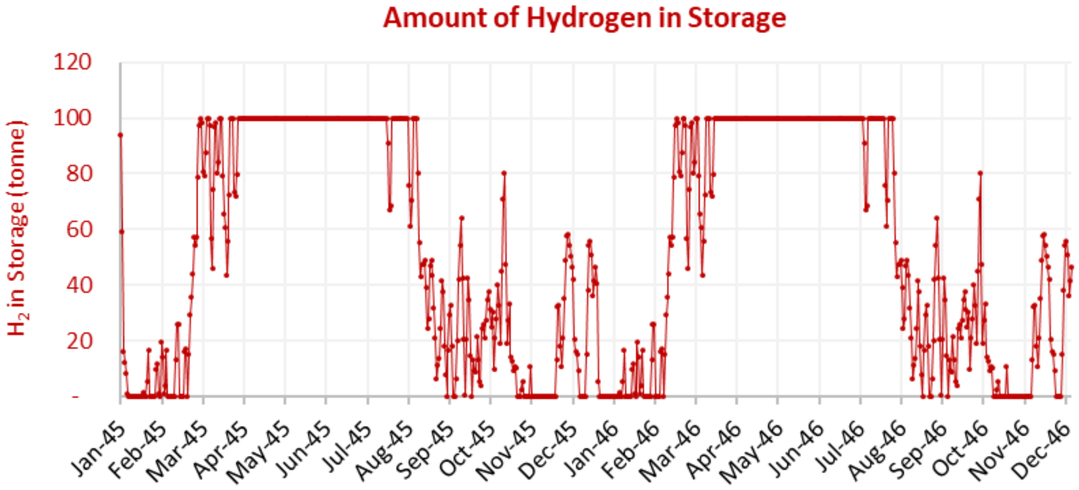


Source: Guidehouse analysis for CEC (2025)

Figure 34: Output charts for lower electric scenario for NCNC, production = 47 tonne H_2/day, storage = 100 tonnes H_2 (two years)







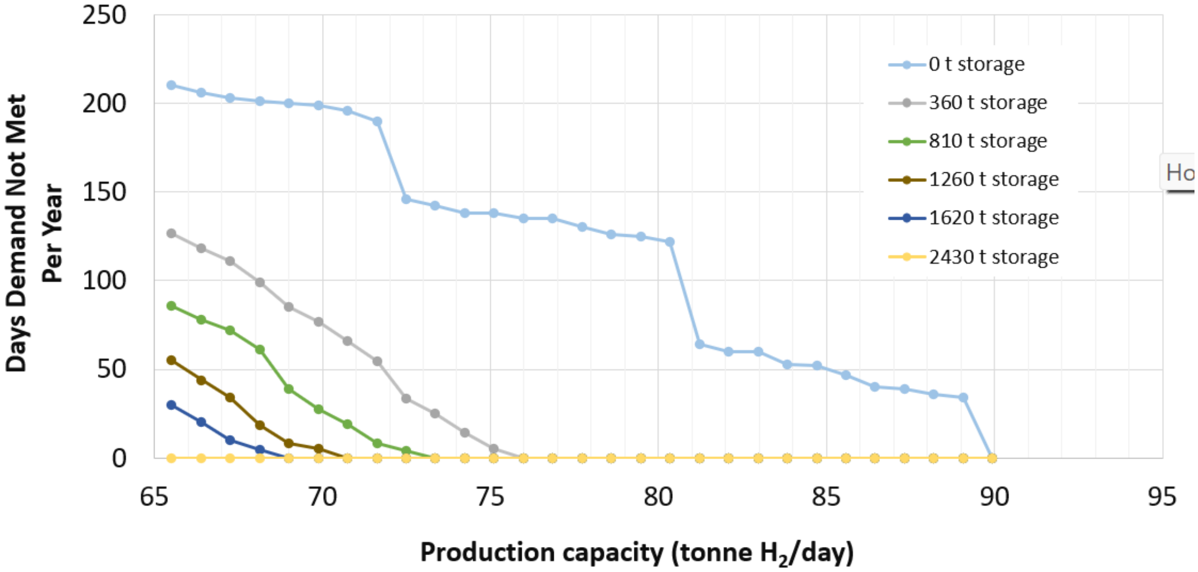
Source: Guidehouse analysis for CEC (2025)

Map of Feasible and Reasonable Combinations of Production and Storage

The lower scenario IVCA analysis proceeded along the same lines as the upper scenario, with exploration of the production-storage space against the metric of days of demand not met to define efficient frontiers for all PAs.

Figure shows the initial exploration results for LADWP. In the lower scenario, it takes about 2,430 tonnes of H_2 storage (vs. 61,550 for the upper scenario) in LADWP to enable the production capacity to have no unused portion.[367] The full exploration space is shown in the form of a surface in Figure 36.

Figure 35: Production/storage/"demand not met" space (for six of the 28 levels of storage analyzed) for 2045 LADWP electric power production, lower scenario



Source: Guidehouse analysis for CEC (2025)

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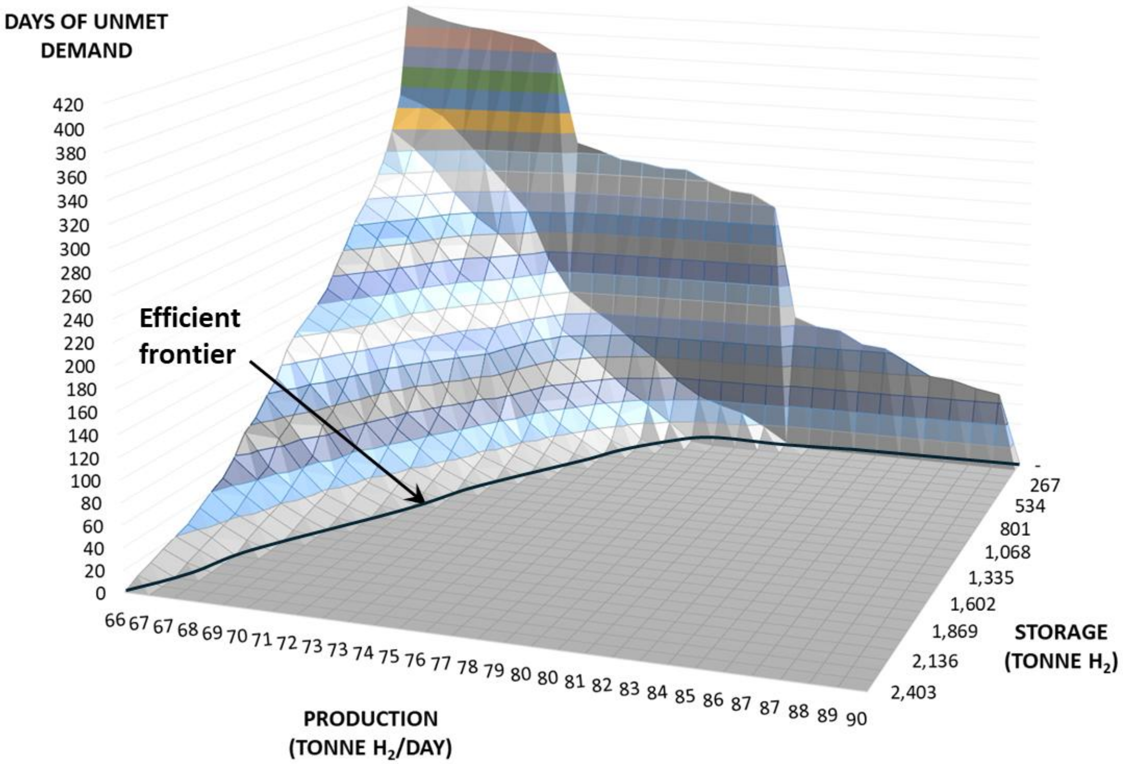
[367] A small amount of unused capacity can occur during the first year when there is a full storage facility at the start of the analysis period.

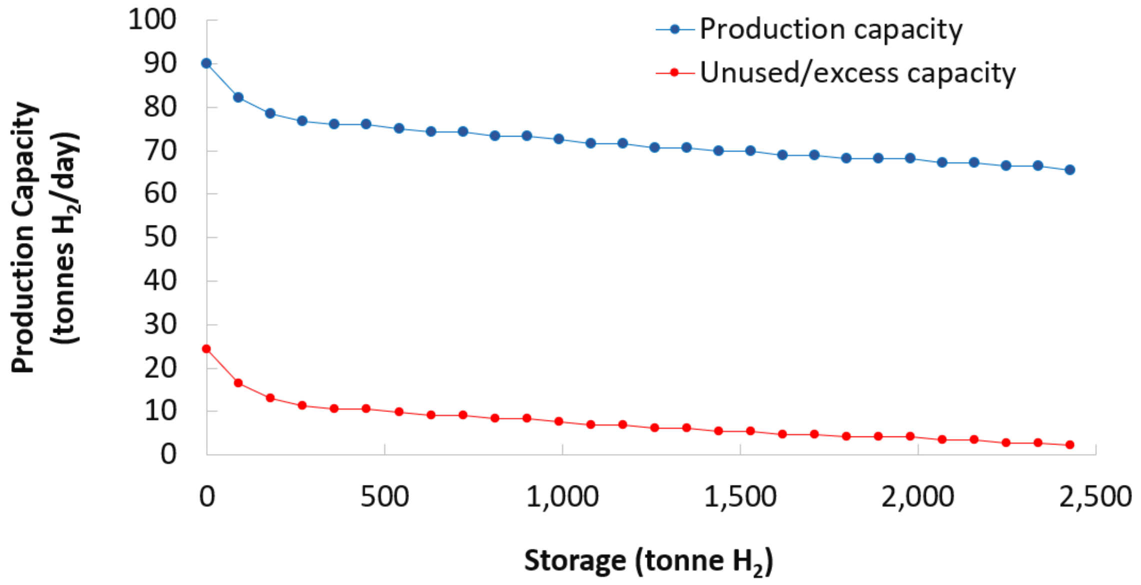
Figure 36: Full space of production, storage, and days of unmet demand, 2045 LADWP electric power lower scenario



Source: Guidehouse analysis for CEC (2025)

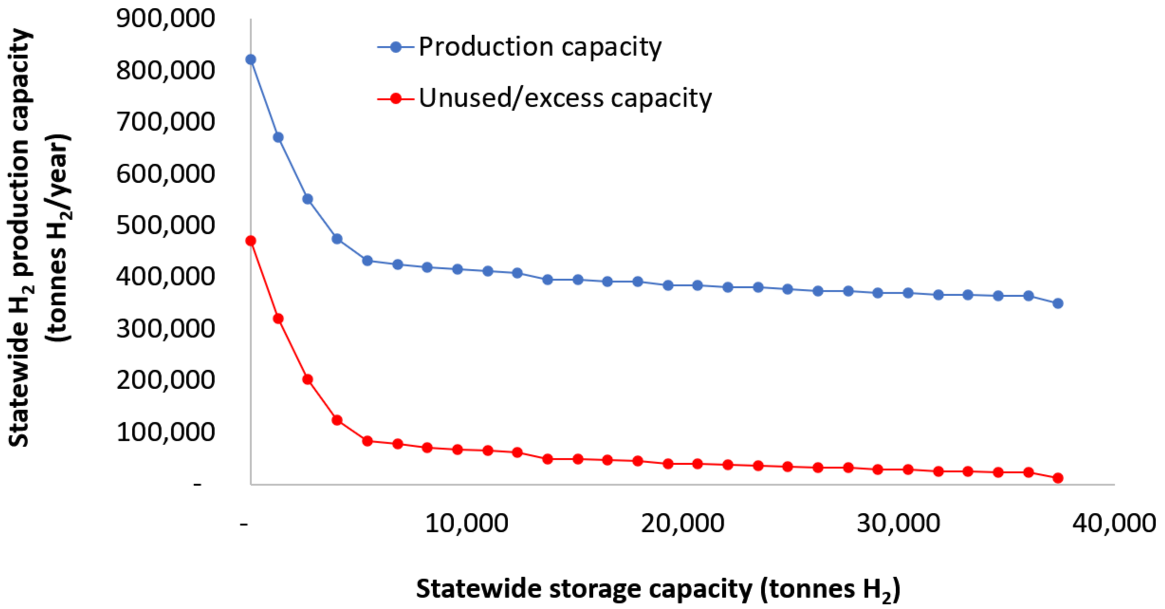
As before, the production capacity needs to be equal to or greater than the maximum demand to avoid the need for storage entirely; in the case shown above, this happens at 89.8 tonnes H_2/day and results in 27 percent of the production capacity being potentially unused. The efficient frontier of just meeting demand, along with the potentially unused capacity, are shown in Figure for LADWP and Figure 38 for the entire state.

Figure 37: Production capacity and unused/excess capacity, LADWP lower electric power scenario, based on modeling for two years



Source: Guidehouse analysis for CEC (2025)

Figure 38: Statewide tradeoff of hydrogen production capacity vs. available storage for the lower electric power scenario



The chart assumes that storage would (and could) be implemented in a distributed way according to PA-level needs across the state.

Source: Guidehouse analysis for CEC (2025)

Recalling the discussion about "residual unused production capacity" relative to the upper electric power scenario, that phenomenon is much less pronounced for the lower electric power scenario. Whereas this residual unused capacity is about 14 percent of the upper scenario annual demand (about 235,000 tonnes of hydrogen), for the lower scenario it is only 3.4 percent of the annual demand (about 12,000 tonnes of hydrogen). The reason for this difference is that except for IID there is no long summer period of idle demand that replenishes storage and then leaves large amounts of production capacity unutilized.

Supply-Demand Curve for All of California

The IVCA results of storage, production, and unused capacity for all of the PAs in the state are listed in Table 31 of Appendix E. The efficient frontier and unused capacity curves for the lower electric power scenario are shown in Figure 38. The statewide total amount of storage capacity that would be needed to prevent unused production capacity is about 38,000 tonnes of H_2. This is far lower than the upper electric power scenario, but it is still a large amount of storage that would require California to have geological storage facilities, if and when depleted oil and gas reservoirs are developed to be a safe and economical means of hydrogen storage. What might be a better tradeoff of excess production capacity for storage capacity is discussed in the summary section below.

Comparison to the 2023 IEPR Estimate

As noted in the discussion of the upper scenario, the 2023 IEPR estimated the requirement for hydrogen production to equal the level that just meets the demand, which is the 350,000 tonnes of H_2 per year estimated by UCI. This is equivalent to 4.62 GW_e of electrolyzer capacity if all the hydrogen is produced by electrolysis in 2045.

For each efficient frontier combination of production capacity and storage, the amount of electrolyzer capacity that would be needed in the 100 percent electrolysis case is listed in Table 32 of Appendix E. In the best case of having abundant storage capacity, the required statewide electrolyzer capacity is the minimum 4.62 GW_e. In the worst case of no storage being available, 10.84 GW_e of electrolysis capacity (2.35 times the best case) would be needed.

Summary of Electric Power Lower Scenario IVCA

As was the case of the upper electric power scenario, there is a spectrum of possibilities for adoption of hydrogen-fueled electric power plants that replace a portion of geothermal power production and LDES support of the power grid. These possibilities again depend on the success of development of technology for storing hydrogen in depleted oil and gas reservoirs and the level of adoption of such storage in the state. Unlike the upper scenario, the amount of storage that is likely to accompany the hydrogen production capacity may be manageable, though that could be as much as three times what is currently stored in the U.S. Gulf Coast.

- **If no hydrogen storage is available**, the dedicated hydrogen production capacity would need to be 822,000 tonnes/yr, which is 2.4 times what the power plants in the lower s scenario would actually be using. That is, the *excess* production capacity would have to be 135 percent of what actually is purchased for use on the electric power grid.

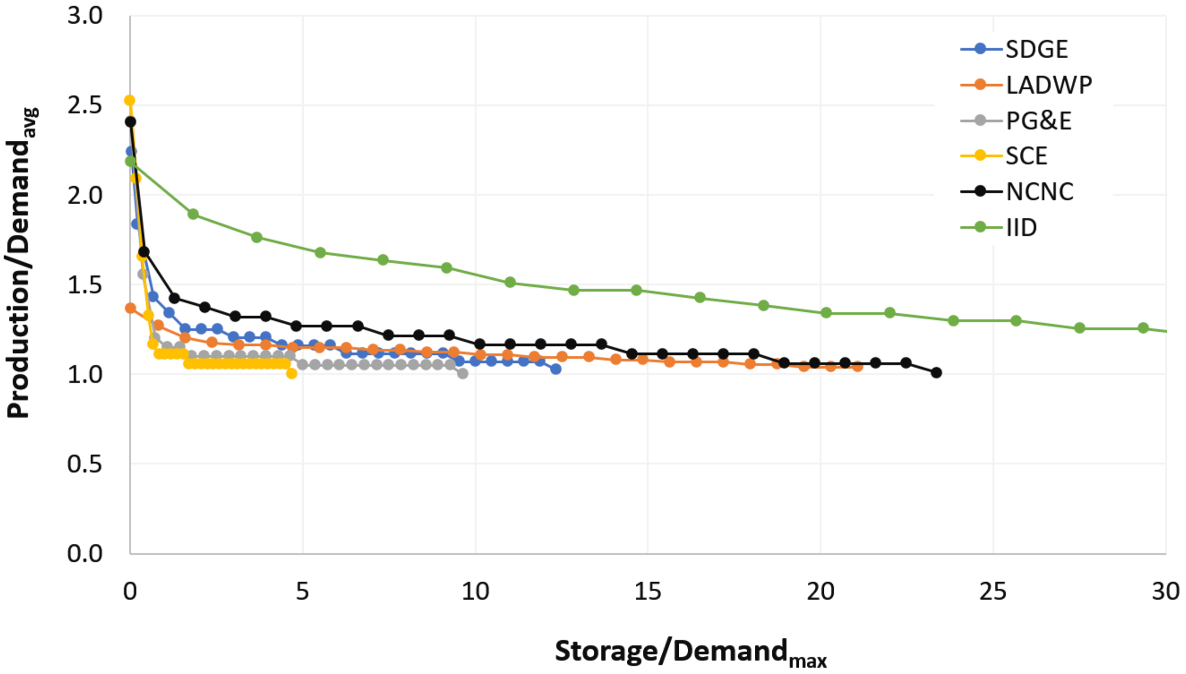
If limited storage is available, the dedicated hydrogen production capacity would depend on just how limited storage may be, with the tradeoffs being as shown in Figure 38 for the assumption that storage could and would be implemented in a distributed way according to need across the state. Most notably, if the economics of hydrogen production can tolerate a 23 percent excess of installed capacity, then only 5,400 tonnes of storage would need to be developed statewide.

- **If ample hydrogen storage is available**, the dedicated hydrogen production capacity for the electric power sector could be the minimum value of 350,000 tonnes/year.

Similarity of Production-Storage Tradeoffs Among the Pas

The underlying tradeoffs involved in matching supply and demand apply to all scenarios (as well as both electric power production and transportation end uses). Figure shows the result of scaling storage and production by the same features of the demand profile used for the upper scenario analysis.

Figure 39: Normalized storage vs. production curves for all major California regions for the lower demand scenario.



Source: Guidehouse analysis for CEC (2025)

As before, almost all the curves fall within a fairly narrow band, but in this case with the notable exception of IID. That PA has the highest coefficient of variation (COV), and its fluctuations and seasonal behavior are closer to those of the demand profiles in the upper scenario than they are to the lower scenario. In fact, plotting the IID normalized curve along with the others in the upper bookmark group shows that for a normalized storage parameter (storage/demand$_{max}$) of 10 or greater the IID profile lies right on top of the upper bookmark curves.

The preliminary conclusion to be drawn is that the efficient frontiers of demand curves with broadly similar features can be considered to be equivalent, regardless of the magnitude of total demand: they fall on the same scale when production capacity is normalized by average demand and storage capacity is normalized by the maximum demand. There are multiple types of demand curves possible, each having its own “class” of efficient frontier. Notwithstanding these differences, it can be seen from the results of the IVCAs done for the upper and lower electric power scenario, along with the IVCA results below for transportation, that efficient frontiers for all types of all have a common general shape: a relatively narrow region of steep decline of production capacity that breaks rather sharply into a longer region of shallow slope. The first place to look for a satisfactory tradeoff of production capacity vs. storage capacity – if one is possible – is just to the right of the start of the shallow-sloped region of the efficient frontier, where there is much less left to gain in production capacity in comparison to the potential gain in storage capacity.

Ability to Utilize "Unused" Production Capacity

Due to both the lower level of absolute demand and the greater day-to-day and season-to-season uniformity of the demand, there is a great deal less excess production capacity in the low scenario, as is evident in Figure 39. The maximum total amount of hydrogen production capacity available for other purposes is less than one-third of the 2045 hydrogen consumption forecast by CARB in the 2022 Scoping Plan.

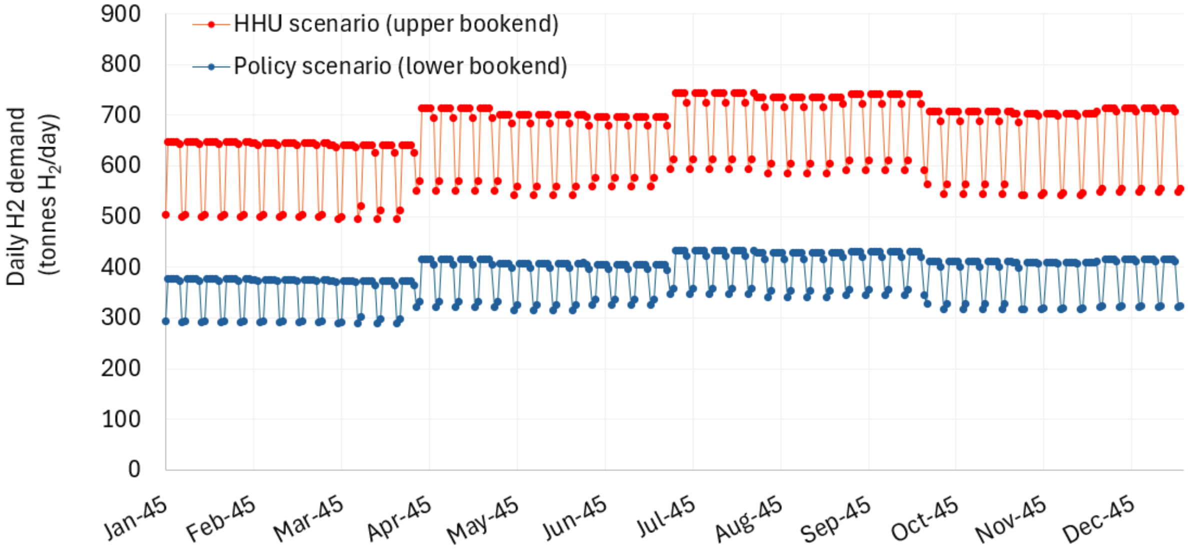
There still remains potential issues of mismatch in the timing of availability of unused capacity with the demand profiles of transportation (the main end-use predicted by CARB) and the other applications. In several regions – particularly those with demand that is seasonally uniform, or close to uniform (for example, Figure 42) – the available excess production varies greatly at a granular level of days. Installing storage to smooth out availability of hydrogen produced by the excess capacity would simply negate the need for that much or all of that excess capacity in the first place. That is, if storage is available in such quantities, it is most efficient to use it to serve the original demand with less installed production capacity; if storage is not available, then smoothing out the availability of excess hydrogen is not even possible.

Transportation Sector IVCA Results

Similarities in Demand Among Transportation Scenarios and Planning Areas

Unlike the electric power scenarios, the two transportation scenarios had virtually identical variations in demand across the entire year. Figure 40 shows the demand profiles for each scenario for LADWP. Although upper and lower demand differs in quantity each day, their patterns of day-to-day variations are identical. Scaling up the lower scenario profile by multiplying it by the ratio $\frac{(ave\ demand)_{upper}}{(ave\ demand)_{lower}}$ results in data points that are all but indistinguishable from the upper scenario. Table 14 summarizes the key size metrics for all of the PAs in both scenarios.).

Figure 40: Comparison of demand profiles for upper and lower transportation scenarios, LADWP (2045)



Source: Guidehouse analysis for CEC (2025)

Table 14: Average and maximum hydrogen demand for both scenarios and each PA

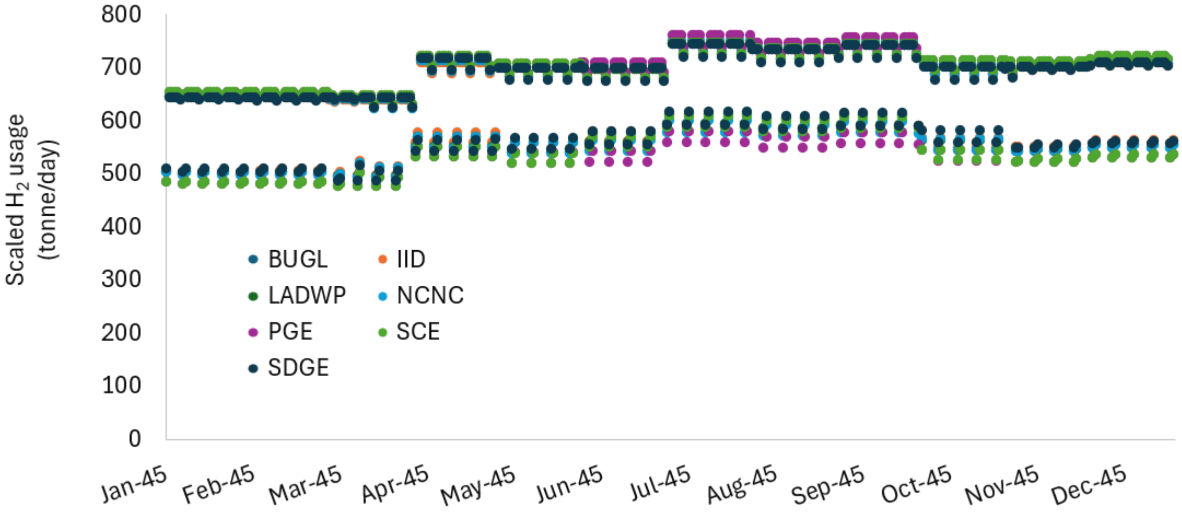
PA Zone	HHU H_2 Demand (tonnes H_2/day)		Policy H_2 Demand (tonnes H_2/day)	
N/A	Maximum	Average	Maximum	Average
BUGL	79	69	46	40
IID	28	24	16	14
LADWP	744	655	433	382
NCNC	302	264	176	154
PGE	1624	1400	946	815
SCE	1341	1177	781	685
SDGE	270	238	157	138

Source: Guidehouse analysis for CEC (2025)

Moreover, the key metric of variability, coefficient of variation (COV), for the two scenarios is within one-tenth of one percent among every PA except IID, where they are within one-quarter of one percent. Thus, for the purpose of elucidating the details of the supply-demand matching for transportation, analysis of the upper scenario was all that was needed and was all that was performed. Even within a single scenario, there is strong similarity in the demand profile among the seven PAs. Figure below shows the upper scenario demand profiles for all of the PAs after scaling to the same average demand level as the LADWP profiles, using a scaling factor of $\frac{(ave\ demand)_{LADWP}}{(ave\ demand)_{PA}}$.

It is clear that there are only minor variations among the daily transportation demand profiles of the PAs, not large enough to merit a full IVCA assessment for each. Based on the similarities in demand profiles of the different PAs and scenarios, much of the detailed IVCA work discussed below is based on a single analysis of the LADWP profile with "spot checks" via analysis of the SCE and SDGE PAs.

Figure 41: All upper scenario transportation hydrogen profiles, scaled to LADWP average



Source: Guidehouse analysis for CEC (2025)

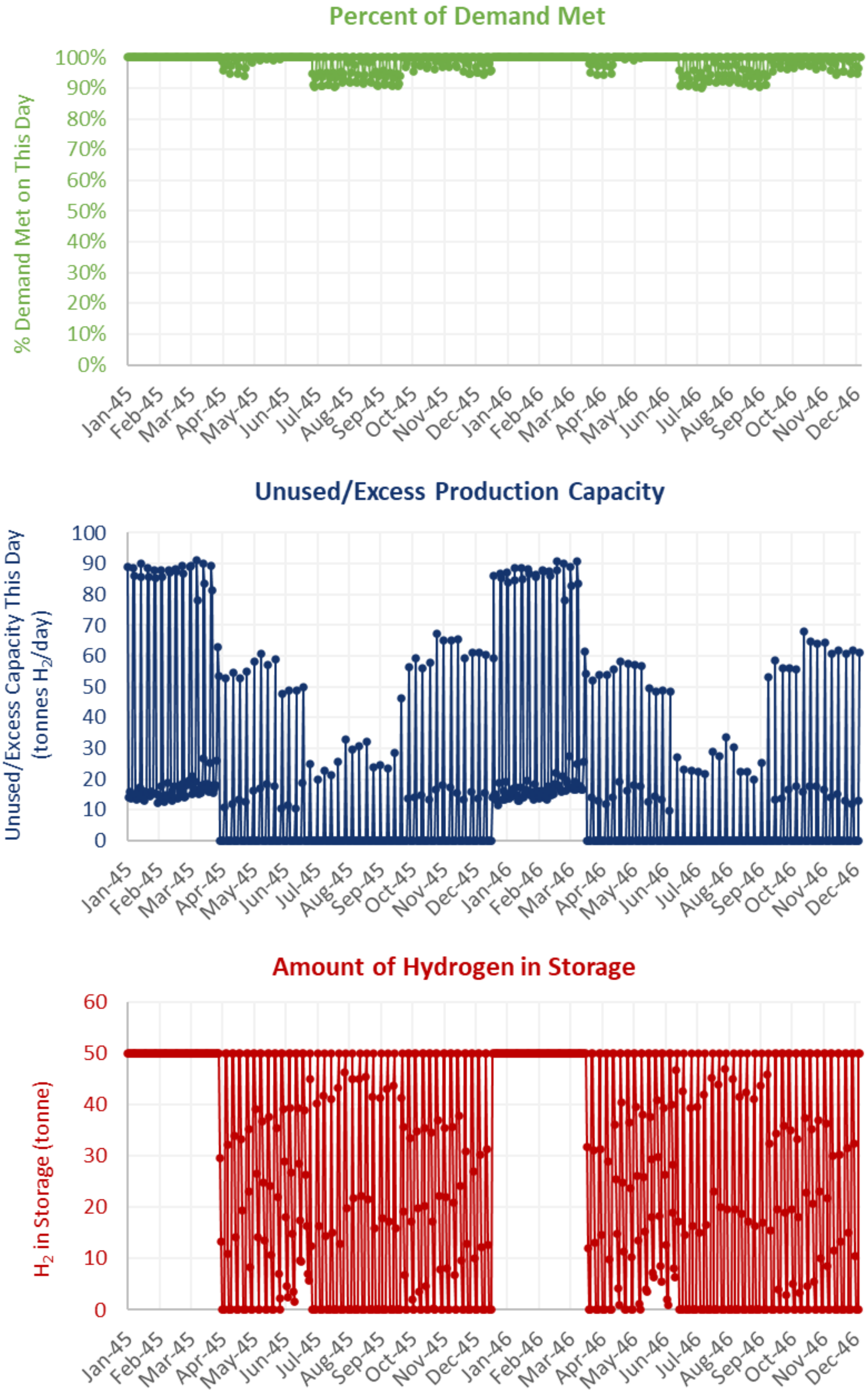
Model Output and Interpreting the Charts

Figure 42 (below) shows the output charts produced by the tool for the upper transportation scenario for LADWP for 2045 and 2046 where, as was the case in the electric power IVCA, the 2046 demand profile is identical to that of 2045. The combination of 338 tonnes/day of hydrogen production – 3.1 percent above the average demand – with 50 tonnes of storage leads to 101 days of unmet demand each year.

Because there are no large swings in demand to deplete hydrogen storage, the alternating weekday-weekend pattern is evident in the variations in amount of hydrogen stored and the unused hydrogen production capacity. With demand being lowest throughout the winter, storage gets full during that entire season and excess production capacity is highest then as well. Conversely, summer has the largest demand, which depletes the storage facility more often than other seasons. It is hard to see the frequency of depleted storage in Figure 42, but Figure 43 below makes it easier by showing the state of storage for only one year. The difference between seasons is small, but only in summer is storage depleted as much as four days in a row and full as little as one day in a row. With as many days as there are of partially full or empty storage, it is worth noting that the storage capacity stays full 72 percent of the time.

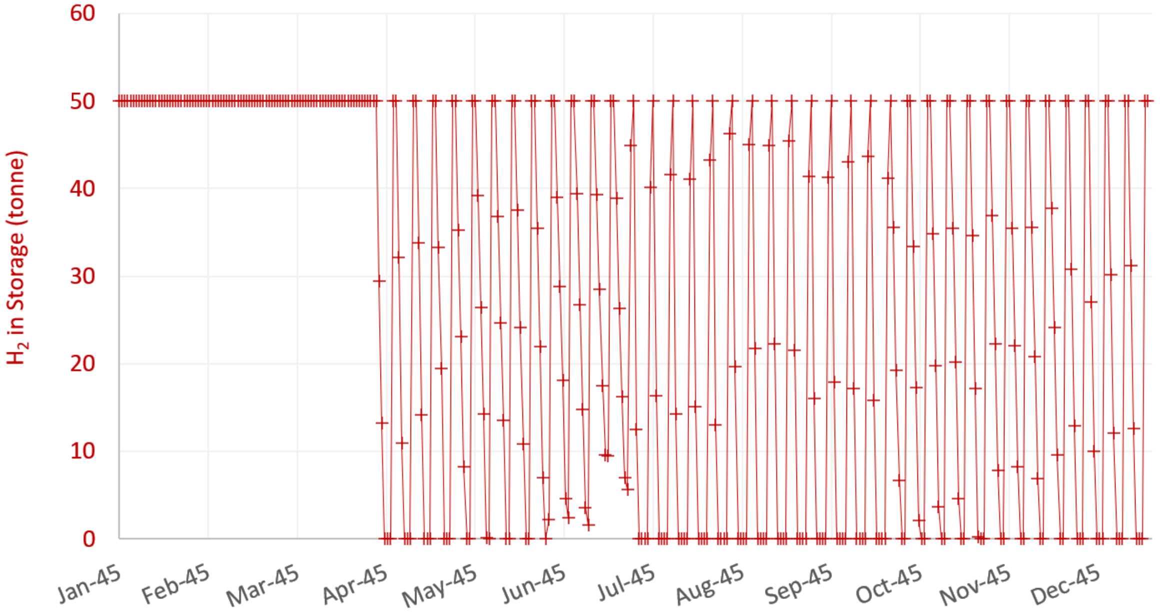
Days with unused production capacity occur at least weekly throughout the year, even during the summer months, but no more than twice per week from April 1 through December 31. Every day from January 1 through March 31 has some unused production capacity, again corresponding to the season of lowest demand. The magnitude of excess capacity on days when it is present varies significantly from season to season.

Figure 42: Output charts for upper transportation scenario for LADWP, production = 338 tonne H_2/day, storage = 50 tonnes H_2 (two years)



Source: Guidehouse analysis for CEC (2025)

Figure 43: Hydrogen in storage for a single year, LADWP upper transportation scenario, production = 338 tonne H_2/day, storage = 50 tonnes H_2



Source: Guidehouse analysis for CEC (2025)

Supply-Demand-Storage Dynamics

The transportation IVCA is inherently more complex than that used for the electric power sector, as was shown in Figure . Thanks to the simplifying assumption of having a single owner and/or a cooperative marketplace, the dynamics of supply-demand matching are in essence the same as those observed in the electric power sector analysis.

With the demand profiles for transportation being so much more confined in magnitude and regular in pattern than those of the electric power sector, there is little need to address the effects of large swings in demand and dominating but highly variable seasonal patterns. Supply-demand matching in the transportation sector can be analyzed at a higher level, drawing from the insights gained from the electric power sector analysis. Applying these insights to the present case yields the following:

- To reliably meet daily demand at fueling stations, an installed hydrogen production capacity of at least the average daily demand is required.
- Production capacity above the peak daily demand could also provide a reliable hydrogen supply, but as with the electric power analysis it is assumed that such additional capacity is undesirable and would not be installed exclusively to meet transportation needs. Thus, the focus is again on a production capacity ranging from average to maximum daily demand.
- A useful measure of how much unused/excess production capacity might be required for a PA (or statewide) is the ratio of the unused capacity – the "overbuild" – to the actual demand, as a percentage. The maximum possible overbuild of production for any given scenario analyzed using IVCA, which occurs in the "no storage" case, can be expressed as a percentage multiple of the actual demand as follows:

$$\textbf{Overbuild factor, \%} = \frac{\text{(max capacity - demand)}}{\text{demand}} \cdot 100\,\%$$

$$= \frac{(\text{max daily demand - ave daily demand}) \cdot 365}{(\text{ave daily demand}) \cdot 365} \cdot 100\,\%$$

$$= \frac{(\text{max daily demand - ave daily demand})}{(\text{ave daily demand})} \cdot 100\,\%$$

> For example, an overbuild factor of 250 percent would mean that the unused capacity is 2.5 times as much as the demand; i.e., the used capacity. Total required production capacity is the sum of the demand and the unused capacity, which in this case would come to (100 percent + 250 percent) = 350 percent of demand.

The overbuild factor thus encapsulates the maximum magnitude of unused capacity that might be found in each PA. The overbuild factors for all scenarios and every PA are listed in Table 15. In contrast to the high amount of excess production capacity required for both of the electric power scenarios, the overbuild levels for the two transportation scenarios only range from 14 percent to 16 percent of the nominal production capacity.[368]

Table 15: Overbuild factor, as a percentage of the ideal production capacity, all PAs and scenarios

Planning Area	Upper Electric Power	Lower Electric Power	Upper Transportation	Lower Transportation
LADWP	831	37	14	14
IID	11[369]	118	14	14
NCNC	510	140	15	15
PG&E	563	141	16	16
SCE	598	152	14	14
SDGE	1,946	128	14	14
BUGL	N/A	N/A	14	14
Statewide	636	135	15	15

Source: Guidehouse analysis for CEC (2025)

Supply-Demand Curves

When manually exploring supply and demand matching in the LADWP PA, a time horizon of two years was used in the transportation IVCA, which is identical to the analyses for the electric power IVCA. However, for developing the efficient frontier only one year of demand was analyzed, primarily because a large computational effort is involved in each efficient frontier run.[370] The accuracy of the efficient frontier results was double-checked via manual two-year runs for a number of points along the frontier: specifically, storage levels of 0, 25, 50, 100, 200, 500, 1,000, 2,000, and 2,500 tonnes H_2 were validated using manual

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[368] Note that the numbers are identical for the two transportation scenarios because their demand profiles are built from essentially identical SB 100 profiles.

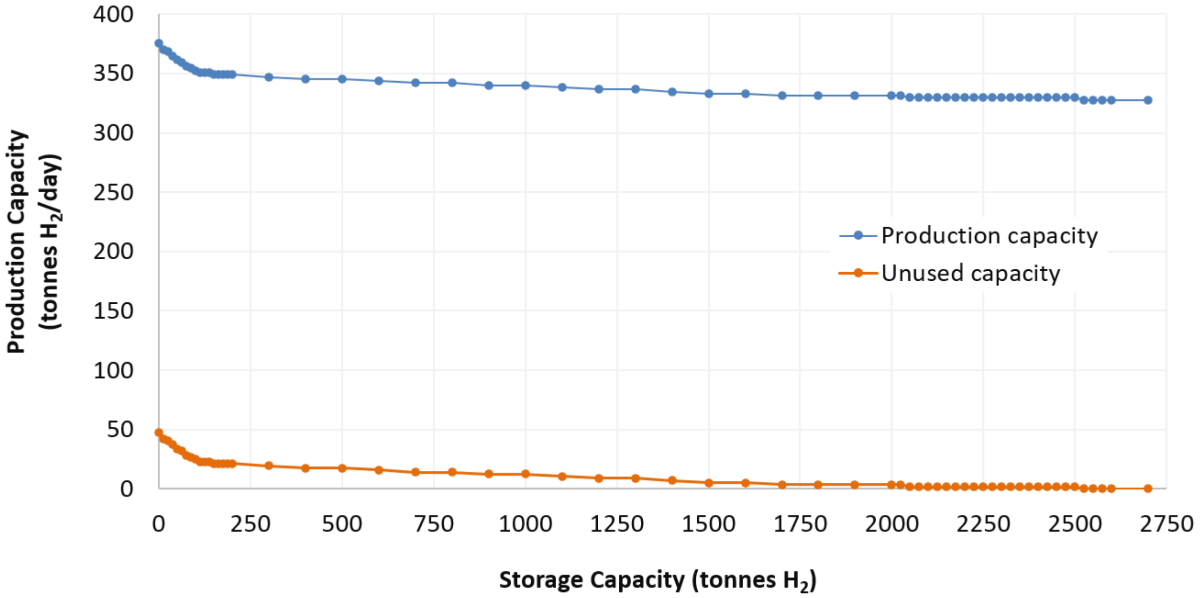
[369] The extremely low level of potential unused capacity compared to the other upper scenario electric power PAs is due to IID's demand profile being very different from the others – very flat with a small number of low-to-zero demand days.

[370] A single efficient frontier calculation involves 1,680 analyses of different combinations of storage capacity and production capacity.

calculations. The one-year results were found to be accurate to within 0.5 percent of the two-year values.

The efficient frontier of one of the two identical LADWP regions is plotted in Figure 44 along with the potentially unused production capacity. The unused production capacity for the no-storage condition is not very large and, in fact, it takes a great deal of storage (2,525 tonnes of H_2) to eliminate unused capacity completely. A relatively small amount of storage goes a long way toward reducing the excess capacity: 100 tonnes of storage reduces unused capacity from 47.7 tonnes H_2/day to 24.7 tonnes H_2/day, a production capacity that is only 7.5 percent above the average daily demand. This quantity of hydrogen storage is much less than what would be considered full storage, and it is several orders of magnitude smaller than what would be required in the electric power sector; however, implementing 100 tonnes of storage using tanks is still a significantly large project, especially at this time.

Figure 44: Efficient frontier for (one-half of) LADWP – tradeoff of hydrogen production capacity and unused capacity vs. available storage, upper transportation scenario



Source: Guidehouse analysis for CEC (2025)

The efficient frontiers for all of the PAs, and that of the state as a whole, should be quite similar to that of LADWP, as their profiles are nearly identical in all major features and their framework would be considered in regions of similar size to the “one-half of LADWP” region.

Delivery Considerations for Fueling Stations with On-site Storage

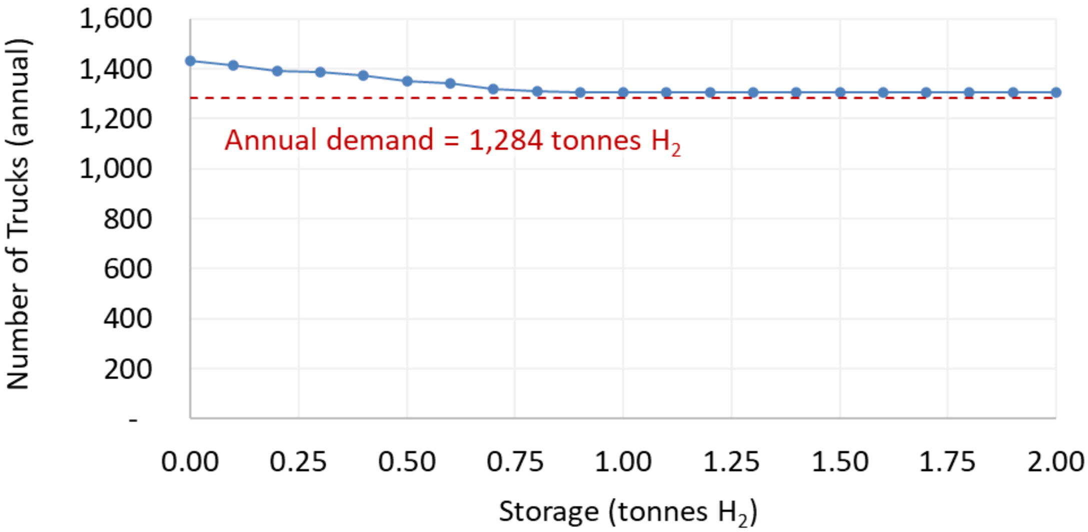
As mentioned earlier, an analysis of delivery issues was performed for the transportation scenarios. The core logistical challenge is that hydrogen is delivered in discrete quantities (i.e., full truckloads), whereas a station's daily demand is variable and continuous. A station needing 3.3 tonnes of hydrogen on a given day cannot order 3.3 trucks; it must order a whole number, potentially creating inefficiencies. The analysis examined a single fueling station to quantify the impact of on-site storage on the efficiency of hydrogen delivery via trucks. In particular, it sought to understand whether the buffer of on-site storage could minimize or eliminate the need to have additional truck rolls that, in aggregate across 55-75 refueling stations, could put a serious strain on on-road hydrogen delivery resources.

Analysis of On-Site Storage and Trucking Requirements

The model analyzed a representative fueling station (nominal capacity of 4.0 tonnes H_2/day) with an annual demand of 1,284 tonnes of hydrogen to determine the relationship between the size of its on-site storage tank and the average number of daily truck deliveries required. Similar to the main IVCA, the methodology used a simple daily mass balance to study the level of storage, ability of demand to be met, and the number of truck deliveries that would be necessary for the various levels of storage investigated.[371]

The results are shown in Figure 45. Having a tonne or more of onsite hydrogen storage reduces the number of truck trips from 1,432 to 1,304 per year. With that storage the partial delivery issue still creates 20 extra truck trips, but this is a small increase (1.6 percent) that can be accommodated in regional logistics planning.

Figure 45: Impact of onsite storage at refueling stations on number of truck trips carrying 1 tonne of H_2



Source: Guidehouse analysis for CEC (2025)

This finding has several important implications:

1. **Logistical efficiency:** A modest amount of on-site storage can substantially reduce the total number of extra truck deliveries over a year, from 11.5 percent to 1.6 percent, which in turn lowers transportation costs, fuel consumption, and associated emissions.
2. **Operational flexibility:** The storage buffer allows a station to maintain uninterrupted service better by absorbing the daily fluctuations in customer demand while still accommodating the inflexible nature of whole-truck deliveries.
3. **Validation of IVCA assumptions:** The station-level analysis confirms that the broader challenge of system-wide supply-demand matching can be effectively

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[371] As discussed in the Supply and Demand Assumptions section above, the analysis assume pre-knowledge of the amount of hydrogen to be sold each day. The number of trucks that would be scheduled each day is very similar to what would be scheduled without pre-knowledge, given the refueling station's expected knowledge of average seasonal sales per day.

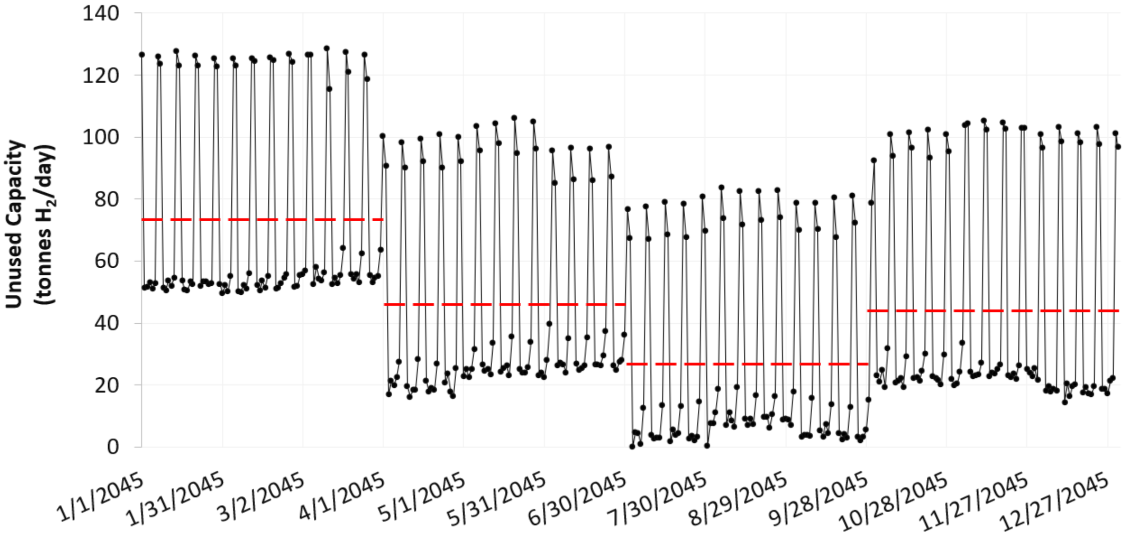
decoupled from last-mile delivery logistics, provided that fueling stations are equipped with appropriately sized on-site storage buffers. This validates the IVCA's focus on system-level production and centralized storage as the primary drivers of the overall value chain's economic viability.

Ability to Utilize “Unused” Production Capacity

Whether or not having 14-16 percent excess production capacity is a viable hydrogen production business model would require case-by-case evaluation of proposed projects and their business cases. However, it is possible to assess the likelihood that this excess capacity may be useful to other offtakers.

As previously noted, although there is great regularity in the variation of demand, primarily being a weekday-weekend pattern, there is also a seasonal variation (e.g., see Figure). Figure 46 below shows the daily amount of potentially unused production capacity in one of the LADWP regions for the upper transportation scenario, in the event of no system-level hydrogen storage being available. The seasonal averages, shown by red-dashed lines, illustrate how the seasonal variability in demand translates to a seasonal variability in excess production capacity available to provide hydrogen to other customers.

Figure 46: Daily amounts of unused capacity for transportation (upper scenario) in an LADWP region for no system-level storage



Red dashed lines are seasonal averages

Source: Guidehouse analysis for CEC (2025)

Absent hydrogen storage to smooth out the fluctuations in the daily rate of production, offtakers that purchase any hydrogen deriving from the excess capacity would have to be highly flexible in their usage – on both a seasonal and a weekly basis. Deploying storage to enable those users to have a more firm, constant supply reduces or eliminates the advantage of increasing production capacity to avoid system-level storage. Thus, the only situation in which the excess production capacity can be economically accommodated is one in which there are customers with high tolerance for large variations in supply.

It should be noted that, for the often-realistic case of hydrogen production involving intermittent inputs of energy and/or feedstock, having some excess production capacity is generally a requirement in the design of the facility. This is due to the need for onsite storage to compensate for days in which the variability in inputs prevents the facility from delivering the committed quantity of hydrogen. Analysis shows that, for a given level of committed offtake, deployment of onsite storage for intermittent and otherwise variable production requires additional production capacity that ensures that the onsite storage is adequately refilled on a timely basis.[372]

Comparison to 2023 IEPR Results

No direct comparison of the present results to the 2023 IEPR transportation scenario analyses can be made, for several reasons: (1) the 2023 analyses keyed off of scenarios that would take place in *2040*, rather than 2045, and (2) the lower scenario is based on a different set of usage assumptions, which are those that defined modified AATE 3 scenario modeling.

A high level, indirect comparison can be made by noting that the lack of accounting for day-to-day demand variations in supply-demand matching means that the values cited in the 2023 IEPR refer to the minimum possible production capacity. They would have to be accompanied by adequate hydrogen storage to be achievable, which was not quantified in the prior analysis.

The current analysis shows that production capacity would have to be about 15 percent higher than the minimum value if there is no systemwide hydrogen storage. However, adding roughly 0.3 tonnes of storage per tonne of average demand would enable production capacity to be only about 7-8 percent higher than average demand.[373]

Summary of Transportation IVCA Scenarios

Because of the strong similarity between demand profiles among PAs and between scenarios, it is reasonable to assume that the quantitative relationships between supply, demand, and storage that were found for the LADWP analysis apply as well to all the other cases. These include: (1) the amount of storage needed to permit the minimum production capacity, relative to average demand, and (2) the amount of storage that would be needed, per tonne of average demand, to enable production capacity to be 7-8 percent above the minimum level. Both relationships were tested for two other high scenario PAs, SCE and SDGE, and found to hold well, thus providing some validation for the estimates below:

- **If no hydrogen storage is available**, the dedicated hydrogen production capacity for transportation would need to be at least 1.6 million tonnes/yr for the upper scenario and 0.93 million tonnes/yr for the lower scenario. These are both 15 percent larger than their respective minimum production capacities, as expected.
- **If limited storage is available**, the dedicated hydrogen production capacity would depend on just how limited storage may be, with the tradeoffs similar to the efficient frontier curve of LADWP (Figure). Notably, if the economics of hydrogen production can tolerate a 7-8 percent excess of installed capacity, then only 1,170 (680) tonnes of

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[372] Guidehouse analysis of the onsite storage requirements of an electrolytic hydrogen facility that would be coupled with its variable renewable power source but committed to deliver a constant supply of hydrogen to its customers. Various levels of committed output were possible by having an appropriate level of storage, but the higher the output commitment the larger the storage requirement. A reasonable tradeoff was having storage be just under two days' worth of output, with the firm offtake commitment being about 82 percent of what it might deliver if storage were not needed. That represented 18 percent "excess capacity."

[373] This comes from the earlier result that 100 tonnes of H_2 storage would allow a production capacity of 7.5 percent above average demand in an LADWP PA region of average demand = 327.7 tonnes/day.

storage for the upper (lower) scenario would need to be developed statewide.

- **If ample hydrogen storage is available (see below),** the dedicated hydrogen production capacity for the electric power sector could be the minimum values of 1.4 million and 0.81 million tonnes/year for the upper and lower scenarios.

The amount of hydrogen storage needed to completely reduce production capacity to its minimum is about 7.85 times the average demand in the region studied. Based on this assumption, **the total maximum statewide storage needed for transportation purposes can be estimated to be about 30,000 tonnes for the upper scenario and 17,500 tonnes for the lower scenario.**

IVCA Key Findings

The IVCA indicates that the feasibility of large-scale hydrogen deployment depends not only on total production and demand, but also on how well supply, end use, delivery mode, and storage requirements align across locations and time periods. In both the electric power and transportation sectors, the analysis shows that production-storage tradeoffs, regional demand patterns, and facility-scale constraints materially affect which combinations of hydrogen production and storage are practical. The results also suggest that some production capacity may remain underutilized unless supported by appropriately matched demand, delivery infrastructure, and storage. Overall, the IVCA highlights that hydrogen system planning must consider operational and spatial matching across the value chain, rather than evaluating production targets in isolation.

Resource Requirements and Economics

Key Resource Assumptions

The analysis of production pathways contains quite a few assumptions; the full set of these assumptions is documented in Appendix C. Several of these are important enough to spell out here:

- Consistent with taking on several key values from the CARB Scoping Plan, the IEPR assumes the SP's estimate of usage of RNG and biomass (woody) as given quantities. This "spoken-for" usage amounts to only 4.8 percent of the dry tonnes of biomass, but it accounts for 67 percent of the RNG.
- The total amount of available RNG is thus estimated to be sufficient to produce only 175,000 tonnes of H_2 per year. Therefore, all three production portfolios were designed to use 100 percent of this potential production capacity.
- Among the different sources of RNG, landfill sites have the largest potential to produce RNG. However, analysis of the EPA Landfill Methane Outreach Program (LMOP) Landfill Database shows that less than 10 percent of 115 landfills that collect landfill gas have sufficient flow to produce more than 15 tonnes of H_2 per day.[374] Only 20 percent have enough gas to produce more than 10 tonnes H_2/day. Furthermore, one very large compressed natural gas (CNG) trailer (at 272 bar) can only carry the equivalent amount of RNG to produce 3.5 tonnes of H_2 (using SMR)[375], which makes daily delivery of

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[374] Guidehouse analysis, and: "LMOP Landfill and Project Database." U.S. Environmental Protection Agency. https://www.epa.gov/lmop/lmop-landfill-and-project-database

[375] Guidehouse analysis, assuming the trailer to carry 540,000 scf of CNG at 272 bar: "CNG Trailer Leasing." CNG Delivery. https://cngdelivery.com/cng-trailer-leasing/

significant quantities of offsite RNG somewhat impractical. Based on this, the size of RNG-processing facilities – SMRs and pyrolysis plants – was assumed to be 15 tonnes H_2/day for the analysis. (An alternative scenario that was not explored in the analysis would be to deliver large amounts of RNG from multiple suppliers via fossil gas pipelines – to the extent that the gas system is still employed in 2045 and reaches the RNG sources.)

- It's assumed that by 2045 the capabilities and costs of both technologies will have converged to make it a toss-up for developers as to which technology to choose.
- Electrolysis renewable energy resources are predicated on the "one-sixth" rule of thumb for sizing electrolyzers relative to the RE asset capacity to get a capacity factor of around 45 percent (discussed in the section on Electrolysis Parameters and Associated Facility Size Constraints).
- All water resources refer to usage at the production plant (i.e., process water) and do not include water associated with electric power, resource extraction, feedstock transportation, or construction. Except for pyrolysis, the water consumption values are those used in NREL's October 2024 H2A-Lite model.[376] Process parameters for pyrolysis are less available than other hydrogen production methods, but a NETL study documents water consumption from a process simulation of catalytic pyrolysis.[377]

Resource Analysis Results – General

This section is a brief overview of the three production portfolios (Balanced, Electrolytic-Heavy, and Biogenic Full) and two *resources analysis scenarios* ("combined upper scenarios" and "combined lower scenarios," respectively representing the most and least hydrogen that would be deployed when considering both electric power and transportation applications).

The proportions of each type of feedstock comprising the three production portfolios are summarized (again) in Table 16 and Table 17 for the two resource analysis scenarios.

Table 16: Production portfolio mixes (as a percentage) in 2045 for the combined upper and lower (electric power and transportation) scenarios

Scenario	Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Water (electrolysis)	72	40	44
Combined Upper	Fossil gas (SMR+CC and pyrolysis)	12	40	22
Combined Upper	Biomass (gasification)	9	14	28
Combined Upper	RNG (SMR and pyrolysis)	6	6	6

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[376] "H2A-Lite: Hydrogen Analysis Lite Production Model." National Laboratory of the Rockies. https://www.nlr.gov/hydrogen/h2a-lite

[377] "Tradeoffs in Life Cycle Water Use and Greenhouse Gas Emissions of Hydrogen Production Pathways." U.S. Department of Energy, Office of Scientific and Technical Information. https://www.osti.gov/servlets/purl/199733131

Scenario	Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Lower	Water (electrolysis)	75	34	6
Combined Lower	Fossil gas (SMR+CC and pyrolysis)	5	33	5
Combined Lower	Biomass (gasification)	10	18	74
Combined Lower	RNG (SMR and pyrolysis)	10	15	15

Source: Guidehouse analysis for CEC (2025)

Within the analysis of each resource scenario, the limiting cases of no storage and full storage (as much storage as needed to allow the production capacity to be equal to the average demand) were computed.

In the no-storage case, production capacity needs to be overbuilt, so production capacity, numbers of plants, CAPEX investments, and – for electrolysis – renewable electricity plants are higher than they would be for full storage. These resources are referred to here as *capacity-related resources*. The huge demand profile variability of the upper electric power scenario leads to a much greater difference in capacity-related resources for the "combined upper scenarios" resource scenario than the "combined lower scenarios." The resource analysis results are generally shown for each production portfolio, and within each of those the results are shown for the four major feedstock types: (1) electrolysis (i.e., water), (2) RNG, (3) biomass, and (4) fossil gas.

An important point to remember is that the amount of hydrogen produced per year in any given scenario is the same, regardless of the production capacity and amount of hydrogen storage installed. Thus, the non-capacity-related resources – the electricity, water, and feedstocks used – are the same for the no-storage and full-storage limits.

Hydrogen Production Capacity

Table 17 shows the amount of production capacity that would be needed for the combined upper and combined lower resource analysis scenarios. It's worth noting that the allocation of capacity among the four feedstock groups is the same for both the full storage and no storage limits. That is, the no-storage limit values are just a scaled version of the full-storage values.

Table 17: Production capacity requirements (million tonnes per year) by feedstock and portfolio, full-storage case; no-storage is 4.5x for the combined upper and 1.5x for the combined lower scenarios

Scenario	Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Water (electrolysis)	2.2	1.2	1.3
Combined Upper	Fossil Gas (SMR+CC, pyrolysis)	0.37	1.2	0.64

Scenario	Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Biomass Gasification (FR, UW, CR)	0.28	0.42	0.86
Combined Upper	RNG (SMR, pyrolysis)	0.18	0.18	0.17
Combined Lower	Water (electrolysis)	0.87	0.39	0.072
Combined Lower	Fossil Gas (SMR+CC, pyrolysis)	0.058	0.38	0.058
Combined Lower	Biomass Gasification (FR, UW, CR)	0.12	0.21	0.86
Combined Lower	RNG (SMR, pyrolysis)	0.12	0.17	0.17

Source: Guidehouse analysis for CEC (2025)

For the combined upper scenarios, the total production capacity required in the event of having no storage would be 4.5 times that of the case of having full storage. Most of the unused or excess capacity derives from the high scenario supply to the electric power sector.

The situation is much better for the combined lower scenarios; however, a lack of storage would still lead to a need for 50 percent more production capacity than what would be delivered. Having a much smaller total demand for hydrogen means that the contribution of biomass in the Biogenic Full portfolio is much more dominant than it would be in the combined upper scenarios case.

Numbers of Production Plants and Associated CAPEX Investment

Closely related to the required production capacity are the numbers of production plants of each type needed and the CAPEX cost for purchasing and installing those plants. The analysis presumed hypothetical adoption trajectories of each production pathway, starting from the present situation with almost all current hydrogen being from fossil SMR (which is assumed would install carbon capture shortly). Electrolysis and biogenic pathways ramp up quickly in the next five years and then sustain growth through 2035, while the proportion of total production steadily ramping down at various paces, depending on the portfolio. Note that there is no usage of fossil gas in SMR plants in the combined lower scenarios Biogenic Portfolio implementation. The only usage of fossil gas is in pyrolysis, comprising only 5 percent of the total production of hydrogen via that pathway.

Several assumptions underlying these calculations are given below:

- To get electrolyzer capacity factors as high as reasonably possible for the assumed case of utilizing renewable power from a single generating site as a behind-the-meter facility, it was necessary to assume that the electrolysis plant could be no larger than one-sixth of the capacity of the power plant.[378] With a renewable capacity of 450 MW_e, this leads

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[378] Based on an analysis by Guidehouse Inc. of NREL reference profiles of solar and wind plants. The associated capacity factor is 45 percent.

to an electrolyzer plant size of 15.6 tonnes H_2/day.

- Literature review and potential limitations in the ability to gather or aggregate biogenic materials led to assumed plant capacities of 15 tonnes H_2/day for pyrolysis and 49.3 tonnes/day for biomass gasification.
- SMR plant sizes were assumed to be 100 tonnes H_2/day for fossil gas and 15 tonnes/day for RNG. The former size is in line with current California plants and the expectation that ultra-large fossil fuel plants will not be deployed in the state; the latter size is consistent with expected availability of RNG from large landfills.

The numbers of plants are shown in Table 18 and the CAPEX results are shown in Table 19. With the exception of the Biogenic Full portfolio in the combined lower resource scenario, electrolysis plants are the largest component of the mix and its CAPEX, regardless of storage level or resource scenario. The Electrolytic-Heavy portfolio would require the most production plants and most CAPEX: for full storage, 202 and 472 production plants at \$26.0B and \$64.5B, combined lower scenarios and combined upper scenarios respectively. This is due to the assumed capacity factor of electrolyzer plants being one-half that of all other types of plants, as well as the plant size being small. On the other hand, the Biogenic Full portfolio would require the least, at 119/368 plants and \$9.5B/\$46.2B for full storage combined lower/upper scenarios cases. Gasification plants are assumed to be relatively large and are among the least expensive on a per-tonne H_2/day production capacity basis.

The CAPEX costs shown in Table 19 are total overnight cost (TOC), which includes equipment, installation, engineering procurement costs (EPC), and project and process contingencies. The 2025 costs were calculated from various literature sources, after which learning curve cost reductions were applied for 2026 through 2045.[379]

The capital cost per (kg H_2/day) is expected to decrease between 2025 and 2045 as follows:[380,381]

- For electrolytic hydrogen (4.2 to 20.8 tonnes of hydrogen per day): from 5,080 to 3,700 \$/(kg/day) (or 2,342 to 1,709 \$/kW$_e$).

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[379] Electrolyzer costs: "Electrolysis Techno-Economic Analysis – CAPEX Rates." Low-Carbon Resources Initiative, EPRI, and GTI Energy. https://apps.epri.com/lcri-electrolysis-tea/en/capex-rates.html

Biomass gasification, SMR, and SMR+CC costs: "H2A-Lite: Hydrogen Analysis Lite Production Model." National Laboratory of the Rockies. https://www.nrel.gov/hydrogen/h2a-lite

Pyrolysis costs:

1. Guidehouse analysis of data from: Moghaddam, Alireza Lotfollahzade, Sohrab Hejazi, Moslem Fattahi, Md Golam Kibria, Murray J. Thompson, Rashed AlEisa, and M. A. Khan. 2025. *Methane Pyrolysis for Hydrogen Production: Navigating the Path to a Net Zero Future*. Journal of Energy and Environmental Science. https://pubs.rsc.org/en/content/articlelanding/2025/ee/d4ee06191h
2. Rupp, Brad. 2021. *High-Throughput Methane Pyrolysis for Low-Cost, Emissions-Free Hydrogen.* PARC. https://web.archive.org/web/20240509090123/https:/arpa-e.energy.gov/sites/default/files/2021-01/07%20OK%20-%2020210112-ARAPE%20Methane%20Pyrolysis%20Meeting-PARC.pdf

[380] Source: Guidehouse, Inc. The analysis from Guidehouse led to tables derived from a per-unit CAPEX, in \$/(kg/day) for each pathway. Guidehouse modeled how these costs will change over time based on expected learning curves and assumptions regarding the evolution of the technologies.

[381] In the capital cost-per-energy values listed, electrolysis is given on the standard basis of input power to the electrolyzer, while the other values are given on the basis of energy (HHV) of hydrogen produced per day.

- For SMR with carbon capture (100 tonnes of hydrogen per day): from 5,710 to 4,680 $/(kg/day) (or 42,500 to 34,800 $/(MMBtu/day)).
- For SMR with no carbon capture (RNG plants, 15 tonnes of hydrogen per day): from 7,140 to 5,840 $/(kg/day) (or 53,100 to 43,500 $/(MMBtu/day)).
- For gasification (50 tonnes of hydrogen per day): from 2,590 to 1,950 $/(kg/day) (or 19,300 to 14,500 $/(MMBtu/day)).
- For pyrolysis (15 tonnes of hydrogen per day): from 2,700 to 1,840 $/(kg/day) (or 20,100 to 13,700 $/(MMBtu/day)).

Table 18: Number of production plants required for each portfolio, full-storage case; no-storage is 4-4.5x (combined upper) and 1.1-1.8x (combined lower) higher

Scenario	Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Water (electrolysis)	381	213	231
Combined Upper	Fossil Gas (SMR+CC, pyrolysis)	34	88	47
Combined Upper	Biomass Gasification (FR, UW, CR)	20	27	54
Combined Upper	RNG (SMR, pyrolysis)	37	36	36
Combined Lower	Water (electrolysis)	155	70	13
Combined Lower	Fossil Gas (SMR+CC, pyrolysis)	17	31	22
Combined Lower	Biomass Gasification (FR, UW, CR)	9	14	54
Combined Lower	RNG (SMR, pyrolysis)	21	42	30

Source: Guidehouse analysis for CEC (2025)

Table 19: CAPEX[382] (in billion dollars)) required for each portfolio, full-storage case; no-storage is 4.5x for combined upper and 1.5x for combined lower scenarios

Scenario	Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Water (electrolysis)	58	29	35
Combined Upper	Fossil Gas (SMR+CC, pyrolysis)	3.5	16	4.5
Combined Upper	Biomass Gasification (FR, UW, CR)	1.8	2.7	5.4
Combined Upper	RNG (SMR, pyrolysis)	1.0	2.4	1.0
Combined Lower	Water (electrolysis)	23	9.6	1.9
Combined Lower	Fossil Gas (SMR+CC, pyrolysis)	1.1	5.1	1.1
Combined Lower	Biomass Gasification (FR, UW, CR)	0.74	1.4	5.4
Combined Lower	RNG (SMR, pyrolysis)	0.68	2.4	1.0

Source: Guidehouse analysis for CEC (2025)

Renewable Energy and its Land Requirement for Electrolysis

As noted above, reaching a reasonably economic capacity factor of 45 percent for an electrolyzer production facility that is co-located with a wind or solar facility is assumed to only be possible if the renewable energy facility is about six times as large as the electrolyzer rating.[383]

Renewable power needs for the combined upper and combined lower resource analysis scenarios are listed in Table 20. Note that except for the Biogenic Full portfolio in the combined lower scenario, the amount of renewable power that would need to be available to support electrolytic hydrogen would be several to many times the current total existing installed capacity of wind and solar power assets.

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[382] The CAPEX (Capital Expenditure) represents the TOC, or Total Overnight Cost, which is the total upfront investment for a project, such as the power plant, excluding any financing costs (interest) that accrue during the multi-year construction period, as if the entire facility was built instantly ("overnight") with 2023 prices. It's a standardized metric used in energy economics to compare the pure construction costs (engineering, equipment, labor, land) of different technologies fairly, removing variables such as construction time and interest rates.

[383] Per data from CEC's Energy Assessment Division, realized solar and wind capacity factors (i.e., including curtailment) in 2023 were 22.6 percent and 25.3 percent, respectively. Capturing curtailed energy should add about 1.2 percent to the capacity factor, which still results in only 23.8-26.5 percent. Unless very low-carbon grid power is available to supplement the renewable energy or a large battery is present, only undersizing of the electrolyzer with respect to the wind or solar farm will lead to a high enough capacity factor.

Table 20: Renewable power (GW) capacity required for electrolysis

Scenario	Storage	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Full Storage	171	95	104
Combined Upper	No Storage	764	425	463
Combined Lower	Full Storage	69	31	5.7
Combined Lower	No Storage	104	47	8.6

Source: Guidehouse analysis for CEC (2025)

The land area required for this renewable energy is shown in Table 21. As in the 2023 IEPR, this assumes that all of the power comes from solar PV and assumes the same value of seven acres per MW_e.

Table 21: Land area (Acres) required for renewable energy (assuming solar PV)

Scenario	Storage	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Full Storage	1,199,000	667,000	728,000
Combined Upper	No Storage	5,350,000	2,970,000	3,240,000
Combined Lower	Full Storage	483,000	218,000	40,000
Combined Lower	No Storage	728,000	329,000	60,000

Source: Guidehouse analysis for CEC (2025)

Note that the large land area required limits the applicability of producing hydrogen onsite electrolytically at power plants and refueling stations. Assuming that the electrolyzer would be sized at the same electrical rating of the renewable energy, it would have a capacity factor just under 30 percent and a single MW_e of solar PV (seven acres of land) would yield only about 140 kg H_2 per day. This is only suitable for users of small amounts of hydrogen.

Electricity Requirements

The amounts of electricity used to produce the hydrogen for the various production portfolios and feedstock types are summarized in Table 22. Naturally, much more electricity is needed to support electrolysis than the other types of hydrogen production; because of the scale, consumption by electrolysis is shown in a separate figure.

Fossil gas uses more electricity than RNG or biomass, because that feedstock is mostly deployed via SMR with carbon capture and the capture process uses a significant amount of electricity. The use of electricity for pyrolysis depends on how much each of the three technologies – plasma, thermal, and catalytic – is adopted; the present analysis assumes an equal split, but if the plasma method is predominant the pyrolysis electricity use will be much higher than shown here.

Table 22: Electric energy supply (GWh/year) required, by feedstock and portfolio

Scenario	Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Water (electrolysis)	112,548	62,571	68,281
Combined Upper	Fossil Gas (SMR+CC, pyrolysis)	1,427	4,617	2,315
Combined Upper	Biomass Gasification (FR, UW, CR)	342	519	1,040
Combined Upper	RNG (SMR, pyrolysis)	994	723	844
Combined Lower	Water (electrolysis)	45,342	20,482	3,738
Combined Lower	Fossil Gas (SMR+CC, pyrolysis)	382	1,802	555
Combined Lower	Biomass Gasification (FR, UW, CR)	142	260	1,041
Combined Lower	RNG (SMR, pyrolysis)	607	720	884

Source: Guidehouse analysis for CEC (2025)

Note also that for the combined upper scenarios the amount of RNG to be used would be the same for all three production portfolios, but the amount of electricity consumed varies between portfolios, This is due to the fact that RNG use is split differently between SMR and pyrolysis in each portfolio and the electricity requirement is higher for pyrolysis than for SMR.

Onsite Water Requirements

Water requirements are given in billions of gallons per year in Table 23. The 12-14 billion gallons per year needed in the Combined Upper Scenario is about 0.10% of the annual urban and agricultural water use in California, and about 0.05% of water use under management.[384] The water requirement for the Combined Lower Scenario is lower, being only about 30% as much.

As expected, electrolysis is a major consumer of water. However SMR – with and without carbon capture – uses more water per kg H_2 produced than electrolysis.[385] This primarily stems from the cooling water requirement for SMR, but also from its use for the steam

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[384] "Water Data Plan and Tools." California Department of Water Resources. https://water.ca.gov/Programs/California-Water-Plan/Data-and-Tools

[385] "H2A-Lite: Hydrogen Analysis Lite Production Model." National Laboratory of the Rockies. https://www.nrel.gov/hydrogen/h2a-lite

Note that H2A's values for water consumption for SMR derive from NETL techno-economic analyses. See: Lewis, Eric, Shannon McNaul, Matthew Jamieson, Megan S. Henriksen, H. Scott Matthews, John White, Liam Walsh, et al. 2022. *Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies*. National Energy Technology Laboratories. https://netl.doe.gov/projects/files/ComparisonofCommercialStateofArtFossilBasedHydrogenProductionTechnologies_041222.pdf feedstock.[386] As noted earlier, there is no SMR usage in the Biogenic Full portfolio in the combined lower scenarios, however there is still a small amount of water use for fossil gas, attributable to pyrolysis. Fossil gas is also de-emphasized in the Electrolysis-Heavy portfolio under combined lower scenarios conditions.

Table 23: Water supply (Billion gallons/year) required, by feedstock and portfolio

Scenario	Feedstock	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	Water (electrolysis)	8.20	4.50	5.00
Combined Upper	Fossil Gas (SMR+CC, pyrolysis)	2.30	7.40	4.20
Combined Upper	Biomass Gasification (FR, UW, CR)	1.00	1.50	3.00
Combined Upper	RNG (SMR, pyrolysis)	0.37	0.49	0.43
Combined Lower	Water (electrolysis)	3.30	1.50	0.27
Combined Lower	Fossil Gas (SMR+CC, pyrolysis)	0.20	2.00	0.02
Combined Lower	Biomass Gasification (FR, UW, CR)	0.40	0.74	3.00
Combined Lower	RNG (SMR, pyrolysis)	0.27	0.49	0.42

Source: Guidehouse analysis for CEC (2025)

Non-Water Feedstock Requirements

The final inputs to be accounted for are the non-water feedstocks, which include materials inputs used to provide process heat. These are listed in Table 24. The feedstock requirements for biomass gasification and methane pyrolysis are less well-determined than those for SMR and electrolysis, as the former technologies are both less mature and have a number of significantly different variations (e.g., plasma, thermal, and catalytic pyrolysis) within the same overall category.

Table 24: Non-water feedstock required, by feedstock and portfolio

Scenario	Feedstock Type	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Upper	RNG (SMR, pyrolysis) (million MMBtu)	33	31	32
Combined Upper	Biomass Gasification (FR, UW, CR) (million bone dry tonnes) [BDT]	2.8	4.3	8.6
Combined Upper	Fossil Gas (SMR+CC, pyrolysis) (million MMBtu)	66	211	114

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[386] Note that a significant portion of the water withdrawn for cooling is ultimately consumed by evaporation, windage, and blowdown. Combined with water used to produce hydrogen directly and water used for other process purposes (e.g., in CO_2 absorption solvent), onsite SMR water demand is on the order of 60% consumptive. See: Anaya, Karina, Abayomi Olufemi Oni, and Amit Kumar. 2025. *Water intensity for hydrogen production with and without carbon capture and sequestration*. Journal of Environmental Chemical Engineering. https://www.sciencedirect.com/science/article/pii/S2213343725022687

Scenario	Feedstock Type	Electrolytic-Heavy	Balanced	Biogenic Full
Combined Lower	RNG (SMR, pyrolysis) (million MMBtu)	22	31	32
Combined Lower	Biomass Gasification (FR, UW, CR) (million bone dry tonnes) [BDT]	1.2	2.1	8.6
Combined Lower	Fossil Gas (SMR+CC, pyrolysis) (million MMBtu)	11	70	12

Source: Guidehouse analysis for CEC (2025)

Similar to the other inputs, fossil gas feedstocks are lower in magnitude than RNG for the Electrolytic-Heavy and Biogenic Full portfolios of the combined lower scenarios.

Conclusion

The analysis indicates that the feasibility of large-scale hydrogen deployment depends on both the matching of supply with demand and the availability of the resources used to produce the hydrogen. Across the scenarios evaluated, hydrogen storage emerges as a major lever for reducing production overbuilding and improving supply-demand matching, while the choice of production portfolio materially affects resource requirements, land use, and capital costs. Taken together, these findings underscore the importance of integrated planning across the full hydrogen value chain.

Chapter 8:
CEC Investments Advancing Clean Hydrogen

Key Takeaways

This chapter provides an overview of current CEC investments in hydrogen incentives and hydrogen research.

Hydrogen Vehicles & Refueling Infrastructure

Through the Clean Transportation Program, the California Energy Commission is supporting the adoption of zero-emission hydrogen fuel cell electric cars by expanding California's network of hydrogen refueling stations throughout the state.[387] The Energy Commission is investing in a sufficient network of public hydrogen stations, and is coordinating with the Air Resources Board to establish this network across California to support the fuel cell electric cars that are on the road now, and to encourage more consumers to consider these zero-emission vehicles.

Clean Hydrogen Program Established by AB 209

Assembly Bill 209 (Budget Committee, Chapter 251, Statutes of 2022) authorizes the CEC to establish and administer the Hydrogen Program to provide incentives to eligible in-state hydrogen projects for the demonstration or scale-up of production, processing, delivery, storage, or end use of hydrogen consistent with California Public Resources Code sections 25664 and 25664.1. The CEC has named the program the Clean Hydrogen Program.[388] The program focuses on demonstration or scale up of clean hydrogen[1] production, processing, delivery, storage, or use. It also provides cost share for California-based entities to leverage clean hydrogen federal funding opportunities. When the program was established in 2022, it was originally appropriated $100 million from the General Fund (GF). However, series of budget enactments since then significantly trimmed the funding and with no budget allocated to it from the Fiscal Year 2025-26 budget appropriations, the program's funding has been reduced to $4 million. At this level of funding, the program is considering the following possible uses:

- Producing clean hydrogen at distributed scale (1 to 5 metric tons per day) through eligible hydrogen production pathways for various hard-to-electrify sectors (e.g., industrial facilities, heavy-duty/offroad transportation, back-up electricity generation). Project activities may include processing, delivering, storing, or using hydrogen in addition to production, but must avoid any benefit to oil refineries or facilities associated with fossil fuels.

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[387] "Hydrogen Vehicles & Refueling Infrastructure." California Energy Commission. https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program/clean-transportation-funding-areas-1

[388] "Clean Hydrogen Program." California Energy Commission. https://www.energy.ca.gov/programs-and-topics/programs/clean-hydrogen-program;

"CEC Greenhouse Gas Reduction Fund Clean Hydrogen Program Expenditure Record." California Energy Commission. https://efiling.energy.ca.gov/GetDocument.aspx?tn=261328&DocumentContentId=97700

- Researching innovative strategies, methodologies, or technologies to advance clean hydrogen production.

Research and Development Programs

The Electric Program Investment Charge (EPIC) program supports the development of emerging clean energy innovations to overcome barriers to achieving the state's energy goals and deliver benefits in the form of equitable access to safe, affordable, reliable, and environmentally sustainable energy for electricity ratepayers.[389] EPIC is funded by California investor-owned utility customers under the auspices of the CPUC. The CEC, PG&E, SCE, and SDG&E administer EPIC with oversight from the CPUC. Among its broad portfolio of R&D investments, EPIC has supported projects to advance clean electricity generation and long-duration energy storage technologies and research, inclusive of hydrogen.

The Gas Research and Development (R&D) Program was established by the CPUC in 2004, pursuant to Assembly Bill 1002 (Wright, Chapter 932, Statutes of 2000).[390] The CEC administers the Gas R&D Program with oversight from the CPUC. The program is funded through a surcharge on gas consumed within the service territories of California's investor-owned gas utilities. The Gas R&D Program invests in gas system-related public interest research directed towards developing science or technology, the benefits of which accrue to California citizens and are not adequately addressed by competitive or regulated entities. The Gas R&D Program currently funds research under investment themes of gas system integrity, decarbonization, and environmental and social research. Among this portfolio, the Gas R&D Program has supported projects to advance technologies and assess impacts related to the use of hydrogen as a renewable gas to support decarbonization.

Table 25 provides a summary of CEC R&D topics and associated projects funded through EPIC and the Gas R&D Program.

Table 25: CEC R&D Projects Advancing Clean Hydrogen

Category	R&D Topics	Relevant CEC R&D Projects[391]
Electrolysis	• Develop novel electrolytic hydrogen production technologies • Validate flexible ramping of alkaline electrolyzer following variable renewable generation	• EPC-19-044 • EPC-19-037

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[389] "Electric Program Investment Charge – EPIC." California Energy Commission. https://www.energy.ca.gov/programs-and-topics/programs/electric-program-investment-charge-epic-program

[390] "Gas Research and Development Program." California Energy Commission. https://www.energy.ca.gov/programs-and-topics/programs/gas-research-and-development-program

[391] Additional CEC R&D project information can be found at: "Energize Innovation Fund." Energize Innovation. https://www.energizeinnovation.fund/

Category	R&D Topics	Relevant CEC R&D Projects[391]
Biogenic Production[392]	• Develop novel biogenic hydrogen production technologies	• PIR-21-003 • PIR-21-004 • PIR-21-005 • PIR-21-007
Storage	• Research use of low-pressure hydrogen storage in metal hydrides for distributed clean power generation • Research use of cryo-compressed hydrogen for lower cost delivery and storage for distributed clean power generation • Research feasibility of geologic hydrogen storage in California gas storage facilities	• EPC-20-005 • EPC-25-026 • PIR-24-003
Delivery	• Assess safety and integrity impacts of targeted hydrogen blending in the gas pipeline network	• PIR-22-003
Electricity Generation	• Identify pathways to improved flexibility and efficiency of hydrogen-based power-to-power systems • Develop mobile hydrogen fuel cell generators for energy resilience • Develop low-emissions hydrogen engine technologies for distributed power generation • Assess the role of hydrogen in California's decarbonizing electric system	• EPC-19-037 • EPC-21-018 • EPC-21-003 • EPC-23-004 • EPC-23-009 • PIR-23-008 • PIR-23-009 • PIR-23-011

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[392] In June 2022, the California Energy Commission (CEC) awarded Southern California Gas Company (SoCalGas) a $750,000 grant (Agreement PIR-21-003) to develop a modular hydrogen production system using catalytic non-thermal plasma (CNTP). The project entails converting biogas to Low-Carbon H2.

CNTP is a low-temperature technology for converting biogas into hydrogen by combining electrical energy with chemical catalysts. The process does not require extremely high temperatures; it is primarily conducted at moderate temperatures (400 - 500 C) thereby reducing energy consumption and GHG emissions.

"CNTP Biogas to Low-Carbon H2 Conversion Project." Energize Innovation. https://www.energizeinnovation.fund/projects/cntp-biogas-low-carbon-h2-conversion-project;

"Grant Request Form – CNTP Biogas to Low-Carbon H2 Conversion Project." California Energy Commission. https://www.energy.ca.gov/filebrowser/download/4288?fid=4288#

Category	R&D Topics	Relevant CEC R&D Projects[391]
Transportation	• Develop and demonstrate technology solutions to enable hydrogen for challenging, heavy-duty transportation end-uses	• PIR-20-001 • PIR-20-002 • PIR-20-003 • PIR-21-001 • PIR-21-002 • PIR-23-006 • PIR-23-007
Other – synergistic considerations	• Research the potential of hydrogen to decarbonize large buildings and industry in California	• PIR-22-001

Source: CEC (2025)

Chapter 9:
Summary of Takeaways and Conclusions

Development of the hydrogen infrastructure to meet the needs of California electricity and transportation sectors will require a significant, sustained commitment. Many complex elements need to converge and scale to make hydrogen work.

The following summarizes the benefits and challenges in a hydrogen economy:

- Hydrogen can be used for power generation through electrochemical conversion in fuel cells or combustion in turbines. It is increasingly viewed as a tool for decarbonization and long duration energy storage, however there are economic and technical challenges such as production costs, delivery (dedicated pipelines), and storage.
- Hydrogen offers substantial potential as an energy source in the transportation sector due to its high energy density by weight, and it is increasingly being utilized for heavy-duty transportation, including long-haul trucking, maritime shipping, and aviation, where its rapid refueling and high payload-to-weight ratio provide advantages over current battery-electric technologies. However, the use of hydrogen in the transportation sector faces challenges in scaling-up, primarily due to the high cost of clean and renewable hydrogen production, limited refueling infrastructure (coupled with the current high cost of fuel cell vehicles), and energy losses associated with compressing or liquefying the gas for storage and transport.
- Additional challenges for hydrogen production pathways include cost competitiveness with traditional fuels (e.g., hydrogen vs. fossil gas and diesel), the need for on-site and off-site hydrogen storage as it serves as a buffer against fluctuations in demand and renewable resources, and regulatory challenges as hydrogen is widely regulated at federal and state levels. Hydrogen production pathways are also reliant on an extended supply chain to remain feasible (e.g., currently the majority of electrolyzers are produced in Asia). Other challenges are associated with operational (power sources), safety, and environmental issues where advanced leakage detection and monitoring technology would be incorporated into the design of the hydrogen-producing plants.

Hydrogen Production Pathways

There is no single ideal hydrogen production pathway for California. All of the pathways considered in this work have tradeoffs that will play a large role in determining the production portion of the future hydrogen economy. Expressed broadly, those tradeoffs are summarized in Table 26 below.

Table 26: Major production pathway tradeoffs

Production Pathway by Feedstock	Contributions	Challenges
Water (electrolysis)	Zero carbon intensity[393]	• High cost, in large part due to the high cost of electricity • Large need for renewable electricity capacity • Intermittent/variable input power • Potential issues with induced grid emissions
Fossil gas (SMR+CC & pyrolysis)	• Large quantities of feedstock are available • Reliable production output • Lowest cost (as of now)	• Higher carbon intensity • Need for CO_2 disposition • Requires continuation of fossil gas system
Biomass (gasification)	Low or negative carbon intensity[394]	• High cost • Some feedstocks can be intermittent or variable • Many sources produce in small quantities in a distributed manner • Competition by other uses
RNG (SMR+CC)	Low or negative carbon intensity[395]	• High cost • Produced in small quantities in a distributed manner • High competition by other uses

Source: Guidehouse analysis for CEC (2025)

It is important to realize that much of what is summarized above may become obsolete over time, for example when affected by policies, maturation of technologies and production processes, market drivers, and macro- and micro-economics. Regardless of all these uncertainties, it is fortunate that the hydrogen supply chain will not be dependent on (and potentially constrained by) a single type of production process, feedstock supply, or source of input energy. Several production processes that were not analyzed in this work due to lower maturity or adoption level (e.g., solid oxide electrolysis and autothermal reforming) could also get developed to the level that they become competitive with the ones discussed in this report.

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[393] Some GHG accounting methods may assign a non-zero, but small, carbon intensity.

[394] Ibid.

[395] Carbon intensity depends on source and processing methods.

Hydrogen Storage

Regardless of what scenario may play out over time, having adequate amounts of hydrogen storage is “table stakes” for adequate development of a viable hydrogen economy. Storage will be needed at all locations in the value chain – at production facilities, the end-use locations and, in many situations, as a freestanding systemwide resource (analogous to fossil gas or gasoline storage).

The need for systemwide storage will be especially critical when the hydrogen economy involves considerable quantities of hydrogen produced by multiple facilities and serving multiple large end-users, especially when there is significant temporal variability in demand, production capacity, or both.

Tank storage is currently suitable for quantities up to several tonnes. With time and the development of technologies and practices for managing larger storage quantities in tanks (as well as reductions in cost), tank storage may become a reasonable option at the level of dozens of tonnes at a single location. It is hard to imagine safely and economically reaching quantities of hundreds or thousands of tonnes of above-ground tank storage at a single facility, though ultimately time will tell.

Therefore, for widespread and significant adoption of clean hydrogen in California, underground geologic storage would be needed. Whether or not this becomes feasible will depend on the outcome of ongoing technology development efforts in storage via depleted oil and gas reservoirs,[396] as the state does not have salt cavern resources. This could take years to complete and scale.

Hydrogen Transport and Delivery

While truck transport of hydrogen is efficient for small volumes of hydrogen, the development of a pipeline network is essential for connecting large-scale hydrogen production centers with large-scale demand. Pipeline transport of hydrogen is the most efficient and economical solution for transport of large volumes of hydrogen.

Hydrogen is less energy dense than fossil gas at the same pressure and temperature and interacts with some pipeline materials differently, potentially increasing costs for engineering, materials, and compressor equipment. Repurposing existing fossil gas pipelines will be costly when the blend is more than 10 percent hydrogen due to more stringent pipeline standards. Transitioning an existing pipeline to higher blends of hydrogen is also challenging logistically because of the transition period where the fossil gas pipeline is still needed to serve existing customers, yet those customers cannot handle a higher blend of hydrogen.

Compressed gaseous hydrogen delivered via tube trailers using trucks offers operational flexibility but the volume that can be delivered economically over extended distances is limited. Investments in liquid hydrogen infrastructure require additional costly handling considerations as liquid hydrogen must be stored at extremely low temperatures and some LH_2 may become economically obsolete once pipeline infrastructure is available that can deliver hydrogen at lower cost.

Hydrogen Value Chain Analysis

The following conclusions can be drawn from the IVCA and resource analysis work:

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[396] And possibly storage in lined caverns.

1. It is important to have an estimate of how much hydrogen will be needed every year, but it's just as essential to estimate the *production capacity* needed. Production capacity is a driver of hydrogen cost and the need for higher input resource availability and greater infrastructure buildout.
2. The minimum production capacity required is the level needed to meet that *average demand* for hydrogen. To achieve this minimum, there must be sufficient systemwide and local hydrogen storage to compensate for days in which demand is higher than average.
3. The amount of hydrogen storage needed to produce a viable hydrogen economy depends on two major factors: (1) the level of production capacity, relative to the maximum amount of hydrogen that might be needed on any day, and (2) the variability of the hydrogen demand from day to day. The lower the production capacity and the greater the demand variability, the more hydrogen storage will be needed.
4. It is possible to do without hydrogen storage if the production capacity is high enough to meet the highest demand needed on any day. The tradeoff is a higher cost of extra infrastructure to produce hydrogen, deliver it to end users, and supply the production plants with greater energy and feedstocks for short periods of time (akin to electric transmission line needs to meet very brief peak power periods). In addition to the higher costs, some or all of the additional production capacity may have to lie idle because of lack of offtakers and/or intermittent and variable timing of production that makes it difficult to match with what commercial offtakers do exist.
5. The supply-demand analysis shows that the magnitude of storage required in many cases is so large (e.g., hundreds to thousands of tonnes of hydrogen) that tank storage is clearly impractical. California’s geology both creates opportunities and poses challenges for the implementation of geologic storage of hydrogen at the strategic quantities needed to meet the energy needs of the state for extended periods of time. While depleted oil and gas reservoirs offer the greatest potential for geological storage, and lined rock caverns are also available, the suitability for hydrogen storage for either of these is not yet proven. Significant research and development efforts are needed.
6. The upper electric power scenario combines a high level of hydrogen demand with daily and seasonal demand variations that provide no reasonable path forward: without hydrogen storage in the hundreds of thousands of tonnes, production capacity and associated infrastructure would need to be increased by multiples of what is necessary to serve the demand.
7. The lower electric power scenario leads to a more realistic future scenario where the hydrogen production capacity can be kept to more manageable levels with tens of thousands of tonnes of storage.
8. Both of the transportation scenarios can be met without resorting to very high levels of storage or excess production capacity. A relatively small increase in production capacity above the minimum could be accomplished with levels of hydrogen storage that should be possible to achieve by 2045 (though they are challenging at the moment).
9. The amount of hydrogen needed for power plants is so large as to preclude the feasibility of delivering it via on-road modes of transport. Rather, pipelines would need to be installed. This would also facilitate the use of the associated storage facilities. Once a pipeline network is in place, it can be expected that refueling stations will be

established in locations with access to the pipeline, where possible. Refueling station delivery will otherwise be by truck, with refueling stations needing to have at least one tonne of onsite hydrogen storage meant to prevent the need for partial-load deliveries.

10. Production of hydrogen at the site of consumption is infeasible at scale for electrolytic hydrogen technologies. It may be possible to accomplish with non-electrolytic production pathways, but the topic requires further investigation.
11. To properly analyze the need for storage and/or production capacity, one must know more than just the annual level of demand. It is critical to specify the demand on a daily basis. Additionally, the current analysis assumes a constant supply but when supply varies and/or is intermittent (the typical situation when electrolysis and/or certain biogenic feedstock pathways are dominant) a complete supply-demand analysis will also require specification of supply variation.

CEC Investments Advancing Clean Hydrogen

The Energy Commission is investing in a sufficient network of public hydrogen refueling stations and is coordinating with the Air Resources Board to establish this network across California to support the fuel cell electric cars that are currently on the road, and to encourage more consumers to consider these zero-emission vehicles. The CEC manages a broad portfolio of innovative public interest research and development projects on clean hydrogen production, storage, delivery, and usage in the electricity and transportation sectors with funding from the EPIC and Gas R&D programs.

APPENDIX A:
Abbreviations and Acronyms

Abbreviation	Meaning
AB	Assembly Bill
ARCHES	Alliance for Renewable Clean Hydrogen Energy Systems
ATJ	alcohol-to-jet
ATR	autothermal reforming
ASME	American Society of Mechanical Engineers
BEV	battery electric vehicle
CARB	California Air Resources Board
CAPEX	Capital Expenditure
CATF	Clean Air Task Force
CCS	carbon capture and storage
CEC	California Energy Commission
CGH_2	compressed gaseous hydrogen
COV	coefficient of variation
CPUC	California Public Utilities Commission
DOT	U.S. Department of Transportation
FCEV	fuel cell electric vehicle
FOG	fats, oils, and grease
GFT	gasification Fischer-Tropsch
DOE	U.S. Department of Energy
GO-Biz	CA Governor’s Office of Business and Economic Development
GHG	greenhouse gas
H_2	hydrogen
HEFA	hydroprocessed esters and fatty acids
HDV	heavy-duty vehicle
HHV	higher heating value
HRS	hydrogen refueling station
HYBRIT	Hydrogen Breakthrough Ironmaking Technology
IID	Imperial Irrigation District
IVCA	Integrated Value Chain Analysis
LCA	life cycle analysis
LADWP	Los Angeles Department of Water and Power
LBNL	Lawrence Berkeley National Laboratory
LH_2	liquid hydrogen

Abbreviation	Meaning
LHV	lower heating value
LLNL	Lawrence Livermore National Lab
MDHD	medium duty and heavy duty
MEA	monoethanolamine
MMBtu	million British thermal units
NCNC	Northern California Non-California Independent System Operator
NETL	National Energy Technology Laboratory
NREL	National Renewable Energy Laboratory
OEM	original equipment manufacturer
PA	Planning Area
PEM	proton exchange membrane
PG&E	Pacific Gas & Electric
PNNL	Pacific Northwest National Laboratory
PrOx	preferential oxidation
PSA	pressure swing adsorption
psia	pounds per square inch absolute
PTC	production tax credit
R&D	Research and Development
RNG	renewable natural gas
RTE	round trip efficiency
SAF	sustainable aviation fuel
SB	Senate Bill
SCE	Southern California Edison
scf	standard cubic foot (at EIA standard conditions of 60°F and 1 atm)
SDG&E	San Diego Gas & Electric
SMR	steam methane reforming
SNL	Sandia National Laboratory
SoCalGas	Southern California Gas
tpd	tonnes (metric tons) per day
UHS	underground hydrogen storage

APPENDIX B: Glossary

Anaerobic digestion

Anaerobic digestion is a chemical process in which organic matter is broken down into biogas by bacteria and without the presence of oxygen. The process occurs in a reactor known as an anaerobic digestor, which varies in form depending on the type and conditions of the organic matter.[397] Organic matter, in this report, refers to animal manure, food waste, and wastewater. Landfill gas is created when anaerobic digestion occurs naturally to organic waste at a landfill.

Biogas/biomass

Biogas is the gas produced by the breakdown of organic matter, as described in the anaerobic digestion definition above. [398] It is usually a mix of methane, carbon dioxide, and other gases. Biomass is any organic material from plants and animals.

Biogenic feedstock

Biogenic feedstocks refer to substances that are produced by living organisms. They are classified as first, second, or third-generation biofuels. First-generation biofuels, or conventional biofuels, refer to the digestible portions of crops such as corn, soy, or wheat. Second- and third-generation biofuels, or advanced biofuels, are the non-digestible portions of crops such as peels, as well as waste residues from the processing of organic waste.[399] This analysis does not differentiate between biogenic feedstocks, unless otherwise specified.

Biomethane / RNG

Biomethane, or Renewable Natural Gas (RNG), refers to methane produced from biogenic sources. It is produced by “upgrading” biogas (i.e. removing any carbon dioxide or other gases) or through gasification. Nearly 90 percent of global biomethane is produced by upgrading biogas via technologies such as membrane separation and water scrubbing.[400]

Blue hydrogen

Blue hydrogen is hydrogen produced from fossil gas, via processes such as steam methane reforming (SMR) or autothermal reforming (ATR), in which CO_2 that is produced is captured through carbon capture and storage (CCS).

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[397] “How Does Anaerobic Digestion Work?” U.S. Environmental Protection Agency. https://www.epa.gov/agstar/how-does-anaerobic-digestion-work

[398] Ibid.

[399] “What Are Biogenic Feedstocks?” 2021. Environmental Technology. https://www.envirotech-online.com/news/air-monitoring/6/breaking-news/what-are-biogenic-feedstocks/56584

[400] “An introduction to biogas and biomethane.” International Energy Agency. https://www.iea.org/reports/outlook-for-biogas-and-biomethane-prospects-for-organic-growth/an-introduction-to-biogas-and-biomethane

Byproduct

A byproduct is a secondary product formed during a chemical reaction that is not the desired product.[401] In the case of steam methane reforming (SMR), hydrogen is the primary, desired product, whereas carbon dioxide is a byproduct. When this byproduct is a gas, it might be referred to as an "off-gas".

Capacity factor

The capacity factor refers to the ratio between actual production and nameplate production. The maximum usually assumes continuous, full-capacity operation, whereas the actual is indicative of real operating conditions.[402] Capacity factor is measure that is influenced by both how many hours equipment is running and the level of intensity or output it is run at.

Capital expenditures (CAPEX)

CAPEX is the contraction of the term capital expenditures, and refers to the expenditures made to acquire, upgrade, and maintain physical assets such as property, plants, buildings, technology, or equipment.[403]

Carbon intensity

Carbon intensity reflects the amount of carbon emitted per unit of energy consumption. It is usually measured in units of kilograms of carbon-dioxide equivalent per British thermal unit (Btu) of energy, where each type of carbon emitted is scaled to carbon dioxide emissions.[404]

Compressed gas

Compressed hydrogen is alluded to throughout this analysis, especially in the context of storage mechanisms. A compressed gas refers to a gas stored in a container with higher pressure than its atmospheric pressure. In practice, this increases the density of the gas, allowing the same amount to take up smaller volumes.

Curtailment

Curtailment, or curtailed power, refers to the intentional scaling back of energy production to meet lower demand. This term most often refers to variable renewable energy sources such as solar and wind, which can be "turned off" when more energy is produced than necessary. The practice helps to balance the electricity grid by preventing the overflow of electricity.[405]

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[401] "BY-PRODUCT Definition & Meaning." Merriam-Webster. https://www.merriam-webster.com/dictionary/by-product

[402] "Glossary - Capacity factor." U.S. Energy Information Administration. https://www.eia.gov/tools/glossary/index.php?id=Capacity_factor

[403] "Capital Expenditure (CapEx) Definition, Formula, and Examples." Investopedia. https://www.investopedia.com/terms/c/capitalexpenditure.asp

[404] "Glossary - Carbon intensity." U.S. Energy Information Administration. https://www.eia.gov/tools/glossary/index.php?id=Carbon_intensity

[405] "What Is Power System Curtailment?" 2024. National Renewable Energy Laboratory. https://docs.nrel.gov/docs/fy25osti/90517.pdf

Digestate

Digestate is the wet mixture produced as a secondary product during anaerobic digestion. It is usually separated into solids and liquids. Due to its richness in nutrients, it is usually used as crop fertilizer.[406]

Dispatchable power generation

Dispatchable power generation refers to sources of power that can be used on demand, such as hydroelectric, geothermal, and hydrogen.[407] This type of power is useful during times of low generation, system outages, or peak demand. Hydrogen can dispatch power at any time by traveling through a fuel cell to generate electricity.

Fuel cell

A device or an electrochemical engine with no moving parts that converts the chemical energy of a fuel, such as hydrogen, and an oxidant, such as oxygen, directly into electricity. The principal components of a fuel cell are catalytically activated electrodes for the fuel (anode) and the oxidant (cathode) and an electrolyte to conduct ions between the two electrodes, thus producing electricity.

Green hydrogen

Green hydrogen is hydrogen produced via the electrolysis of water. It involves an electrochemical reaction between renewably generated electricity and water to produce hydrogen and oxygen. Since the electricity comes from renewable sources such as solar or wind, the production process is considered to have minimal greenhouse gas emissions.

Grey hydrogen

Grey hydrogen is hydrogen produced through steam methane reforming (SMR) of fossil gas. Unlike blue hydrogen, this process releases carbon dioxide emissions into the atmosphere. It is the most common type of hydrogen production today, accounting for over 96 percent of all hydrogen produced.[408]

Guidehouse

Guidehouse refers to Guidehouse, Inc., a consulting firm providing technical assistance to the CEC for low carbon fuels.

Intermittent and/or variable power sources

Intermittent power sources, or variable renewable energy (VRE), refer to energy resources that are not always readily available or vary in the level of output, such as wind and solar. These two energy resources fluctuate in their ability to produce power, as they depend on the availability of wind and light, respectively.[409] Intermittent power sources are the opposite of dispatchable power sources.

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[406] "Basic Information about Anaerobic Digestion." U.S. Environmental Protection Agency. https://www.epa.gov/anaerobic-digestion/basic-information-about-anaerobic-digestion

[407] "Dispatchable Generation Fact Sheet." Pasadena 100. https://pasadena100.org/dispatchable-generation/

[408] "E3 Technology Brief 2." 2024.

[409] "Intermittent Renewable Energy." Bonneville Power Administration. https://www.bpa.gov/energy-and-services/efficiency/demand-response/intermittent-renewable-energy

Levelized cost of hydrogen (LCOH)

Average cost of a kilogram of hydrogen that accounts for the total expenses involved in producing hydrogen throughout its entire lifecycle.[410]

Long-duration energy storage (LDES)

There is no single definition for LDES in the energy community. For this analysis, long duration energy storage (LDES) is an energy storage system that is able to provide at least 10 hours of stored energy but can include systems able to provide seasonal storage.

OEM

OEM, or Original Equipment Manufacturer, refers to the company that designs, builds, and supports marketing and after-sales maintenance of the final product to purchasers.

Retrofitting power plants

Retrofitting a power plant refers to altering existing technology or adding new technology to change plant operation. This may include retrofitting an SMR plant to add carbon capture technology, for example. Retrofitting is one way to enhance technology and efficiency without requiring massive infrastructure overhaul.

Roundtrip efficiency

The roundtrip efficiency (RTE) of an energy storage system is defined as the ratio of the total energy output by the system to the total energy input to the system, as measured at the point of connection. The RTE varies widely for different storage technologies. A high value means that the incurred losses are low.[411]

Slurry

A slurry is a mixture of liquid and an insoluble substance. In this analysis, slurry refers to the result of pre-processed organic waste that is fed to a gasifier or anaerobic digestor when producing hydrogen.

Syngas

Syngas, short for "synthesis gas", is a gas mixture of hydrogen, carbon monoxide, and carbon dioxide that is a product during gasification processes. Syngas is usually an intermediate used to produce other fuels such as methanol.

Technology Readiness Level (TRL)

Technology Readiness Levels (TRL) are a type of measurement system used to assess the maturity level of a particular technology. Each technology project is evaluated against the parameters for each technology level and is then assigned a TRL rating based on the project's

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410 "Levelized Cost of Hydrogen Calculator." 2024. European Hydrogen Observatory. https://observatory.clean-hydrogen.europa.eu/tools-reports/levelised-cost-hydrogen-calculator

411 "Energy Storage System Efficiency GridPIQ." Pacific Northwest National Lab. https://gridpiq.pnnl.gov/v2-beta/doc/technologies/es/es-efficiency/

progress. There are nine technology readiness levels. TRL 1 is the lowest and TRL 9 is the highest.[412]

- TRL 1: Basic principles observed and reported
- TRL 2: Technology concept and/or application formulated
- TRL 3: Analytical and experimental critical function and/or characteristic proof-of-concept
- TRL 4: Technology validation in laboratory environment
- TRL 5: Technology validation in relevant environment
- TRL 6: System/subsystem model or prototype demonstration in a relevant environment
- TRL 7: System prototype demonstration in an operational environment
- TRL 8: Actual system completed through test and demonstration
- TRL 9: Actual system proven in an operational environment

Tonne

A metric ton is 1,000 kilograms. Approximately 1.10 US ton.

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[412] Manning, Catherine. 2023. "Technology Readiness Levels." The National Aeronautics and Space Administration. www.nasa.gov/directorates/somd/space-communications-navigation-program/technology-readiness-levels/

APPENDIX C: Assumptions

The table below captures key assumptions from analysis presented in this report.

Table 27: SB 1075 Hydrogen Analysis Assumptions for the 2025 IEPR

Assumption	Impact
Leakage can occur at any stage of the value chain	• Higher leakage rates negatively impact the cost of delivered hydrogen • Higher greenhouse gas emissions if leakage is not mitigated
Storage calculations • Distribution and transmission pipeline infrastructure will be proportional to county-level population levels • Distribution network has a 6” diameter and 13.6 bar (200 psia) pressure • Transmission network has 48” diameter and 102 bar (1,500 psia) pressure	• Conservative estimates of storage with respect to pressure, which will cause the overestimation of hydrogen storage capacity
IVCA - Supply • Non-overlapping infrastructure between electricity and transportation applications • Independent hydrogen economy (production, storage) for electricity and transportation sectors • All hydrogen production done via electrolysis, powered by renewable energy • No analysis of intermittency (constant supply) • Total production in 2045 = 350,000 tpy • Electrolyzer energy requirement: 52 $kWh_e/kg\ H_2$ • Electrolyzer CF: 45 percent	• Clear and distinct value chains for the electricity and transportation sectors • Does not account for potential efficiencies of shared resources • No effect on the matching of supply and demand • Does not account for potential supply with resources such as biomass • Presents a best-case scenario in which different sources of hydrogen have complementary production profiles for stable, year-long production

Assumption	Impact
IVCA – Electric power • Electric power plant efficiency of 50 percent • In 2045, conversion occurs via advanced fuel cells and hydrogen turbines (low-scenario) • Efficiency of conversion: 70 percent	• Does not account for use of retrofitted fossil gas plants for hydrogen combustion, which would lower efficiencies • Lower greenhouse gas • Higher infrastructure needs
IVCA – Transportation • Day-to-day variability in transportation demand is the same as that of electric vehicle demand • MDHD is based on the CEC's SB 100 Scenarios • MDHD vehicle capacity: 4-6 tpd	• Reflects the reality of the marketplace, where a set of refueling stations does not behave in a synchronized way
IVCA – Storage • Filling and withdrawal frequencies will be on the order of months • Storage can be distributed appropriately across states	• May differ from required applications of hydrogen storage in California • Does not account for midstream infrastructure to bring hydrogen from storage to end-use facilities
Production pathways • RNG use will continue to grow, but will compete with other end-uses • Biomass has a high potential • Fossil gas pathways will not be prioritized	• Limited available RNG feedstock for hydrogen end-use in production pathways analysis • Limited use of fossil gas to produce hydrogen • Biomass availability will encourage gasification technologies to be used in significant proportions

Assumptions for the Hydrogen Value Chain Analysis

Hydrogen Production Portfolio Analysis

Each of the sets of assumptions described below applies to the following pathways: electrolysis, SMR+CC, SMR, biomass gasification, pyrolysis. There are some subcategories of characteristics that differentiate different varieties of the pathway or feedstock, e.g., thermal vs. catalytic vs. plasma pyrolysis.

- Plant capacities were assumed to remain constant for each pathway, with values derived from existing literature and technology, although the analysis was designed to allow capacity to be modified as the user intends.
- For electrolysis, a capacity factor of 45 percent was assumed, whereas for all chemical

processes – SMR, biomass gasification, and pyrolysis – a capacity factor of 90 percent was used. SMR feedstock rates and electricity consumption rates (to produce 1 kg H_2) for NG and RNG were taken from the calculations for SMR+CC and SMR, respectively, in "Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies" (2022) - DOE/NETL-2022/3241.

- Hydrogen yield from biomass gasification was assigned 100 kg H_2 per bone dry tonne (bdt), as recommended in "Biomass gasification for hydrogen production," IEA Bioenergy (2025). Other values are found in the literature, including 75-77 kg H_2/bdt from NREL's H2A and 80 kg H_2/bdt from the Green Hydrogen Coalition; however, the larger value was chosen in light of the analysis addressing the state of affairs in 20 years (i.e., 2045).
- Water usage for electrolysis, biomass gasification, and SMR production pathways was derived from NREL's H2A-Lite model values, whereas pyrolysis water usage was assumed from "Tradeoffs in Life Cycle Water Use and Greenhouse Gas Emissions of Hydrogen Production Pathways". Water usage for pyrolysis was approximated using an average value for catalytic and plasma pyrolysis from ANL, GREET, Black and Veatch, and Monolith Technologies.
- The baseline cost of producing hydrogen daily for biomass gasification and SMR without CCS was based on total installed costs and nameplate capacities, as presented in H2A-Lite. SMR with CCS uses E3's cost for a 483 tpd plant with H2A's scaling factor of 0.44. The cost per production capacity baseline capacity for 75,000 kg/day was assumed for gasification and 200,000 kg/day for SMR. The baseline cost of pyrolysis was assumed to based on Guidehouse's fit to data in the review article, "Methane pyrolysis for hydrogen production: navigating the path to a net zero future," combined with the Project Vision data point, all fit to a power law relationship of ($/tpd) as a function of a power of (tpd). The baseline cost of electrolysis production was based on EPRI-LCRI PEM midsize electrolyzers, as forecast by year, average of high and low values in table.
- Learning curves were used to model the change in CAPEX over time for each pathway, based on the technology's development. Electrolyzer learning curves were derived from the EPRI-LCRI Electrolysis Techno-Economic Analysis. Learning curves for the chemical processes – SMR, gasification, and pyrolysis – were based on the general learning curve equation, $Y = a(N+X)^b$, where X represents the number of years, N represents the initial number of plants, Y represents the learning curve, and a and b are derived based on the technology's maturity. SMR was assumed to have a learning curve of 10.5 percent and 8 plants so far, based on "Technological evolution of large-scale blue hydrogen production toward the U.S. Hydrogen Energy Earthshot" (2024). The learning curves for gasification and pyrolysis were estimated based on their relative maturities to SMR. Both are less mature than SMR, although gasification is slightly more mature than pyrolysis, leading to learning curves of 13 percent and 16 percent, respectively. By 2045, this results in the CAPEX of electrolysis, SMR, gasification, and pyrolysis being 73 percent, 82 percent, 75 percent, and 68 percent the CAPEX in 2025.
- The cost curves used the learning curves as well as cost exponents derived from cost per capacity exponents found in the H2A-Lite data. These exponents were used to model the change in CAPEX from 2025 to 2045.

Resource Requirements and Economics

- Biomass availability in California is taken from the 2022 Updated CARB Scoping Plan. Except where noted, this report adopts the estimates for biogenic feedstock availability used in the E3 Technology Brief: Task 2 (December 2024) document. Those derive from the CARB Scoping Plan as follows: (1) 2045 RNG estimates are those in Figure H-3 of Appendix H, (2) biomass estimates also follow Appendix H, except that use of agricultural biomass for electricity is *not* assumed to increase from 1.1 million tonnes/yr (as discussed on p. 63 of Appendix H).

- RNG from Renewable Natural Gas in California Characteristics, Potential, and Incentives: 2023 Update, CEC-200-2023-010. "ICF High" forecast/scenario:

Table 28: Resource Potential (MMBtu) by RNG type

RNG type	Resource Potential (MMBtu)
Livestock/Dairy	16,200,000
WWTP gas	8,600,000
Landfill gas	46,000,000
MSW (food)	12,760,000

Leakage Analysis

The development of the leakage analysis to determine the emissions reductions required some assumptions. Firstly, the amount of fuel energy being replaced was determined based on the 2022 Scoping Plan.

In addition, the percentage of leakage across the hydrogen value chain were from the Columbia Center on Global Energy Policy’s analysis of Hydrogen Leakage, which included a 1.5 percent blue hydrogen production leakage and 4 percent green hydrogen production leakage, as well as leakage percentages across the transport and distribution process. Meanwhile, Guidehouse assumed fossil gas leakage to be 1 percent based on the 45VH2-GREET assumption, while diesel had a 0 percent leakage. Leakage rates across the transport and delivery value chain were modeled by assuming a “Baseline” case, which mostly relies on pipeline transport and a “Truck-Heavy” case.

Global warming potentials for hydrogen, methane, and diesel fuel were assumed to be 11.6, 30, and 0 from the article "A multi-model assessment of the Global Warming Potential of hydrogen”. Finally fossil gas was assumed to have an emissions factor of 50.15 gCo2e/MJ and fuel energy of 50 MMBtu/tonne based on EIA and DOE data, respectively. Similarly, diesel was assumed to have an emissions factor of 70.27 gCO2e/MJ and fuel energy of 40.4 MMBtu/tonne, assuming a density of 7.0 lb/gal.

Other Assumptions

Estimated Production Capacity of hydrogen from RNG from Landfills

The production capacity assumes that landfill gas is 50 percent methane, based on EPA identification from the LOMP. In addition, it is assumed that 0.158 MMBtu of RNG is required per kilogram of H_2 produced, from "Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies" (2022) - DOE/NETL-2022/3241.

Compression Energy (Fig 7)

The compressor energy for various inlet and outlet pressures was calculated using an equation from DOE’s H2A Delivery Scenario Model (HDSAM). This equation was combined with the optimum multistage compression ratio, a commonly used engineering equation based on the principles of entropy.

Storage tank size/dimensions (Fig 8)

Calculations for tank storage gas volume assume an aspect ratio of 2.0. The calculation assumes that all of the inner space in the tank is occupied by hydrogen gas; i.e., it ignores any engineered structures or equipment that might be needed for a particular tank technology or design.

Potential for storing hydrogen in former fossil gas pipelines (Table 12)

The assumptions used for the storage calculations are as follows:

- The total amounts of distribution and transmission pipeline miles in each county are proportional to the percentage of the state's population residing in the county.[413] (Miles of distribution pipeline and transmission pipeline were taken from PHMSA.[414])
- A representative or average pipeline in the distribution network has the properties of 6" diameter and 13.6 bar (200 psia) pressure. This should result in a conservative estimate (results in higher hydrogen storage) with respect to pressure, but not necessarily so with respect to pipeline diameter. As will be explained below, there is a great deal of discontinuity among pipelines in the distribution network, so hydrogen storage would be very distributed into many small-quantity pockets.
- A representative or average pipeline in the transmission network has the properties of 48" diameter and 102 bar (1,500 psia) pressure. This is conservative (again, in the sense of overestimating hydrogen storage capacity) with respect to both pressure and diameter. This portion of the pipeline system is more aggregated (though not fully so) than the distribution networks, so in many cases a good portion of the transmission system should be available from any given access point.

Miscellaneous assumptions

- Guidehouse calculates that 15.4 tonnes/day is sufficient to provide 300 MWh of electric power daily for a 50 percent efficient power plant, which is not insignificant.
- Using their RNG price estimate and LCOH breakdown, Guidehouse estimates that the LCOH would be \$9.06/kg H_2 if the RNG cost were at the E3 upper scenario.
- Note – this one is covered in the Production Pathway Analysis section: Guidehouse estimates the CAPEX cost of pyrolysis plants to be about 68 percent of today's cost by 2045 (see the production modeling section below for details).
- Guidehouse estimates that CAPEX costs could drop 25 percent or more by 2045.

Guidehouse has performed an analysis of the storage and production capacity requirements – related only to intermittency and variability of electric power input – of an electrolytic hydrogen facility that would be coupled with its variable renewable power source but committed to deliver a constant supply of hydrogen to its customers.

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[413] "California Counties by Population (2025)." World Population Review. https://worldpopulationreview.com/us-counties/california

[414] "Pipeline Miles and Facilities 2010+." Pipeline and Hazardous Material Safety Administration. https://portal.phmsa.dot.gov/analytics/saw.dll?Portalpages

APPENDIX D:
Signposts

Signposts are issues and challenges to closely track across production, delivery, storage, and end use. Table 29 and Table 30 provide examples of technical and economic aspects of different value chain elements and synergistic considerations that need to monitored for clean hydrogen to have the best possible chance of success in California.

Table 29: Potential Signpost Topics – Production, Storage, Delivery

Category	Technical	Economic
Electrolysis	• Availability and adoption of reliable electrolyzers • Reliable renewable-based electricity supply for extended periods to power electrolyzers	• Availability of low-cost electrolyzers • Extremely low-cost electric power
Biogenic production	• Efficient collection and movement of feedstock for processing • Efficient sorting of feedstocks for processing • Biofuel (e.g., biomethane) vs. conversion to hydrogen	• Cost for consistently available feedstock • Centralized processing and conversion • Carbon capture costs, where relevant
Storage	• Acceptance and certification of reliable operation of low-leakage methane storage facilities for gas from renewable sources • Acceptance and certification of depleted oil and gas wells for hydrogen storage	• Cost of maintaining underground facilities for methane • Cost of new storage facilities for hydrogen • Cost of out of state underground facilities for hydrogen
Delivery	• Limits on hydrogen blend allowed in existing pipelines • Acceptance and certification of upgraded or new T&D pipelines to accommodate hydrogen • Acceptance and certification of associated equipment (e.g., compressors)	• Cost for building/upgrading intra-state gas pipelines to accommodate hydrogen • Cost for building interstate hydrogen pipelines

Source: Guidehouse analysis for CEC (2025)

Table 30: Potential Signpost Topics – End Uses

Category	Technical	Economic
Electricity generation	• Availability and adoption of high reliability and easy-to-maintain fuel cells • Availability and adoption of hydrogen-capable gas turbines/generators	• Fuel cell costs • Hydrogen-capable gas turbine/generator costs
Transportation	• Availability and adoption of hydrogen-fueled transportation equipment (ground, marine, aviation) • Number and location of fueling facilities • Capacity utilization at fueling facilities	• Cost of hydrogen transportation equipment • Fueling facilities build out costs • Retail fuel costs and the impact of markups along the supply chain
Other – synergistic considerations	• Industrial use of hydrogen – location/quantities • Need for green ammonia for in-state industrial use and fertilizer production • Risk of end use applications are understood and calculable	• Industrial end use of hydrogen – costs • Cost of imported green ammonia • Cost of developing CA green ammonia supply chain and production ecosystem • Insurance premiums

Source: Guidehouse analysis for CEC (2025)

APPENDIX E:
Ancillary Material

Table 31: Efficient frontier conditions – storage, production capacity, and the resulting unused capacity – for upper electric power scenario, all PAs except IID

LADWP			NCNC			PG&E			SCE			SDG&E		
Storage T	Produc-tion tpd	Unused Capacity Tpy	Storage T	Produc-tion tpd	Unused Capacity Tpy	Storage T	Produc-tion tpd	Unused Capacity Tpy	Storage T	Produc-tion tpd	Unused Capacity Tpy	Storage T	Produc-tion tpd	Unused Capacity Tpy
-	2,587	842,917	-	2,066	630,890	-	12,647	3,920,049	-	11,601	3,627,652	-	3,231	1,121,784
1,100	1,680	511,865	1,000	1,573	450,771	8,000	9,961	2,939,932	7,500	8,761	2,591,209	1,675	1,914	641,012
3,425	1,185	331,291	3,875	1,264	339,484	24,850	7,660	2,108,117	21,250	6,986	1,943,432	3,350	1,365	440,690
5,750	1,020	271,100	6,750	1,203	317,647	41,700	7,276	1,972,254	35,000	6,631	1,815,771	5,025	1,256	400,626
8,075	938	241,508	9,625	1,141	295,811	58,550	6,892	1,836,456	48,750	6,276	1,689,943	6,700	1,146	360,561
10,400	855	212,287	12,500	1,079	273,975	75,400	6,509	1,700,659	62,500	5,922	1,564,114	8,375	1,036	320,497
12,725	855	212,287	15,375	1,018	252,255	92,250	6,509	1,700,659	76,250	5,922	1,564,114	10,050	926	280,433
15,050	773	183,185	18,250	956	230,603	109,100	6,125	1,565,274	90,000	5,567	1,438,316	11,725	816	240,512
17,375	773	183,185	21,125	956	230,603	125,950	5,742	1,430,775	103,750	5,212	1,312,665	13,400	816	240,512
19,700	773	183,185	24,000	894	208,975	142,800	5,358	1,296,320	117,500	5,212	1,312,665	15,075	816	240,512
22,025	690	154,285	26,875	833	187,492	159,650	5,358	1,296,320	131,250	4,857	1,187,045	16,750	707	201,545
24,350	690	154,285	29,750	833	187,492	176,500	4,974	1,161,929	145,000	4,502	1,061,571	18,425	707	201,545
26,675	608	125,647	32,625	771	166,242	193,350	4,591	1,027,666	158,750	4,502	1,061,571	20,100	707	201,545
29,000	608	125,647	36,500	771	166,242	210,200	4,591	1,027,666	172,500	4,147	936,098	21,775	597	162,578
31,325	608	125,647	38,375	709	144,992	227,050	4,207	893,404	186,250	4,147	936,098	23,450	597	162,578

LADWP			NCNC			PG&E			SCE			SDG&E		
Storage T	Production tpd	Unused Capacity Tpy	Storage T	Production tpd	Unused Capacity Tpy	Storage T	Production tpd	Unused Capacity Tpy	Storage T	Production tpd	Unused Capacity Tpy	Storage T	Production tpd	Unused Capacity Tpy
33,650	608	125,647	41,250	709	144,992	243,900	4,207	893,404	200,000	3,792	811,003	25,125	597	162,578
35,975	525	97,793	44,125	648	124,214	260,750	3,824	759,141	213,750	3,792	811,003	26,800	487	123,652
38,300	525	97,793	47,000	648	124,214	277,600	3,824	759,141	227,500	3,437	686,656	28,475	487	123,652
40,625	525	97,793	49,875	586	103,581	294,450	3,440	626,960	241,250	3,437	686,656	30,150	487	123,652
42,950	525	97,793	52,750	586	103,581	311,300	3,440	626,960	255,000	3,082	563,135	31,825	377	84,740
45,275	443	70,310	55,625	524	82,961	328,150	3,056	497,822	268,750	2,727	439,946	33,500	377	84,740
47,600	443	70,310	58,500	524	82,961	345,000	3,056	497,822	282,500	2,727	439,946	35,175	377	84,740
49,925	443	70,310	61,375	524	82,961	361,850	2,673	369,605	296,250	2,372	316,957	36,850	377	84,740
52,250	361	43,005	64,250	463	62,358	378,700	2,673	369,605	310,000	2,372	316,957	38,525	268	45,828
54,575	361	43,005	67,125	463	62,358	395,550	2,289	241,480	323,750	2,372	316,957	40,200	268	45,828
56,900	361	43,005	70,000	401	41,756	412,400	2,289	241,480	337,500	2,017	193,968	41,875	268	45,828
59,225	361	43,005	72,875	401	41,756	429,250	2,289	241,480	351,250	2,017	193,968	43,550	268	45,828
61,550	278	15,713	75,750	339	21,354	446,100	1,906	113,565	365,000	1,662	71,691	45,225	158	6,925

Source: Guidehouse analysis for CEC (2025)

Table 32: Ranges of potential electrolyzer capacities (MWe) required in each PA to meet the upper scenario electric power demand.

LADWP		NCNC		PG&E		SCE		SDGE	
Storage t	MW electrolyzer	Storage t	MW electrolyzer	Storage t	MW electrolyzer	Storage t	MW electrolyzer	Storage t	MW electrolyzer
	12,455	0	9,949	0	60,891	0	55,855	0	15,558
1,100	8,088	1,000	7,573	8,000	47,962	7,500	42,183	1,675	9,216
3,425	5,706	3,875	6,088	24,850	36,880	21,250	33,638	3,350	6,574
5,750	4,912	6,750	5,791	41,700	35,033	35,000	31,929	5,025	6,045
8,075	4,515	9,625	5,494	58,550	33,186	48,750	30,220	6,700	5,517
10,400	4,118	12,500	5,197	75,400	31,339	62,500	28,511	8,375	4,988
12,725	4,118	15,375	4,900	92,250	31,339	76,250	28,511	10,050	4,460
15,050	3,721	18,250	4,603	109,100	29,492	90,000	26,802	11,725	3,931
17,375	3,721	21,125	4,603	125,950	27,645	103,750	25,093	13,400	3,931
19,700	3,721	24,000	4,306	142,800	25,798	117,500	25,093	15,075	3,931
22,025	3,324	26,875	4,009	159,650	25,798	131,250	23,384	16,750	3,403
24,350	3,324	29,750	4,009	176,500	23,951	145,000	21,675	18,425	3,403
26,675	2,927	32,625	3,712	193,350	22,104	158,750	21,675	20,100	3,403
29,000	2,927	35,500	3,712	210,200	22,104	172,500	19,966	21,775	2,874
31,325	2,927	38,375	3,415	227,050	20,257	186,250	19,966	23,450	2,874
33,650	2,927	41,250	3,415	243,900	20,257	200,000	18,257	25,125	2,874
35,975	2,530	44,125	3,118	260,750	18,410	213,750	18,257	26,800	2,346
38,300	2,530	47,000	3,118	277,600	18,410	227,500	16,548	28,475	2,346
40,625	2,530	49,875	2,821	294,450	16,563	241,250	16,548	30,150	2,346
42,950	2,530	52,750	2,821	311,300	16,563	255,000	14,839	31,825	1,817
45,275	2,133	55,625	2,524	328,150	14,716	268,750	13,130	33,500	1,817
47,600	2,133	58,500	2,524	345,000	14,716	282,500	13,130	35,175	1,817
49,925	2,133	61,375	2,524	361,850	12,869	296,250	11,421	36,850	1,817
52,250	1,736	64,250	2,227	378,700	12,869	310,000	11,421	38,525	1,289
54,575	1,736	67,125	2,227	395,550	11,022	323,750	11,421	40,200	1,289
56,900	1,736	70,000	1,930	412,400	11,022	337,500	9,712	41,875	1,289

LADWP		NCNC		PG&E		SCE		SDGE	
Storage t	MW electrolyzer	Storage t	MW electrolyzer	Storage t	MW electrolyzer	Storage t	MW electrolyzer	Storage t	MW electrolyzer
59,225	1,736	72,875	1,930	429,250	11,022	351,250	9,712	43,550	1,289
61,550	1,339	75,750	1,633	446,100	9,175	365,000	8,003	45,225	760

Source: Guidehouse analysis for CEC (2025)

Table 33: Efficient frontier conditions – storage, production capacity, and the resulting unused capacity – for lower electric power scenario in each PA

LADWP			IIID			NCNC			PG&E			SCE			SDGE		
Stor-age t	Prodn tpd	Unused capy tpy	Stor-age t	Prodn tpd	Unused capy tpy	Stor-age t	Prodn tpd	Unused capy tpy	Stor-age t	Prodn tpd	Unused capy tpy	Stor-age t	Prodn tpd	Unused capy tpy	Storage t	Prodn tpd	Unused capy tpy
0	90	8,850	0	413	81,729	-	97	20,712	-	394	84,379	-	1,199	264,118	-	58	11,960
90	82	5,984	824	357	61,557	30	73	11,843	100	295	48,218	216	992	188,614	28	40	5,167
180	79	4,710	1,648	333	53,524	121	58	6,669	180	221	21,098	432	785	113,109	56	35	3,469
270	77	4,088	2,472	317	47,528	212	52	5,191	322	188	9,045	648	630	56,481	84	33	2,633
360	76	3,821	3,296	309	44,754	303	52	4,515	464	188	9,045	864	527	18,729	112	31	2,243
450	75	3,559	4,120	293	39,249	394	50	4,515	606	188	9,045	1,080	527	18,729	140	31	2,243
540	75	3,259	4,922	285	36,498	485	50	3,847	748	180	6,031	1,296	527	18,729	168	31	2,243
630	74	3,283	5,768	277	33,836	576	50	3,847	890	180	6,031	1,512	527	18,729	196	30	1,860
720	74	3,289	6,592	269	31,193	667	50	3,847	1,032	180	6,031	1,728	527	18,729	224	30	1,860
810	73	3,023	7,416	261	28,555	758	48	3,178	1,174	180	6,031	1,944	527	18,729	252	29	1,860
900	73	2,757	8,240	253	25,934	849	48	3,178	1,316	180	6,031	2,160	501	9,291	280	29	1,476
990	72	2,538	9,064	247	23,503	940	46	3,178	1,458	180	6,031	2,376	501	9,291	308	29	1,476
1,080	72	2,898	9,888	245	25,954	1,031	46	3,178	1,600	180	6,031	2,592	501	9,291	336	29	1,476
1,170	72	2,435	10,712	237	22,535	1,122	46	2,565	1,742	180	6,031	2,808	501	9,291	364	29	1,476
1,260	71	2,238	11,536	237	20,315	1,213	46	2,565	1,884	171	3,590	3,024	501	9,291	392	28	1,476
1,350	71	2,238	12,360	229	20,315	1,304	46	2,565	2,026	171	3,590	3,240	501	9,291	420	28	1,127
1,440	70	1,981	13,184	229	16,879	1,395	44	2,565	2,168	171	3,590	3,456	501	9,291	448	28	1,127

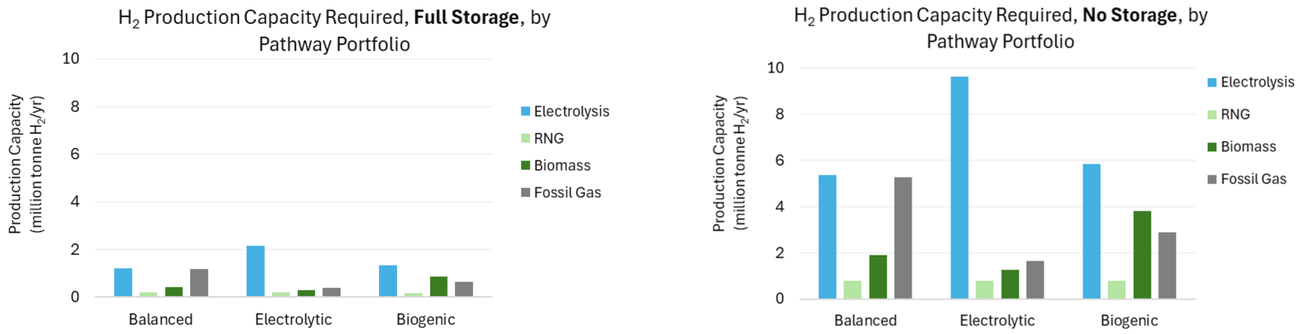
LADWP			IIID			NCNC			PG&E			SCE			SDGE		
Storage t	Prodn tpd	Unused capy tpy	Storage t	Prodn tpd	Unused capy tpy	Storage t	Prodn tpd	Unused capy tpy	Storage t	Prodn tpd	Unused capy tpy	Storage t	Prodn tpd	Unused capy tpy	Storage t	Prodn tpd	Unused capy tpy
1,530	70	1,981	14,008	213	13,940	1,486	44	1,965	2,310	171	3,590	3,672	501	9,291	476	28	1,127
1,620	69	1,725	14,832	213	11,865	1,577	44	1,965	2,452	171	3,590	3,888	501	9,291	504	28	1,127
1,710	69	1,725	15,656	205	11,575	1,668	44	1,965	2,594	171	3,590	4,104	501	9,291	532	28	1,127
1,800	68	1,477	16,480	205	10,534	1,759	42	1,965	2,736	171	3,590	4,320	501	9,291	560	27	1,127
1,890	68	1,477	17,304	197	10,534	1,850	42	1,965	2,878	171	3,590	4,536	501	9,291	588	27	786
1,980	67	1,238	18,128	197	10,222	1,941	42	1,366	3,020	171	3,590	4,752	501	9,291	616	27	786
2,070	67	1,238	18,952	189	8,649	2,032	42	1,366	3,162	171	3,590	4,968	501	9,291	644	27	786
2,160	66	999	19,776	189	8,649	1,223	42	1,366	3,304	171	3,590	5,184	501	9,291	672	27	786
2,250	66	999	20,600	189	6,849	2,214	42	1,366	3,446	171	3,590	5,400	501	9,291	700	27	786
2,340	66	999	21,424	189	6,849	2,305	40	1,366	3,588	171	3,590	5,616	501	9,291	728	27	786
2,430	66	999	22,248	189	6,849	2,396	40	771	3,730	163	1,171	5,832	475	1,372	756	26	445

Source: Guidehouse analysis for CEC (2025)

Resource Analysis Charts

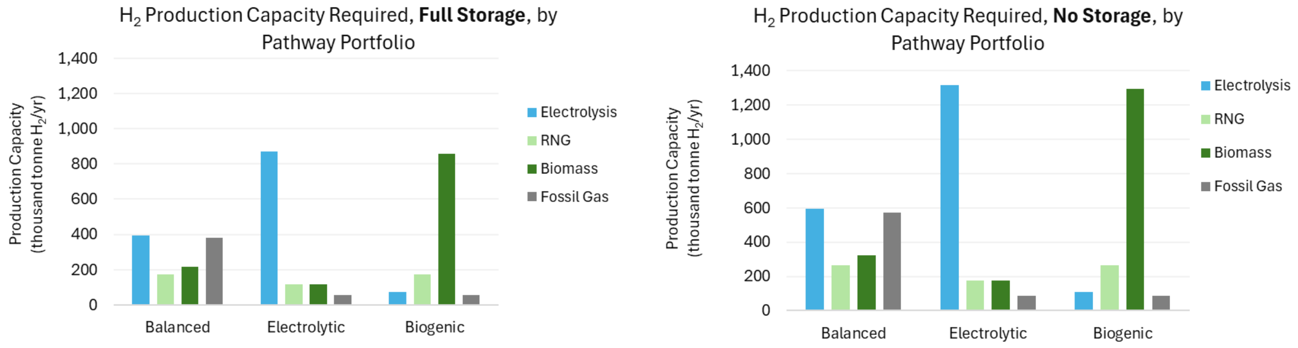
Hydrogen Production Capacity

Figure 47: Production capacity requirements, by feedstock and portfolio, for combined <u>upper</u> scenarios, full-storage and no-storage cases



Source: Guidehouse analysis for CEC (2025)

Figure 48: Production capacity requirements, by feedstock and portfolio, for combined <u>lower</u> scenarios, full-storage and no-storage cases

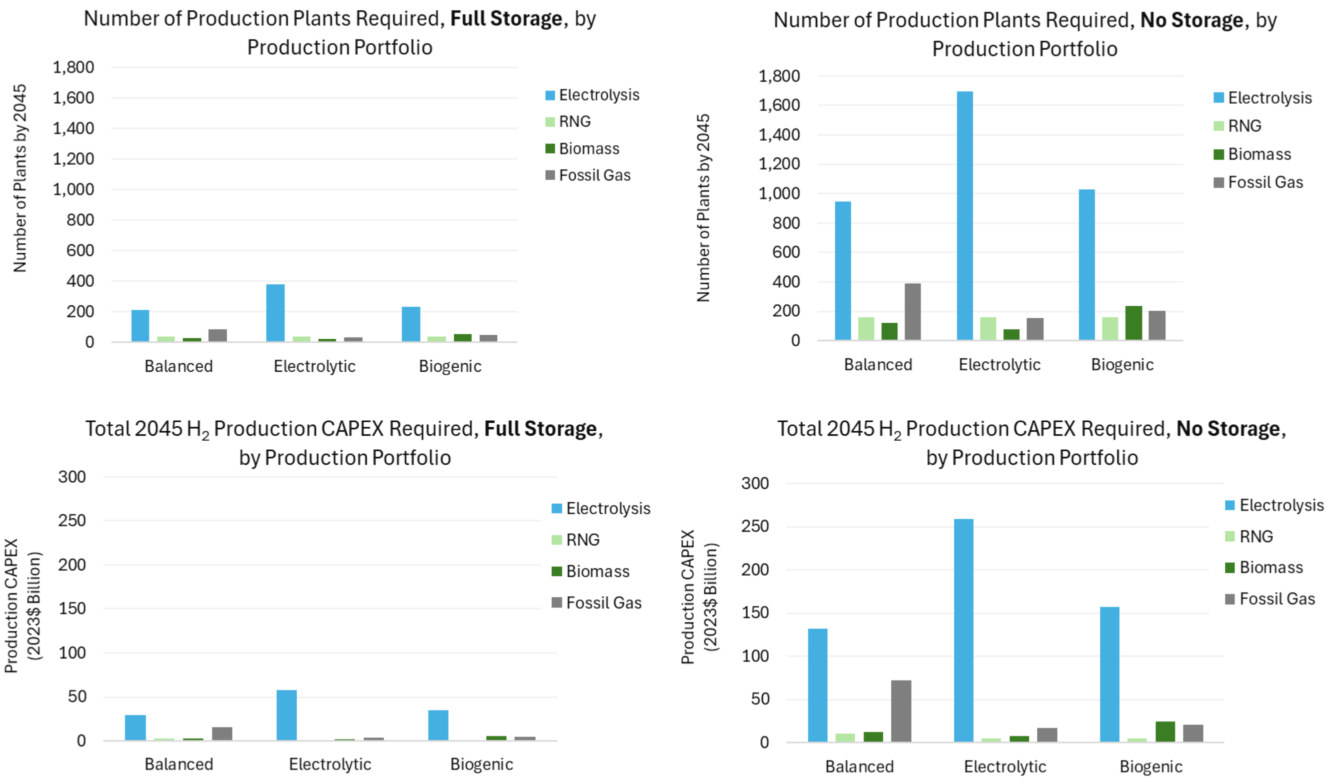


Note that the Y-axis scale is *thousands* of tonnes of H_2/year

Source: Guidehouse analysis for CEC (2025)

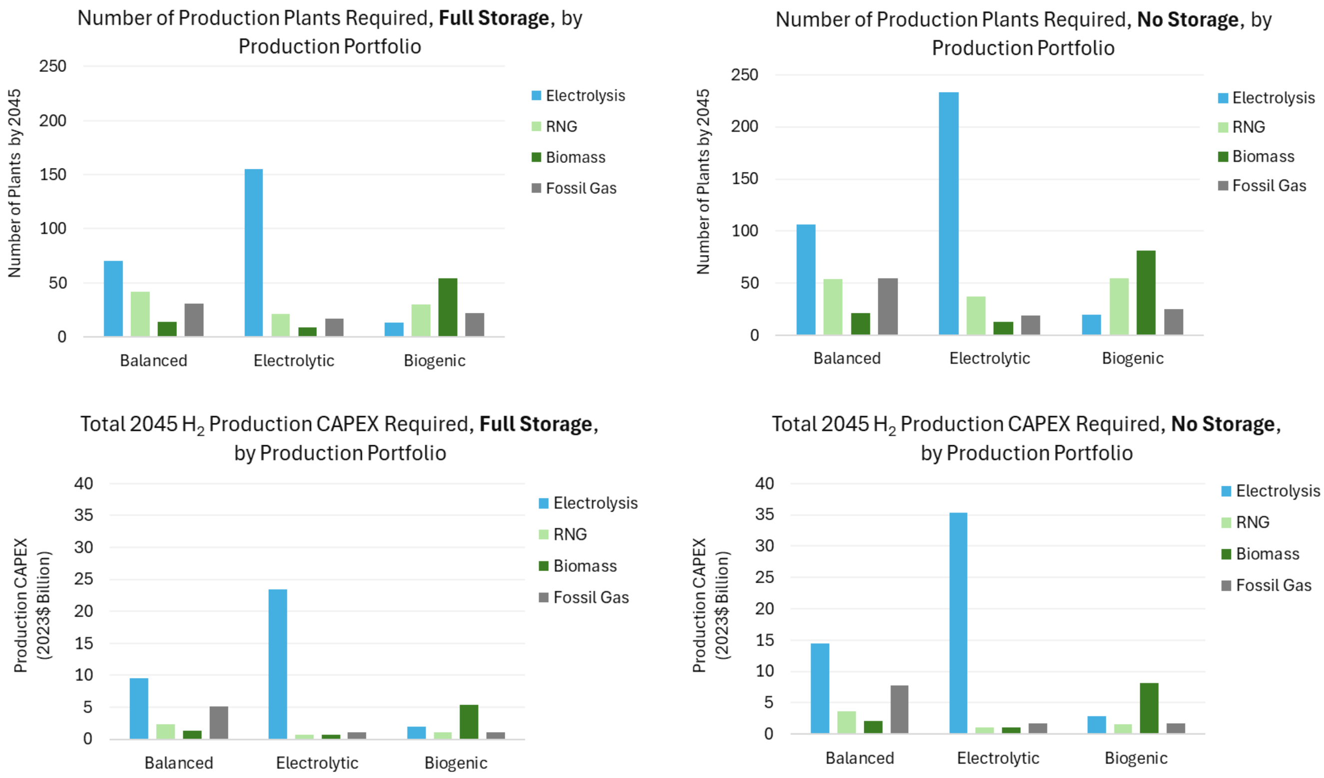
Numbers of Production Plants and Associated CAPEX Investment

Figure 49: Number of production plants and CAPEX (total overnight cost) required for each portfolio; combined upper scenarios, full- and no-storage cases



Source: Guidehouse analysis for CEC (2025)

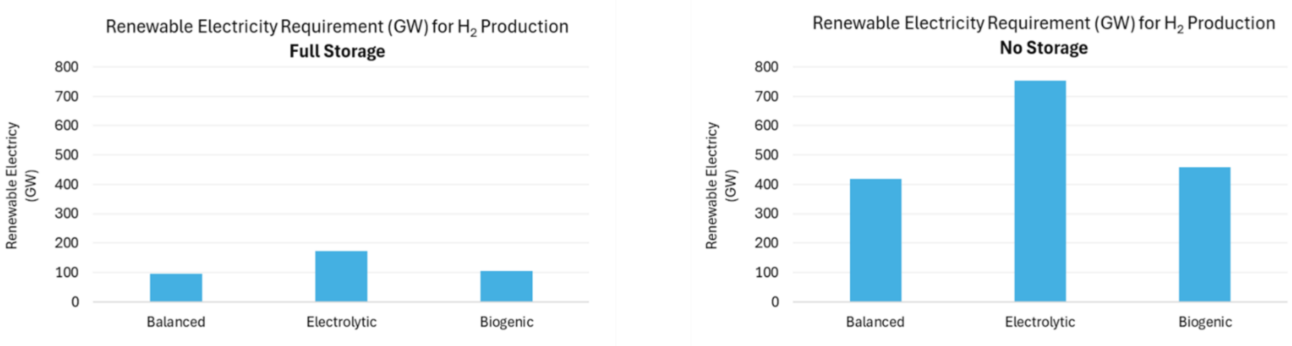
Figure 50: Number of production plants and CAPEX (total overnight cost) required for each portfolio; combined lower scenarios, full- and no-storage cases



Source: Guidehouse analysis for CEC (2025)

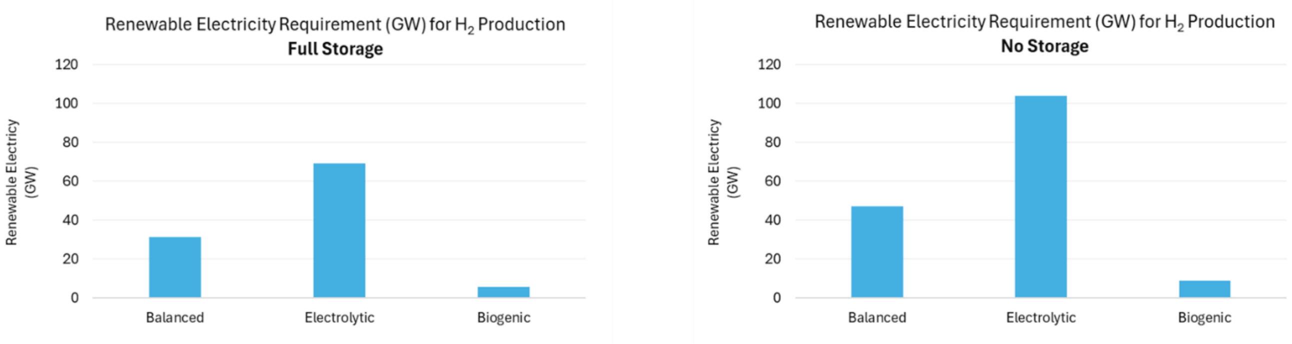
Renewable Energy and its Land Requirement for Electrolysis

Figure 51: Renewable power capacity required for electrolysis; combined upper scenarios, full-storage and no-storage cases



Source: Guidehouse analysis for CEC (2025)

Figure 52: Renewable power capacity required for electrolysis; combined <u>lower</u> scenarios, full-storage and no-storage cases



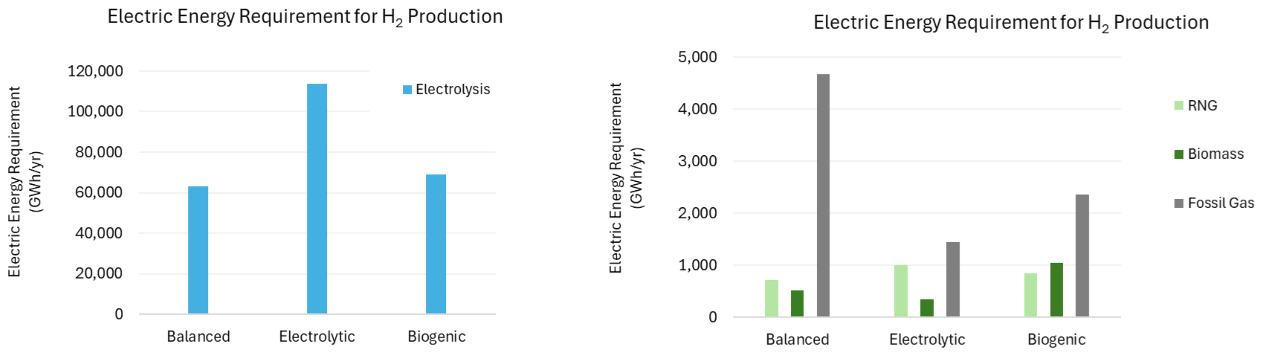
Source: Guidehouse analysis for CEC (2025)

Table 34: Land area required for renewable energy (assuming solar PV), all values in acres

Scenario	Storage	Balanced	Electrolytic	Biogenic
Combined Upper	Full Storage	667,000	1,199,000	728,000
Combined Upper	No Storage	2,970,000	5,350,000	3,240,000
Combined Lower	Full Storage	218,000	483,000	40,000
Combined Lower	No Storage	329,000	728,000	60,000

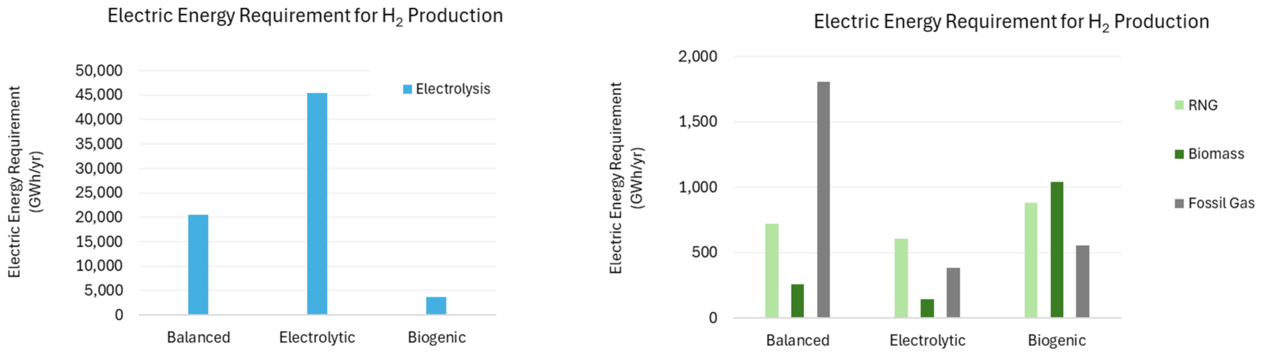
Electricity Requirements

Figure 53: Electric energy supply required, by feedstock and portfolio; combined <u>upper</u> scenarios



Source: Guidehouse analysis for CEC (2025)

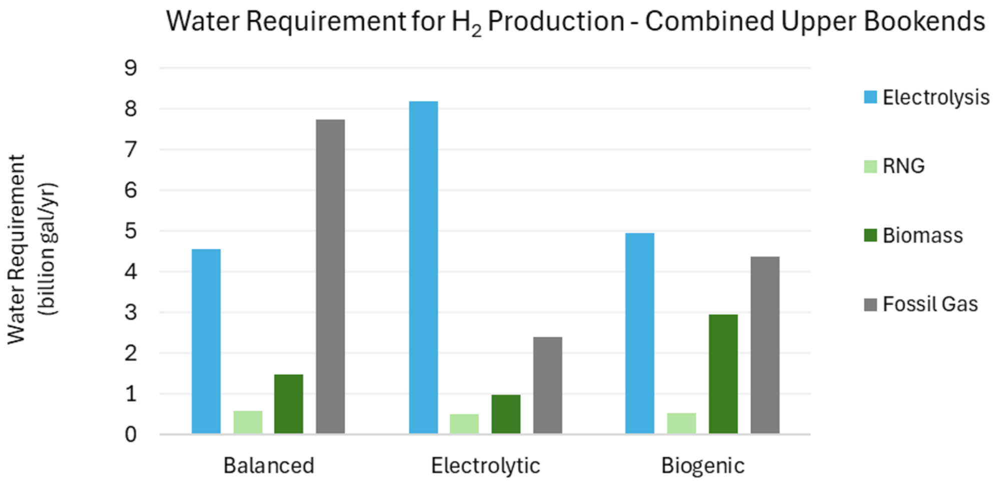
Figure 54: Electric energy supply required, by feedstock and portfolio; combined lower scenarios



Source: Guidehouse analysis for CEC (2025)

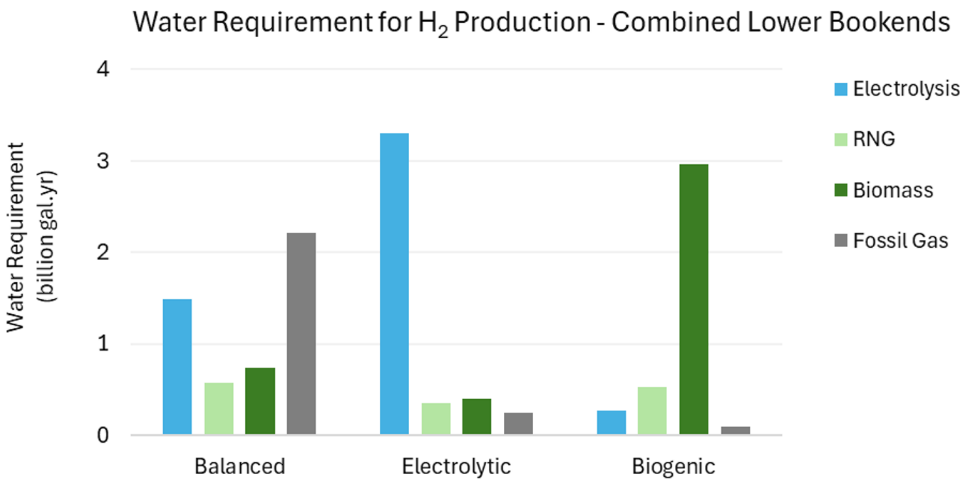
Water Requirements

Figure 55: Water supply required, by feedstock and portfolio; combined upper scenarios



Source: Guidehouse analysis for CEC (2025)

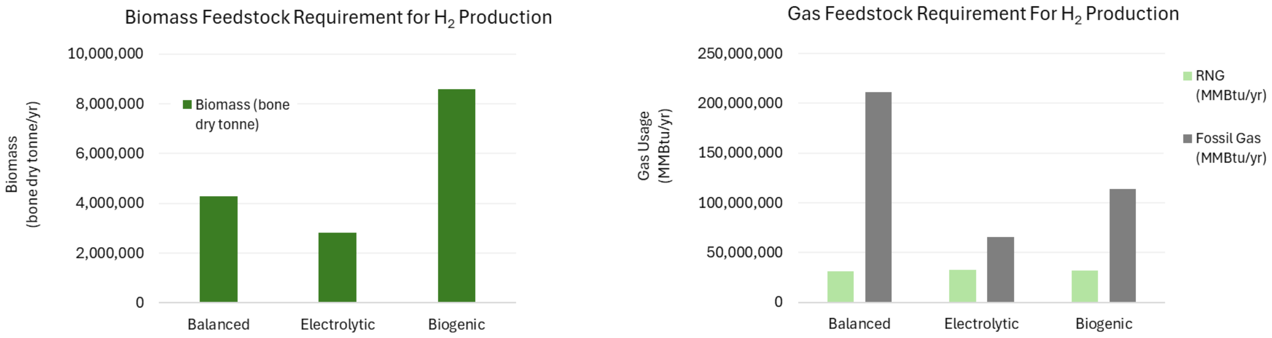
Figure 56: Water supply required, by feedstock and portfolio; combined lower scenarios



Source: Guidehouse analysis for CEC (2025)

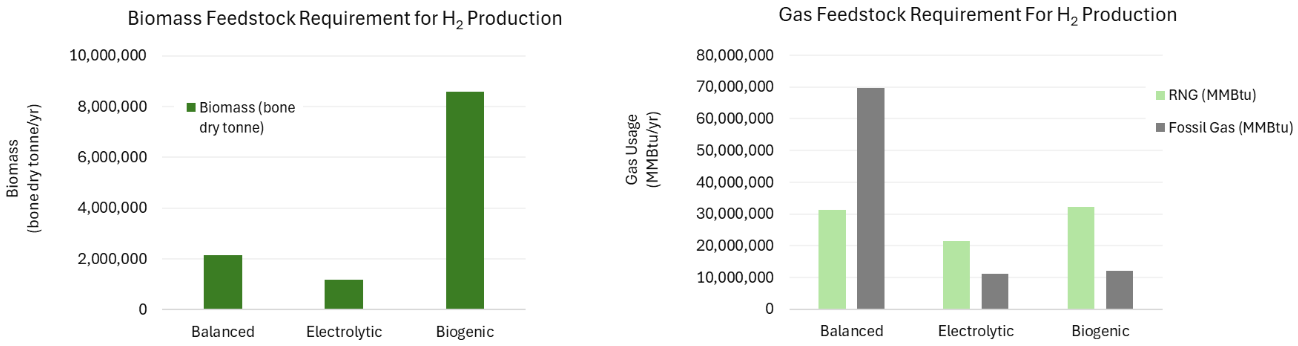
Non-Water Feedstock Requirements

Figure 57: Non-water feedstock required, by feedstock and portfolio; combined upper scenarios



Source: Guidehouse analysis for CEC (2025)

Figure 58: Non-water feedstock required, by feedstock and portfolio; combined lower scenarios



Source: Guidehouse analysis for CEC (2025)

Table 35: Total emissions from combustion in a business-as-usual case

Sector	Assumed fuel	Comb. emissions factor (tCO2e/EJ)	Fuel energy usage being replaced (EJ/yr)	Combustion emissions (tpa CO2e)
Electric power	Fossil gas	50,150,000	0.226	11,333,900
Transportation	Diesel fuel	70,270,000	0.203	14,229,999
Industrial	Fossil gas	50,150,000	0.019	928,410

Source: Guidehouse analysis for CEC (2025)

Table 36: Total emissions from leakage in a business-as-usual case

Sector	Assumed fuel	Fuel energy (EJ/tonne)	Amt of fuel replaced (tpa)	Leakage (tpa)	Leakage emissions (tCO2e/yr)
Electric power	Fossil gas	5.27E-08	4.28E+06	42,850	1,285,488
Transportation	Diesel fuel	4.26E-08	4.75E+06	N/A	N/A
Industrial	Fossil gas	5.27E-08	3.51E+05	3,510	105,300

Source: Guidehouse analysis for CEC (2025)

Table 37: Total emissions from leakage and combustion combined in a business-as-usual case

Sector	Assumed fuel	Total emissions, leakage & combustion (tCO2e/yr)
Electric power	Fossil gas	12,619,388
Transportation	Diesel fuel	14,229,999
Industrial	Fossil gas	1,033,710
Total	N/A	27,883,097

Source: Guidehouse analysis for CEC (2025)

Table 38: Total value chain emissions from 100 percent green hydrogen adoption

Sector	Assumed fuel	H_2 used (tpa)	Production emissions (tCO2e/yr)	Production leakage emissions (tCO2e/yr)	Pipeline transport and storage leakage emissions	Pipeline local distribution leakage emissions (tCO2e/yr)	Truck transport and storage leakage emissions (tCO2e/yr)	Direct use on site (transport) leakage emissions	End-use leakage emissions (tCO2e/yr)	Total emissions (tCO2e/yr)
Electric power	Green H_2	1,616,222	N/A	749,92	168,734	33,747	56,245	1,500	562,445	1,572,596
Transportation	Green H_2	1,428,067	N/A	662,623	16,566	9,939	662,623	N/A	381,008	1,732,760
Industrial	Green H_2	130,552	N/A	60,576	3,029	3,332	22,716	151	7,572	97,376

Source: Guidehouse analysis for CEC (2025)