Green Hydrogen Proposals Across California

An assessment of opportunities and challenges for using hydrogen to meet state climate goals

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May 21, 2024

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Acknowledgements

We are grateful to Theo Caretto, Shana Lazerow, Arjun Makhijani, Drew Michanowicz, Seth Shonkoff, and Adrienne Underwood for their insight and feedback during the development of this report. Any errors or omissions remain our own.

About PSE Healthy Energy

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Table of Contents

Executive Summary

Local and state governments across California have set ambitious goals to mitigate greenhouse gas emissions in the coming decades. In recent years, policymakers, utilities, and other planners statewide have increasingly relied on green hydrogen as a component of their plans to meet climate targets, yet our review of these plans has found that they rarely align. Statewide, decision-makers have set a wide range of targets for green hydrogen deployment, with different primary end-uses, timelines, and definitions of what makes hydrogen "green" or "clean." In many cases, these plans also lack sufficient detail to fully characterize the potential impacts—positive and negative—of proposed hydrogen deployment strategies. The adoption of green hydrogen—and its role in the economy-wide energy transition that California will undertake in the coming decades—holds implications for climate change, public health, equity, safety, cost, the environment, and the overall feasibility and speed of achieving the State's climate goals.

In this report, we review current plans for green hydrogen adoption to support California's climate goals, and also discuss potential adverse consequences associated with its proposed deployment. Where there is insufficient information, we outline the key questions that must be addressed to better understand the impacts of these proposals. The questions that guide our report largely fall into two categories:

> 1) What are the *direct* impacts of hydrogen adoption across multiple applications (for example, what are the potential public health hazards of using hydrogen compared to existing fossil fuel use or other clean alternatives?);
>
> 2) What are the *indirect* and *system-level* impacts of proposed hydrogen strategies (for example, how does proposed hydrogen adoption change the required rate of renewable energy deployment in the next twenty years?).

The proposed adoption pathways for green hydrogen vary significantly by plan. For instance:

- The **California Air Resources Board's (CARB) 2022 Scoping Plan for Achieving Carbon Neutrality** allocates the majority of hydrogen to transportation, proposes blending hydrogen into existing natural gas pipelines, and only uses hydrogen in power plants for emergency backup.
- In contrast, the **Los Angeles Department of Water and Power's (LADWP) Strategic Long Term Resource Plan** aims to repower all of its natural gas plants by 2035 to burn hydrogen to meet regular power demand.
- Meanwhile, the federally-funded **Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) hydrogen hub** supports hydrogen use in power plants and for transportation but does not propose blending it into existing natural gas distribution pipelines.

This misalignment exists across all aspects of the proposed green hydrogen system, including where and how it is produced, how it is transported, how it is used, and how soon its adoption will take place. The enactment of conflicting plans by local and state planners raises the risk of energy security and reliability challenges. These challenges emerge when there are numerous local and state planners relying on different end uses for a limited hydrogen supply or who have varying expectations for the renewable energy that might be used to produce it. This lack of coordination may also undermine the ability of local and state planners to meet their climate goals. It could also result in inefficient infrastructure investments and potential stranded assets.

While many of the proposed hydrogen adoption pathways lack the detail to fully evaluate their outcomes, the direct and system-level impacts of each plan can be organized into key categories. These categories, with relevant examples, include:

Climate Change. The climate impacts of hydrogen adoption depend largely upon:

- **How "Green" or "Clean" Hydrogen Is Defined.** Defining hydrogen as "renewable," "green," or "clean" depends largely on the greenhouse gas footprint of the energy source (e.g., biogas, wind energy, grid electricity) used to produce that hydrogen. However, there is no clear consensus for defining what counts as "renewable" in this context, nor for calculating the greenhouse gas footprint of hydrogen production. ARCHES, for example, has supported the use of *existing* renewable energy resources to produce hydrogen. Using existing resources risks increasing greenhouse gas emissions by redirecting energy that might have previously displaced the need for natural gas power generation, causing natural gas use to increase.
- **Indirect Atmospheric Climate Impacts.** Hydrogen is not a greenhouse gas, but it can indirectly contribute to climate change when leaked into the atmosphere by affecting the concentration of other greenhouse gases. This effect means that the global warming potential of hydrogen is roughly 37 times higher than that of carbon dioxide over a 20-year period and about 8–12 times higher over a 100-year period, although these estimates are an active area of study. Unfortunately, hydrogen leakage rates are poorly characterized system-wide and are rarely accounted for when evaluating the climate benefits of hydrogen adoption across California.
- **Deployment Pathways and Alternatives.** The climate impacts of hydrogen adoption depend on which energy source it is displacing, which alternatives might exist for that end-use, and how the energy needed to produce hydrogen might otherwise be used. Examples include:
    - Burning hydrogen at a power plant, as proposed by LADWP, uses roughly two to four times as much energy compared to solar+battery storage (when this alternative is feasible). Producing hydrogen with renewable electricity, transporting it to a power plant, and then burning it is likely less than 35 percent efficient overall, and possibly *much* lower (although very few 100 percent hydrogen turbines are commercially

available, so these values are somewhat speculative). Therefore, using renewable energy and battery storage directly would enable three times as much fossil fuel to be displaced—and displace three times the amount of greenhouse gas emissions.

    - The CARB Scoping Plan proposes to blend hydrogen into natural gas pipelines at a level of 20 percent by volume. However, this blend only displaces a maximum of 6–7 percent of greenhouse gas emissions because hydrogen is less dense than natural gas (a 20 percent hydrogen by volume blend is only 6–7 percent hydrogen on an energy basis), and even less if any hydrogen leaks. If the goal from pipeline blending is to decarbonize home heating, air source heat pumps are a more effective option, as they require roughly one-fifth the renewable electricity as burning hydrogen to heat a home.

Energy System. To reach the state's 2045 climate neutrality targets—which is the goal of the CARB Scoping Plan—California will have to rapidly deploy renewable energy resources such as wind and solar. CARB does not include the energy used to produce hydrogen in their energy resource build estimates, so we incorporate that demand as well. CARB also excludes the energy required for two other key components of their climate mitigation portfolio: direct air capture of carbon dioxide and carbon capture and storage (CCS). Deployed simultaneously, these carbon-mitigation technologies risk competing for a potentially limited supply of renewable resources. We therefore estimate the deployment rates needed to meet the combined demand for all climate mitigation strategies in 2045 to better understand their compounding impact on renewable energy requirements.

- **Scoping Plan Base Case.** CARB estimates that it will need a total of 128 gigawatts (GW) of new renewable energy capacity in 2045. We estimate that this deployment will require *doubling* the historic average annual construction rate of wind and solar and maintaining this build rate *every year until 2045*—which is also an average construction rate equivalent to the maximum renewable energy ever deployed in California in a single year.
- **Scoping Plan Base Case *Plus* Hydrogen.** However, the Scoping Plan's base deployment rate is likely an underestimate; the Scoping Plan does not include the energy required to produce hydrogen or to meet other demands such as the direct air capture of carbon dioxide. Instead, the Scoping Plan states that this demand will be met with "off-grid" solar and, for 36 percent of the hydrogen used in 2045, with biofuels. We estimate that 26–29 GW of off-grid solar would be needed to meet the hydrogen demand under the Scoping Plan. This estimate grows to 41–45 GW if biofuels cannot be scaled up to produce hydrogen, leading to a total of 20–35 percent more renewable capacity that must be built by 2045.
- **Scoping Plan Base Case *Plus* Hydrogen, Direct Air Capture of Carbon Dioxide, and CCS.** Moreover, the energy required for direct air capture in the Scoping Plan would require an additional 73 GW of solar; the energy required for CCS would add another 10 GW. Altogether, these combine to approximately 250 GW of new renewables by 2045, *which would require nearly quadrupling California's historic average annual renewable energy deployment rate.*

- **Scoping Plan Base Case *Plus* Hydrogen, Direct Air Capture, and Hydrogen in Place of CCS.** The California Energy Commission has explored an additional contingency in which the remaining natural gas plants in CARB's Scoping Plan all burn hydrogen in 2045. This contingency, combined with the above requirements, could require up to *4.3 times the historic average annual growth of renewables.* This level of renewable energy deployment is ambitious for all scenarios, and highlights the competing demands for renewable energy resources to simultaneously meet numerous proposed demands in 2045, including renewable energy targets in the power sector, hydrogen production, and direct air capture.

Public Health and Equity. The public health hazards of hydrogen vary by application, and have significant equity implications. Currently, fossil energy production, transmission, and use are the largest sources of criteria air pollutants, toxic air contaminants, and other health damaging air pollutants of any sector in California. Low-income communities and communities of color are disproportionately exposed to these emissions. As such, the deployment of hydrogen to displace fossil energy holds multiple potential equity implications, both positive and negative. These impacts depend, in part, on the hydrogen technology used:

- **Fuel Cells.** Hydrogen applications that displace fossil fuel combustion, such as running heavy-duty trucks on hydrogen fuel cells rather than diesel fuel, have the potential to reduce criteria air pollutant and toxic air contaminant emissions and thus provide public health benefits, particularly in environmentally overburdened communities such as those next to freeways.
- **Combustion of Hydrogen.** However, *burning* hydrogen (rather than using a fuel cell) produces nitrogen oxides (NO_x), similar to burning natural gas. Exposure to nitrogen dioxide (NO_2), is associated with respiratory health impacts and contributes to the atmospheric formation of secondary air pollutants, most notably tropospheric ozone and particulate matter. Burning hydrogen in residential gas appliances and at natural gas power plants risks perpetuating these emissions, including in California's designated disadvantaged communities, because natural gas plants are disproportionately located near these communities.

Safety. The production, transport, and use of hydrogen, like any combustible fuel, entail safety risks for those working with hydrogen infrastructure or living nearby. These risks may be elevated for certain applications. For example, blending hydrogen into natural gas pipelines often requires operating pipelines at higher pressures, and hydrogen-natural gas blends at these higher pressures have been shown to leak from pipelines at higher rates than natural gas alone. Hydrogen also risks embrittling pipelines, leading to an increased risk of failure in the long term. Mitigating such risks would require dedicated monitoring and maintenance, including tailored interventions to protect potentially vulnerable populations such as multilingual emergency communication plans reflecting local community needs, all of which would likely require ongoing sources of funding.

Costs. We did not analyze the full costs of hydrogen deployment in California, but we identified a number of considerations as to how cost and risk should be incorporated into planning. These include:

- **Stranded Assets.** There is a risk of creating stranded assets if hydrogen infrastructure is built but not used. This has already occurred for light-duty vehicle hydrogen fuel stations, which outpaced demand and some of which have been taken offline.
- **Uncertain Hydrogen Supply and Transport.** Many plans do not have a well-defined supply of hydrogen, leading to energy insecurity risks if production, transport, and storage infrastructure are not built in line with demand. For example, LADWP aims to begin repowering gas plants with hydrogen beginning with the Scattergood Generating Station in 2029, but the proposed Angeles Link hydrogen pipeline to provide hydrogen to Los Angeles does not have an identified production source, route, or permitting; there is also minimal if any existing hydrogen trucking and storage infrastructure. These unknowns may lead to significant delivery and price volatility risks, as well as a wide range of uncertainty about how infrastructure costs could affect hydrogen supply costs and how these costs could be passed on to ratepayers.
- **Opportunity Costs.** Investment in hydrogen infrastructure, or in renewable energy supply to produce hydrogen, should be compared to alternative decarbonization pathways. Many proposed plans do not include a full quantification of hydrogen production, transport, and delivery costs, so the relative costs of hydrogen pathways compared to other pathways to meet decarbonization goals have not been fully explored.

Environment. A comprehensive accounting of the environmental impacts of hydrogen use would require a full lifecycle analysis, including the potential impacts of the energy sources used to produce hydrogen. A full lifecycle analysis of proposed hydrogen pathways is beyond the scope of this report; however, we do highlight particularly salient considerations. For example, hydrogen produced from dairy biogas may have associated environmental impacts due to dairy waste management, which can affect air, water, and soil quality. Using biomass to produce hydrogen has a wide range of potential impacts, from the benefits of using woody debris that might otherwise burn in wildfires to the public health consequences associated with trucking biomass potentially long distances across the state to hydrogen production sites. The siting of solar and wind to produce hydrogen also holds implications for land use and biological diversity. Additionally, electrolytic hydrogen production requires splitting water, which may face supply constraints in certain areas of California, particularly in more arid or overdrawn regions. For example, the Angeles Link pipeline is considering siting hydrogen production facilities in the Central Valley, the Mojave Desert, and near Blythe. The first has significant competing water demands while the latter two are in the desert with limited water resources.

Feasibility. Many of the above considerations affect not only the societal costs and benefits, but also the overall feasibility of using “green” hydrogen to meet decarbonization goals. For example, the required rapid deployment of renewable energy resources and hydrogen infrastructure buildout to meet the goals and targets in various plans for hydrogen in California may run into several barriers.

These include access to capital and finance, workforce training, supply chain scaling, and permitting. Moreover, multiple competing demands for hydrogen might undermine the ability of any individual organization or agency to achieve its hydrogen goals and associated climate targets. Additionally, a lack of coordinated prioritization around the many needs for renewable electricity—including direct use, hydrogen production, carbon capture and storage, and direct air capture—may lead to an inefficient build-out of energy resources.

Before rapidly expanding hydrogen infrastructure, we recommend that planners and decision-makers better characterize the impacts, both positive and negative, of hydrogen deployment scenarios and alternatives. This assessment will require a more comprehensive analysis of hydrogen production, transport, and use for proposed applications, including resolving the many outstanding unknowns and uncertainties, and may require the development of contingency plans should proposed deployments prove infeasible. We also make the following recommendations:

1. Develop stringent, consistent definitions for “green” or “clean” hydrogen to ensure that hydrogen adoption provides verifiable additional climate benefits with minimal environmental impacts.
2. Improve interagency coordination on hydrogen planning to ensure competing goals and demands do not lead to system inefficiencies or undermine the State’s ability to meet decarbonization targets.
3. Better characterize hydrogen leakage rates and pipeline safety risks before committing to hydrogen infrastructure expansion; ensure sufficient safety measures are built into hydrogen deployment, including ongoing funding for monitoring and maintenance.
4. Address equity concerns throughout hydrogen planning processes, including ongoing meaningful community engagement and incorporation of equity considerations when addressing public health and safety concerns.
5. Consider the system-level and lifecycle impacts of hydrogen production and use—including potential cost, public health, equity, environmental, and climate implications—within policy planning.
6. Evaluate alternative technologies and deployment scenarios and each scenario’s sensitivity to techno-economic assumptions.
7. Avoid hydrogen pipeline blending due to minimal potential climate benefit and possible safety risks.
8. Fill outstanding research gaps to address unknowns. A primary example includes the need to comprehensively model energy demand to better understand and optimize combined renewable energy requirements in the power sector, for hydrogen production, and to power the direct air capture of carbon dioxide.

While decision-makers are keen to push forward with hydrogen, setting strict standards for what constitutes “clean,” addressing critical unknowns, and ensuring alignment across decarbonization solutions and pathways will be critical to successfully achieving California’s climate goals.

1. Introduction

1.1 Goals of This Report

Local and state governments across California have set ambitious goals to mitigate greenhouse gas emissions in the coming decades. These efforts range from city-level climate action plans to the State's overarching 2045 target of reducing total greenhouse gas emissions by 85 percent from 1990 levels, and offsetting the rest through carbon removal strategies to achieve statewide *carbon neutrality*.[1] With targets set, officials are now determining *how* to achieve rapid emissions reductions. In different planning arenas, one fuel has gained significant new traction in recent proposals: hydrogen.

The goal of this report is to investigate the opportunities, challenges, and risks associated with existing proposals to scale hydrogen in California. To do this, we examine the role of hydrogen within several proposed energy transition plans in California, including those from the California Air Resources Board (CARB), from the Los Angeles Department of Water and Power (LADWP), and from the Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) hydrogen hub. We then analyze the implications of using hydrogen across a broad range of proposed applications, with a particular emphasis on the energy inputs required to produce hydrogen and the climate, environmental, and public health dimensions associated with its production and use. Based on this analysis, we identify potential impacts, knowledge gaps, and key points of misalignment between existing plans, of which there are many.

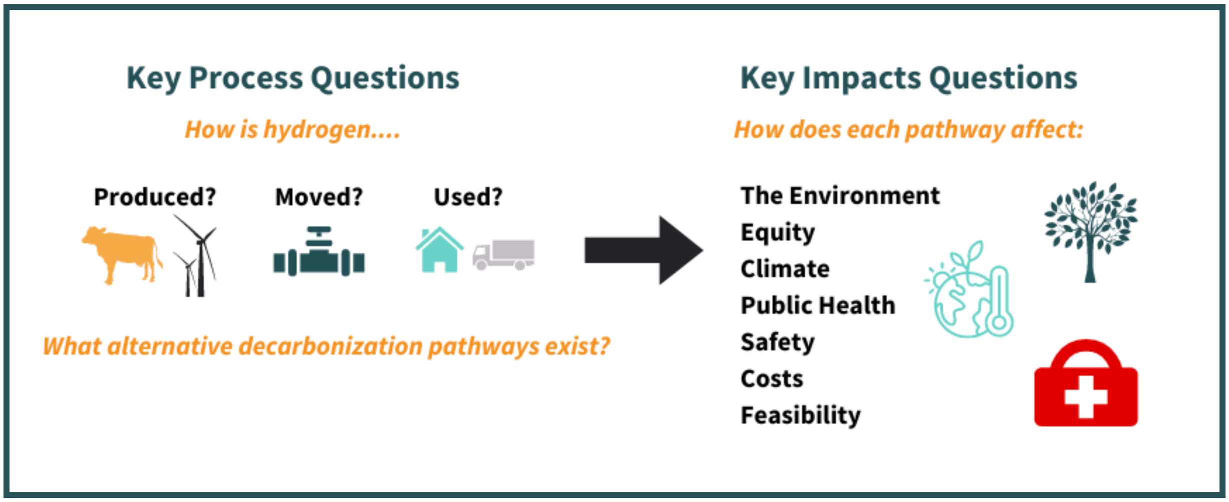
To identify these potential benefits, consequences, and uncertainties, we explored questions related to the key steps for incorporating hydrogen into our energy system. We also asked questions about the outputs of these process-related inquiries, focusing on the impacts both within and outside of the energy system.

Key questions to fully characterize proposed hydrogen use include (**Figure 1.1**):

- How is hydrogen produced (e.g., from solar power or biofuels) and transported?
- What application will it be used for (e.g., in transportation, power plants, or industry)?
- Are there *alternative* non-hydrogen pathways to meet climate goals that may have lower impacts or may be easier to achieve?

[1] As directed in Assembly Bill 1279, the California Climate Crisis Act. (2022).

Figure 1.1: Key Questions for Assessing Hydrogen Proposals. These questions focus on the process of generating, transporting, and using hydrogen; the impacts of these various processes; and what alternative pathways may be worth considering.



Key impact questions include:

- What are the potential environmental impacts of hydrogen production and use?
- What are the public health and safety risks? What equity concerns might arise?
- What are the climate benefits or concerns, including the climate impacts of hydrogen leakage?[2]
- How quickly and how feasibly can hydrogen production scale up to meet the proposed level of deployment and what would this cost?[3]
- How do these challenges, impacts, or benefits compare to alternative pathways to achieve the same climate goals, if such pathways exist?

In this report, we primarily focus on approaches that are under active consideration within the state of California,[4] noting that exploring every possible pathway to produce and use hydrogen across California is beyond our scope. We exclude a thorough analysis of so-called "gray hydrogen" (produced directly from natural gas, and the primary means of production today across the globe) and of "blue hydrogen" (gray hydrogen equipped with carbon capture and storage) because California's policies primarily focus on "green" or "clean" hydrogen produced from renewable or low-carbon

[2] Leakage of hydrogen into the atmosphere can cause indirect climate change impacts because it can affect concentrations of other climate pollutants, such as methane, ozone, and water vapor.
[3] We do not explore cost in detail in this report, but highlight it here as one key dimension for assessing hydrogen plan feasibility.
[4] Nevertheless, the decisions made within the state also hold the potential to set a precedent and impact policies and pathways adopted across the U.S.

energy (see **Table 2.1** below). However, there are numerous proposed definitions of “green” and “clean,” some of which may have much larger greenhouse gas impacts than their proponents claim (see **Section 5.2**). These include approaches that propose using grid electricity (e.g., electricity produced from gas plants) and “offsetting” the carbon footprint of that electricity with renewable energy credits purchased from other sources. We also omit proposals such as the use of green hydrogen to support oil and gas production, which is prohibited in most California initiatives.

We also strive to examine some of the *systems-level* considerations associated with hydrogen deployment in order to better understand the effects of existing plans in aggregate and their interaction with other decarbonization strategies. As part of this analysis, we identify competing demands for renewable energy resources as a particularly important consideration. Because this tension arises, for example, in CARB’s heavy reliance on both green hydrogen and the direct air capture (DAC) of carbon dioxide (CO_2) to achieve 2045 greenhouse gas targets—both would require significant energy inputs—we provide dedicated space in this report to address DAC and carbon capture and sequestration (CCS). We examine how this systems-level analysis implies a very large total statewide demand for renewable energy and an accelerated build rate—a challenge which likely requires integrated planning, and would not be as apparent if each technology proposal were examined individually.

Given that many of the current proposals do not detail full pathways to hydrogen production and use, many aspects within our analysis remain uncertain. Throughout this report, we also highlight the unknowns that still need to be addressed in order to better characterize the impacts of hydrogen adoption in California.

1.2 Outline of This Report

This report aims to highlight a number of key issues related to hydrogen production and deployment to achieve California’s climate goals. In **Section 2** we provide a brief summary of some of the primary proposals for hydrogen adoption across California, including those from CARB, LADWP, and ARCHES. In **Section 3**, we evaluate the energy resource requirements needed to produce hydrogen from various sources, including renewable electricity, biomass, and biogas, and calculate the energy efficiency of each pathway. We compare this input energy demand to using renewable electricity to directly meet end-use demand, including in the power sector, for transportation, and for heating. We also briefly discuss considerations for different biofuel sources and water requirements for hydrogen production. In **Section 4**, we examine the renewable electricity, biomass, and biogas deployment levels that would be required to meet the level of 2045 hydrogen demand identified in the CARB Scoping Plan (2022a); we also examine the combined system-level energy requirements to meet both hydrogen and direct air capture energy requirements under the Scoping Plan. In **Section 5,** we discuss the climate considerations associated with hydrogen production and use, including both the indirect atmospheric impacts of hydrogen leaks as well as the climate considerations associated with the opportunity cost of using renewable energy to produce hydrogen rather than directly displace fossil fuels. **Section 6** examines public health and equity considerations, in particular related to emissions of nitrogen oxides (NO_x) associated with hydrogen combustion, including the risk of ongoing pollutant emissions in state-defined "disadvantaged communities." **Section 7** provides a deep dive on LADWP's proposed hydrogen repower of the Scattergood Generating Station, including the lack of existing green hydrogen infrastructure. Finally, **Section 8** outlines key policy considerations and trade-offs between decarbonization pathways, and summarizes our findings, recommendations, and outstanding uncertainties related to hydrogen deployment.

2. Overview of the Hydrogen Landscape in California

Proposals to use hydrogen to meet California's climate goals have been advanced by both direct and indirect policies and programmatic goals, as well as by various stakeholder groups throughout the state. Direct funding, incentives, and initiatives include, but are not limited to 1) federal funding for hydrogen hubs, 2) state-level incentives from the California Energy Commission (CEC) for hydrogen pilot projects, and 3) plans by LADWP to repower its gas plants with hydrogen (U.S. Department of Energy [DOE], n.d.-a; CEC, 2022; LADWP, 2022a). Indirect policies and programs include not only overarching state goals, such as the 2045 climate targets outlined above, but also zero emission vehicle programs, low carbon fuel standards for cars, and other technology-agnostic measures for which hydrogen is being proposed. A partial list of these proposals is included in **Table 2.1**.

Table 2.1. Partial List of Hydrogen Incentives, Programs, and Deployment Plans in California

Examples of Hydrogen Incentives, Programs, and Plans in California						
	Region	**Lead Agency**	**Name**	**Description**	**Status (2024)**	**Hydrogen Greenhouse Gas or Energy Requirement**
Programs and Incentives	Federal	Internal Revenue Service	45 V Tax Credit[5]	Tax credit for clean hydrogen (H_2) production	Rule proposed in 2023	< 4 kg CO_2e per kg H_2 (incentive increases as CO_2e declines)[6]
	Federal	U.S. Department of Energy	Clean Hydrogen Hub Program	Up to $1.2 B awarded to CA for the Alliance for Renewable Clean Hydrogen Energy Systems[7]	Awarded in 2023	< 4 kg CO_2e per kg H_2 (incentive increases as CO_2e declines)
	State	California Energy Commission	Clean Hydrogen Program	$100 M in incentives for H_2 production and use	Allocated by AB 209 in 2022[8]	H_2 derived from Renewables Portfolio Standard-eligible sources
	State	California Air Resources Board	Low Carbon Fuel Standard (LCFS)	Provides LCFS credits for hydrogen used in various transportation applications	Ongoing	Credits vary by application according to CARB guidelines, including natural gas-produced hydrogen offset with biomethane CCS[9,10]
	State	California Energy	Clean Transportation	Supports zero emission vehicle infrastructure	Ongoing	33+ or 40+ percent renewable hydrogen, depending on installation year;[11] currently follows LCFS

[5] Federal Register (2023). Section 45v Credit For Production Of Clean Hydrogen; Section 48(A)(15) Election To Treat Clean Hydrogen Production Facilities As Energy Property. Proposed Rule by the Internal Revenue Service.

[6] CO_2e = carbon dioxide equivalent

[7] ARCHES. (2023). California Awarded Up to $1.2 Billion to Advance Hydrogen Roadmap and Meet Climate and Clean Energy Goals.

[8] California Energy Commission. (2022). Staff Workshop on the Implementation of the Clean Hydrogen Program.

[9] Projects with a minimum of 40 percent "renewable" hydrogen qualify for LCFS credits. "Renewable" includes hydrogen produced directly from natural gas and "offset" through carbon capture of biomethane through "book and claim." Source: California Energy Commission. (2024, March 11). 023-2024 Investment Plan Update for the Clean Transportation Program. Docket No. 28-ALT-01, 57.

[10] California Air Resources Board. Retrieved on March 1, 2024. LCFS Electricity and Hydrogen Provisions.

[11] California Energy Commission. (2024, March 11). 2023-2024 Investment Plan Update for the Clean Transportation Program. Docket No. 23-ALT-01, 57.

		Commission	Program	deployment, including H_2 fueling stations		
Plans	State	California Air Resources Board	2022 Scoping Plan for Achieving Carbon Neutrality[12]	Includes H_2 in portfolio to meet state's 2045 carbon neutrality goals	Final; updated every five years	Electrolytic H_2 from renewable energy and biogenic H_2 from biomass gasification with CCS and steam methane reforming of biogas
	State	California Energy Commission	2023 Integrated Energy Policy Report (IEPR)[13]	Assesses use of hydrogen in power and transportation sectors	Draft; full update every two years	Electrolytic hydrogen from renewable energy[14]
	Los Angeles	Los Angeles Department of Water and Power	Strategic Long Term Resource Plan (SLTRP)[15]	Assumes five gas power plants will be repowered to burn H_2 by 2035	2022; updated every two years	Likely alignment with federal tax incentive guidelines

[12] California Air Resources Board. (2022). 2022 Scoping Plan Documents.
[13] California Energy Commission. (2023). 2023 Integrated Energy Policy Report.
[14] Will consider biogenic hydrogen in the next iteration.
[15] Los Angeles Department of Water and Power. (2022). 2022 Power Strategic Long-Term Resource Plan.

In this report, we provide additional details on three of these hydrogen plans and initiatives below:

1. The California Air Resources Board Scoping Plan for Achieving Carbon Neutrality;
2. The federally-supported hydrogen hub Alliance for Renewable Clean Hydrogen Energy Systems;
3. The Los Angeles Department of Water and Power's Strategic Long-Term Resource Plan (SLTRP).

Notably, the proposals for hydrogen use by different agencies and regions frequently do not align. For example, the Scoping Plan only relies on hydrogen use in power plants as an emergency backup to ensure reliability in 2045, whereas ARCHES considers power plants to be a primary application for hydrogen; and LADWP aims to begin repowering its gas plants to run on hydrogen in 2029. Moreover, there is a lack of alignment between these plans and initiatives regarding what should be considered "clean" or "green" hydrogen (as evidenced in **Table 2.1**), including how various biofuels are incorporated and whether renewable energy generation should be co-located with hydrogen production. These different definitions are addressed further in **Section 5.2**.

CARB 2022 Scoping Plan for Achieving Carbon Neutrality. Under California's Global Warming Solutions Act (AB 32, 2006), CARB is required to release a Scoping Plan every five years outlining a plan for the state to achieve its economy-wide greenhouse gas targets (CARB, 2022b). CARB's 2022 Scoping Plan Scenario includes a 1,700-fold increase in renewable hydrogen production by 2045, totaling 0.23 exajoules (EJ).[16] This amount is equivalent to about nine percent of the Scoping Plan's projected total 2045 energy demand,[17] excluding the energy required to power direct air capture or to produce the hydrogen itself, which are not included in CARB's energy demand projections. According to the Scoping Plan, 87 percent of this hydrogen is allocated to the transportation sector, eight percent to industry, and the remainder to the commercial and residential sectors as well as for oil and gas production and refining, as detailed in **Section 4.1**. CARB assumes that 9.3 gigawatts (GW) of hydrogen-burning combustion turbine power plants will be built by 2045, but *no actual hydrogen fuel* is allocated to the power sector as these plants are only intended to be available for reliability (CARB, 2022c).[18] However, the Scoping Plan does include hydrogen blended into existing gas pipelines serving buildings and industry. The hydrogen itself is produced using multiple energy sources: renewable electricity resources such as wind and solar (the electricity is used to split water and produce hydrogen via electrolysis); biogas (via steam methane reforming); and biomass (via gasification). The energy

[16] 0.23 exajoules of hydrogen is equivalent to ~1.9 million metric tons (MMT) of hydrogen.
[17] The Scoping Plan projects that California's total economy-wide energy demand in 2045 will actually be about *half* of today's due to energy efficiency savings, including through electrification.
[18] The Scoping Plan documentation includes the build-out of hydrogen-burning power plants, but no fuel is allocated to the power sector. Private communication with CARB staff indicated that these plants are not used in modeled everyday power generation, but only added to provide reliability in the case of an emergency. However, it is unlikely that in practice these plants would be built and yet burn no fuel; at a minimum, they would burn hydrogen when an emergency situation does inevitably arise. It is unclear what the relative cost of these plants is compared to alternative approaches to meet emergency peak demand, including demand response.

inputs required to produce hydrogen via each of these methods are detailed in **Section 3.1**. The Scoping Plan also aims for the State to achieve carbon neutrality in part through the direct air capture of CO_2, which itself requires a significant energy input. In **Section 4** we examine how much energy is required to both produce hydrogen *and* power direct air capture as outlined in the Scoping Plan, as well as what this combined resource build implies for the required deployment rates of renewable resources such as wind and solar. We also look at additional sensitivity to a 2045 scenario developed by the California Energy Commission in its 2023 Integrated Energy Policy Report (IEPR) in which hydrogen is burned at power plants in lieu of the natural gas currently used in the Scoping Plan.

Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES). ARCHES is a public-private partnership that was allocated up to $1.2 billion in 2023 by the U.S. Department of Energy to serve as a hydrogen hub under the Clean Hydrogen Hub Program. The program is funded by the 2021 Bipartisan Infrastructure Law to coordinate regional support for clean hydrogen development (DOE, n.d.-a). ARCHES is initially focusing on projects using hydrogen in medium- and heavy-duty transportation, ports, and power plants, which in the latter case could include both fuel cells and hydrogen combustion (ARCHES, n.d.). Unlike the CARB Scoping Plan, ARCHES is not pursuing the blending of hydrogen in gas pipelines. ARCHES aims to use hydrogen produced from renewable energy and biomass resources, although it explicitly excludes dairy biogas and fossil-generated hydrogen offset with biomethane credits (unlike the low carbon fuel standard (LCFS), as discussed in **Table 2.1** and **Section 5.2**) (DOE, n.d.-a). However, ARCHES has written to the Internal Revenue Service that it believes clean hydrogen incentives 1) should not have explicit requirements to ensure that the renewable energy powering hydrogen production is *additional* compared to existing renewable resources, 2) nor should the renewable power be required to be located in the same region as the hydrogen production, 3) nor should hydrogen producers be required to have hourly matching of its energy use with actual hourly renewable energy production (see **Section 5.2**) (Galiteva et al., 2023). University of California faculty have expressed concern that non-adherence to such requirements might actually increase greenhouse gas emissions in California (UC Berkeley Faculty, 2023).

LADWP Strategic Long-Term Resource Plan. LADWP undertakes a periodic planning exercise, the SLTRP, to ensure that there is sufficient capacity on its grid to meet the demand for energy and power across Los Angeles while simultaneously meeting climate and clean energy goals. The mayor's office and city council in Los Angeles have set goals to achieve 100 percent carbon-free electricity by 2035 (LADWP, 2021, 2022b). Simultaneously, three of LADWP's four in-basin gas-fired power plants are required by the state to retire because they rely on once-through cooling using ocean water, which can harm marine life (California State Water Resources Control Board [State Water Board], 2023a). In light of these goals, and taking into account modeling done under the LA100 Study conducted by the National Renewable Energy Laboratory (NREL), the 2022 SLTRP proposes burning hydrogen at new units at all four of LADWP's in-basin gas plants by 2035 (NREL, 2021). It also relies on burning hydrogen at Utah's Intermountain Power Project, from which LADWP imports power. LADWP plans to first build and deploy new hydrogen-burning combustion turbine units at the Scattergood Generating Station in

2029 (see **Section 7**), followed by units at the Harbor, Haynes, and Valley Generating Stations. These are planned to total 2.1 GW[19] by 2035 (notably, this is more than half of the 4.06 GW of hydrogen combustion turbines that CARB expects to have available *statewide* in 2035, and none of CARB's proposed plants are expected to be used except as backup). The SLTRP does not specify *how* the hydrogen will be produced, although it does suggest that all of it will have to comply with federal clean hydrogen tax incentive requirements for carbon dioxide equivalent (CO_2e) emissions (see **Table 2.1**). It also does not specify *where* the hydrogen will be produced. In parallel, Southern California Gas Co. (SoCalGas) is proposing to build the Angeles Link pipeline to deliver hydrogen produced from renewable energy to Los Angeles from outside the LA Basin, but it also does not specify the energy resources nor the specific location where the hydrogen would be produced (SoCalGas, 2022a). SoCalGas estimates that hydrogen demand in its territory, which Angeles Link would supply, would reach 1.9–6 million tons per year of hydrogen in 2045 (SoCalGas, 2024). This is equivalent to 0.27–0.86 EJ and more than the Scoping Plan projects for the entire state.

These three plans are just some of those being pursued in California, but illustrate the array of hydrogen applications, production sources, and rates of deployment under consideration in different jurisdictions.

3. Background on Proposed Hydrogen Production and Use

The global hydrogen supply today is primarily produced from fossil fuels.[20] In the United States, 95 percent of hydrogen is produced via steam methane reforming (SMR) of natural gas (Hydrogen and Fuel Cell Technologies Office, n.d.). However, because fossil fuel-derived hydrogen is associated with significant greenhouse gas emissions, proposals to expand hydrogen use in California primarily consider "green" hydrogen options. These proposals include hydrogen produced from water using renewable electricity (via a process called electrolysis, which splits water into hydrogen and oxygen) and hydrogen derived from biofuels, such as biomethane from dairy farms (via steam methane reforming) and wood waste from forest management activities (via biomass gasification).

Since hydrogen is generated from other energy sources, producing and using it results in energy losses associated with inefficiencies in every energy conversion process. The overall efficiency of substituting hydrogen into existing systems depends on the technologies used to produce and compress it, how it is stored and transported, any potential leakage throughout the hydrogen system, and its final application.

[19] This is lower than today's in-basin gas plant capacity.
[20] There is a growing interest in the possibility of mining naturally-occuring hydrogen from underground geologic formations, but this source is novel and there remain many unanswered questions about its potential. For more on the potential lifecycle greenhouse gas impacts of mining hydrogen, including sensitivity to the methane fraction in the fuel source, see Brandt (2023).

In the following sections, we first review the efficiency of various hydrogen production, storage, and transport pathways. Next, we evaluate the efficiency of various applications for hydrogen, such as burning hydrogen at power plants to produce electricity. We then apply these efficiencies to the Scoping Plan in **Section 4** to better understand how much California would have to expand its renewable energy capacity (or, in some scenarios, biomass usage) in order to have enough energy to meet the Scoping Plan's hydrogen goals.

3.1 Energy Efficiency of Proposed Hydrogen Production, Storage, and Transport Methods

California stakeholders are considering three main methods for producing "green" hydrogen: electrolysis, biomass gasification with carbon capture and storage, and steam methane reforming of biogas. Each method requires different energy inputs, has different process efficiencies, and incurs different environmental and climate hazards, risks, and impacts. We discuss climate impacts and additional environmental and human health considerations in **Section 5** and **Section 6,** respectively.

Proposed Hydrogen Production Methods in California

Electrolysis relies on running electricity through an electrolyzer to split water into its component parts—hydrogen and oxygen. This process has a very low CO_2 footprint if the electricity used to make and compress the hydrogen is generated from renewable sources and if hydrogen is transported to where it will be used without incurring additional carbon emissions.

Biomass gasification uses high temperatures and a gasification agent, such as oxygen or steam, to convert biomass, such as wood waste, into hydrogen, carbon monoxide, CO_2, and other trace elements. A water-gas shift reaction then uses additional water to convert the carbon monoxide into hydrogen and CO_2. The resulting gas is then upgraded, cleaned, and separated using a combination of scrubbers and filters to remove unwanted elements and a pressure swing adsorption process to recover high-purity hydrogen that would otherwise be lost in the waste stream (International Energy Agency Bioenergy, 2018).

Steam methane reforming uses high temperatures and steam to convert methane into hydrogen and carbon monoxide, then employs a water-gas shift to produce additional hydrogen, and a pressure swing adsorption process to capture hydrogen that would have been lost in the waste stream. This process requires gas with a high concentration of methane (e.g., biomethane (CH_4)), rather than biogas, which typically contains some CO_2 and other trace gases in addition to methane. To create biomethane, biogas is collected from dairy farms, landfills, or other sources and purified by removing CO_2, water, hydrogen sulfide, and other elements. This purified biomethane can then be used to create hydrogen, or blended with or used in place of natural gas (NREL, 2016).

Hydrogen transport and storage methods also influence the total efficiency of using hydrogen. Some of the most critical factors are whether the hydrogen is stored as a gas or liquid and, if required, how the hydrogen is transported to its final end use. Efficiency ranges for different steps in the hydrogen production process are outlined in **Table 3.1**.

Table 3.1. Efficiencies of Hydrogen Production and Delivery Process Steps. Given the limited deployment and rapidly changing technological maturity of these technologies, many of the estimates below are uncertain or based on modeling results rather than *in-situ* measurements. Additionally, the efficiency of transporting hydrogen fuel sources (e.g., water and biofuels) before hydrogen generation is not included in this table. These factors will have an impact on the overall efficiency of using hydrogen. Additionally, not all methods for producing, compressing, storing, and transporting hydrogen are included in the table.

Efficiencies of Hydrogen Production and Delivery Process Steps				
Process Step		**Efficiency Range**[21]	**Description**	**Source**
Production	Alkaline electrolysis	60–80%	A widely commercialized, well-known technology. Least expensive of existing electrolysis options. Operates between 20–80°C and outputs hydrogen at 3–200 bar.	22, 23, 24, 25, 26, 27, 28
	Proton exchange membrane (PEM) electrolysis	60–85%	A newer electrolysis technology. More flexible than alkaline electrolyzers but higher cost, in part because electrolyzer membranes use noble metals. Operates at 20-200°C and outputs hydrogen at 10–200 bar.	
	Solid oxide electrolysis	74–97%	Still in the research and testing phase. High efficiency, high temperature electrolysis that operates at 500–1,000°C and outputs hydrogen at 10–60 bar.	

[21] Efficiency ranges are reported in lower heating value (LHV).
[22] Amores et al. (2021). Renewable hydrogen production by water electrolysis. *Sustainable Fuel Technologies Handbook.*
[23] Alptekin, F.M., & Celiktas, M.S. (2022). Review on Catalytic Biomass Gasification for Hydrogen Production as a Sustainable Energy Form and Social, Technological, Economic, Environmental, and Political Analysis of Catalysts. *American Chemical Society*, *7*(29), 24918-24941.
[24] Pashchenko, D. (2024). Green Hydrogen as a power plant fuel: What is energy efficiency from production to utilization? *Renewable Energy*, *223*, 120033.
[25] Deloitte. (2023). Green Hydrogen: Energizing the Path to Net Zero. Figure 26 Hydrogen production technology cost data.
[26] International Energy Agency. (2019). The Future of Hydrogen.
[27] DeSantis, D., James, B., & Saur, G. (2019). Current (2015) Hydrogen Production from Distributed Grid PEM Electrolysis. National Renewable Energy Laboratory.
[28] International Energy Agency. (2023). ETP Clean Energy Technology Guide.

	Gasification *(of biomass)*	30–60%	Total process efficiencies depend on the type of biomass, its moisture content, the gasification agent, whether heat is supplied externally or by combusting some of the existing biomass, the gasification reactor design, the gas cleaning methods, and the required hydrogen purity levels. Gasification also uses some natural gas and electricity. Efficiency reported here does not include carbon capture and storage (CCS).	[29, 30, 31, 32]
	Steam methane reforming *(of biomethane)*	74–85%	Reported efficiency does not include upgrading biofuels to the higher purity biomethane that is used to generate hydrogen. Including biogas upgrading drops the efficiency to 64–74 percent, as this process is estimated to be roughly 87 percent efficient. The efficiency of upgrading other biofuels (e.g., animal waste, wastewater sludge, etc.) to biomethane depends on the specific fuel.	[33, 34, 35]
Compression & Storage	Compression *(gaseous H_2 stored in pressurized*	80–97%	Energy requirements and process efficiency depend on starting pressure and desired storage pressure (larger increases in pressure require more energy). Energy required for compression is not linear with increasing pressures; for pressures greater than 700 bar, energy required increases exponentially. Many sources indicate a 90–97 percent efficiency	[36, 37, 38, 39, 40, 41, 42]

[29] Alptekin, F.M., & Celiktas, M.S. (2022). Review on Catalytic Biomass Gasification for Hydrogen Production as a Sustainable Energy Form and Social, Technological, Economic, Environmental, and Political Analysis of Catalysts. *American Chemical Society Omega*, *7*(29), 24918-24941.
[30] Elgowainy et al. (2022). Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production. Argonne National Laboratory.
[31] Mann, M., & Steward, D. M. (2018). Current Central Hydrogen from Biomass via Gasification and Catalytic Steam Reforming. National Renewable Energy Laboratory.
[32] Zhou et al. (2021). Life-Cycle Greenhouse Gas Emissions of Biomethane and Hydrogen Pathways in the European Union. International Council on Clean Transportation.
[33] Ibid.
[34] Wang et al. (2022). Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model Ⓡ (2022 Excel). Argonne National Laboratory.
[35] Saur, G., & Milbrandt, A. (2014). Renewable Hydrogen Potential from Biogas in the United States. National Renewable Energy Laboratory.
[36] Elgowainy et al. (2022). Hydrogen Life-Cycle Analysis in Support of Clean Hydrogen Production. Argonne National Laboratory.
[37] Wang et al. (2022). Greenhouse gases, Regulated Emissions, and Energy use in Technologies Model Ⓡ (2022 Excel). Argonne National Laboratory.
[38] Pashchenko, D. (2024). Green hydrogen as a power plant fuel: What is energy efficiency from production to utilization? *Renewable Energy*, *223*, 120033.
[39] Ghorbani et al. (2023). Hydrogen storage in North America: Status, prospects, and challenges. *Journal of Environmental Chemical Engineering*, *11*(3), 109957.
[40] Kayfeci, M., & Kecebas, A. (2019). Chapter 4 - Hydrogen storage. *Solar Hydrogen Production Processes, Systems and Technologies*, 85-110.
[41] Noh et al. (2023). Environmental and energy efficiency assessments of offshore hydrogen supply chains utilizing compressed gaseous hydrogen, liquefied hydrogen, liquid organic hydrogen carriers and ammonia. *International Journal of Hydrogen Energy*, *48*(20), 7515-7532.
[42] Tarhan, C., & Cil, M. A. (2021). A study on hydrogen, the clean energy of the future: Hydrogen storage methods. *Journal of Energy Storage*, *40*, 102676.

	cylinders)		range for compression up to 880 bar, though Kayfeci & Kecebas (2019) suggest that up to 20 percent of hydrogen's energy content may have to be used for compression at fuel stations.	
	Liquefaction *(liquid H_2 stored in low-temperature storage tanks)*	60–72%	Energy intensive and incurs boil-off losses. Liquefaction efficiency depends on process scale, with smaller operations showing lower efficiencies. Liquid hydrogen also suffers boil-off losses of 0.1–4 percent per day, with higher losses from smaller tanks. The efficiency of storing liquid hydrogen depends on the storage vessel size, insulation, pressure, and cooling as well as the length of storage time. Cryo-compressed storage, which uses cryogenic temperatures and high pressure, can also decrease boil-off losses.	43, 44, 45, 46, 47, 48, 49, 50
	Geological storage *(low-pressure, gaseous H_2*	78–92%*	Hydrogen can be stored in salt caverns, depleted oil and gas wells, aquifers, caverns, and similar underground sites. The efficiency of geological storage is influenced by the physical and chemical characteristics of the storage medium, with different operational requirements dictating the required amount of compression, recovery ratios, amounts of	51, 52, 53 , 54, 55

[43] Kurz et al. (2022). Chapter 6: Transport and Storage. *Machinery and Energy Systems for the Hydrogen Economy*, 218.
[44] Pashchenko, D. (2024). Green hydrogen as a power plant fuel: What is energy efficiency from production to utilization? *Renewable Energy*, *223*, 120033.
[45] Ghorbani et al. (2023). Hydrogen storage in North America: Status, prospects, and challenges. *Journal of Environmental Chemical Engineering*, *11*(3), 109957.
[46] Kayfeci, M. & Kecebas, A. (2019). Chapter 4 - Hydrogen storage. *Solar Hydrogen Production Processes, Systems and Technologies*, 85-110.
[47] Barthelemy et al. (2017). Hydrogen storage: Recent improvements and industrial perspectives. *International Journal of Hydrogen Energy*, *42*(11), 7254-7262.
[48] Morales-Ospino et al. (2023). Strategies to recover and minimize boil-off losses during liquid hydrogen storage. *Renewable and Sustainable Energy Reviews*, *182*, 113360.
[49] Noh et al. (2023). Environmental and energy efficiency assessments of offshore hydrogen supply chains utilizing compressed gaseous hydrogen, liquefied hydrogen, liquid organic hydrogen carriers and ammonia. *International Journal of Hydrogen Energy*, *48*(20), 7515-7532.
[50] Tarhan, C., & Cil, M. A. (2021). A study on hydrogen, the clean energy of the future: Hydrogen storage methods. *Journal of Energy Storage*, *40*, 102676.
[51] Okoroafor et al. (2022). Assessing the underground hydrogen storage potential of depleted gas fields in northern California. In *SPE Annual Technical Conference and Exhibition*, D031S057R006.
[52] Kayfeci, M., & Kecebas, A. (2019). Chapter 4 - Hydrogen storage. *Solar Hydrogen Production Processes, Systems and Technologies*, 85-110.
[53] International Energy Agency. (2019). The Future of Hydrogen.
[54] Zivar, D., Kumar, S., & Foroozesh, J. (2021). Underground hydrogen storage: A comprehensive review. *International Journal of Hydrogen Energy*, *46*(45), 23436-23462.
[55] Langmi et al. (2022). Chapter 13 - Hydrogen storage. *Hydrogen Production by Water Electrolysis. Electrochemical Power Sources: Fundamentals, Systems, and Applications*, 455-486.

	stored in depleted gas fields)		gas loss or leakage, and potential repurification requirements. *Each method has different operational and efficiency considerations, and storage efficiencies are an active area of research. (Further detail in **Section 3.1.2.1**.)	
Transport (200 miles)	Pipelines	96–99%	Transporting hydrogen through pipelines requires energy for compression. Kurz et al. (2022) suggests the energy required is roughly 0.5 percent of hydrogen's higher heating value[56] (HHV) for every 100 miles, which equates to roughly 1.18 percent of hydrogen's lower heating value to travel 200 miles. Pipeline transport efficiency ultimately depends on pipeline pressure, pipeline distance, and, in the case of blended fuels, the percentage of hydrogen to natural gas. (Blends require more energy for compression along the pipeline than natural gas alone. Further detail in **Section 3.1.2.2**.) Typical hydrogen pipelines operate at 500–1,200 psi (35–83 bar), though high-pressure systems (up to 15,000 psi/1,034 bar) have been proposed, while natural gas pipelines typically operate at 200–1,500 psi (14–103 bar).	[57, 58]
	Trucks *(compressed gas in tube trailers)*	82–96%	Efficiency of transporting hydrogen by truck is driven by the amount of hydrogen a trailer can carry, the weight of said trailer, and the distance traveled. The level of compression used for transporting gaseous hydrogen varies. While DOT typically limits tube trailers to 250 bars, pressures above 500 bars can be used with special exemptions. DOE also reports a common hydrogen carrying capacity of 380 kg for steel tube trailers and 560–900 kg for storage containers made with modern composite materials. Oak Ridge National Laboratory illustrated that a truck's fuel efficiency decreases as weight increases, and for heavy loads, converges around 3.5 MPG regardless of speed. The efficiency range here is for the 200 mile, one-way transport of a 380–900 kg hydrogen trailer by a low-sulfur diesel truck with a 3.5–7.2 MPG efficiency range, and considers the energy required by the truck as a fraction of the energy in the hydrogen it is transporting.	[59, 60, 61]

[56] The heating value is the amount of energy contained within a combustible fuel. Higher heating values refer to the gross energy/caloric value, including the latent heat from vaporizing water during combustion, while the lower heating value is the net energy/caloric value, assuming that the latent heat is not recovered. For more precise definitions, please see the Pacific Northwest National Laboratory's H2 Tools 'Lower and Higher Heating Values of Fuels'.

[57] Kurz et al. (2022). Chapter 6: Transport and Storage. *Machinery and Energy Systems for the Hydrogen Economy*, 218.

[58] Penev, M., Zuboy, J., & Hunter, C. (2019) Economic analysis of a high-pressure urban pipeline concept (HyLine) for delivering hydrogen to retail fueling stations. *Transportation Research Part D: Transport and Environment*, *77*, 92-105.

[59] U.S. Department of Energy. (n.d.). Retrieved on April 9, 2024. Hydrogen Tube Trailers.

[60] Kurz et al. (2022). Chapter 6: Transport and Storage. *Machinery and Energy Systems for the Hydrogen Economy*, 218.

[61] Franzese, O. (2011). Effect of Weight and Roadway Grade on the Fuel Economy of Class-8 Freight Trucks. Oak Ridge National Laboratory.

	Trucks *(liquid H_2)*	88–99%	Liquid hydrogen can suffer boil-off losses between 0.1 and 4 percent per day. Losses of up to five percent can also occur when transferring liquid hydrogen between storage containers (e.g., during the final stage of transport and delivery), with potentially even higher losses if transferring from high to low pressure. However, Petitpas suggests that these losses can be almost entirely mitigated by using certain fill methods and recovery solutions. Efficiency of this transport method also depends on the size of the tanker used, with liquid H_2 tanks of 2,100–5,000 kg reported in the literature. The efficiency range here is for the 200-mile, one-way transport of a 2,100–5,000 kg hydrogen tanker by a diesel truck with a 3.5–7.2 MPG efficiency range, and considers a single day's boil of losses and the energy required by the truck as a fraction of the energy in the hydrogen it is transporting.	[62, 63, 64]
Leakage		80–100%	Estimates of leakage rates at different points in the hydrogen production, storage, transport, and end use process vary, ranging from 0.2–20 percent for the full value chain. The highest leakage rates are associated with liquid hydrogen. Leakage associated with electrolysis, compression, and gas transport often range from 3–6 percent as outlined by Fan et al. (2022) and Arrigoni & Bravo Diaz (2022), though higher values have also been suggested.	[65, 66, 67]

[62] Aziz et al. (2021). Liquid Hydrogen: A Review on Liquefaction, Storage, Transportation, and Safety. *Energies*, *14*(18), 5917.
[63] Jallais, S., & Bernard, L. (2018). Pre-normative REsearch for Safe use of Liquid Hydrogen: LH_2 Installation Description.
[64] Kurz et al. (2022). Chapter 6: Transport and Storage. *Machinery and Energy Systems for the Hydrogen Economy*, 218.
[65] Esquivel-Elizondo et al. (2023). Wide range in estimates of hydrogen emissions from infrastructure. *Frontiers in Energy Research*, *11*, 1207208.
[66] Fan et al. (2022). Hydrogen Leakage: A Potential Risk for the Hydrogen Economy. *Center on Global Energy Policy, Columbia SIPA*.
[67] Arrigoni, A., & Bravo Diaz, L. (2022). Hydrogen emissions from a hydrogen economy and their potential global warming impact. *Publications Office of the European Union*, EUR 31188 EN, JRC130362.

3.1.1 Conversion Efficiencies for Hydrogen Production Pathways

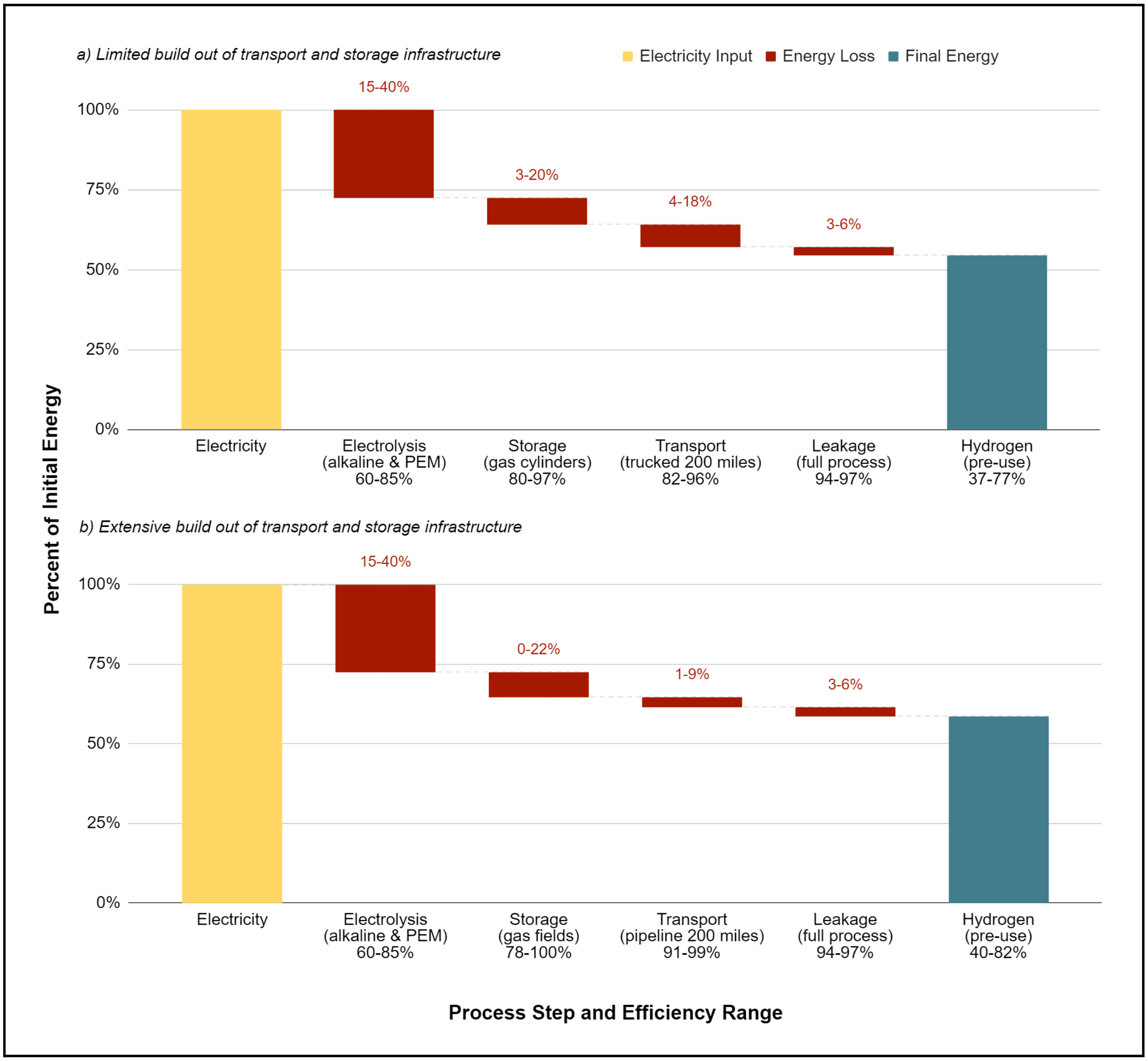
For each hydrogen production pathway, the total process efficiency will depend on the specific generation technologies and their fuel sources, the pressures chosen for compression, the methods used for storage and transport, and how far the hydrogen must travel to reach its end use. Efficiencies and related considerations for electrolysis, biomass gasification, and steam methane reforming of biogas—the three processes used to produce hydrogen in the Scoping Plan—are discussed below. We also discuss the possible effects on efficiency of using intermittent renewable electricity to power electrolysis.

3.1.1.1. Electrolysis

Electrolysis is one of the primary proposed methods of producing hydrogen in the Scoping Plan and other proposals across the state. In the near term, electrolysis pathways will use alkaline or proton exchange membrane (PEM) electrolyzers to generate hydrogen. Then, unless and until hydrogen pipeline infrastructure is established in California, it is likely that hydrogen will be trucked to where it is needed. Pressurized cylinders are a simple, commonly used way to store and transport hydrogen and are useful for small-to-medium-scale storage. However, the low energy density of gaseous hydrogen poses an efficiency challenge—with trade-offs required between the amount of compression (higher compression requires significantly more energy) and the efficiency of transport (the lower the compression, the lower the energy density, and the more energy required for transport). If hydrogen does not need to travel far to reach its designated end use, it is likely most efficient for it to be stored and transported as compressed gas. However, if large volumes of hydrogen need to be moved, it may become more efficient to transport it as liquid hydrogen, despite the energy intensity of the liquefaction process.

As shown in **Figure 3.1**, end-to-end hydrogen production and delivery process efficiency will likely improve over time with the build-out of dedicated transport infrastructure including pipelines. These improvements are likely to be modest unless there are additional efficiency improvements in specific technologies, including electrolysis. Some efficiency estimates suggest that the longer-term scenario gains in efficiency due to pipeline transport may be offset by losses in efficiency associated with the need for underground storage. There is significant uncertainty surrounding this comparison, however, because estimated underground storage efficiencies are still an active area of research. Additionally, there is very little *in-situ* data from hydrogen storage in depleted gas fields, which are among the most likely candidates for bulk hydrogen storage in California. Further confounding factors include the transport distance and volume of hydrogen required, both of which affect the efficiency of hydrogen transport and storage. The relative cost of various technologies may also preclude some higher-efficiency options. Finally, end-use efficiency varies depending on the application, which influences whether storage is required as well as the required amount of compression.

Figure 3.1: Efficiency of Hydrogen Produced via Electrolysis. Chart a) shows possible efficiencies achievable in a near-term scenario given a limited buildout of transport and storage infrastructure. Transport and storage efficiencies are unlikely to simultaneously reach the highest ends of their respective ranges, as higher transport efficiencies correspond with lower storage efficiencies, and vice versa, due to the energy required for compression. Chart b) shows updated efficiencies assuming a more extensive infrastructure build out, which includes the potential for underground storage and hydrogen transport via dedicated pipelines. Achieving efficiencies in this range would require significant amounts of dedicated hydrogen infrastructure. Long-term efficiencies may also increase with electrolyzer technology improvements. (See **Section 3.1.1.2** for more on this.) Storage in b) reaches 100 percent efficiency to reflect that some use cases for hydrogen may not require it. Storage in a) and transport in b) include the energy required for compression at hydrogen refueling stations, as the Scoping Plan primarily uses hydrogen for transportation applications. (See **Section 4.1**.)



The final efficiency ranges in **Figure 3.1** are largely due to uncertainties inherent in each process step and how efficiencies from each step may chain together for a specific use case. For example, generating hydrogen and transporting it via a pipeline for immediate use is more efficient than storing the hydrogen underground before transport. As hydrogen leakage rates are not well characterized, hydrogen lost to leakage may also be outside of the listed range, depending on production, storage, and transport methods (See **Section 5.2** for more on this.). In the future, the adoption of solid oxide electrolyzers (which are not yet commercialized) or other future electrolyzer technologies may increase overall efficiencies. Efficiency improvements may be particularly notable for the longer-term scenario. However, the improvements will ultimately depend on how quickly electrolyzers are built in California, when and whether projected future efficiencies are achieved, the cost of more efficient technologies when compared to the cost of hydrogen, and other related factors. The electrolyzer efficiencies above also do not reflect hydrogen generated using intermittent renewable energy (as outlined in the Scoping Plan). We discuss potential impacts of renewable energy operations below.

3.1.1.2 Electrolyzer Operations Using Intermittent Renewable Energy

Solar and wind are intermittent and often do not provide constant, steady state power. However, electrolyzers require a baseline level of power in order to maintain the internal pressure and temperature needed to operate safely—known as a minimum load requirement. For example, when a PEM electrolyzer starts up after a long idle period, such as overnight when there is no sun, this minimum load requirement may be set as high as 34 percent of nominal power to ensure the startup process is not interrupted before the electrolyzer reaches its minimum operating pressure (Lopez et al., 2023). However, when the electrolyzer is already operating, the minimum load requirement is much lower—as low as 7.6 percent for a PEM electrolyzer (Lopez et al., 2023). Thus, there can be efficiency penalties for repeated cold start-ups, which could happen on a daily basis if electrolyzers are powered by intermittent solar or wind energy.

Electrolyzers can also face performance and equipment concerns from the intermittent operations and fluctuating currents characteristic of renewable energy (**Table 3.2**). Turning an electrolyzer on and off to follow intermittent power generation can, in some cases, cause equipment to degrade faster than it would with a steady source of power. Changes in weather conditions can also cause the incoming electric current to fluctuate. For example, the current fluctuates as a solar panel receives different amounts of sunlight based on the time of day and changes in cloud cover. This can change the voltage, temperature, gas pressure, and gas purity within an electrolyzer, as well as cause some electrolyzer technologies to wear out (e.g., degrade) more quickly (Kojima et al., 2023). Pairing solar and wind, aggregating renewable energy from a wide geographic area, and pairing renewables with storage can all help smooth out current fluctuations and increase the operating time of a plant (Kojima et al., 2023). However, this may be difficult to accomplish for facilities using dedicated, off-grid solar power systems, as proposed in the Scoping Plan. Producing hydrogen from renewable electricity that would otherwise be curtailed may be an effective way to reduce input energy costs, but it may lead to higher electrolyzer inefficiencies.

Table 3.2. Electrolyzer Operations Using Intermittent Renewable Energy. Different electrolyzer technologies have different potential performance concerns when using intermittent renewables.

Electrolyzer Operations Using Intermittent Renewable Energy		
	Performance Given Fluctuating Currents[68]	**Performance Given Intermittent (On/Off) Operations**
Alkaline Water Electrolysis	Can safely follow power fluctuations if a protection current is used to prevent on/off operations	Degradation of catalysts due to reverse current during on/off operations
Proton Exchange Membrane (PEM)	Some performance degradation	Degradation only when quickly switching between on/off (e.g., every 10 minutes)
Solid Oxide Electrolyzer	Possible degradation depends on operating temperature and heat management	

All electrolyzer cells degrade and become less efficient over time. This degradation can be accelerated by certain characteristics inherent to operating with renewable energy, as described above. The extent to which renewable-based operations will impact fuel cells also depends on attributes specific to each technology. Based on current research, PEM cells face the least damage from intermittent operations. Alkaline electrolysis cells can also maintain performance when power levels fluctuate, provided intermittency is minimized. Solid oxide electrolyzer cells, which are still under development, currently degrade quickly during all operations (Skafte et al., 2022). Further research is needed to develop cost-effective solutions to cell degradation and performance issues faced by all three technologies when operating under renewable-energy-focused conditions.

Uncertainties Surrounding the Trade-Offs Between Capital Costs and Operating Costs When Using Renewables

One potential concern with producing hydrogen from renewable energy operations is that an intermittent electricity supply will lead to lower operational electrolyzer capacity. Given their high capital costs, electrolyzers are most economical when operating continuously at or near full

[68] Kojima et al. (2023). Influence of Renewable Energy Power Fluctuations on Water Electrolysis for Green Hydrogen Production. *International Journal of Hydrogen Energy.* Volume 48, Issue 12.

capacity—but this requires a constant source of electricity. California's solar capacity factor is around 30 percent (U.S. Energy Information Administration [EIA], 2019a). Pairing electrolyzers with off-grid solar photovoltaics without dedicated battery storage could potentially increase the cost of hydrogen. This increase arises because the production volume per plant is decreased compared to scenarios in which hydrogen is produced using an uninterrupted power source such as the grid.

However, electrolyzer operating costs are dominated by the cost of electricity. Generating hydrogen with curtailed renewable energy (i.e., excess renewable energy that is generated when renewable supply outstrips what can be used) may alleviate this concern depending on the price of grid electricity, the initial cost of capital (which is important for both electrolyzer and solar panel costs), demand for hydrogen, and various incentives for hydrogen producers. Makhijani and Hersbach (2024) illustrated that using curtailed electricity more than offsets the lower electrolyzer capacity factor. Using curtailed electricity to generate hydrogen could also be a way to productively use that energy rather than simply curtailing it. To do so, however, facilities would need to be optimally located to take advantage of renewable energy curtailments, because these curtailments occur both when supply outpaces demand and when supply overwhelms the capacity of local transmission lines. Further analysis would be needed to determine the operating capacity of electrolyzers utilizing curtailed renewables. The Scoping Plan suggests that all electrolytic hydrogen will be produced using off-grid solar, without mentioning the possibility of curtailed renewables.

Critically from an infrastructure perspective, using only renewable energy to generate hydrogen will require more electrolyzers—and therefore a higher capital cost—to generate the same total quantity of hydrogen since production facilities can only operate during a portion of each day. How many electrolyzers will be required depends in part on the size of production facilities, their locations, and whether solar photovoltaic systems are also paired with wind power or energy storage.

3.1.1.3. Biomass Gasification

The production of hydrogen via biomass gasification is another approach being proposed for hydrogen production, including in the Scoping Plan. The efficiency of this process is determined, in part, by the gasification agent and the moisture content of each feedstock (Shayan et al., 2018). Though not included here, the addition of carbon capture and storage (which is proposed in the Scoping Plan) can also affect process efficiencies.

Efficiency ranges for biomass gasification vary widely in the literature, as seen in **Table 3.1** and **Figure 3.2**. This is likely due to the fact that while gasification itself is a mature technology, biomass gasification to produce hydrogen is not yet widely deployed (Zhou et al., 2021).

Figure 3.2: Efficiency of Hydrogen Produced via Biomass Gasification. Efficiency ranges include both a limited and more extensive infrastructure build-out. The highest end of the final efficiency range assumes no storage and dedicated hydrogen pipelines. When stored in compressed gas cylinders and trucked to final use-site, storage and transport efficiencies are unlikely to reach the highest end of the above range.

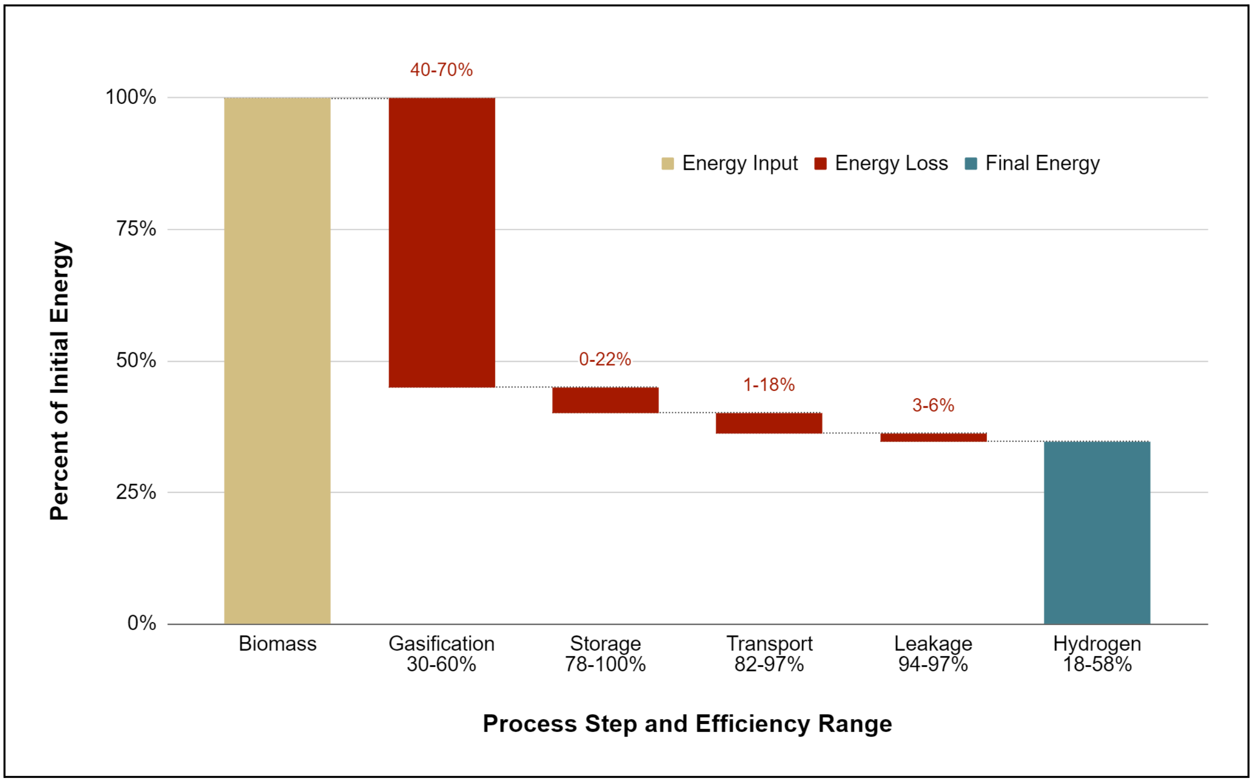


Figure 3.2 shows the efficiency of producing hydrogen via biomass gasification; however, it does not include the energy required to transport biomass to hydrogen generation facilities. The source of each feedstock, and thus the transportation requirements to deliver feedstock to a gasification facility, will also impact the overall efficiency and emissions from its use. Each of the biomass feedstocks outlined in the Scoping Plan presents distinct challenges and may require different policy incentives to ensure that enough feedstock is available for hydrogen production without unintended emissions or equity consequences. (See **Section 4.2.2.1** and **Section 6.2.1** for more.)

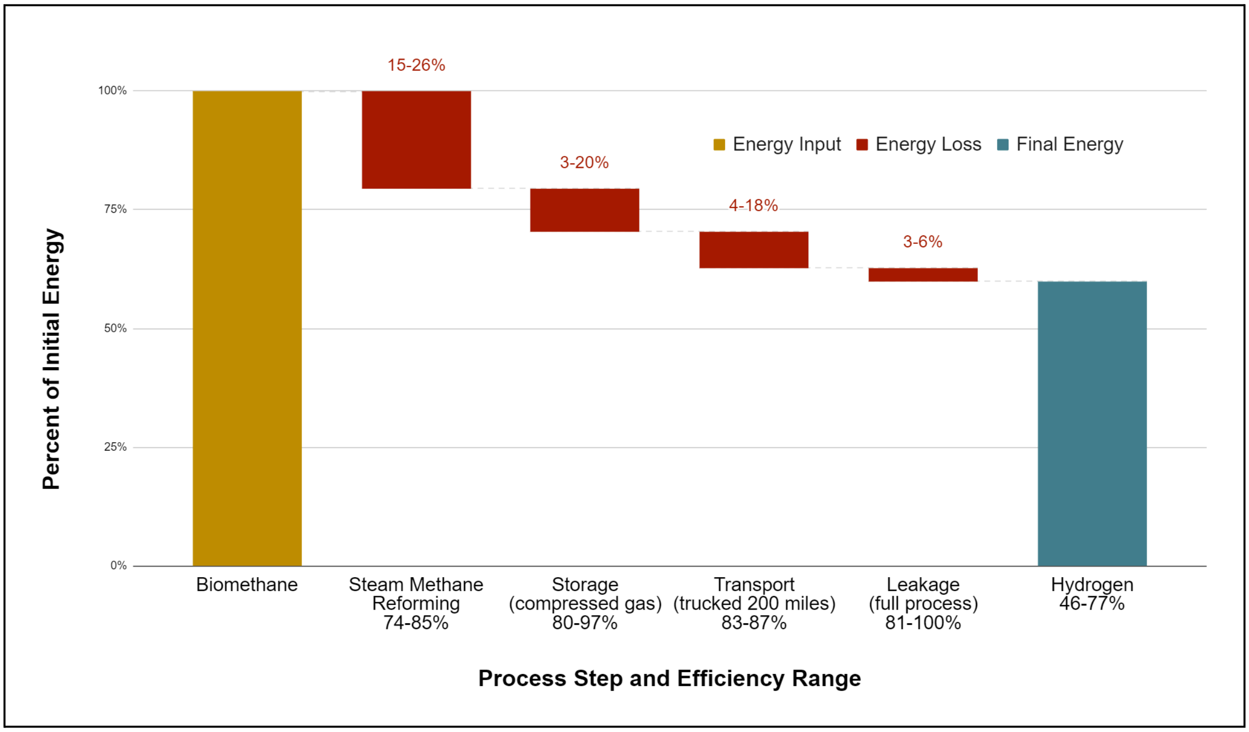
3.1.1.4. Steam Methane Reforming of Biomethane

Until 2040, the Scoping Plan includes hydrogen generated via steam methane reforming of biogas. The Plan indicates that this hydrogen is imported from out of state,[69] though it is somewhat unclear

[69] It is somewhat unclear whether the biomethane used or the hydrogen itself is imported.

whether the biomethane used or the hydrogen itself is imported. **Figure 3.3** outlines hydrogen production efficiencies assuming the hydrogen is produced in California.

Figure 3.3: Efficiency of Hydrogen Produced via Steam Methane Reforming of Biogas. If hydrogen is trucked to its final use site, storage and transport efficiencies are unlikely to reach the highest end of their respective ranges. Efficiencies do not include transport of biogas to the hydrogen generation facility nor any carbon capture and storage included in the process.



As steam methane reforming of biogas is phased out of the Scoping Plan by 2040, **Figure 3.3** does not include efficiencies for underground storage and pipeline transport. Additionally, the Scoping Plan is unclear on exactly where the biogas used for steam methane reforming, or the hydrogen produced this way, is coming from other than that it is being imported. Where and how the biogas for steam methane reforming is sourced may add additional considerations around transport, leakage, and unintended climate consequences. (See **Section 4.2.2.2** for more.)

Regardless of the method used, the overall energy efficiency of hydrogen production depends not only on the generation, compression, storage, and transport processes described above, but also on the specific end use for the hydrogen. This is further discussed in **Section 3.2**.

3.1.2. Hydrogen Storage and Pipeline Transport Considerations

Hydrogen can be stored as a gas or as a liquid. At smaller scales, gaseous hydrogen can be stored in cylinders or vessels at a facility, typically at very high pressure. Liquid hydrogen, which is stored at temperatures below -253˚C, is typically kept in cryogenic storage tanks (DOE, n.d.-b). At large scales, various forms of underground bulk storage will likely be necessary.

The efficiency of hydrogen storage and transport in California depends on the surrounding infrastructure. Hydrogen storage efficiencies vary by method, which in some cases may depend on geography. Hydrogen transport efficiencies depend on both distance and method, with pipeline transport as the most energy efficient. However, building out dedicated hydrogen pipelines is expensive, and blending hydrogen into the existing natural gas stream carries its own costs, challenges, and risks. Considerations for both hydrogen storage and transport, with a focus on pipelines, are discussed below.

3.1.2.1. Bulk Hydrogen Storage

Building out a dedicated "green" hydrogen system in California will require significant amounts of storage, although the magnitude is highly uncertain. Trucked hydrogen, for example, will require more dedicated on-site storage relative to supply than a facility supplied by a pipeline, which can inherently "store" some hydrogen within the pipeline itself.

Proposed formations for large-scale hydrogen storage include aquifers, abandoned mines, depleted oil and gas fields, rock caverns, and salt caverns (Małachowska et al., 2022). Each of these proposed options has its own set of efficiency considerations and geographical constraints. Bulk hydrogen storage in salt caverns has already been demonstrated at a number of sites in the United Kingdom and the U.S. (Miocic et al., 2023). In general, salt caverns have been identified as one of the most promising underground geologic formations for hydrogen storage due to high reported efficiencies and expected long-term structural integrity of the caverns, among other factors (International Energy Agency [IEA], 2019; Małachowska et al., 2022). However, as there is no capacity for underground storage of natural gas in salt caverns in California, there is likely no capacity for underground storage of hydrogen in salt caverns either (EIA, n.d.-a).

Other opportunities for underground storage of hydrogen in California are still under investigation. The California Energy Commission (CEC) has identified knowledge gaps and allocated research funding to better characterize the economics and technical feasibility of underground hydrogen storage across the state, with a request for proposals outstanding as of April 2024 (CEC, n.d.). There has been preliminary research on the potential of using saline aquifers in the Sacramento Basin and depleted oil and gas fields in both Northern and Southern California (Sekar et al., 2024; Okoroafor et al., 2022; SoCalGas, 2021a). (Depleted oil and gas reservoirs are the most common underground pore space in California, with more than 150,000 abandoned or idle wells as reported in Fischer et al. (2020).) However, both storage types have technical challenges leading to efficiency concerns. For example, a study by Zivar et al. (2021) indicated possible efficiency losses due to unrecovered gas and gas mixing. Gas mixing reduces the purity of the hydrogen when storing it in depleted gas reservoirs or aquifers. While losses from unrecovered gas can be mitigated by using a lower-cost "cushion gas" such as CO_2, CH_4, or nitrogen (N_2) to increase the reservoir pressure and boost recovery efficiency, this can introduce mixing. In some cases, microbial activity can also decrease storage efficiency. For example, a study by Haddad et al. (2022) indicated that almost 40 percent of hydrogen injected into an aquifer could transform into hydrogen sulfate, methane, and formate within 90 days because of microbial activity. It is also worth noting that many of these same formations are under consideration for geologic CO_2 storage, and to our knowledge there is no research on the relative value of using these sites for either application or the system-wide potential for CO_2 and hydrogen storage (Kim et al., 2022).

Potential risks associated with underground hydrogen storage range from cyclic stress on the storage facility—which could lead to fault propagation, caprock failure, and well sealing failure—to the acceleration of microbial growth that might clog pores or produce corrosive by-products (e.g., hydrogen sulfide) (Miocic et al., 2023). Across the U.S., others have proposed using existing natural gas storage facilities (including for gas-hydrogen blends) (Lackey et al., 2023). Yet it is unclear whether the existing gas infrastructure at these facilities would be subject to accelerated degradation when exposed to hydrogen. Historic gas leaks from underground natural gas storage, including the unprecedented Aliso Canyon leak in 2015, highlight the need for proper maintenance, monitoring, and emergency response procedures for these and other potential underground hydrogen storage sites (California Public Utilities Commission, n.d.).

Other Hydrogen Carriers

Alternative methods are being explored to more efficiently transport and store hydrogen, although these were not discussed in depth in any of the California-focused hydrogen plans we reviewed. A few of these are briefly outlined below.

Ammonia. Liquid ammonia can be used as a chemical carrier for hydrogen[70] and has been considered for long-distance transport (IEA, 2019). Doing so requires reacting hydrogen with nitrogen to make ammonia (NH_3) and then splitting (or 'cracking') the hydrogen out again later. While generating ammonia only increases the energy required to produce hydrogen by 10–12 percent, splitting the hydrogen back out is around 30–60 percent efficient. This means 40–70 percent of the energy is lost just during the ammonia cracking phase (Makhijani and Hersbach, 2024; Lucentini et al., 2021). The process is also expensive (Wijayanta et al., 2019). Ammonia can also be

[70] This is mostly considered for import and export by countries outside of the U.S.

used directly as fuel. However, doing so generates local pollution (discussed further in **Section 6.2.3**) and greenhouse gas emissions. In fact, Bertagni et al. (2023) estimate that burning ammonia to generate electricity would have a higher greenhouse gas emissions intensity than coal, producing roughly 1,100 grams of carbon dioxide equivalent per kilowatt-hour (gCO_2eq per kWh).

Metal Hydrides. While still in the research phase of development, metal hydrides offer a potentially promising option for stationary storage if research and development can achieve high storage densities at reasonable pressures and temperatures (Ghorbani et al., 2023). However, hydrides still face high energy requirements, low volumetric capacity constraints, high weights, and low reversibility (Tarhan & Çil, 2021).

3.1.2.2. Pipelines

Several existing proposals, including CARB's Scoping Plan and the Angeles Link proposed by SoCalGas, outline the delivery of large volumes of hydrogen via pipelines. As of 2023, California only has about 27 miles of dedicated hydrogen pipelines, clustered in industrial areas (Cerniauskas et al., 2023). The lack of infrastructure for hydrogen means that California would likely have to rely on blending hydrogen into existing gas transmission and distribution pipelines—of which there are more than 100,000 miles spread throughout the state—if it were to try to transport hydrogen via pipeline in the near term (California Public Utilities Commission, n.d.-a). However, dedicated hydrogen pipelines would likely be needed to meet proposed hydrogen demand in the long term and may improve safety risks compared to blending (discussed further below). There are significant unknowns related to the magnitude of pipeline infrastructure buildout that would be required to meet statewide hydrogen targets, due in large part to uncertainties about where the hydrogen would be produced. Hydrogen transmission in pipelines, whether blended or stand-alone, also raises concerns related to safety, cost, and deployment timelines.

Using Existing Pipeline Infrastructure (Blending). Several California utilities are proposing to blend hydrogen with gas in existing pipelines to deliver to buildings, the power sector, and other end users. Pacific Gas and Electric (PG&E) is partnering with the city of Lodi, the Northern California Power Agency, and others on the Hydrogen to Infinity project. This project is a hydrogen gas transmission facility that will test hydrogen production, transport, and storage as well as provide a blend of hydrogen and gas for combustion at a power plant in Lodi (PG&E, n.d.). San Diego Gas and Electric (SDG&E) has proposed a hydrogen blending project at the University of California, San Diego to study the impacts of up to 20 percent hydrogen blending on gas distribution infrastructure (SDG&E, 2022). SoCalGas is testing the use of this blend for gas-based home appliances such as heaters and stoves (SoCalGas, 2021b; SoCalGas, n.d.-a). The Scoping Plan also relies on blending hydrogen into *all* existing gas pipelines at a rate of 20 percent by volume (seven percent by energy) by 2040 (CARB, 2022d).

Blending hydrogen with natural gas requires higher flow rates and higher pressures to deliver the same amount of energy, due to the hydrogen's lower energy density. The increased pressure requirements heighten the risk of gas leakage throughout the gas transmission and distribution system. Initial studies suggest that hydrogen leaks through polymer pipes at a rate seven times higher than natural gas, through joints at roughly a factor of four higher, and altogether that hydrogen-natural gas blends substantially increase total gas leakage rates from pipelines (Penchev et al., 2022).

Transporting hydrogen in steel pipelines also increases the risk of pipeline embrittlement due to hydrogen adsorption, which makes the metal more susceptible to cracking or breaking. This could lead to higher gas leakage rates over time, alongside safety risks (Energy Transitions Commission, 2021). The Hydrogen Blending Impact Study, commissioned by the California Public Utilities Commission, found that hydrogen-gas blends with more than five percent hydrogen by volume increased the risk of steel pipeline embrittlement and the associated leakage rates compared to pure methane (Penchev et al., 2022). Some studies have suggested that blends of up to 20 percent hydrogen by volume can operate without issue. However, the impacts of higher concentrations of hydrogen are still uncertain, as are the abilities of end-use appliances or industrial applications to operate at higher blends (Staffell et al., 2019). In contrast, some pipeline operators have indicated that significant investments would be required to upgrade natural gas pipelines to operate safely with 20 percent hydrogen blends (Martin, 2023). Significant retrofits may be required for pipelines transporting even moderate fuel blends, while full replacements may be required for pipelines that are planned to transport higher fractions of up to 100 percent hydrogen. Despite these issues, the Scoping Plan assumes no additional pipeline maintenance or upgrade costs when blending hydrogen with natural gas at 20 percent volume.

Another proposal under preliminary consideration is to institute hydrogen *de-blending*. This process would mix hydrogen into existing gas systems and then apply technologies such as electrochemical hydrogen separation and purification to 1) reduce the hydrogen concentration in gas blends passing through sensitive infrastructure, and 2) separate out the hydrogen for end use.[71] The California Energy Commission's Gas Research and Development Program is currently considering hydrogen de-blending as one of its primary research objectives in its proposed 2024-2025 budget plan (CEC, 2023a).

Building New Pipeline Infrastructure. In the long term, California will likely need to build out pipeline capacity to meet the proposed levels of hydrogen demand and avoid the safety risks of using hydrogen in infrastructure not designed for it (Khan et al., 2021; Cerniauskas et al., 2023). Initial estimates suggest that hydrogen transmission pipelines will be somewhat more expensive than

[71] It is unclear what the intended end use for this hydrogen would be, although the draft proposal includes a figure indicating power plants, industry, transportation, and buildings would all be potential candidates. This last application, if pursued, would stand in contrast to most other plans in California, and raises significant additional concerns related to feasibility, cost, and safety.

natural gas transmission pipelines, due in part to more stringent design requirements to mitigate leaks from welds, valves, and other components (Khan et al., 2021).

Based on the Scoping Plan, California will need to transport 0.06 EJ of hydrogen to end users in 2030, ramping up to 0.23 EJ in 2045 (meeting nearly nine percent of total energy demand). Other organizations' forecasts vary significantly. In SoCalGas territory alone, the preliminary assessment projects that 2045 demand may reach 1.9–6 million tons per year of hydrogen, which is equivalent to 0.27–0.86 EJ (SoCalGas, 2024). The magnitude of the required pipeline buildout is therefore very difficult to estimate due to several significant uncertainties, including the total final demand, which sectors will require hydrogen, and where and how hydrogen will be produced. For example, hydrogen derived from biofuels would require very different transportation infrastructure if produced in distributed locations near biomass sources, compared to centralizing biomass residues by truck transport at a few larger hydrogen production facilities. Highlighting this uncertainty, the proposed Angeles Link pipeline, intended to supply hydrogen to Los Angeles, has explored sourcing hydrogen from locations ranging from the Central Valley, more than 200 miles away in Blythe on the Arizona border, and even from Utah (SoCalGas, 2022b). (See **Section 7** for more details on Angeles Link.)

As described above, California currently has less than 30 miles of hydrogen pipelines. The U.S. as a whole has roughly 1,550 miles of hydrogen pipelines, mostly in the Gulf Coast (Khan et al., 2021). Hydrogen flows more easily through pipelines than natural gas but is less energy dense, leading to an estimated maximum energy flow of 88 percent compared to natural gas in a pipeline (Khan et al., 2021). However, achieving these flow rates requires much higher pressure, resulting in the need for more energy and cost to compress the gas as well as triggering additional safety and leakage concerns, as noted previously.

Barring major protests, lawsuits, or other challenges, the permitting process for pipelines is expected to take 2.5–4 years to get to the construction phase (Cerniauskas et al., 2023). However, given the novelty of hydrogen pipeline siting in California—and the well-known challenges and delays frequently faced by energy infrastructure proposals statewide—pipeline permitting may well take longer. In addition, the significant uncertainty associated with supply and offtakers (utilities, companies, or other entities that agree to buy hydrogen) seems likely to extend hydrogen pipeline development timelines further (California Council on Science and Technology, 2023). For example, the Angeles Link pipeline, which was first proposed in February 2022, still has no agreed-upon hydrogen supply nor route more than two years later (SoCalGas, 2022c). Adding on additional years for construction, the State is likely many years away from having any dedicated "green" hydrogen transmission pipelines. This raises numerous questions related to the security of supply. For example, if Los Angeles converts its power plants to run on hydrogen beginning in 2029 as proposed, will this hydrogen have to be delivered on trucks? Does this introduce price volatility risks? What happens if storage is limited? Moreover, there are significant stranded asset risks with pipeline buildout. Building a pipeline without dedicated offtakers risks investing billions of dollars in what might be a stranded asset, but even with dedicated offtakers there are uncertainties related to building the infrastructure within the currently proposed timelines.

3.2 Energy Efficiency of Hydrogen Use

Today, hydrogen is predominantly used in crude oil refining, ammonia production, and methanol production (EIA, 2019b). However, climate and energy planners across California are now considering hydrogen for a range of applications, including transportation and long-duration energy storage. The energy efficiency of each of these uses depends on the application itself and should be evaluated in comparison to possible alternatives. A few of these end uses are discussed below. The potential climate impacts of these pathways and pathway trade-offs are discussed in **Section 5.**

3.2.1. Hydrogen in the Power Sector

There are numerous different proposed plans for using hydrogen in California's power sector, depending on the stakeholder. For example, many California utilities, including LADWP, SoCalGas, SDG&E, and PG&E, are proposing to blend hydrogen and natural gas or burn hydrogen directly in electric power plants to replace existing gas-fired electricity generation (LADWP, 2022a; SoCalGas, n.d.-b; SDG&E, n.d.-b; PG&E, n.d.). At the State level, CARB's Scoping Plan proposes to meet all electricity demand without burning hydrogen in power plants for everyday power needs. However, the Plan does rely on the build-out of hydrogen-burning plants to provide emergency backup and to meet resource adequacy requirements. This would, of course, inherently require some amount of hydrogen, but this amount is not estimated in the Scoping Plan.

3.2.1.1. Using Hydrogen to Generate Electricity

While demonstration projects have shown that existing natural gas plants can burn low-level blends of hydrogen and natural gas, hydrogen is not a drop-in replacement for natural gas in existing infrastructure (EPRI, 2023; Larson, 2023). The different chemical properties of hydrogen require some operational changes; for instance, the system needs to be fed more fuel per minute because hydrogen is less energy dense than natural gas (Wilkes et al., 2022). It can also lead to operational instabilities, including potential flashback (where the ignition flame blows backwards), potential blow out (where the ignition flame goes out), and component damage from mechanical and heat stress (Cecere et al., 2023). Additionally, hydrogen blending in existing systems can reduce combustion efficiency, change cooling requirements, and lead to an increase in NO_x emissions that must be managed (Wilkes et al., 2022; Cecere et al., 2023). Using hydrogen in existing gas combustion systems would require either significant retrofits, including for safety and leak detection systems, or full infrastructure replacement.

Combustion turbines designed to burn 100 percent hydrogen have not fully entered the commercial phase, but estimates of current technologies suggest they are roughly 40 percent efficient at converting hydrogen to electricity (Nature Research Custom Media and Kawasaki, 2022).

Hydrogen fuel cells can also be used to provide electric power, as SDG&E is proposing to do with an electrolyzer and fuel cell combination at its microgrid in Borrego Springs (SDG&E, n.d.-a). Depending on the particular technology chosen, fuel cells are 40–60 percent efficient, with alkaline, PEM, and solid oxide fuel cells at the higher (60 percent) end of that range (DOE, 2015). (Other fuel cell types include phosphoric acid and molten carbonate, which are roughly 40 and 50 percent efficient, respectively (DOE, 2015).)

3.2.1.2. Using Hydrogen to Store Electricity

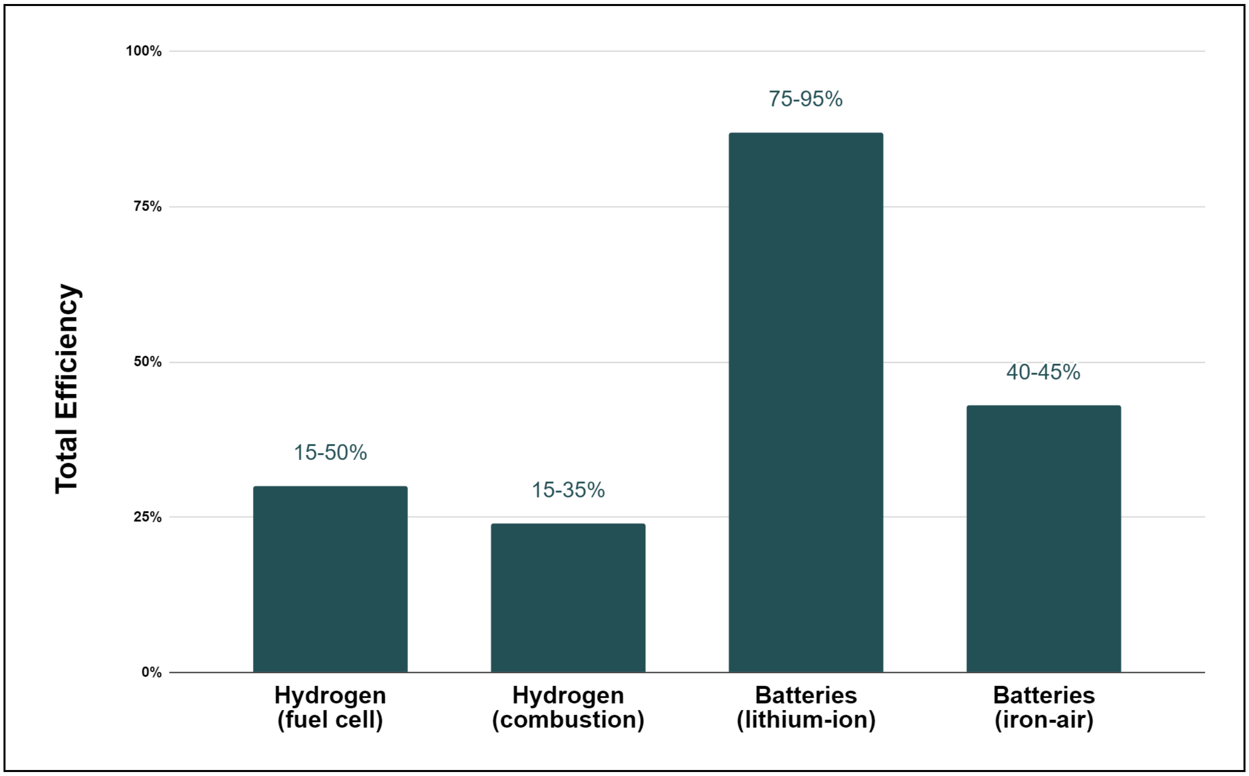
Hydrogen is also under consideration as a means of storing electricity, much like a battery. This approach would use renewable electricity to produce hydrogen and then store that hydrogen to be converted back to electricity when needed. This is the plan for the electrolyzer and fuel-cell combination at Borrego Springs. In this case, SDG&E plans to use local solar to produce hydrogen, store it in tanks at the facility, and then use fuel cells to convert it back to electricity as needed (SDG&E, n.d.-a).

Okoroafor et al. (2022) evaluated California's potential for generating hydrogen from curtailed renewables and storing it in depleted gas fields before converting it back to electricity. Assuming hydrogen generation occurred near storage sites, they estimated a maximum power-to-hydrogen-to-power roundtrip efficiency of 36 percent (Okoroafor et al., 2022). However, their estimates are based on a 64 percent efficiency for converting hydrogen back to electricity, using GE's 9HA combined cycle turbine. Notably, this turbine currently does not support more than a 50 percent hydrogen blend (GE Vernova, n.d.). More research is likely needed to determine these efficiencies under real-world scenarios.

3.2.1.3. Battery Storage as an Alternative to Hydrogen in the Power Sector

The electricity used to produce hydrogen via electrolysis could also be used directly or stored in batteries for later use. In **Figure 3.4**, we compare the full energy losses associated with electrolytic hydrogen production and reconversion back to electricity with an alternative case, in which electricity is stored in either lithium-ion batteries (for short-term storage) or iron-air batteries (for long-term storage). While significantly more efficient than either hydrogen option, lithium-ion batteries are not currently economical for long-duration energy storage on the grid. However, with stakeholders in California considering hydrogen for use in peaker plants, which are typically only activated during peak demand, storage comparisons are worthwhile for grid planning purposes.

Figure 3.4: Comparison of Electricity-to-Storage-to-Electricity Efficiencies for Hydrogen, Lithium-Ion, and Iron-Air Batteries. In each instance, efficiencies are calculated as starting and ending with electricity. For hydrogen, the production efficiency range covers both levels of infrastructure build out depicted in **Figure 3.1.**



In **Figure 3.4**, we adopt Kawasaki Heavy Industries (n.d.) hydrogen turbine combustion efficiency of roughly 40 percent and a fuel cell efficiency of 40–60 percent, as established in the literature (Jamal et al., 2023; DOE, 2015). Using the electricity-to-stored-hydrogen efficiency of 37–82 percent as outlined in **Figure 3.1**, this gives a total efficiency of roughly 15–50 percent using fuel cells and of roughly 15–35 percent via combustion for electrical energy stored as hydrogen and then converted back to electricity. While the technology is not commercially operational, efficiency estimates for a reversible solid oxide fuel cell system operating in 2030 are as high as 52 percent (Glenk and Reichelstein, 2022).

In contrast, existing battery storage options may be more efficient. Lithium-ion batteries are between 78–95 percent efficient, depending on factors such as the specific battery chemistry in use (e.g., lithium cobalt oxide, lithium-iron phosphate, etc.); temperature; operating requirements (e.g., rate of charge or discharge); battery state-of-health (e.g., how old and degraded it is); and the battery management system (Qian, 2011; Lin et al., 2023; Chen et al., 2020; EIA, 2021; NREL, 2022). In electric grid applications, these batteries are typically used for shorter storage durations (roughly 2–6 hours), due in large part to current market forces. Other technologies are currently in various stages of development to provide longer-duration energy storage (e.g., daily, multi-day, or seasonal). For example, iron-air batteries (which are just entering the commercial phase) are marketed for 100-hour storage applications (Form Energy, n.d.). These batteries have poor energy density, so they are meant for stationary applications, but use relatively low-cost, non-toxic materials. Their round-trip efficiency is much lower than lithium-ion battery chemistries (estimates range from approximately 40–46 percent) (Wilson, 2022; Go et al., 2023). This is on par with hydrogen fuel cells but more efficient than hydrogen combustion, although research is being undertaken to bring iron-air battery efficiency to above 60 percent (Fraunhofer Institute for Environmental, Safety and Energy Technology, 2024).

The comparison of energy storage, hydrogen fuel cell, and hydrogen combustion technologies can be overly simplistic without acknowledging that their varying characteristics make each one more or less suitable for different grid applications. Additionally, each technology may operate most efficiently and cost-effectively when meeting multiple grid needs at once. In many cases, a battery or a fuel cell may *not* be optimally utilized if used as a one-for-one replacement of today's natural gas plants. For one, the need for a dispatchable supply of electricity is changing as California adds both renewable energy and flexible demand (e.g., electric vehicles, smart thermostats) to the grid. For example, California's aging natural gas steam plants (including some of LADWP's plants) ramp up very slowly and run for long periods of time, and this lack of flexibility means they do not pair well with intermittent renewables. It may be better to replace these plants with a more flexible technology—which means batteries and fuel cells may actually perform better than the plant they are replacing at meeting specific needs as the grid continues to evolve. Second, energy storage can provide many services beyond electricity *supply*. Energy storage's ability to manage a surplus of daytime solar (i.e., by charging) and to reduce the need for distribution or transmission upgrades, among other applications, means that it may provide significant value above and beyond replacing a natural gas plant's services, and should be valued accordingly. And finally, even if one were to try to replace a gas plant one-for-one, it may be best to do so with a *mix* of technologies. Examples include: using demand response to address rare very high peak demand days; using lithium-ion batteries for short-duration peak supply needs; and using long-duration energy storage or hydrogen fuel cells to manage multi-day or seasonal variations in renewable energy supply. Combining technologies to replace a single gas plant is typically referred to as a "virtual power plant." This approach may be more cost-effective at replacing, for example, LADWP's natural gas power plants, rather than simply swapping out all of the existing natural gas turbines with hydrogen combustion turbines. Using a mix of technologies may also provide more environmental health benefits than hydrogen combustion, which we discuss in **Section 6.1**.

3.2.2. Hydrogen in the Residential and Commercial Sectors

By and large, proposed hydrogen use in California's residential and commercial sectors primarily involves blending hydrogen gas into the existing natural gas system. This strategy and its implications are discussed below. We also compare this decarbonization strategy to directly electrifying end-use in the residential and commercial sectors, with a focus on the alternative approach of using heat pumps to meet space heating needs.

3.2.2.1 Hydrogen Blended into Gas Distribution Pipelines

As mentioned previously, SoCalGas, SDG&E, and PG&E are all proposing to blend hydrogen into existing natural gas pipelines in pursuit of decarbonizing the gas system (SoCalGas, n.d.-c; SDG&E, n.d.-b; PG&E, n.d.). The Scoping Plan also intends for utilities to blend renewable hydrogen into natural gas pipelines serving buildings and industry (at seven percent of energy, which is roughly 20 percent by volume). In 2023, the residential and commercial sectors (namely, buildings) were responsible for 23 and 13 percent of the State's natural gas consumption, respectively; 31 percent was consumed in the industrial sector (EIA, n.d.-b). In California's residential and commercial sectors, natural gas is primarily used for space and water heating (Itron, Inc., 2006; South Coast Air Quality Management District, 2016). Based on data from the U.S. Energy Information Administration, natural gas is the primary source of space heating in 64 percent of households in California and an estimated 54 percent of heated commercial buildings in the Pacific census region (EIA, 2022, 2024).[72]

The main technologies used for natural gas-based heating are furnaces and boilers. Of the homes and buildings that use gas as their main source of space heating, roughly 88 percent of homes in California and 13 percent of commercial buildings in the Pacific region rely on furnaces, which are 59–98.5 percent efficient depending on their age (EIA, 2024). Almost half of commercial buildings that use gas as their main source of space heating use boilers (EIA, 2022). An Energy Star-certified gas boiler has a minimum efficiency of 90 percent, though the efficiency could be much lower for older systems (DOE, n.d.-c).

The impact of hydrogen blends on the efficiency of this heating equipment is still uncertain. A 2022 study on space and water heating equipment funded by a group of gas distribution companies suggested minimal efficiency impacts from hydrogen blends up to 30 percent (Glanville et al., 2022). However, a 2022 study from the California Public Utilities Commission highlighted operational and safety concerns, including impacts on household appliances, from blending hydrogen into the gas system at more than five percent (Penchev et al., 2022). (For more on this, see **Section 3.1.2.2** above on pipeline blending.)

3.2.2.2 Heat Pumps as an Alternative to Hydrogen-Gas Blends for Decarbonized Heating

Numerous independent studies have concluded that using hydrogen instead of gas for space or hot water heating is overall less efficient (and more expensive) than direct electrification alternatives such as heat pumps, given the losses inherent in generating, transporting, and using hydrogen (Rosenow,

[72] These data report commercial building information by region, rather than state. California is included within the Pacific census region.

2022; Makhijani and Hersbach, 2024). Air source heat pumps can provide two to three times more heat energy than they consume in electrical energy, giving them comparable efficiencies of 200 to 300 percent (ENERGY STAR, n.d.). A review of 32 studies suggests that heating a home with hydrogen would require roughly five times the amount of energy required for a heat pump to heat the same space, even assuming an 80 percent electrolysis efficiency (Rosenow, 2022). These findings are higher than our electrolysis efficiency estimates in this report but may be in line with future efficiencies achieved using solid oxide electrolysis cells. The IEA Global Hydrogen Review (2023) also reaffirms that electrifying heating with heat pumps and district heating is more efficient than heating buildings with hydrogen.

In an effort to decarbonize residential and commercial heating, the Scoping Plan directs the deployment of six million electric heat pumps and three million all-electric and electric-ready homes by 2030 (CARB, 2022d). However, only an estimated 600,000 homes in California had heat pumps as of 2021 (Janusch, 2022). There are roughly 13.2 million occupied homes in California, roughly 2.7 million of which use electricity and 8.4 million of which use natural gas for home heating (EIA, 2024). Some of these six million new heat pumps will go to new construction and some to replace electric baseboard heating systems (which are generally less efficient, and more expensive, than natural gas systems) (CEC, 2022a). So under the Scoping Plan, a significant number of homes will likely remain reliant on the existing natural gas system. For residential and commercial buildings still connected to the gas system, the blending of hydrogen into gas pipelines discussed above would reduce greenhouse gas emissions by a maximum of seven percent (see **Section 5**). But replacing gas for home heating with heat pumps, and using renewable electricity to directly power them instead of producing hydrogen, would reduce greenhouse gas emissions by a factor of five (Makhijani and Hersbach, 2024).

3.2.3 Hydrogen in the Transportation Sector

Roughly half of California's greenhouse gas emissions are from transportation, and many decarbonization pathways proposed for this sector rely heavily on hydrogen. This is due in part to potential challenges with electrifying medium- and heavy-duty transport (CEC, 2019). For example, the Scoping Plan assumes that nearly two-thirds of the total 2045 hydrogen supply will be used by medium- and heavy-duty vehicles. It also assumes that by 2035, freight and passenger rail will rely primarily on hydrogen fuel cell technology. Additionally, the Scoping Plan assumed that by 2045, 25 percent of ocean-going vessels will use hydrogen fuel cell technology, and 20 percent of aviation fuel demand will be met by either hydrogen or batteries. (See **Section 4.1** for more on the Scoping Plan's hydrogen-based transportation assumptions.)

Port authorities throughout California are also moving to incorporate hydrogen. In 2023, the Ports of Los Angeles and Long Beach partnered to develop hydrogen fueling stations, mobile hydrogen fueling trucks, hydrogen fuel cell cargo handling equipment, and ultimately, to support the buildout of heavy-duty hydrogen fuel cell trucks (Port of Los Angeles, 2023). These ports are partnering with

ARCHES and their work is supported by DOE hydrogen hub funds (Office of Governor Gavin Newsom., 2023). The Port of San Diego is also exploring the potential of using hydrogen to achieve the zero-emission heavy-duty cargo truck goals outlined in its Maritime Clean Air Strategy (Port of San Diego, 2022).

Fuel cells, rather than combustion, are expected to dominate hydrogen use in the transportation sector. Hydrogen fuel cells have a global efficiency of 40–60 percent, depending on technology (IEA, 2019; DOE, 2015). This is significantly more efficient than gasoline-powered internal combustion engines, which are roughly 12–30 percent efficient, and slightly more efficient than diesel engines, which are around 28–42 percent efficient (DOE, n.d.-d; Albatayneh et al., 2020). In the following subsection we explore hydrogen fuel cell use in passenger vehicles, heavy-duty trucks, trains, and boats.

3.2.3.1 Hydrogen for Passenger Vehicles

Californians are predominantly adopting electric cars (relying on batteries) to replace their gasoline-powered cars, and none of the plans or proposals outlined above focus on hydrogen for use in passenger (or "light duty") vehicles (California Natural Resources Agency, n.d.).[73] However, the overall efficiency of hydrogen fuel cell vehicles and battery-electric vehicles may still be worth noting. Argonne National Laboratories suggests a 62 percent average drive cycle efficiency for the Toyota Mirai, a hydrogen fuel cell electric vehicle (Lohse-Busch et al., 2020). (This efficiency is likely higher than the fuel cell efficiency cited above because the Mirai also has a battery and uses regenerative braking.) However, a study commissioned by Volkswagen suggests the overall efficiency of hydrogen fuel cell cars could be much lower—on the order of 25–35 percent when including hydrogen production, compression, and transport (Volkswagen, 2020).

For battery-electric cars, the overall efficiency is 60-90 percent, depending on electricity line loss, battery efficiency, and whether regenerative braking is used (DOE, n.d.-d). In California, the amount of electricity lost during transmission and distribution is roughly six percent.[74] Electric vehicle battery capacity and efficiency decrease over time as batteries degrade. While fuel cells also degrade and lose efficiency over time, their working lifespan for this application is longer than batteries (De Wolf and Smeers, 2023). Battery electric vehicles are therefore expected to require 2–3 times less renewable electricity to operate than hydrogen fuel cell vehicles. However, the relative environmental impacts of the materials used in batteries as compared to fuel cells, over the full lifetime of the car (including any replacements), should also be considered when comparing these alternatives.

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[73] The Scoping Plan, for example, projects that only three percent of light-duty vehicle energy demand will be met with hydrogen in 2045.
[74] Calculated from the EIA California State Energy Profile. (U.S. Energy Information Administration (n.d.). March 11, 2024. California State Energy Profile. Table 10.).

3.2.3.2 Hydrogen for Heavy-Duty Trucks

In California, fuel cells are being considered more seriously for medium- and heavy-duty trucking. Fuel cells may be more practical in some of these applications because hydrogen fuel cell powertrains can offer longer ranges at lighter weights than their existing battery electric counterparts (Umicore, 2022). Hydrogen fuel cell vehicles also have faster refueling times—refueling takes 10-15 minutes for medium- and heavy-duty trucks with large tanks (DOE, n.d.-e). For comparison, battery electric trucks can take roughly 10 hours to charge with an AC charger or two hours with a DC fast charger (Volvo Trucks, 2021). This makes hydrogen fuel cell trucks a potentially attractive option for trucks used for multiple shifts during a single day, though further research is warranted given the dearth of data on fuel cell trucks.

For fuel cell electric vehicles, fuel efficiencies of 11–15 miles/kg H_2 and 4.79–11 miles/kg H_2 have been reported for medium-heavy and heavy-duty trucks, respectively. However, CARB's Vision 2050 model projects these efficiencies to increase to 16.4–21 miles/kg H_2 and 5.1–16.1 miles/kg H_2 (Forrest et al., 2020). A hydrogen fuel cell truck currently on the road in Europe has a fuel tank storage capacity of 31 kg H_2 and reports an all-electric range of 400 kilometers (roughly 250 miles) (Hyundai, n.d.).

For battery electric vehicles, fuel efficiencies of 1–1.93 kWh/mile and 1.97–2.47 kWh/mile have been reported for medium-heavy and heavy-duty trucks, respectively. CARB projects these to increase to 1.62–2.09 kWh/mile and 2.11–6.61 kWh/mile by 2050 (Forrest et al., 2020). In 2020, the range for these trucks was reported as roughly 170 miles (with battery capacities up to 324 kWh and 435 kWh for medium- and heavy-duty, respectively)(Forrest et al., 2020). Light-duty trucks had reported ranges of up to 300 miles (Forrest et al., 2020). While not yet on the road, Tesla has advertised the release of a heavy-duty semi-truck with a fuel efficiency of around 2 kWh/mile, an estimated range of 500 miles, and that can charge up to 70 percent in 30 minutes with fast charging (Tesla, Inc., n.d.; Kane, 2022). Without efficiency improvements in either battery chemistries or truck designs, increasing the capacity of these batteries could lead to higher weight, which may lower the truck's fuel efficiency. However, efficiency improvements and faster charging times are an active area of research.

Despite their increased weight, battery electric trucks are more efficient than their hydrogen counterparts. The relative efficiency of an electric truck's drivetrain is approximately 85 percent compared to 50 percent for fuel-cell trucks (Gray et al., 2022). However, if we consider the initial conversion efficiency of electrolytic hydrogen production from renewable electricity (assuming an average conversion efficiency of roughly 60 percent (see **Figure 3.1**), then the total relative efficiency of fuel cell trucks is only about 30 percent.

Battery electric vehicles may be better suited than hydrogen fuel cell options for replacing light-duty trucks, particularly at shorter distances and for trucks able to charge overnight. However, for medium- and heavy-duty trucks, hydrogen fuel cells could be a reasonable option given considerations such as truck weights and fueling times. An analysis by Forrest et al. (2020) concluded that the ability of battery electric options to replace fossil-fuel models of medium- and heavy-duty trucks in California is limited by battery capacities and charging rates, while fuel cell electric trucks are limited by their efficiencies, tank size, and the availability of hydrogen refueling infrastructure. This indicates that the efficiency of battery or fuel cell options will ultimately depend on necessary travel distances, truck payload and cargo weights, truck schedules, charging infrastructure availability, and similar factors—as well as future technology improvements.

3.2.3.3 Hydrogen for Trains

Hydrogen fuel cells have also been studied for use in trains, and California plans to convert certain intercity rail lines to hydrogen (Fakhreddine et al., 2023; California Department of Transportation, 2022). Using methods outlined by Washing and Pulugurtha (2015), we estimate the efficiency of trains powered by electrolytic hydrogen fuel cells to be roughly 20–50 percent. This compares to an efficiency of roughly 65 percent for electrified trains that run using a connected catenary system, though this external power system requires more associated infrastructure than on-board fuel configurations. Electrified trains that rely on on-board batteries are currently used mostly for shorter distances, due to similar challenges around charging times and vehicle weight as faced by large trucks (Ghaviha et al., 2019).

A recent study out of Germany, however, determined that hydrogen trains were up to 80 percent more expensive than full electric or battery hybrid options (Ministry of Transportation of Baden-Württemberg, 2022). While the use of hydrogen for trains required little to no change in rail infrastructure, the limited availability of “green” hydrogen and low efficiencies were both cited as issues with the use of hydrogen for this application (Collins, 2022). The Baden-Württemberg state in Germany has been operating a hydrogen rail line for a year, but now plans to switch to more economical electric options (Collins, 2022; RailTech, 2023).

3.2.3.4 Hydrogen for Boats

Combined battery and hydrogen fuel cell systems have also been tested for ocean-going vessels, with overall (combined battery and fuel cell) efficiencies around 60 percent (EO Dev, n.d.). In at least one case, a PEM fuel cell supplied most of the power, with batteries providing energy for peak usage. In 2016, Sandia National Laboratories modeled a high-speed ferry powered by hydrogen fuel cells, which achieved an optimal fuel cell efficiency of 53.3 percent (Pratt and Klebanoff, 2016).

Scripps Institution of Oceanography (Scripps) in San Diego is also developing a hybrid hydrogen research vessel, alongside Sandia National Laboratories and Glosten (Reed et al., 2022). The vessel is designed to use liquid hydrogen to meet most of its energy needs, with diesel generators supplying additional power when necessary (Scripps, 2021). Research is also ongoing for other paired hydrogen fuel cell and battery power systems for ocean-going vessels (Wang, Z. et al., 2022).

Transportation Fueling Infrastructure

Adopting hydrogen in the transportation sector will require the build-out of refueling infrastructure across the state. Depending on the application, the extent of this infrastructure investment may be constrained or widespread. For example, port-related hydrogen refueling infrastructure would be relatively limited to the areas near existing ports, and heavy-duty truck refueling infrastructure would likely be focused near major highways and transit routes. Light-duty vehicle refueling infrastructure, on the other hand, would require much more widespread deployment. These potential investments raise various trade-offs in planning considerations. For example, a lack of fueling infrastructure is likely to inhibit the adoption of hydrogen transportation—no truck driver would want to get stranded without fuel. However, over-building such infrastructure early, without a guaranteed demand, risks that the infrastructure will be underused and become a stranded asset. This has already occurred in California: Shell Global recently announced the closure of its existing light-duty vehicle hydrogen fueling stations and canceled its proposed expansion due to lack of demand (Martin, 2024). The stranded infrastructure risk is higher for technologies where there are clear alternatives, such as electric vehicles, than for applications that have fewer competitive alternatives for decarbonization.

Uncertainty in decarbonization pathways raises a few additional risks. For example, the Scoping Plan assumes that vehicle miles traveled, per capita, will fall by 25 percent below 2019 levels by 2030, and 30 percent below 2019 levels by 2045. However, between 2010 and 2022 (the most recent year data are available), per capita vehicle miles traveled *increased* by four percent, and total vehicle miles traveled increased by nine percent (California Department of Transportation, 2023). The uncertainty of whether sustained reductions in vehicle miles traveled can be achieved—and the compounding uncertainty of whether remaining miles will be powered by electricity or hydrogen—increases the risk of fueling infrastructure investments becoming a stranded asset.

An additional concern related to hydrogen transportation fueling infrastructure is the risk that it will propagate existing inequities at the locations of existing infrastructure. Currently, the state's existing ports are located near the state's most disadvantaged communities and vehicle pollution disproportionately impacts the state's low-income communities and communities of color (California Office of Environmental Health Hazard Assessment [OEHHA], 2023; Reichmuth, 2019). Displacing gasoline and diesel use with hydrogen (or battery electric vehicles) holds the potential to greatly improve the public health impacts of transportation across the state. Replacing gas stations would also have public health benefits, assuming the sites are remediated properly. However, hydrogen infrastructure introduces new safety risks, as described previously. If hydrogen fueling infrastructure is deployed near highways and ports, the same communities that were living next to fossil fuel transportation infrastructure will face safety risks associated with hydrogen infrastructure. As such, deployment of such infrastructure should be conducted in partnership with affected communities and any emergency-response plans should be tailored to reach those communities (e.g., developed with community partners and available in the appropriate language).

3.2.4 Hydrogen in Industrial Processes

Some industrial processes, like cement production, rely on high temperatures that electricity alone cannot generate efficiently. Such high-heat processes are difficult to electrify, and hydrogen offers a promising replacement for fossil fuels in these industries. The Scoping Plan directs hydrogen use for 100 percent of process heat by 2045 for the pulp and paper industries, as well as chemicals and allied products (the latter being those made through mostly chemical processes).[75] The Scoping Plan also stipulates that dedicated hydrogen pipelines would be built in the 2030s to serve some industrial clusters, recognizing the potential for hydrogen to replace fossil fuels in some industrial processes.

Oil refining operations, one of the largest sources of industrial emissions in California, already use hydrogen. Notably, it is used as part of the refining process rather than to provide process heat and is currently primarily produced from natural gas. However, as the state moves towards zero emissions, this sector will likely shrink, requiring less hydrogen (and reducing greenhouse gas emissions overall) (Energy and Environmental Economics, Inc., 2024).

While these industrial processes lack a direct electrification comparison, as previously discussed, hydrogen is not a one-to-one replacement fuel in all industrial applications that currently use natural gas. System retrofits would be required for any significant hydrogen blending in numerous industrial applications, since control systems and other components of current gas turbines, engines, boilers, and other gas combustion systems were not designed for hydrogen or hydrogen blends (IEA, 2019).

Water Used During Hydrogen Production

Producing hydrogen requires water, some of which is consumed during electrolysis or gasification and some of which can be recycled. The exact amounts of water necessary depend on the different technologies used both for hydrogen production (e.g., electrolysis, gasification) and hydrogen plant cooling, as well as the scale of production.

Electrolysis, regardless of specific electrolyzer technology, uses electricity to generate hydrogen by splitting water. Water consumption estimates for electrolyzers vary widely, ranging from roughly 2.4–8 gallons (9–30 kg) per kg of hydrogen (Han and Elgowainy, 2017; DeSantis et al., 2020; Elgowainy et al., 2016; IRENA, 2020; Mehmenti et al., 2018; Makhijani and Hersbach, 2024). This

[75] However, CARB's Scoping Plan data also shows the continued use of natural gas for process heat in these same industries in 2045.

broad range reflects, in part, the difference in water needs between various electrolyzer and cooling technologies and how water consumption is defined. At a basic chemical level, 2.4 gallons (9 kg) of water are needed to produce 1 kg of hydrogen. However, most electrolyzers require pure, deionized water to operate efficiently and avoid membrane degradation (El-Shafie, 2023). The need to filter and purify the water before it is used results in some water being rejected during the purification process. In some estimates, such as those underlying the hydrogen module of Argonne National Laboratory's Greenhouse Gases, Regulated Emissions, and Energy use in Transportation (GREET) model, this rejected water is not considered in the water consumption factor (Elgowainy et al., 2016). Some electrolysis systems also use water for cooling. This can lead to additional water losses through evaporation, since electrolysis generates waste heat during hydrogen production unless electrolyzer cells are operated at or under a specific voltage (and practically speaking, operations occur above this cutoff) (Simon et al., 2010; Harrison et al., 2010).

The above estimates do *not* include the water required to produce the electricity used for electrolysis. If the hydrogen plant relies on dedicated solar, the water intensity of its power source is small. However, this number increases significantly if the plant is drawing power from the electric grid. While not explored here, estimates for the water intensity of hydrogen given various electric grid mixes and decarbonization scenarios are investigated by Grubert (2023). The above estimates also do not consider how the hydrogen may be further converted or used. For example, using hydrogen in combined cycle power plants would require additional water for cooling.

Biomass gasification requires water for both the gasification process and for cooling. However, for the purposes of assessing water usage, cooling water that is not lost to evaporation and process water that is sent to wastewater treatment are not considered to be consumed. The entire process uses an estimated 80.6 gallons (305.5 kilograms) of water per kg of hydrogen, which includes the water that is not consumed during the process (Mann and Steward, n.d.). Of this, 1.3–1.7 gallons are consumed during gasification and roughly 1.9–2 gallons are consumed via evaporation during cooling. This means that, excluding the water sent back for wastewater treatment or recycled during cooling, a total of 3.2–3.7 gallons (12–14 kg) of water are consumed for each kg of hydrogen produced. Although only a fraction of the water is consumed by the process, biomass gasification still requires that the full amount be available.

These estimates do not include water that may be required by the addition of carbon capture and storage (CCS), or the water required to grow, transport, and prepare the biomass used in the process. Given the water necessary to grow biomass feedstocks, bioenergy with carbon capture and storage (BECCS) has potentially the highest water footprint of current carbon capture technologies (Rosa et al., 2020). Using waste biomass can reduce the additive water requirements associated with using biomass to produce hydrogen. But much like understanding the water intensity of the electricity used for electrolysis, it is critical to consider the potential full water impacts of hydrogen production that uses biomass as a feedstock.

Scaling up water consumption for hydrogen based on the Scoping Plan requires assumptions around which technologies will be used and at what scales. Assuming 2.4–8 gal/kg H_2 for electrolysis and 3.2–3.7 gal/kg H_2 for biomass gasification, hydrogen production in California would consume roughly 5.2–12.4 billion gallons (approximately 16–38 thousand acre-feet) of water annually by 2045. This assumes that the state produces 0.23 EJ of hydrogen in 2045, including 0.148 EJ from electrolysis and 0.083 EJ from biomass gasification, as outlined in the Scoping Plan's hydrogen supply targets. This does not account for water that is used but not consumed during the process, such as cooling water that does not evaporate or water sent to wastewater treatment. This also only considers the immediate conversion to hydrogen, and not any additional water inputs that may be specific to different hydrogen end-uses.

For context, thermoelectric power plants such as gas, biomass, and California's sole nuclear generator consumed roughly 24 billion gallons of water to produce almost 111,000 gigawatt-hours (0.34 EJ) of electricity in 2015 (Dieter et al., 2018). We estimate that hydrogen production in 2045 would require 22–52 percent of this water volume while generating a bit more than half (roughly 68 percent) the amount of energy. This means producing hydrogen with dedicated off-grid resources would use half, or less, the amount of water California's thermoelectric generators did in 2015 to generate well over half the amount of energy.

Our estimates for the annual water consumption California needs to produce hydrogen in line with Scoping Plan targets are roughly comparable to the State's freshwater consumption for crude oil refining in 2012, which was an estimated 4.4–11.4 billion gallons (Sun et al., 2018; EIA, n.d.-c). However, this is dwarfed by the State's water consumption for combined oil and gas extraction and refining operations, which was an estimated 280 billion gallons each year between 2018 and 2021, according to analyses by nonprofits FracTracker (Ferrar, 2021) and California Water Watch (2021).

None of these are one-to-one comparisons, though. Hydrogen in the Scoping Plan is intended for use in transportation more than electricity generation. And petroleum products that result from oil and gas operations have a wider variety of uses than hydrogen, such as industrial feedstock, making it difficult to compare by energy content.

In addition to total water consumption, it may be at least as important to consider the local water source and availability of this supply for proposed hydrogen production facilities. While California historically cycles between drought and flood, climate change is driving a downward shift in California's water availability overall. The State estimates a reduction of up to 10 percent in its water supply by 2040, which equates to the loss of roughly 2–3 billion gallons (approximately 6–9 million acre-feet) of water (California Natural Resources Agency, 2022). And this loss in supply is not uniform throughout the state. For example, extreme drought conditions in recent decades have led to an accelerating rate of groundwater loss in the Central Valley (Liu et al., 2022). An analysis by the State

Water Board (2019a) identified 21 “critically overdrafted” groundwater basins (out of 94 priority basins), the bulk of which were concentrated in the Central Valley. As of February 2024, six of these also have inadequate Groundwater Sustainability Plans. In 2022, the Metropolitan Water District of Southern California—which supplements the water supply of a combined 26 cities and public water agencies that serve 19 million people—even instituted water restrictions, citing a lack of adequate water from the Sierra Nevada (Beumont, 2022). The LADWP is a member of this water district, and a portion of SoCalGas’s service territory overlaps with it (Metropolitan Water District of Southern California, 2024; SoCalGas, n.d.-d). These constraints on water supply will be important to consider if SoCalGas’ Angeles Link project pursues hydrogen generation in the Central Valley, which is currently under consideration. Angeles Link is also considering sources in various desert regions in California, which are also likely to face water supply constraints.

In addition to water supply, the right and cost to use water should also be considered. Water rights are prioritized by age of claim, with the oldest right holders given precedent. Water permits for surface and groundwater water diversions are administered by the State Water Resources Control Board. During extreme drought conditions, however, regulators have curtailed water use even to those with water rights. Additionally, in the absence of a fixed contract, water prices can vary widely (Aquaoso, 2021).

Overall, this suggests possible energy security concerns for operations that depend heavily on water. It also indicates that hydrogen production facilities should carefully consider both current and future local water concerns before breaking ground, including availability, competing local demands, seasonal variation, and potential shifts in future supply. While 5.2–12.4 billion gallons of water annually for hydrogen does not appear significant compared to some of California’s other freshwater uses, it could become problematic if generation facilities are not sited with water in mind.

4. CARB Scoping Plan: Hydrogen Energy Requirements and Compounding Interactions with DAC and CCS

Many California planners are considering the role of green hydrogen in decarbonization efforts. The CARB Scoping Plan provides the most comprehensive scenario for hydrogen deployment economy-wide over the coming decades. In this section, we use the energy efficiency values for hydrogen production and use described in **Section 3** to estimate the energy demands required to meet hydrogen deployment goals in the Scoping Plan as well as to calculate the rate of annual average renewable energy deployment that this demand would entail. The energy inputs for hydrogen production in the Scoping Plan are considered to be “off-grid.” However, here we add these inputs to the total renewable energy requirements projected by the Scoping Plan to decarbonize the state's energy systems. This allows us to better understand the *total* renewable energy deployment that may be required statewide. Finally, we also look at the energy requirements for carbon capture and storage as well as direct air capture of CO_2—technologies that, like hydrogen, are omitted from the Scoping Plan's energy modeling. This analysis helps to better understand how these demands may compound and affect total renewable energy requirements and deployment speeds.

4.1 Summary of CARB Scoping Plan Hydrogen Energy Requirements

The 2022 CARB Scoping Plan is the third update to CARB's original Scoping Plan of 2008 and the most up-to-date California state roadmap for achieving sector-by-sector carbon neutrality by 2045. One of the main goals of the current Scoping Plan (compared to previous iterations) is to develop a longer 20-year pathway informed by robust science and centered around equity, as required by Governor Newsom's Executive Order No. 16-22 (2022).

The California 2030 greenhouse gas targets, as defined in statute by AB 32, include all in-state greenhouse gas emissions plus those associated with imported power. By moving to a framework of carbon neutrality by 2045 as directed in The California Climate Crisis Act (AB 1279, 2022), this Scoping Plan is expanded to include all sources and sinks, including natural and working lands, direct air capture (DAC), and other biological and mechanical carbon sequestration processes that are included in the Intergovernmental Panel on Climate Change Sixth Assessment Report (CARB, 2022d, Figure 1-5).

Four separate scenarios were considered in the Scoping Plan for each of the AB 32 Greenhouse Gas Inventory and natural and working lands sectors. The final Scoping Plan scenario integrates actions across the AB 32 Greenhouse Gas Inventory and natural and working lands by choosing one of four alternative scenarios for each of these two broad sectors. All scenarios were compared to a reference scenario that assumes no change beyond the existing policies already in place to achieve the 2030 target of reducing greenhouse gas emissions to 40 percent below 1990 levels, and no new actions in the natural and working lands sector.

The stated aim of the final Scoping Plan scenario is to achieve the AB 1279 targets of achieving carbon neutrality and of reducing greenhouse gas emissions to 85 percent below 1990 levels by 2045 through a technologically feasible, cost-effective, and equity-focused path. The hydrogen requirements in the Scoping Plan scenario can be summarized as follows:[76]

- 45 percent of heavy-duty trucks, 20 percent of buses, and 15 percent of medium-duty vehicles use hydrogen fuel cell electric technology by 2045;

[76] Table 2-1 in Scoping Plan Report and E3's Scoping Plan PATHWAYS Model Outputs

- 20 percent of the aviation fuel demand in 2045 is met by hydrogen (fuel cells) and electricity (batteries), split equally;
- 25 percent of ocean-going vessels use hydrogen fuel cell electric technology by 2045;
- 100 percent of passenger and freight locomotive sales are zero emission by 2030 and 2035 respectively, relying primarily on hydrogen fuel cell technology;
- Hydrogen is used for 25 percent of process heat by 2035 and 100 percent by 2045 in the chemicals, pulp and paper, and allied products industries;
- Renewable ("green") hydrogen is blended in gas pipelines, ramping up linearly from zero percent energy in 2030 to seven percent energy (~20 percent by volume) in 2040 and remaining constant at seven percent energy thereafter. Dedicated hydrogen pipelines are expected to be constructed in the 2030s to serve certain industrial clusters.

The projected hydrogen energy demand by sector is shown in **Figure 4.1** below.

Figure 4.1: Hydrogen Energy Requirements by Sector. Projected hydrogen fuel energy demand by sector under the Scoping Plan. Hydrogen requirements are given in exajoules (EJ).

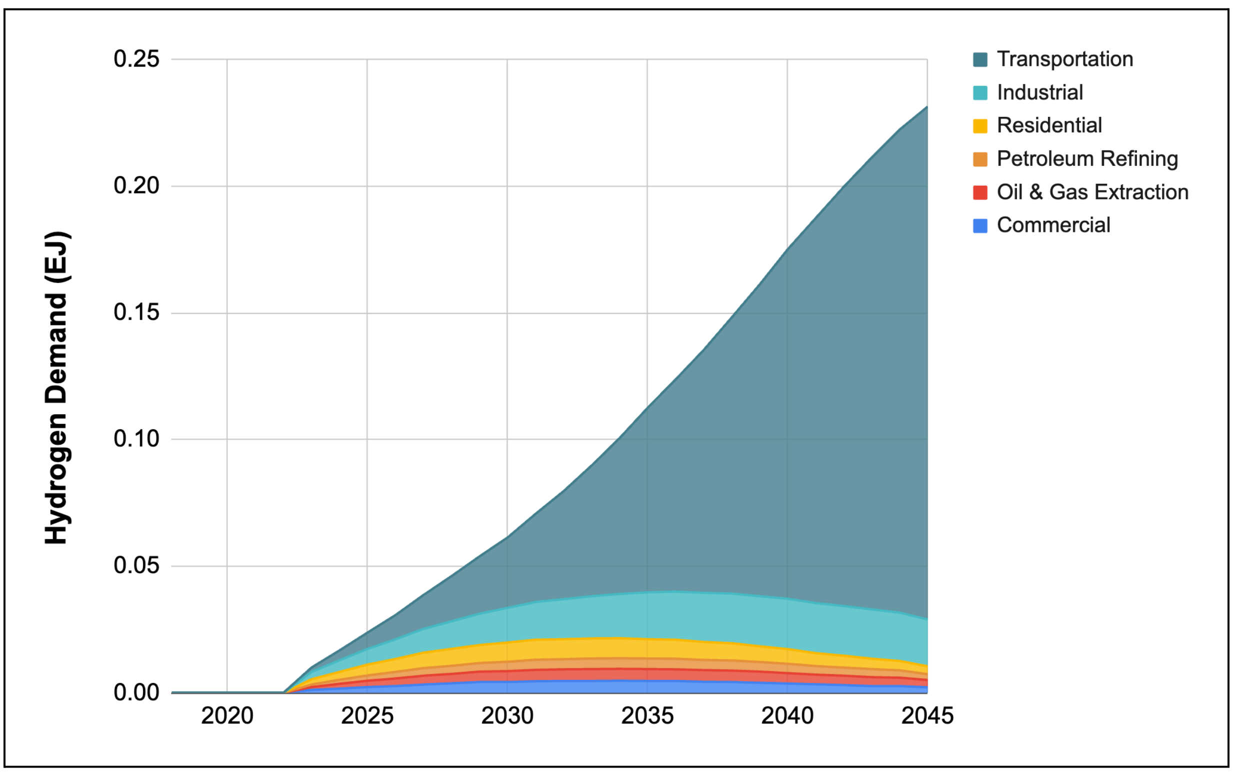
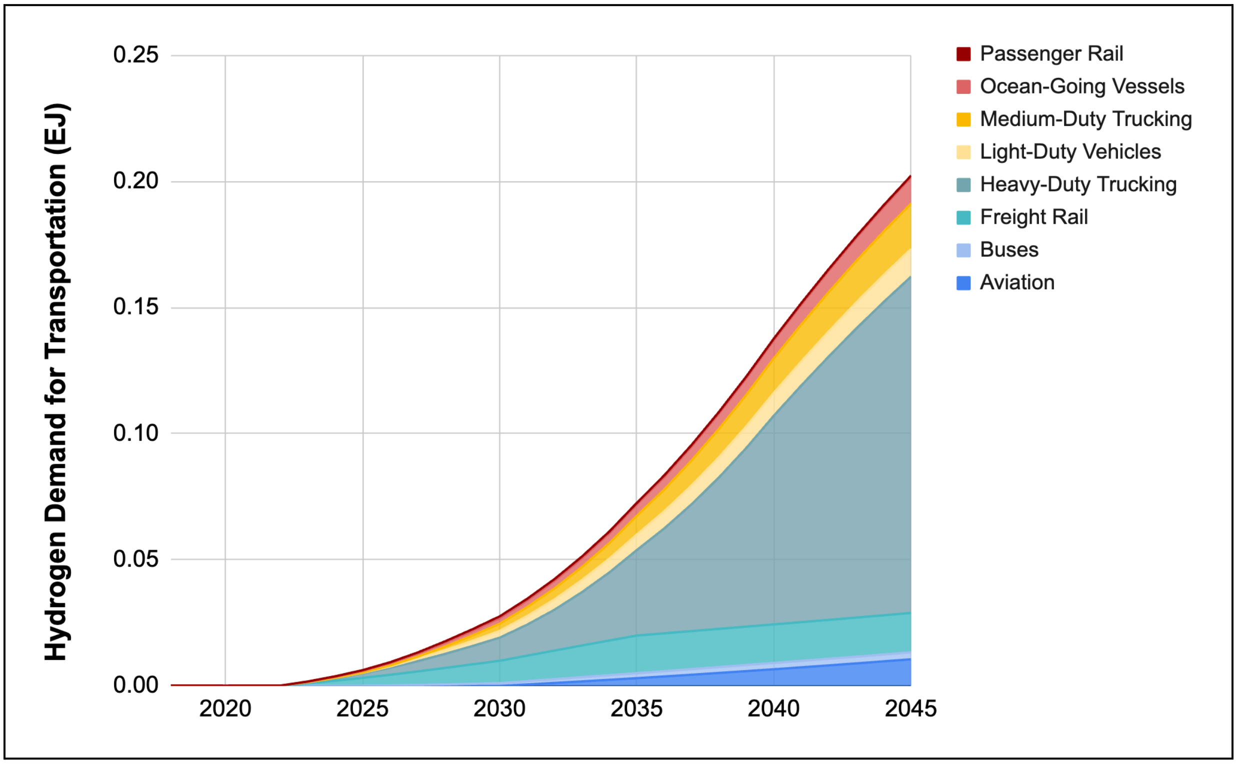


Figure 4.2: Hydrogen Energy Requirements for the Transportation Sector. Projected hydrogen fuel energy requirements for transportation sub-sectors under the Scoping Plan. Hydrogen requirements are given in exajoules (EJ).



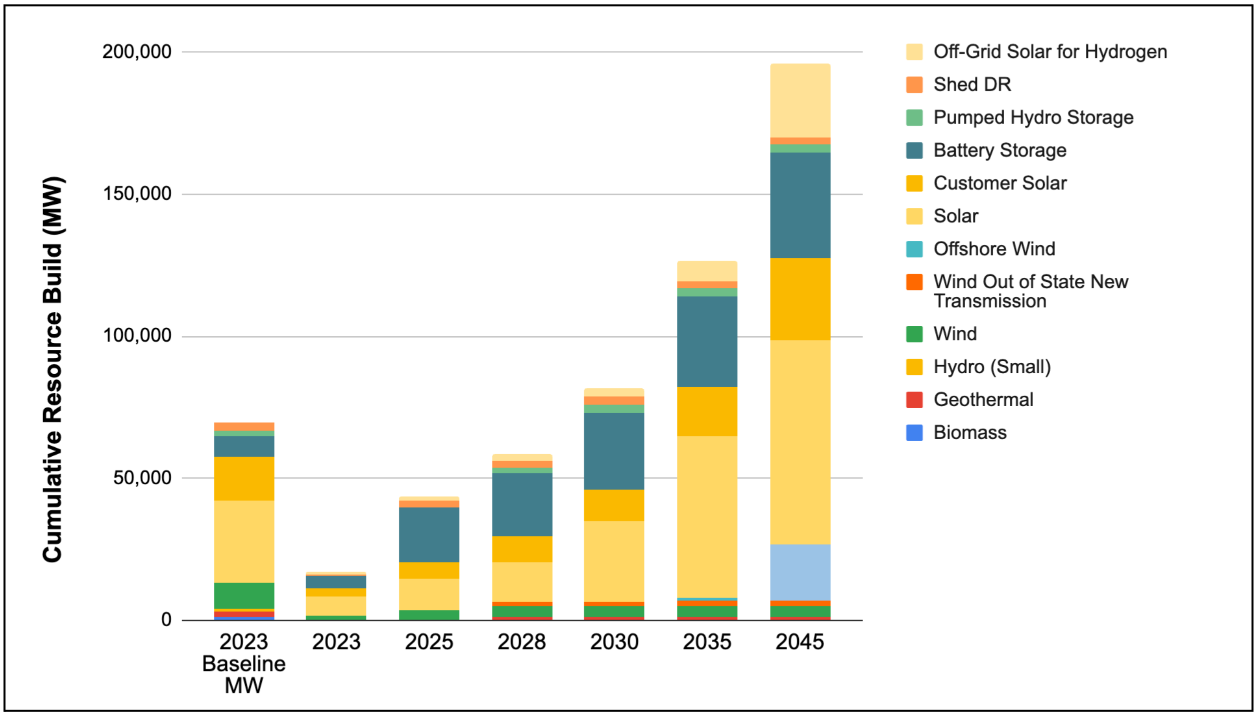
The transportation sector's projected hydrogen energy demand under the Scoping Plan is by far the greatest: the 2045 hydrogen-fuel energy demand in the transportation sector is 10 times greater than in the industrial sector, which, in turn, is 10 times greater than in any of the other sectors. The total projected energy demand for hydrogen fuel in 2045 is 0.23 EJ (~1.9 million metric tons). This is roughly **1,700 times** the current hydrogen supply in California. Nearly 90 percent of the hydrogen energy demand (0.2 EJ) is projected to be in the transportation sector, nearly two thirds of which will come from heavy-duty trucking (**Figure 4.2**).

4.2 Hydrogen Production Under the Scoping Plan

4.2.1 Renewables Capacity Expansion Required to Meet Scoping Plan Targets

The Scoping Plan proposes that roughly two-thirds of the total 2045 hydrogen supply is produced via electrolysis. We estimate that this portion of the hydrogen supply would require about 23–26 GW of additional "off-grid" solar capacity by 2045 that is otherwise not included in the Scoping Plan's projected renewable energy needs (CARB, 2022d, Appendix H). **Figure 4.3** shows the projected cumulative renewable resource build-out under the Scoping Plan, inclusive of this dedicated off-grid solar needed for hydrogen production by electrolysis.

Figure 4.3: Projected Renewable Resource Build Under the Scoping Plan Scenario. This graph shows the additional dedicated off-grid solar needed to meet hydrogen production requirements with electrolysis.



The rest of the hydrogen supply under the Scoping Plan would be produced through steam methane reforming of biomethane and biomass gasification with carbon capture and sequestration. However, there is a high degree of uncertainty around the climate, land use, and environmental justice impacts of using biomass and biomethane for hydrogen production—see **Sections 5.2** and **6.2** below for more details. There is also uncertainty about the scalability of biomass and biomethane to produce this quantity of hydrogen, as we discuss below.

4.2.2 Biofuel Capacity Expansion Required to Meet Scoping Plan Targets

The Scoping Plan proposes that between 36 and 73 percent of California's hydrogen supply will be produced using biofuels, which would require significant growth in biomass and biogas supply and hydrogen production capacity. This is first driven by steam methane reforming of biogas, which starts at 68 percent of the hydrogen supply in 2023 then tapers off to zero by 2040. Hydrogen produced with biomass begins in 2028, ramps up to 53 percent of supply in 2035, and decreases to 36 percent in 2045.

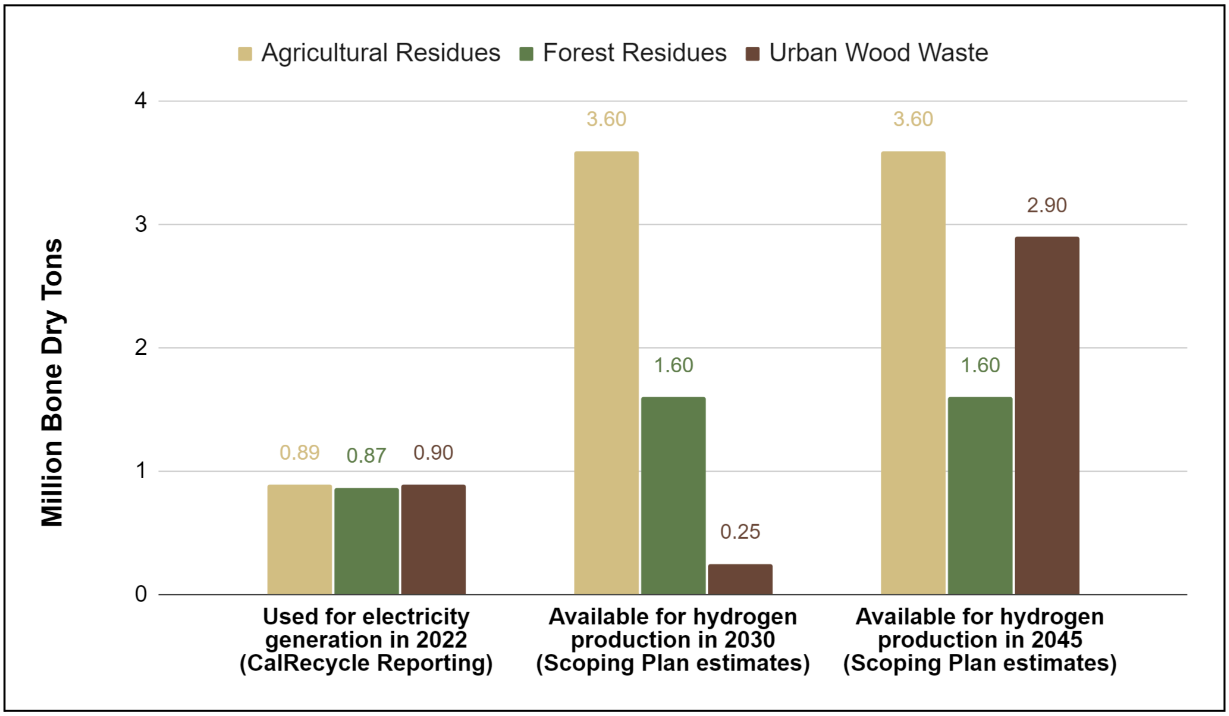
The Scoping Plan relies on an in-state supply of biomass for gasification, paired with carbon sequestration, to produce hydrogen. In contrast, hydrogen produced from biogas via steam methane reforming is assumed to be imported from out of state. Sourcing for these potential biofuel supplies is addressed in the following subsections.

4.2.2.1 Biomass Gasification with CCS

The Scoping Plan assumes that urban, agricultural, and forestry management residues (biomass that currently exists mostly as a waste byproduct) will serve as a feedstock for hydrogen production. The Scoping Plan estimates that California will have 5.3 and 8.1 million bone dry tons[77] per year of agricultural residues, urban wood waste, and biomass from forest management activities available at an appropriate cost for hydrogen production in 2030 and 2045, respectively **(Figure 4.4)**. These sources are expected to supplement biomass currently used for electricity generation. The Scoping Plan estimates that biomass will supply the same amount of electricity in 2045 as in 2023, suggesting this existing biomass supply is unavailable for diversion to biofuels.

[77] A bone dry ton refers to one ton of biomass with zero percent moisture content.

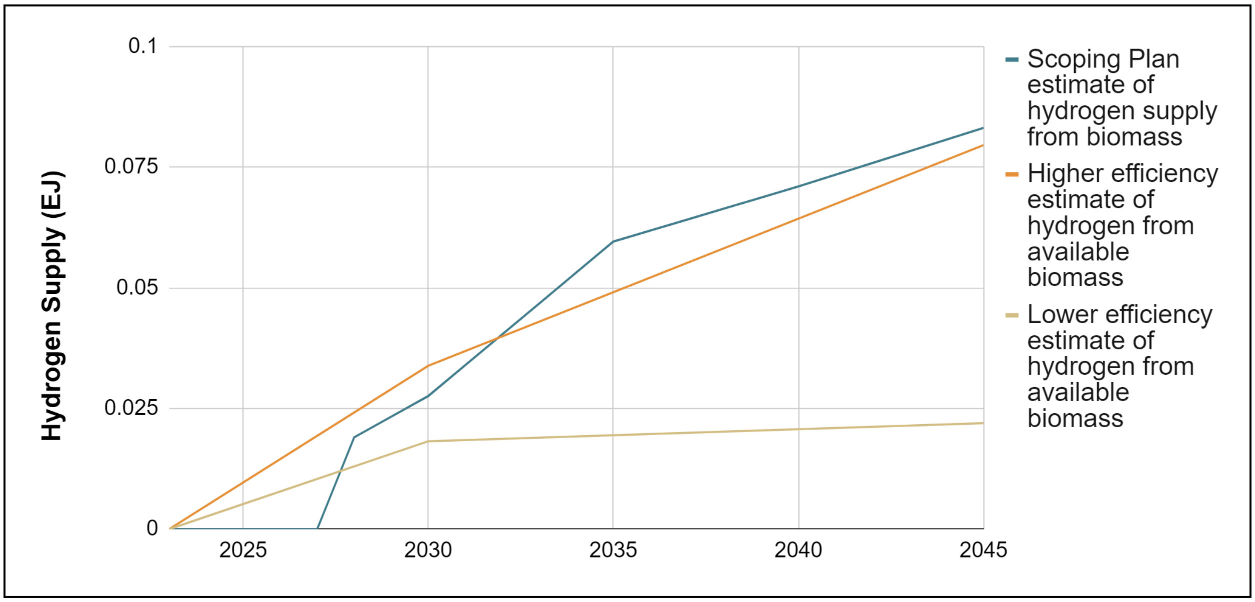
Figure 4.4: Estimated Mobilizable Biomass Feedstocks. The amount of agricultural residues, forest residues (not including mill residues), and urban wood waste used for electricity generation at biomass power plants in 2022. (Left) The amount of those same biomass feedstocks that the Scoping Plan estimates will be available at a reasonable cost for new energy applications such as hydrogen production in 2030 and 2045, respectively. (Middle and Right) The only change between the Scoping Plan estimates for 2030 and 2045 is the amount of mobilizable urban wood waste.



The Scoping Plan indicates that biomass will supply 0.028 EJ of hydrogen in 2030 and 0.083 in 2045. If 5.3 million bone dry tons of biomass are available in 2030, as suggested in the Scoping Plan, California should have enough biomass to produce this hydrogen in 2030 (**Figure 4.5**). However, our calculations suggest that the 8.1 million bone dry tons available in 2045 may not be sufficient to generate the hydrogen supplied from biomass gasification as outlined for that year. Even if gasification plants, storage, and transport methods all operated at the highest ends of their respective efficiency ranges, California may not reach this target without more biomass or significant efficiency improvements.[78]

[78] We suspect our estimate is lower than the Scoping Plan because the latter only accounted for the efficiency of the biomass-to-hydrogen process (excluding related process efficiencies for compression, transport, and storage) and used the heating value of wood fuel to represent the energy content of all biomass sources. In contrast, our analysis included the aforementioned related processes and used the heating values of each proposed fuel type, which are lower than wood, for the associated volume of fuel.

Figure 4.5: Projected and Estimated Hydrogen Supply from Biomass Feedstocks. Higher and lower estimates use the high and low ends of the hydrogen production efficiency estimates from **Figure 3.2**, and were derived using the mobilizable biomass breakdowns provided by the Scoping Plan as seen in **Figure 4.4**. Energy estimates were calculated using higher heating values for each biomass source provided by the Pacific Northwest National Laboratory's H2 Tools (2019) fuel heating calculator.



Lawrence Livermore National Laboratory (LLNL) suggests that California has extensive biomass potential, estimating 28.8 and 32 million tons per year of urban, agricultural, and forestry management residues in 2025 and 2045, respectively (Baker et al., 2020). However, it is not clear how much of this biomass could actually be available for hydrogen, as LLNL does not account for existing or preferential uses of these residues. LLNL also considers different economic constraints in its estimation of available forest management residues compared to CARB's Scoping Plan. Electric power plants in California accepted roughly 3.7 million tons of biomass residue in 2022, with roughly 893,000 tons from agriculture, 895,000 tons from urban waste, and 868,000 tons from forestry management (the remaining 1.1 million tons were from mill residues, which are not included as an option in the Scoping Plan) (CalRecycle, 2023a, 2024). With the exception of forestry residues, these numbers are lower than previous years. CalRecycle partially attributes this decline to less expensive sources of power, which makes it less profitable to use biomass to generate electricity (CalRecycle, 2023a). Taken together, this suggests that while California may have extensive biomass resource potential, there may not be a coherent system or market setup for collecting, transporting, and processing it all to generate hydrogen without cannibalizing existing or preferential biomass uses. Given the uncertainties surrounding the availability of biomass for hydrogen production, we explore what it would take to instead provide all of California's hydrogen supply with solar in **Section 4.2.3**.

Additionally, unless biomass gasification facilities are located only where the appropriate biomass feedstocks are abundant, making use of California's existing biomass resources will require transporting them throughout the state.[79] Transporting this biomass will have energy, emissions, and cost implications. Policies to support the use of any of these waste streams would need to ensure they do not create unintended negative outcomes, such as inadvertently increasing emissions and local traffic pollution in already overburdened communities.

California's Biomass Feedstocks

The Scoping Plan focuses on a few major biomass feedstocks for hydrogen production. Each feedstock is located in a different region of the state and may face challenges for scaling up collection and transport.

Agricultural Residues. LLNL estimates that California will have 12.7 million bone dry tons of agricultural biomass available annually in 2045. In its Scoping Plan, CARB similarly estimates that 10 million bone dry tons of agricultural residues from orchards, vineyards, fields, and seed crops in California will *exist*, but that only around 3.6 million bone dry tons of it will be available at a reasonable cost for hydrogen production each year. However, this does not account for the energy required to transport this biomass to a hydrogen production facility or the energy required to sequester the captured CO_2. Additionally, agricultural residues are concentrated in the Central Valley, a region already overburdened by pollution and facing water constraints.

Forest-Derived Residues. LLNL estimates that there will be 24 million bone dry tons of forest-related biomass available each year between 2025 and 2045, with 15 million of this from forest management activities (Baker et al., 2020). This biomass will be concentrated in rural areas of Northern California and its availability will depend on whether the state has the funding required for, or creates profitable markets around, wildfire fuels management. While some forest residues are already used to generate energy or as feedstock for landscaping products, a significant portion of them are currently either burned or left to decompose. For the past several years, CalFire has offered grants to stimulate more productive use of forest residues and project grantees from 2022 are expected to add more than 1.1 million tons of biomass processing capacity per year (CalFire, 2023). The 2023 solicitation also includes $5 million to support transporting forest biomass to processing facilities. But some of this residue is already spoken for. While the number of electricity-generating biomass facilities has declined over the last decade, for those still operating, an increasing fraction of their biomass has come from forest and sawmill residues (CalRecycle, 2023a).

For its part, CARB estimates that approximately 1.6 million bone dry tons per year of forest-derived residues will be available for hydrogen. This is a small fraction of LLNL's estimate because CARB only

[79] This large-scale truck transport of biomass would also have cost, air pollution, and CO_2 emissions implications.

accounts for residues that can cost-effectively generate hydrogen at carbon prices between $50 and $200 per metric ton. However, even the availability of this lower estimate relies on policy that makes collecting and transporting this biomass profitable.

Urban Wood Waste. In 2021, California sent roughly 5.4 million tons of urban wood waste to landfills (CalRecycle, 2022). The Scoping Plan estimates that less than 0.25 million bone dry tons of this waste will be available for hydrogen production in 2030, but roughly 2.9 million tons will be available by 2045.[80] This is a significant scale up for a biomass source that is spread throughout the state and faces significant challenges to collection and use. California is already not on track to meet existing municipal solid waste reduction goals that could help make urban wood waste available. CalRecycle reports that total organic waste sent to landfills dropped by two million tons annually between 2014 and 2021, and that Organics Grant Program projects awarded between 2021 and 2023 should eliminate a further 15.5 million tons over 10 years (CalRecycle, 2023b, 2023c). However, these reductions represent only around 13 percent of the 27 million tons that would need to be diverted to meet the State's 2025 goal of reducing organic waste sent to landfills 75 percent below 2014 levels (CalRecycle, 2020).

While CalRecycle estimates that roughly five million tons of landfill biomass could instead be used to generate electricity, the amount of urban biomass being sent to power plants in California has declined from around 1.8 million tons in 2015 to around 900,000 tons in 2022 (CalRecycle, 2020; CalRecycle, n.d.; California Compost Coalition, 2023). This is largely because other sources of energy are less expensive, such as wind and solar. This suggests that diverting landfill biomass for hydrogen production will require new incentives (CalRecycle, 2020). The largest markets for urban wood waste are currently as feedstock for biomass power plants, mulch, or compost. However, CalRecycle would prefer that, where possible, urban wood waste is directly reused or used to create particle board and plywood (CalRecycle, n.d.-a). An uptake in these more desirable options could limit the available capacity for hydrogen production.

4.2.2.2 Steam Methane Reforming of Biomethane

Biomass gasification with CCS is projected to meet hydrogen demand only to the extent permitted by feedstock availability. The remaining hydrogen demand in the Scoping Plan Scenario is met with a mix of electrolysis production (as discussed above) and steam methane reformation (SMR) of biomethane through 2040, after which the SMR production path is retired. SMR hydrogen produced from biogas is assumed to be imported and therefore not utilizing available in-state biogas feedstocks.

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[80] This includes non-forest branches and stumps, clean dimensional lumber, engineered wood, pallets/crates from construction and demolition (C&D) sites, and other recyclable woods. It excludes treated/painted/stained wood from C&D sites, which require special handling, and non-forest prunings and trimmings smaller than 4 inches in diameter.

Biogas feedstocks considered in the Scoping Plan include landfills, wastewater treatment facilities, landfill-diverted organic waste, and dairy manure digesters. This biogas is used to produce biomethane, which is then used in the transportation sector for vehicles running on compressed natural gas and in pipeline blending with natural gas. The use of biomethane in transportation is projected to decrease over time, allowing its diversion to pipeline blending or as feedstock for hydrogen production post-2025 (CARB, 2022d, Appendix H, Table H-13).

While the Scoping Plan states that biogas for hydrogen production will be imported, it does not state where it would come from. In the box below, we outline the various in-state sources of biogas on the contingency that a reliable import source cannot be secured.

California's Biomethane Feedstocks

The combined in-state biomethane supply from all sources (landfill gas, wastewater treatment, landfill-diverted organic waste digestion, and dairy manure) under the Scoping Plan scenario is estimated to increase from roughly 26 million MMBtu (one million British Thermal Units) in 2020 to about 91 million MMBtu by 2030, and then decrease slightly to about 82 million MMBtu in 2045 (CARB, 2022d, Appendix H, Table H-13).

Landfill Gas and Wastewater Treatment. CARB estimates that approximately 60 million MMBtu of landfill gas is captured in California at present (Jaffe et al., 2016; CARB, 2016). Of this amount, 20 million MMBtu is used for power generation and the remainder is flared on-site. The Scoping Plan scenario expects higher percentages of landfill gas to be available for energy applications in the coming years: an additional 36 million MMBtu available for new energy applications in 2030, and 26 million MMBtu available in 2045. The additional amount decreases over time because of the state's 75 percent organic waste disposal reduction target (SB 1383). Biomethane generated through anaerobic digestion of sludge at wastewater treatment facilities in California is assumed to grow in proportion to population growth. An estimated 2.3–2.8 million MMBtu is projected to be available for new energy applications in 2030–2045 (CARB 2022d, Appendix H).

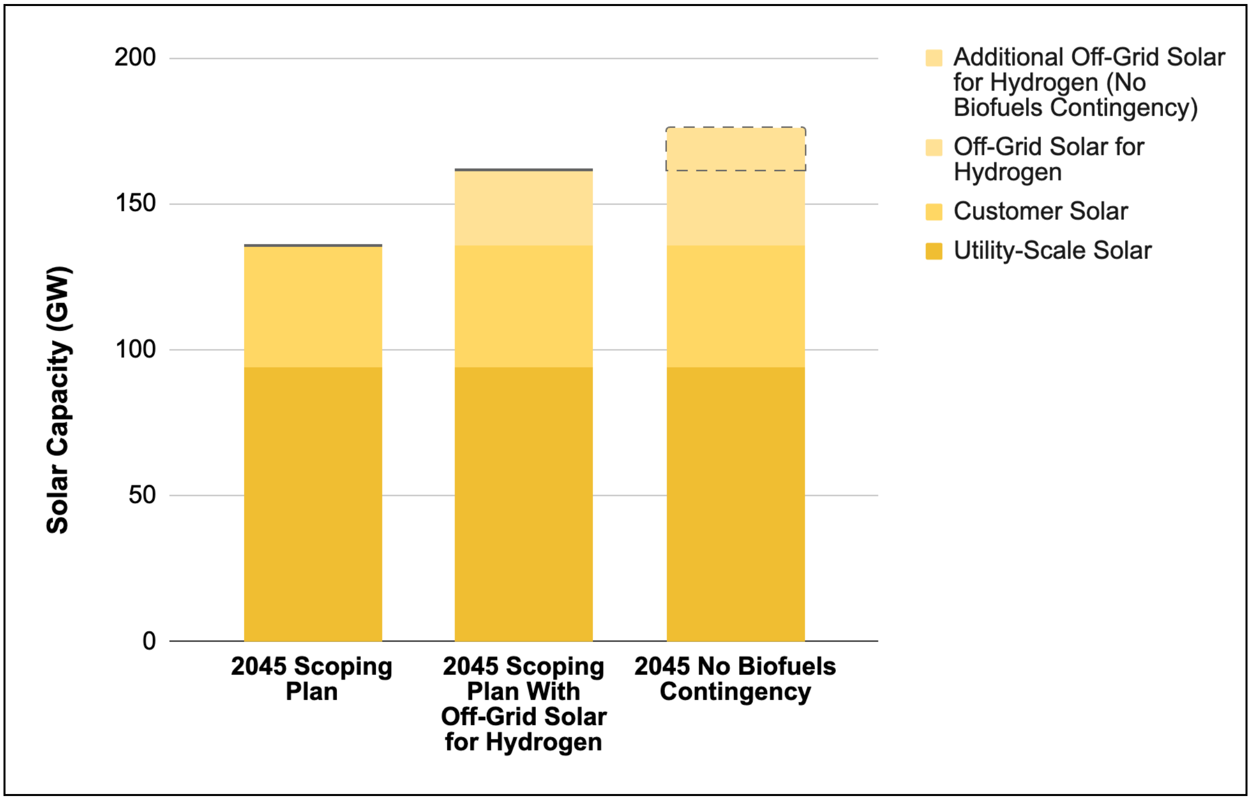
Landfill-Diverted Organic Waste. The Scoping Plan scenario assumes that the 75 percent organic waste disposal reduction target is met by 2025. This would require a large jump in capacity to process landfill-diverted organic waste for energy use (from 0.7 million wet tons in 2020 to 5.5 million wet tons in 2025). Landfill-diverted organic waste is further expected to grow to 5.8 million wet tons by 2045 as growth in waste generation increases proportionally with population growth (CARB, 2022d, Appendix H, Table H-34). This means that an estimated 12 to 13 million MMBtu per year of biomethane from landfill-diverted organic waste is anticipated to be available for new energy applications in 2025–2045 under the Scoping Plan scenario (CalRecycle, 2020a; 2020b). It is assumed that anaerobic digestion yields 2–2.4 MMBtu of biomethane per short wet ton of organic waste (State Water Board, 2019b; SB 1383, 2020).

Biomethane from Dairies. Projections for biomethane production associated with California dairies under the Scoping Plan are generated and calibrated based on dairy supply curves from Jaffe et al. (2016). Under the Scoping Plan scenario, a total of 15 million MMBtu per year is expected to be available for new energy applications in 2030–2045, compared to less than two million MMBtu in 2020 (CARB, 2022d, Appendix H, Figure H-3).

4.2.3 Alternatives to Expanding Biofuel Capacity

In principle, instead of relying on biofuels, all of the hydrogen supply required under the Scoping Plan by 2045 could be produced by renewable electricity from solar (which the Scoping Plan currently assumes will be off grid). Using the mean values of the hydrogen production efficiency ranges outlined in **Figure 3.1** (55 and 60 percent), our calculations indicate that relying solely on electrolysis and off-grid solar to produce hydrogen would require roughly 41–45 GW of dedicated solar to be deployed by 2045 (**Figure 4.6**). These calculations depend in part on how hydrogen is transported (e.g., by truck or pipeline), whether it needs to be stored, and potential losses from leakage. Using the lower end of this range (41 GW of dedicated solar) would imply that the total solar capacity in California in 2045 would need to be approximately 30 percent higher than projected solar under the Scoping Plan scenario, and that the overall renewables capacity would have to be about 18 percent higher. To meet this projected demand, the average annual build rates of renewables would have to double compared to historic annual build rates (see **Section 4.5** below).

Figure 4.6: Projected 2045 Solar Capacity Required Under the Scoping Plan. Included is the additional off-grid solar needed to meet the projected 2045 hydrogen production requirements with electrolysis, as well as an electrolysis-only contingency scenario without the inclusion of biofuels to meet hydrogen needs.



4.3 Direct Air Capture Energy Inputs in the Scoping Plan

Direct air capture (DAC) of CO_2 has received growing interest in recent years as ongoing carbon emissions threaten to push atmospheric concentrations of CO_2 well beyond the levels required to maintain temperature increases below 1.5˚C or even 2˚C. DAC fits into a broader set of carbon dioxide removal (CDR) strategies aimed at curbing excess CO_2 in the atmosphere, including additional efforts such as carbon-sequestering land management techniques. Many consider DAC a necessary approach to mitigating the impacts of greenhouse gas (GHG) emissions and believe that even if GHG emissions stopped today, CDR technologies will be valuable to draw down atmospheric CO_2 concentrations. Others are concerned about both the potential for a moral hazard in employing DAC—namely, that it will enable ongoing CO_2 emissions and the emissions of associated air pollutants. Additionally, as with any nascent technology, the potential for unknown public health and safety risks associated with DAC has raised concerns over the industry's growth. In-depth analysis of these issues is beyond the scope of this report, but we do discuss them in further detail in **Section 6.**

In this section we examine the energy inputs required for DAC. While this report focuses primarily on hydrogen, we include DAC here because 1) the Scoping Plan estimates suggest that it will require a significant amount of energy to power, and 2) because a siloed analysis of the energy requirements for hydrogen alone may obscure the potential for competing demands for renewable energy to meet economy-wide climate goals.

Executive Order B-55-18 (2018), from Governor Jerry Brown, set a goal of achieving California-wide carbon neutrality by 2045 and *net negative emissions thereafter.* In 2022, AB 1279 made the 2045 carbon neutrality target binding. Importantly, the goal for emission reductions was set at only 85 percent below 1990 levels. As such, the remaining 15 percent of emissions could be directly captured using techniques such as carbon capture and storage, or offset with DAC or other carbon removal technologies. In its Scoping Plan, CARB relies on a mix of 1) carbon sequestration in natural and working lands, 2) DAC, and 3) bioenergy with carbon capture and sequestration to remove 75 million metric tons (MMT)of CO_2e from the atmosphere per year by 2045. However, DAC is relied upon far more than the other two strategies due to perceived challenges in scaling more sequestration in natural and working lands. This level of removal (75 MMT CO_2e per year) is equivalent to roughly 20 percent of California's total annual GHG emissions today, which totaled 369 MMT CO_2e in 2020 (CARB, 2022e). The Scoping Plan also relies on the capture of another 25 MMT of CO_2e per year using carbon capture and sequestration at facilities such as cement manufacturing and gas plants, which we discuss in **Section 4.4**.

Energy Requirements for Direct Air Capture

Numerous DAC technologies are under development. Although a few are in the demonstration phase, DAC companies have only just begun to operate commercially (Galluci, 2023). The costs, efficiencies, energy inputs, and the likely array of technologies that might be in place by 2045 are therefore highly uncertain. As an overarching process, DAC typically consists of flowing air over some kind of sorbent material (either solid or liquid) that captures low-concentration CO_2 from the ambient air. Subsequently, this sorbent *releases* a concentrated CO_2 stream through a process (such as heating) so that the sorbent can return to its initial state and be reused. In the final stage, this concentrated CO_2 stream is captured and either used for various industrial purposes or is compressed, transported, and sequestered underground (McQueen et al., 2021). Other processes are also under development.

These and other proposed DAC processes require significant energy inputs. For example, for many liquid sorbents, releasing the CO_2 requires heating temperatures of 800-900 ˚C (Climeworks, 2023). Other technologies require lower-level heat (e.g., Climeworks' sorbent releases CO_2 at 100 ˚C).

While technology requirements are still uncertain, we can create an initial estimate using reports from current technologies. Climeworks, which uses a solid sorbent to adsorb CO_2, reports using 400 kilowatt-hours (kWh) of electrical and 1,600 kWh of thermal energy per ton of CO_2 removed (Beuttler et al., 2019). Assuming that there may be some conversion losses from wind- and solar-powered electricity to a steady supply of thermal energy, we apply a five percent loss associated with converting electricity to high-temperature thermal storage before use (Rissman and Eric, 2023). This value is somewhat uncertain—if renewable electricity generation is much more variable than the energy input required by DAC, and energy must be stored for a long time, there may be much higher standby energy losses. Nevertheless, we calculate approximately 2,084 kWh of renewable electricity will be needed for every ton of CO_2 captured. This is in line with the lifecycle values used in climate change Integrated Assessment Models of approximately 2-3 kWh/kg CO_2, and a literature summary finding a range of 150-1,400 kWh electricity and 1,170-2,083 kWh thermal per ton of CO_2 captured (Babacan et al., 2020; Fasihi et al., 2019). This literature summary settled on a model of 250 kWh electric and 1,750 kWh thermal. For our purposes, we will use the Climeworks estimates of energy demand. The transport and storage of CO_2 requires additional energy inputs, but these are expected to be much lower than the initial capture process.

We attempted to create a rough estimate of the energy requirements for DAC in 2045, looking at a few possible targets. Governor Gavin Newsom set a carbon removal target of 20 MMT CO_2e by 2030 and 100 MMT CO_2e by 2045. The Scoping Plan assumes that 64.4 MMT CO_2e per year of carbon removal will come from DAC in 2045. We note that if we were to assume that 15 percent of 1990 emissions must be removed using DAC (assuming 85 percent direct emission *reductions*, as directed by law) this would also lead to removal of an estimated 64 MMT CO_2e in 2045 (CARB, n.d.). Therefore, we ask the question: how much renewable energy would we need to remove 64 MMT CO_2e per year from the atmosphere?

The Scoping Plan sets a DAC target of 2.26 MMT CO_2 in 2030, growing to 64.4 MMT CO_2 in 2045. Using the values calculated above, we estimate this would use approximately 0.017 EJ of energy in 2030, and 0.48 EJ of energy in 2045. This represents an 18 percent total increase in energy consumption in 2045 compared to the existing sectoral end uses modeled in the Scoping Plan (currently modeled at 2.63 EJ). In other words, 15 percent of California's entire energy demand by 2045 would have to go towards removing California's remaining GHG emissions directly from the atmosphere. The Scoping Plan does not include the energy demand for DAC because it assumes all energy inputs will be "off grid." However, the Scoping Plan estimates California would need roughly 64 GW of off-grid solar for DAC in 2045. Assuming the energy demand for DAC is met with solar power at a 30 percent capacity factor, we calculate DAC would require 2.6 GW of solar in 2030 and 74 GW of solar in 2045.
The calculation above excludes any energy storage (e.g., electric or thermal batteries) that might be needed to smooth out the variable renewable energy inputs for use in DAC.

The energy demand for DAC could be met through multiple channels. Additionally, there may be opportunities to use waste heat, solar thermal energy, or geothermal energy to support the high thermal demand of many of the DAC technologies. A key question for future research is how much waste heat, geothermal energy, or other resources could be dedicated to DAC to mitigate the need to build additional solar and wind resources. In addition, these technologies are likely to operate close to all of the time, not just when wind or solar energy is generated, although this may depend on the technology type. Finding alternative heat sources to support DAC would therefore also mitigate some of the need for energy storage for wind and solar energy.

4.4 Carbon Capture and Storage Energy Inputs in the Scoping Plan

In addition to DAC, carbon capture and storage (CCS) at existing carbon-emitting facilities is widely proposed as a mechanism to reduce carbon emissions and achieve carbon neutrality. The energy inputs for CCS are typically lower per ton of CO_2 captured than for DAC because the emissions streams have a higher concentration of CO_2, making it easier to capture. However, CCS at existing facilities runs the risk of continuing to propagate, or even increase, the emissions of other health-damaging air pollutants from the facilities themselves and throughout the lifecycle of input fuels used. For example, unless stringency of on-site emissions controls is increased, the adoption of CCS technologies at gas power plants would likely increase the amount of natural gas burned in order to run CCS processes. This, in turn, would run the risk of increasing on-site health-damaging air pollutant emissions. It would also risk increasing the total upstream emissions of health-damaging air pollutants and lifecycle greenhouse gases associated with the production, processing, and transport of natural gas because total natural gas demand would increase (Michanowicz et al., 2021). The full impacts related to CCS are beyond the scope of this report. Instead, we focus on the energy requirements of CCS to better understand how these might combine with DAC and hydrogen production to estimate the total amount of renewable energy that must be built by 2045.

The Scoping Plan targets the capture and storage of 25 MMT of CO_2 emissions by 2045 (above and beyond DAC), including specifically for gas power plants (16.7 MMT), cement non-energy emissions (4.2 MMMT), petroleum refining (2.8 MMT), and other industrial energy-use emissions (1.3 MMT). Of note, the Scoping Plan assumes no CCS will occur at power plants until 2045, and all CCS will be added at once (CARB, 2022f). This seems unlikely, since such a massive deployment of infrastructure would necessarily require a ramp-up time to deploy, not only for the CCS systems at the plants themselves, but also for transporting and storing the carbon. Depending on the application, CCS requires approximately 2.8–4.1 MJ per metric ton of CO_2, accounting for capture and compression but not transportation and storage energy (Young et al., 2019; Dávila et al., 2023). We estimate this comes to about 0.08 EJ of energy demand in 2045. It is unclear exactly how much of this energy demand is reflected in the Scoping Plan. The Scoping Plan, which estimates a need for approximately 0.01 EJ of energy to support CCS at refineries, is unclear about energy demand for other industrial CCS, and states that the efficiency impacts of CCS at gas power plants are *not* included. Following similar calculations as above, we estimate that the energy required to support CCS in 2045 would be the equivalent of the generation from 12.2 GW of solar. To be conservative, we assume industrial CCS energy demand is already included in CARB's modeled resource build-out, so we include an additional 8 GW of "solar" to support CCS at power plants in 2045. Of course, there is a reasonable probability that such energy demand would come from increased gas generation at these power plants, but we include “solar for CCS” as a proxy for this energy demand.

Proposed CCS and DAC Deployment Rates in the CARB Scoping Plan

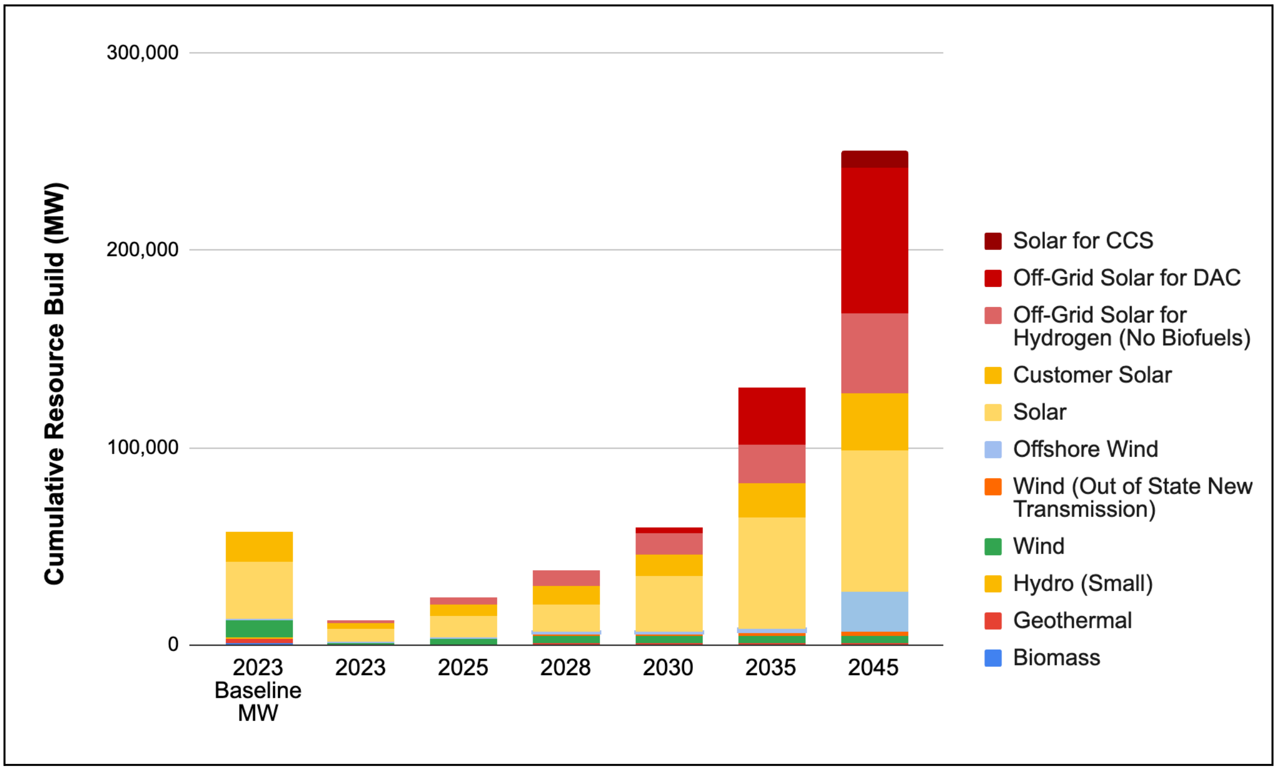
Achieving the Scoping Plan’s proposed DAC and CCS goals will require not only the deployment of sufficient energy resources to power the associated equipment, but also the deployment of DAC and CCS infrastructure itself. Given the novelty of both technologies, it is not meaningful to compare future deployment rates to current deployment rates (as we did for energy infrastructure) since both are in their infancy. Instead, we look at the proposed rate of deployment for each technology in the Scoping Plan. The total cross-sector CO_2 captured by CCS phases in at nearly 5 million metric tons in 2028, ramping quickly to 13.2 million metric tons in 2030, at which point CCS slowly declines to 8.8 million metric tons in 2044, due in part to a decline in total refinery operations and associated CCS needs. In 2045, CCS volume is expected to nearly triple to 25 million metric tons. This tripling is due almost entirely to the use of CCS at natural gas power plants. It is unclear how the state plans to outfit its gas plants and triple its CCS infrastructure within a single year. It appears that this target may be the result of some artifact of the model—namely, that CCS is introduced in 2045 to meet end-point carbon emission targets but is otherwise not one of the resources selected by the RESOLVE model used for the Scoping Plan. However, the state would likely need to introduce such infrastructure in a phased approach rather than a single-year deployment in order to better manage associated financial, workforce, permitting, safety, and other risks.

DAC is deployed at a much more consistent rate from 2030 to 2045. The scale of deployment of carbon transport and storage infrastructure is likely to mitigate some of the rapid CCS deployment needs in 2045. However, even when combining all carbon direct removal targets (CCS, DAC, BECCS, and some additional working lands), the expected deployment of CCS above would entail an increase in total annual carbon storage requirements by 20 percent in a single year, from 2044 to 2045.

4.5 Cumulative Energy Requirements of Hydrogen, DAC, and CCS

Adding the energy resource requirements for CCS, DAC, and hydrogen production to the proposed renewable energy additions under the Scoping Plan enables us to see the true scale of renewable energy deployment required to meet our greenhouse gas targets. We find that adding CCS, DAC, and hydrogen **doubles** the renewable energy resources California needs to deploy by 2045, reaching nearly 250 GW of *new* solar and wind (and significant energy storage as well, although estimating these values are beyond the scope of this report). This cumulative renewable energy resource build is shown in **Figure 4.7.** This total declines slightly if we produce hydrogen in part from biofuels, as proposed in the Scoping Plan. However, even if biofuels are the source of 36 percent of the hydrogen supply, the total renewable energy capacity required increases by three quarters compared to the renewables currently projected as needed to replace existing economy-wide fossil fuel use.

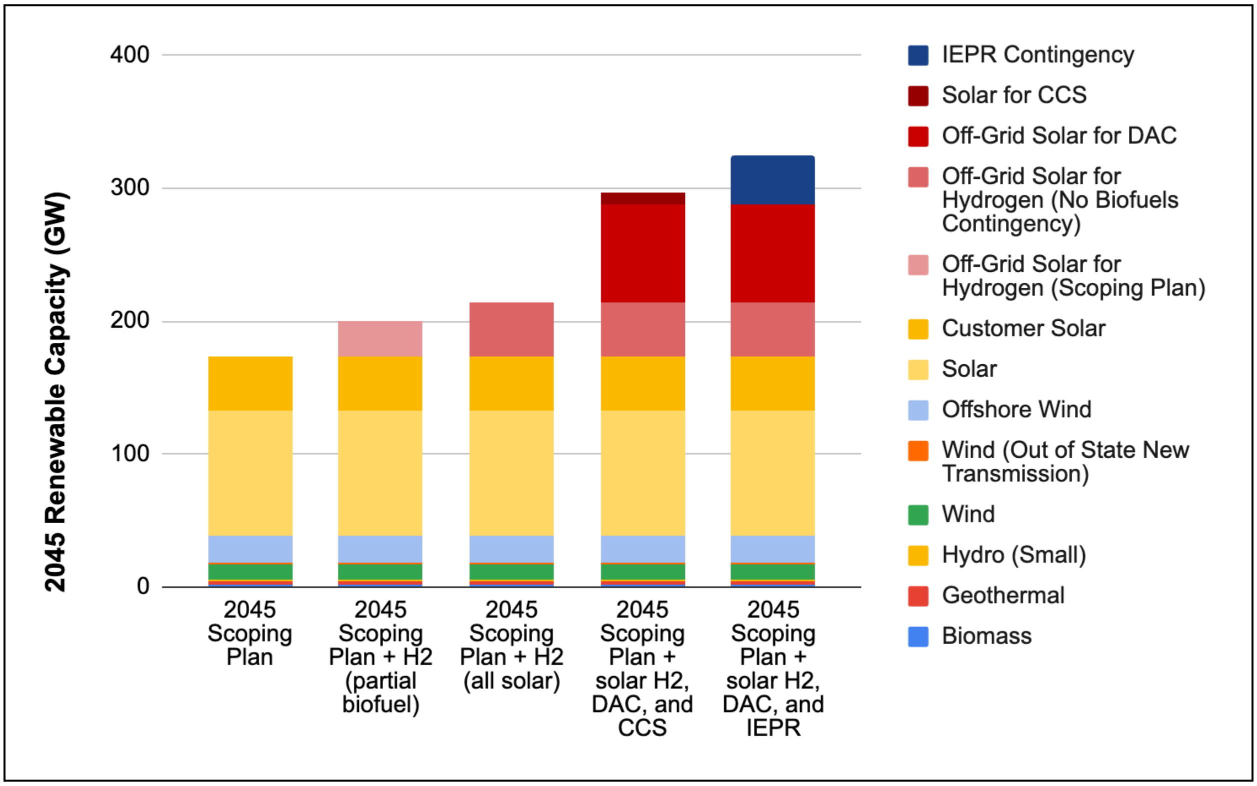
Figure 4.7. Cumulative Renewable Energy Resource Capacity Added 2023–2045 Including CCS, DAC, and Hydrogen Requirements.



We also consider a contingency scenario based on California's 2023 IEPR where natural gas used for electricity production with CCS under the Scoping Plan is replaced by green hydrogen (CEC, 2023b). The IEPR estimates that approximately 1.8 million metric tons of green hydrogen would be required to provide the same amount of energy as the natural gas remaining for electricity generation in 2045. The total solar capacity needed to generate the electricity for producing this hydrogen via electrolysis (assuming a 30 percent capacity factor) is equivalent to 36 GW.

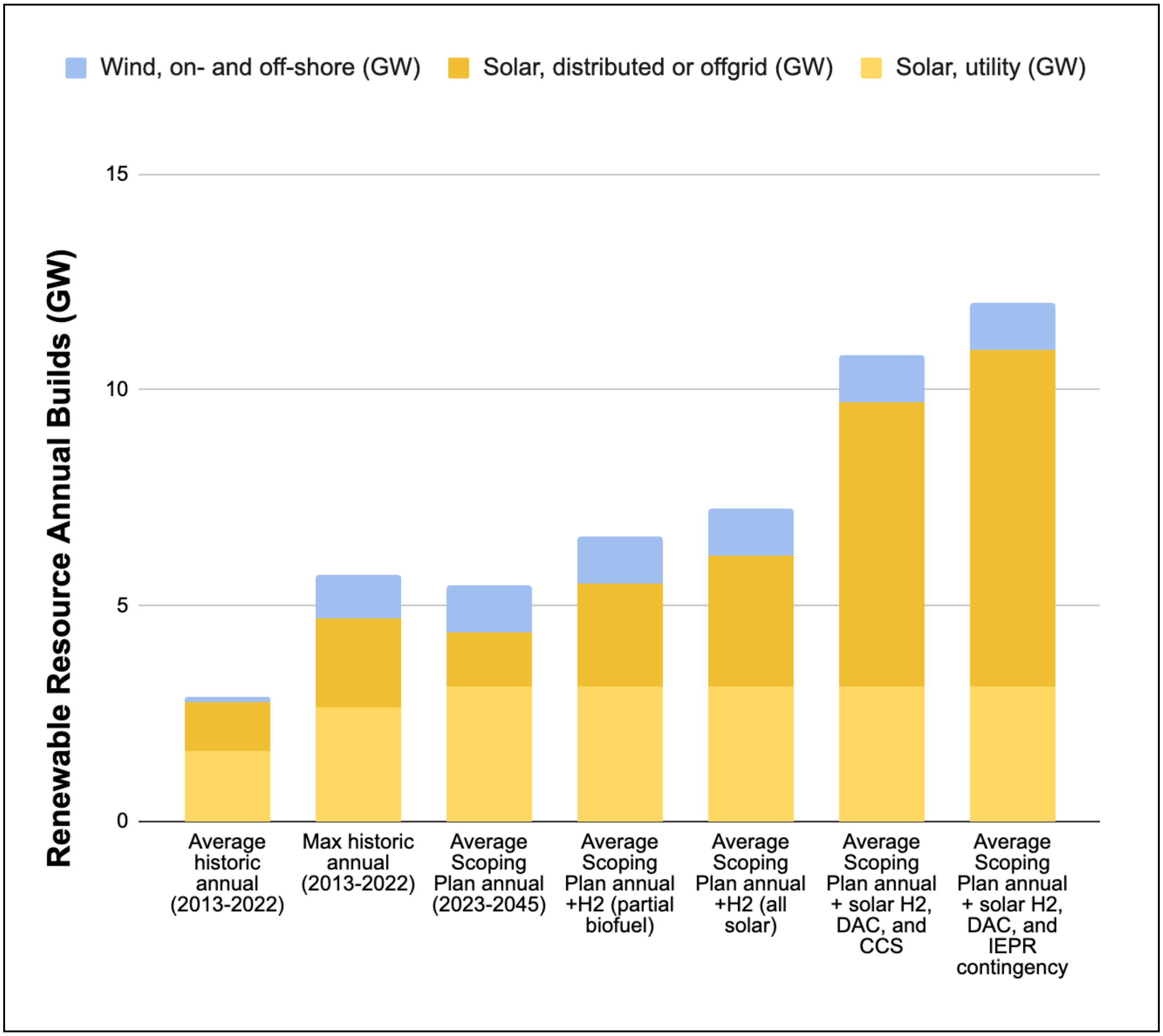
The total impact of adding DAC, CCS, and hydrogen (including the IEPR contingency) on renewables build-out by 2045 compared to the Scoping Plan scenario is illustrated in **Figure 4.8**. Adding CCS, DAC, and hydrogen nearly doubles the renewable energy resources needed by 2045, reaching nearly 300 GW of solar and wind. Adding the IEPR contingency increases the renewable energy resource capacity needed by 2045 to roughly 325 GW.

Figure 4.8. Renewable Energy Resource Capacity in 2045, Including Hydrogen, CCS, DAC, and IEPR Contingency Requirements.



To meet the Scoping Plan target, we estimate that about 5.5 GW of wind and solar, on average, would have to be built every year between now and 2045. This exceeds the maximum historic *simultaneous* annual build rates of wind, utility solar, and distributed solar combined, which is about 4.1 GW. The sum of the maximum annual build rates California has achieved for each resource individually—summing the maximums for the different years in which the most wind, utility solar, and distributed solar were built, which did not occur at the same time—is 5.8 GW. So the Scoping Plan *average* annual build is roughly equivalent to seeing the maximum annual deployment of utility solar, the maximum annual deployment of distributed solar, and the maximum annual deployment of wind *every year* for more than two decades. The *average* historic annual build over the last ten years has only been 2.8 GW, meaning California would have to nearly double its average annual rate of renewable energy construction. To meet the Scoping Plan targets when including both biomass and solar to produce hydrogen, the solar+wind build rate increases to 6.6 GW a year. If expanding biomass as a feedstock proves infeasible for hydrogen production, the annual build rate increases to 7.3 GW. If we include energy for direct air capture and gas power plant CCS as well as hydrogen (assuming all the energy comes from off-grid solar), then the annual build rate is *nearly four times the historic average*, and more than 2.5 times the maximum historic annual growth in renewables. Adding the IEPR contingency of replacing natural gas needed for electricity generation in 2045 with green hydrogen further increases the annual build rate to *4.3 times the historic average*, and *roughly 3 times the* *maximum historic annual growth* in renewables. These annual addition requirements are shown in **Figure 4.9**.

Figure 4.9. Historic and Projected Annual Solar+Wind Capacity Build Rates.



It is worth noting that the Scoping Plan also assumes widespread adoption of energy efficiency, including through electrification (e.g., electric cars are more efficient than gasoline-powered vehicles), such that economy-wide energy consumption in their model is projected to drop to half of 2023 values by 2045. If these efficiency savings are not achieved, the resource buildout would have to be even larger. However, as described in **Section 3,** the direct use of electricity (or electricity and batteries) is more efficient than using hydrogen in many cases. If we can reduce the number of resources powered by hydrogen compared to electricity, the renewable resource build will partially decline. For example, Makhijani and Hersbach (2024) estimated that heating homes with renewable electricity would use one fifth of the electricity of heating a home with electrolytically-produced hydrogen. Even these potential savings in the renewable resource build for hydrogen, however, will still be dwarfed by the amount of renewable resources needed to meet DAC demand.

These estimates have numerous caveats. For example, if waste heat, or direct geothermal heat, can be used to power DAC, it will reduce the amount of wind or solar that must be built. However, this calculation does give a general idea of the magnitude of renewable energy buildout required when incorporating CCS, DAC, and hydrogen to meet California's 2045 carbon neutrality goals. We also did not include any additional energy storage needs. As noted previously (and further discussed in **Section 5**), there are going to be trade-offs for whether direct air capture and hydrogen production are run in response to available wind and solar power—reducing their overall efficiency and increasing the required facility capacity needed for each—or whether wind and solar are coupled with batteries. The batteries would ensure a consistent renewable energy supply, but also require significant additional upfront costs and materials. Future research should model the cost trade-offs between these two approaches.

5. Climate Considerations

5.1 Greenhouse Gas Implications of Hydrogen Use

The production and use of hydrogen holds multiple implications for climate change. Currently, "green" hydrogen deployment is being proposed across California in order to directly displace fossil fuels, and therefore displace fossil fuel greenhouse gas emissions. However, the climate benefit of using "green" hydrogen is not as straightforward as simply calculating the greenhouse gas reductions associated with the displaced fossil fuels. This is due to a number of considerations, which fall into three broad categories:

1) **Indirect atmospheric climate impacts:** Hydrogen is not a greenhouse gas, but it can indirectly contribute to climate change when leaked into the atmosphere by affecting the concentration of other greenhouse gases.
2) **Production and infrastructure emissions:** The energy source (e.g., biogas) used to produce hydrogen can have a greenhouse gas impact, as can the build-out of associated infrastructure (e.g., use of cement).
3) **Deployment pathways and alternatives:** The impacts (both positive and negative) of hydrogen adoption depend on what energy source it is displacing and what alternatives might exist for that end-use, as well as alternative applications of the energy used to produce the hydrogen itself.

We discuss these categories in the California context below.

5.2 Hydrogen's Indirect Climate Impacts

Hydrogen has the potential to leak throughout its production, transport, and use, similar to natural gas (Penchev et al., 2022; Mejia et al., 2020; Alvarez et al., 2018). Once in the atmosphere, hydrogen is relatively short-lived compared to greenhouse gases such as CO_2 and methane, with an atmospheric lifetime of approximately two years (Novelli et al., 1999). In the atmosphere, hydrogen can affect climate change by 1) increasing the atmospheric lifetime of methane, a potent greenhouse gas; 2) increasing tropospheric ozone, which also acts as a greenhouse gas; 3) increasing stratospheric water vapor, which can amplify the greenhouse effect; and 4) having additional aerosol production impacts, which can positively and negatively affect climate change (Sand et al., 2023). The cumulative effect of hydrogen's atmospheric impacts is still an area of active research. One recent meta-analysis suggested a 100-year global warming potential (GWP) of 8 (±2) and another aggregation of models estimated 11.6 (±2.8) (Derwent, 2023; Sand et al., 2023). Over a 20-year period, this latter study estimates that hydrogen has a GWP of 37.3 (±15.1)—namely, that a molecule of H_2 has a warming effect in the atmosphere that is 37.3 times as powerful as CO_2.

As a result of these indirect warming impacts, any leakage from hydrogen infrastructure could further accelerate climate change. Hydrogen leakage rates are also highly uncertain, with limited *in situ* measurements. Still, there are reasons to be concerned about the potential for hydrogen leaks to pose climate risks. First, we know that existing natural gas infrastructure leaks methane (Alvarez et al., 2018). Given that hydrogen is both the smallest molecule and must be transported at higher pressure, it is likely that hydrogen would pose even higher leakage risks—and as noted previously, natural gas-hydrogen blends have been found to leak at higher rates than pure natural gas (Penchev et al., 2022). A recent literature review found full value chain estimates of hydrogen leakage ranged from 0.2-20 percent (Esquivel-Elizondo et al., 2023). Ocko et al. (2022) estimated that a 10 percent leakage rate of "green" hydrogen (i.e., produced from renewables) replacing fossil fuels would actually *increase* the climate impact by approximately 74 percent over the near term (0–5 years). More recently, Sun et al. (2024) found that a 10 percent leakage rate would reduce the 20-year climate benefit of replacing fossil fuels with "green" hydrogen by roughly 25 percent. Bertagni et al. (2022) found that "green" hydrogen leakage rates over nine percent would increase atmospheric concentrations of methane, even when the hydrogen is used to displace fossil fuels, and that lower leakage rates still undermine the climate benefits of replacing fossil fuels with hydrogen. Moreover, all of these findings rely on the assumption that the hydrogen in question is truly *green*—that is, that it has no lifecycle GHG emissions. However, there are numerous approaches to defining green or clean hydrogen including, for example, how the federal government defines "clean" for its 45V Hydrogen Tax Credit. How policymakers define "green" hydrogen will have long-lasting implications for its climate impacts. These considerations are detailed in the box at the end of this subsection.

The Scoping Plan includes hydrogen produced from both biofuels and renewables. The methane leakage rates associated with proposed biofuel feedstocks are uncertain. However, it is likely that biogas would leak from production and transportation infrastructure much like natural gas—where methane leakage is known to occur throughout the gas infrastructure. This could make biogas-based hydrogen more similar to *blue* hydrogen (i.e., produced from natural gas with carbon capture and sequestration) than *green*. Ocko et al. (2022) found that if three percent of methane is leaked during blue hydrogen production and use[81] then switching from fossil fuels to blue hydrogen would not yield *any* climate benefit for more than 25 years. Bertagni et al. (2022) estimate that a two percent methane leakage rate would actually mean switching to blue hydrogen would increase overall methane emissions.

Biofuels are sometimes considered climate neutral due to the fact that they often rely on biomass feedstocks that have absorbed CO_2 from the atmosphere. In the Scoping Plan, biomass gasification is coupled with CCS with the goal of achieving *negative* carbon emissions. But these assumptions must be made with caution: carbon re-released in the form of methane is significantly more potent that any CO_2 removed from the atmosphere (by a factor of 83 on a 20-year timescale according to IPCC (2021)), and biogas produced from non-natural sources such as waste streams cannot necessarily be considered carbon-neutral.

It should also be noted that like all energy resources, any infrastructure associated with hydrogen will have its own climate footprint. This footprint is due to the energy required to produce input materials and direct greenhouse gas emissions from material production processes (e.g., from cement). Estimating hydrogen's climate footprint falls beyond the scope of this report, but measures can be taken (e.g., electrifying equipment; incorporating captured CO_2 into cement) to reduce some of these potential impacts.

In spite of the uncertainties surrounding hydrogen’s indirect climate impact, one general finding is clear: hydrogen leakage should be minimized to ensure the climate benefits of any proposed hydrogen use. Given the lack of data on hydrogen leakage, increased data collection and monitoring is required before hydrogen adoption can be assumed to benefit California’s climate goals to the degree projected in current climate plans. Similarly, before using biogas and biofuels as a feedstock for hydrogen production, increased measurement and data collection of lifecycle greenhouse gas emissions is needed. In particular, more information is needed to determine the climate footprint of methane leakage from biogas production and use and to identify opportunities to mitigate any leaks.

Clean Hydrogen: Principles for Achieving GHG Reductions

Green hydrogen is, by definition, hydrogen produced by renewable energy. Unfortunately, determining what counts as renewable is a harder question than it appears at face value. How to ensure that using renewable energy for hydrogen does not inadvertently increase greenhouse gas

[81] This is only slightly higher than estimates by Alvarez (2018), which provides a leakage estimate of 2.3 percent of natural gas gross withdrawals or 2.9 percent of natural gas by end use.

emissions in another part of the energy system is also important to address.

The answers to these questions can be roughly grouped into two sets of concerns. The first question—what is renewable?—applies in particular to biofuel resources such as landfill gas, crop waste, urban organic waste, dairy farm methane, and so forth. There is no consensus on how to calculate the greenhouse gas footprint of these resources, nor on how much of a greenhouse gas footprint should render any source as non-renewable. For example, how do we address methane leakage associated with landfill gas or dairy methane? Many of these values are poorly characterized due to both lack of study and the wide range of material variability in constituent feedstocks, even within the same class (e.g., agricultural residues).

The second question is whether the hydrogen is produced *directly* from renewable energy, or whether the energy is considered renewable because of the purchase of renewable energy credits or greenhouse gas (GHG) offsets produced elsewhere. If credits or offsets are used, this raises concerns that emission reductions may not be truly *additional*.

To begin to answer this first question, the federal Internal Revenue Service and the Treasury proposed a Clean Hydrogen Tax Credit (Section 45V) to support clean hydrogen development in December 2023 (IRS, 2023). The proposed rule defines green hydrogen as having lifecycle GHG emissions of less than 4 kg of CO_2e per kg of hydrogen produced, with the greatest tax credits for green hydrogen with less than 0.45 kg of CO_2e per kg of hydrogen produced. The proposed rule defines lifecycle GHG emissions as those reflected in Argonne National Laboratory's GREET model (Wang, M. et al., 2022). They note, however, that many biofuel pathways are not reflected within the model. There is also some uncertainty about the lifecycle emissions of the fuels currently included.

A second concern about how biofuel greenhouse gas emissions are estimated has arisen in relation to how biofuels are addressed in California's low-carbon fuel standard (LCFS). Currently, hydrogen can be used to meet the LCFS standard by buying the *environmental attributes* of renewable electricity generated elsewhere and then producing electrolytic hydrogen from grid electricity. This is known as *book-and-claim* (CARB, 2022g). There are concerns that this might indirectly increase emissions because the hydrogen is not directly using renewable energy generated for the specific purpose of producing hydrogen, which we discuss below.

Book-and-claim also enables the purchase of methane emissions reduction at dairy farms to offset methane emissions associated with low-carbon fuel production. The logic is that methane is a far more potent greenhouse gas than CO_2, and preventing it from entering the atmosphere can be considered a net positive for the climate even if CO_2 is emitted in the process of burning it. There are concerns that hydrogen producers who make hydrogen in the conventional way—via steam methane reforming of natural gas—could purchase carbon offsets from California dairy farms and landfills and claim that their hydrogen is green. If green hydrogen incentives and subsidies are allowed to flow to the dominating SMR industry, it could shut down the fledgling industry of green hydrogen production via electrolysis before it even begins. Numerous analyses have also suggested that the book-and-claim system might create perverse incentives, including poor management of methane at dairy farms in order to receive LCFS credits for reducing said methane (St. John, 2023).

Numerous researchers and organizations have settled on three pillars to ensure that green hydrogen produced with grid electricity is actually produced in a way that does not increase economy-wide emissions (UC Berkeley Faculty, 2023; Haley and Hargreaves, 2023; Jenkins, 2023). The three pillars include:

- **Additionality.** The renewable energy (e.g., wind, solar power) used to produce hydrogen should be *new,* not existing. Another option may be to use renewable energy that would otherwise be curtailed. This protects against buying up renewable electricity that is currently being used to meet load elsewhere on the grid—which might result in a gas plant being used to meet that load instead, resulting in no net GHG benefits overall.
- **Regional Alignment.** The renewable energy should be located in the same grid region (e.g., balancing authority) as the hydrogen production. Since energy demand may be locally specific, this ensures that purchasing wind energy in Iowa to "produce" hydrogen in California, for example, does not result in an increase in gas plant use in California because there is insufficient transmission to California to directly meet local demand.
- **Time Matching.** This requirement ensures that hydrogen does not place any additional demand on the grid that cannot actually be met with renewables. For example, if hydrogen is produced at night, but the renewable energy is entirely in the form of solar electricity generated during the day, that nighttime hydrogen production will still require additional grid investments to either store electricity or to ramp up evening gas plant generation.

A recent paper by Ricks et al. (2023) modeled hydrogen production and found that without these requirements, "green" hydrogen production would result in more greenhouse gas emissions than gray hydrogen when accounting for direct and indirect emission impacts. The most stringent form of meeting these requirements is ensuring that all hydrogen production is directly attached to the renewable energy generation at the same site and is not balancing out electricity demand with grid electricity. This is effectively what the Scoping Plan calls for by assuming that all electrolytic hydrogen is produced via off-grid solar. However, there may be reasons to locate production separately from actual electricity generation (e.g., in order to produce hydrogen closer to where it may be used, even if wind or solar is not available at that site).

The proposed federal 45V tax credit currently reflects these three pillars to some extent, phasing in these requirements over a few years and providing the highest tax credits for hydrogen production that can demonstrate all three requirements are being met. In contrast, ARCHES wrote a letter to the Internal Revenue Service, explicitly asking that these pillars *not* be required, and suggesting that it should be okay to 1) use existing generation, 2) use renewable energy from anywhere, and 3) average energy demand for hydrogen production over the whole year, rather than matching hourly (Galiteva et al., 2023). The final federal rule, as well as the design of California-specific incentives, will hold strong implications for the true lifecycle GHG impacts of green hydrogen use to meet the state's climate targets.

Numerous environmental justice and community-based organizations in California have come together to develop *Equity Principles for Hydrogen* (2023). These principles incorporate the three pillars above to ensure GHG emission reductions, but more broadly address environmental and equity concerns including sustainability of the water supply used in hydrogen production; the exclusion of renewable energy credits, carbon capture and sequestration, fossil fuel, and biofuel feedstocks; and ensure meaningful coordination, input, engagement with, and oversight from Tribal and environmental justice communities. Moreover, these principles include guidance for ensuring safety measures are included for hydrogen infrastructure, including in particular mitigating risks posed to environmental justice communities, prohibiting hydrogen transport in existing methane gas infrastructure, and addressing safety and leakage data and knowledge gaps *before* building infrastructure. The *Equity Principles* also emphasize the goal of electrifying current fossil fuel-reliant end uses whenever possible, meeting this demand directly with renewable energy, and only using green hydrogen when those are not possible.

5.3 Comparing Hydrogen Adoption Pathways and Alternatives

The potential climate impacts of hydrogen fuel adoption depend, in part, on the application proposed, what the hydrogen is replacing, and what alternatives exist to meet that end use. In this section, we focus on the climate impacts of a few specific applications for hydrogen.

Power Plants. Currently, the LADWP, among others, is proposing to replace natural gas used in power plants with hydrogen. However, not all California decisionmakers assume hydrogen-based power generation is a core component of decarbonization. The Scoping Plan proposes a build-out of hydrogen-burning power plants for backup reliability purposes but reports nominal actual expected hydrogen combustion at these plants. Burning "green" hydrogen (produced from wind or solar power) instead of natural gas at a power plant ostensibly reduces direct CO_2 emissions by approximately 0.44 metric tons/MWh—the emission rate of natural gas combustion (EIA, 2023). When considering lifecycle methane emissions, this amount rises to approximately 0.85 metric tons/MWh using a 20-year GWP using emissions estimates from Alvarez (2018). However, these estimates do not consider *alternative approaches* to meeting power demand. As we saw in **Figure 3.4**, burning "green" hydrogen in power plants results in efficiency losses of 65 percent or more. The mix of viable alternatives that can be used in lieu of burning hydrogen in power plants will depend, in part, on how the power generated by that plant is expected to be used. Batteries, for example, may be able to replace peak power provided by power plants, but may not be suited to replace all power plant operations. Hydrogen, in contrast, may be more useful for long duration and seasonal storage applications, as discussed in **Section 3.2.1**—although hydrogen fuel cells may provide a reasonable alternative to hydrogen combustion. However, in cases where multiple technologies can meet energy system requirements, their relative energy input requirements should be evaluated.

For the case of *peaking* power plants, which generate power to meet multi-hour demand spikes (such as on hot summer afternoons), the renewable energy used to produce hydrogen could instead be paired with a lithium-ion battery. For this application, roundtrip losses would be less than 20 percent and perhaps much lower—the specifications for a lithium iron phosphate battery (a type of lithium-ion battery), for example, report losses under five percent (Mongird et al., 2020; Battery Space, n.d.). The resulting implication is that using renewable energy and batteries could replace more than three times the amount of gas power generation compared to using “green” hydrogen in the power plant. This means that hydrogen use in a power plant would only reduce greenhouse gas emissions by less than one third compared to the renewable plus battery option.

For smoothing out multi-day and seasonal fluctuations in the availability of renewable energy resources, long-duration energy storage technologies will be needed. Even if energy is stored in a lower-efficiency long-duration battery, such as iron-air (estimated at ~45 percent efficient), the climate benefit of the input electricity would be more than 40 percent higher compared to combusting hydrogen in a power plant due to the higher potential for displacing natural gas. The indirect atmospheric climate impacts of hydrogen leakage further reduce the relative climate benefit of combusting hydrogen in the power sector. Hydrogen fuel cells have similar efficiency—and, therefore, similar climate benefits—as long-duration batteries such as iron-air. But fuel cells' climate benefits can be eroded if hydrogen leakage rates are high because of the indirect climate impacts of hydrogen in the atmosphere (and to a smaller extent, due to energy loss).

Hydrogen Gas Pipeline Blending for Residential and Commercial Use. The Scoping Plan relies on blending hydrogen into *all* existing gas pipelines at a level of 20 percent by volume by 2040, with the goal of achieving climate benefits by displacing natural gas. At 20 percent by volume, hydrogen would supply only about 6–7 percent of the energy in the gas mixture due to its lower energy density compared to methane. Thus, the maximum climate benefit of this hydrogen blend is inherently no more than a 6–7 percent reduction in greenhouse gas emissions (Bard et al., 2022). Similarly, Makhijani and Hersbach (2024) found that this 20 percent hydrogen blend in gas would only reduce greenhouse gas emissions by six percent. As before, this is an upper limit that could be further diminished by the climate impact of hydrogen leakage. As noted previously, higher delivery pressures, leakage rates through polymer pipes, and pipeline embrittlement risks may all contribute to increased leakage. Additional research is required to fully characterize the climate impact of methane plus hydrogen leakage in blended pipelines, as well as from end-use appliances themselves.

Hydrogen for Transportation. Hydrogen has been proposed for numerous transportation-related applications across California, as shown in **Figure 4.2**. CARB has proposed that the largest supply would be dedicated to running heavy-duty trucks on fuel cells. Using “green” hydrogen to replace diesel in heavy duty trucks would eliminate on-road CO_2 (and, importantly, diesel particulate matter) emissions, but may have some risk associated with the near-term climate impacts from any hydrogen leakage (Makhijani and Hersbach, 2024). Sun et al. (2024) found that the climate benefits of using hydrogen fuel cells in heavy-duty trucks is particularly sensitive to the hydrogen leakage rate, compared to other applications.

The primary proposed alternative for decarbonizing trucking is to use battery-electric trucks. Currently, hydrogen may be favorable in some situations, due to 1) longer ranges for fuel cell trucks (although battery-electric trucks are rapidly increasing their range); 2) faster fueling times; and 3) the lighter weight of fuel cells compared to batteries, which is particularly important for applications where local infrastructure has weight limitations (such as ports). However, as discussed in **Section 3.2.3.2**, battery electric trucks are more efficient than hydrogen fuel cell trucks because the latter have a relative total efficiency of only around 30 percent when accounting for energy lost from the production and transport of electrolytic hydrogen. All else being equal, the same amount of renewable electricity could replace about 2.8 times as much gasoline, and therefore greenhouse gas emissions, if used in battery-electric trucks than if converted to hydrogen and used in hydrogen fuel cell trucks.

6. Health and Safety Risks, Equity, and Unknowns

6.1 Hydrogen Combustion

Hydrogen gas itself is not a health-damaging air pollutant. However, its flammability poses safety risks, and the combustion of hydrogen produces nitrogen oxides (NO_x). Much like natural gas, hydrogen gas is transported and stored under pressure and is flammable upon ignition. Like any fuel, leaks of hydrogen can also cause safety concerns if it ignites. Compared to natural gas, hydrogen ignites more easily, has a lower ignition energy, a lower flammability limit, and a wider flammability range (DOE, n.d.-f). As noted previously, hydrogen is typically transported at higher pressures than methane, and its presence in gas pipelines can cause embrittlement, increasing the risk of leakage as pipelines age (Khan et al., 2021; Penchev et al., 2022). California's historic experience with the natural gas system—including the San Bruno pipeline explosion, which killed eight people, as well as the unprecedented 2015 leak at the Aliso Canyon underground gas storage facility—informs a number of safety-related needs to ensure safe hydrogen adoption (Pipeline Safety Trust, n.d.; California Public Utilities Commission, n.d.). Essential safety measures include:

1) Dedicated funding for inspections and maintenance throughout the lifespan of any hydrogen infrastructure.
2) Significantly better characterization of the risks of hydrogen use in existing gas infrastructure, in dedicated hydrogen infrastructure, and both as a standalone fuel and when blended with gas in a wide range of pipeline materials.
3) Planning and funding to safely prepare for the end-of-life of any infrastructure.
4) Appropriate ventilation and leak detection systems.
5) Comprehensive emergency management plans, including dedicated emergency response messaging in multiple languages. For example, the Merrimack Valley gas explosions in 2018 highlighted the need for dedicated communication in commonly-spoken languages in the affected region (Massachusetts Emergency Management Agency, 2020).
6) Tailored guidelines, standards, and engagement considerations for environmental justice communities, including a consideration of whether risk contributes to cumulative burdens in the surrounding community.

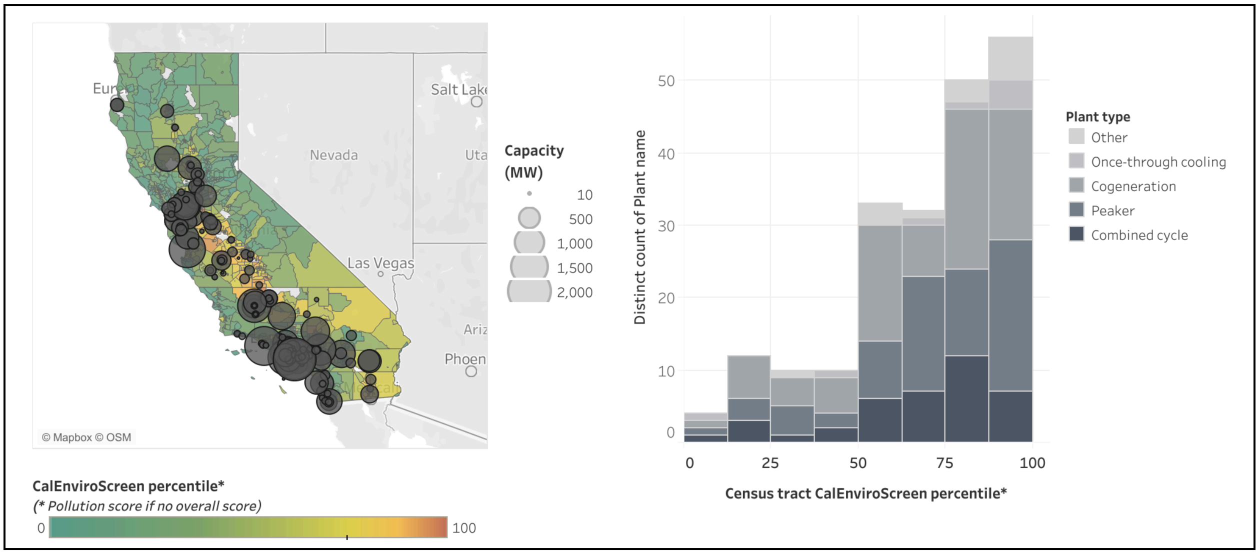
In addition to the safety concerns associated with hydrogen systems, the combustion of hydrogen raises public health concerns due to the production of nitrogen oxides (NO_x). NO_2, which is part of NO_x along with NO, is considered a criteria air pollutant by the U.S. Environmental Protection Agency due to its adverse effects on the respiratory system. It also reacts in the atmosphere to form both ozone and particulate matter ($PM_{2.5}$), which are associated with a wide range of cardiovascular and respiratory health impacts. Children, the elderly, and those with underlying conditions are particularly vulnerable to exposure to these air pollutants (U.S. Environmental Protection Agency, 2023).

Although NO_x is not produced when hydrogen is used in fuel cells, it is a byproduct of hydrogen combustion in applications such as power plants. The level of NO_x emitted depends, in part, on the emissions controls available in any given technology. Since hydrogen burns at higher temperatures than natural gas, NO_x production typically increases at higher temperatures. Actual NO_x emission rates depend on numerous additional factors, such as whether an appliance burning a natural gas-hydrogen blend has sensors that enable it to automatically adjust the fuel-to-oxygen ratio (which also affects carbon monoxide production) (Penchev et al., 2022). Although in some cases, NO_x emissions per unit energy of hydrogen burned may exceed those from natural gas, standard emission controls in applications such as power plants can mitigate these increases (EPRI, 2023). As a result, replacing natural gas with hydrogen fuel leads to increased or constant NO_x emissions, with reductions unlikely unless emission standards change. Large facilities with emissions controls, and appliances with automatic sensors, may better maintain similar levels of NO_x emissions than non-adaptive appliances, such as stoves with a pre-set air excess ratio (Penchev et al., 2022). More research is needed to better understand how these public health risks may vary with different natural gas-hydrogen fuel blends, home appliance settings, and other factors.

6.1.1 Health and Equity Dimensions of Hydrogen Combustion at California Power Plants

As noted above, numerous stakeholders have proposed repowering gas plants in California with hydrogen, though these proposals vary widely. LADWP aims to burn hydrogen at all of its gas plants in the Los Angeles Basin by 2035. In contrast, the CARB Scoping Plan (2022d) envisions hydrogen as an emergency backup at combustion turbines, while ARCHES (n.d.) supports hydrogen use in the power sector but sets no specific targets. Repowering gas plants with hydrogen across California raises a range of public health and equity concerns. First, California's gas plants are disproportionately located in the state's disadvantaged communities, as defined by the state's environmental justice screening tool CalEnviroScreen (OEHHA, 2023). **Figure 6.1** shows a map of California's gas plants overlaid with CalEnviroScreen (left) alongside the distribution of plants by CalEnviroScreen score (right). This plot shows that the state's gas plants are disproportionately located in places with high cumulative public health, environmental, and socioeconomic burdens. This trend holds when analyzing populations living within a 6-mile radius of each plant as well, rather than just the census tract where the plant is located (Krieger et al., 2016).

Figure 6.1: California Gas Plants by Census Tract CalEnviroScreen Score Percentile. Map of California gas plants by capacity (MW) overlaid with census tract CalEnviroScreen Score (left); distribution of gas plants census tract CalEnviroScreen score (right). Adapted from Krieger (2020).



These findings raise a number of concerns for repowering these plants with hydrogen. The first concern is that substituting hydrogen for natural gas at these plants, even if total emissions do not increase, will continue to disproportionately impact some of the state's most vulnerable populations and overburdened communities. Second, introducing hydrogen—a fuel with poorly characterized safety risks such as those associated with building out hydrogen pipelines and storing hydrogen on-site—may introduce new hazards to these communities. Finally, although gas plants are not the primary contributors to poor air quality across the state, they are expected to continue meeting peak electricity demand in the future. It is likely they will be used on hot summer days when air quality is already poor, exacerbating acute air quality conditions. Some gas plants in the San Joaquin Valley have been shown to have two-thirds of their operations occur on days when air pollution exceeds federal air quality standards—worsening these conditions (Krieger et al., 2016). Without careful planning, repowering these gas plants with hydrogen could perpetuate safety and public health risks in the state's most disadvantaged communities. One possible pathway to mitigate public health risks, though not infrastructure safety risks, is to use fuel cells instead of hydrogen combustion at power plants because fuel cells do not produce NO_x as a byproduct.

6.1.2 Health and Equity Dimensions of Hydrogen Use in Transportation

Using hydrogen in the transportation sector will also have significant health and safety impacts. While hydrogen combustion in transportation will release NO_x, most proposals for the transportation sector rely on hydrogen fuel cells rather than hydrogen combustion (unlike the power sector). Supporting hydrogen fuel cell adoption in the transportation sector, much as for the power sector, will likely help reduce air pollutant emissions. Since the transportation sector in California is one of the primary drivers of poor air quality, and because vehicle pollution disproportionately impacts the state's disadvantaged communities, pathways to reduce these emissions (e.g., by using hydrogen fuel cells in heavy-duty trucks) are likely to reduce pollution levels in some of the state's most environmentally burdened areas (California Energy Commission, 2019; Reichmuth, 2019). This is particularly true for replacing diesel in medium- and heavy-duty trucking but may be less true for using hydrogen in light duty vehicles, which can use renewable electricity more efficiently through direct use in batteries (see **Section 3.2.3.1** above). If batteries become more economical at powering heavy-duty trucks in the future, they would use renewables more efficiently than hydrogen fuel cells, therefore enabling any new renewable energy builds to displace *more* fossil fuels and hence more health-damaging air pollutants. However, any transition that increases hydrogen access along these transportation corridors, must consider that any safety risks will likely also disproportionately affect these same communities.

6.1.3 Health and Equity Dimensions of Hydrogen Combustion in Homes

Current concerns regarding hydrogen use in homes and businesses are primarily the result of proposals to blend hydrogen in gas pipelines, as in CARB's Scoping Plan. Most existing proposals cap the hydrogen fraction in pipelines at 20 percent by volume. As noted, even low fractions of hydrogen can embrittle pipelines, potentially increasing gas leakage rates. This embrittlement, coupled with hydrogen's wider flammability range compared to gas, may heighten safety risks. Burning hydrogen-gas blends in home appliances may also increase indoor NO_x emissions, depending on appliance settings.

There is also a risk that wealthier homes and homeowners may more readily afford the switch to electric appliances such as heat pumps and induction stoves, resulting in lower-income and renter households being left behind on gas appliances and pipelines. The populations face a significant risk of being stranded on the natural gas system, with gas rates expected to skyrocket due to the diminishing number of customers left on the gas distribution system (Krieger et al., 2020). Blending expensive hydrogen into pipelines will likely exacerbate the problem of rising gas distribution costs. The same renter and lower-income households left covering those costs will also face the public health and safety risks associated with hydrogen combustion in homes.

Health and Equity Considerations for Direct Air Capture and Carbon Capture and Sequestration

State-level and global strategies to meet greenhouse gas targets and limit global temperature rise rely on direct air capture (DAC) of carbon and carbon capture and sequestration (CCS) associated with specific facilities. Global models indicate that maintaining temperatures below a 2˚C increase requires reliance on some form of negative greenhouse gas emissions (Gasser et al., 2015). Even after emissions are stabilized, carbon capture may be valuable for drawing down existing atmospheric concentrations. However, using CCS, DAC, and other carbon capture technologies to achieve climate targets must be balanced with a few other considerations.

The first is the question of *moral hazard*: there is a concern that overreliance on DAC or CCS may be seen as a "license" to continue to use fossil fuels and to emit GHGs today—which also implies ongoing emissions of the health-damaging air pollutants that are frequently emitted alongside GHGs, as well as the propagation of upstream and downstream environmental and health impacts associated with fossil fuel use. This ongoing use risks perpetuating the many inequities associated with current fossil fuel consumption, including high cumulative pollution burdens in low-income communities and communities of color, leading to ongoing environmental justice concerns even as net GHG emissions fall.

Second, current DAC technologies require significant energy inputs, as detailed in **Section 4**. A reasonable question is therefore to weigh whether new renewable energy resources should be used to power DAC or should be used to *directly* displace fossil fuels. This trade-off holds more weight in the near term while renewable energy resources are limited and will hold less weight once fossil fuel use has been largely eliminated from our economy. Comparisons further depend on whether DAC (and, to some extent, CCS) can make use of waste heat or other energy resources that cannot be easily used to displace fossil fuels.

Finally, DAC and CCS encompass a broad array of carbon capture and carbon storage techniques. The full environmental, health, and equity risks and concerns associated with carbon capture, compression, transmission, and storage, must be addressed for each technology and within each community where such technology use is proposed.

A primary concern associated with both DAC and CCS, independent of capture technology, is the transport and storage of CO_2 itself. CO_2 transport and storage are relatively mature technologies that are frequently employed in the fossil fuel industry—notably for enhanced oil recovery—as well as for other commercial applications, such as in the food and beverage industry. Carbon capture and storage solely for the purpose of atmospheric carbon removal is a younger but rapidly growing field. Carbfix in Iceland, for example, has now been storing carbon in underground basalt formations since 2014 (Carbfix, n.d.). The risks associated with CO_2 transport and storage are largely associated with the unexpected and accidental leakage of CO_2. CO_2 is heavier than air, which means it can settle close to the ground in low-lying areas. People or animals trapped in such an area—or, for example, asleep when exposed—risk suffocation or death (U.S. Centers for Disease Control and Prevention, n.d.). Any impurities in a CO_2 stream, such as hydrogen sulfide, can add additional risks

(Congressional Research Service, 2022). The massive rupture and leakage from a CO_2 pipeline in Satartia, Mississippi in 2020, which sent dozens of residents to the hospital, provides an example of both the risks of CO_2 transport as well as how these risks can be compounded by poor communication and risk management by the responsible industry (Zegart, 2021). Some of these risks could be mitigated with technologies that, for example, store CO_2 as a solid, as well as through hazard mitigation and communication plans co-developed with nearby communities.

There are also potential environmental and public health risks associated with both CCS and DAC, although these are still poorly characterized in many places and are likely to vary significantly by technology type, site, and application. The first concern with CCS is that it requires additional energy to power (often on the order of 15–25 percent) (European Environment Agency, 2011). If this energy can come from renewable energy resources, then impacts can be mitigated. However, if this energy requires additional consumption of fossil fuels, such as natural gas, then the increase in energy consumption would result in a concomitant increase in upstream health-damaging air pollutants[82] *even if all on-site air pollutant emissions are mitigated.* These emissions include both criteria air pollutants (e.g., NO_x, $PM_{2.5}$) and hazardous air pollutants (e.g., benzene, toluene) associated with the production, processing, and transport of fossil fuels. Second, while some on-site emissions are likely to be mitigated through the CO_2 purification process (as leaving such co-pollutants in the CO_2 stream can poison the catalysts used for CCS) the actual air pollutant emissions vary widely by process. For example, CCS at natural gas combined cycle plants can nearly eliminate NO_x emissions if following an oxyfuel combustion process but can actually increase NO_x emissions if CCS is applied post-combustion, and is further associated with a significant increase in ammonia emissions (European Environment Agency, 2011). These trade-offs necessitate equity-related discussions to address air pollution exposures for populations living near to and downwind from these facilities, and consideration of decarbonization pathways that might avoid such emissions.

In the case of DAC, the potential environmental and public health risks are much more uncertain given the wide range of technologies under development and lack of technology maturity. The impacts of these facilities also depend on the energy source used. For example, wind and solar power is unlikely to greatly increase public health risks, but many proposed DAC facilities in California are co-located with biomass electricity generation, which can emit health-damaging air pollutants, raising additional public health concerns.

[82] For discussion of health-damaging air pollutant emissions throughout the oil and gas supply chain, see: Michanowicz et al. (2021).

6.2 Biofuel Feedstocks and Ammonia

The use of biofuels (e.g. biomass and biogas) as proposed by the Scoping Plan poses potential public health and safety risks, particularly during the transport of feedstocks and production of hydrogen. Using ammonia as a chemical carrier for hydrogen, discussed in **Section 3**, can also contribute to health concerns. Both are discussed below.

6.2.1 Biomass

Biomass gasification for hydrogen production poses some public health risks, including increased on-road emissions from biomass transport and potential pollution near generation facilities. Biomass gasification plants require significant amounts of feedstock that must be transported to wherever facilities are located. This will result in increased pollution along common trucking corridors and potentially in the communities surrounding the gasification plants unless biomass feedstocks are transported using zero-emission vehicles. The process of biomass gasification also has the potential to increase pollution near the plant if emissions and effluent are not carefully controlled (Intelligent Energy for Europe Programme, 2009). Dust, soot, tar, and particulate matter are all components of the gas created during gasification, and the exhaust gas contains carbon monoxide, harmful organic compounds such as benzene, NO_x, and particulate matter (Intelligent Energy for Europe Programme, 2009). Existing models suggest that while biomass energy CCS (BECCS) facilities can help meet California's greenhouse gas targets and reduce statewide emissions of health-damaging air pollutants, their use would still lead to localized increases in health-damaging pollutants, in particular $PM_{2.5}$ (Wang et al., 2020).

Both transport and gasification pollution risks could exacerbate existing inequities in certain regions. For example, agricultural residue is primarily generated in the Central Valley, which is also host to at least some usable CO_2 storage locations (Kim et al., 2022). This may incentivize companies to build biomass gasification with CCS facilities in the region. However, the area is already beset by heavy air pollution and is home to a significant portion of California's disadvantaged communities (OEHHA, 2023; CARB Scoping Plan, 2022d, Figure 4-12). Siting these facilities in or near already overburdened communities in the Central Valley has the potential to increase local pollution from biomass transport to these facilities, further harming public health. In certain areas of the state, including in the Central Valley, water availability could also become a key issue (as discussed at the end of **Section 3**).

6.2.2 Biogas

Landfills and the dairy-livestock industry are the two largest sources of methane emissions in California (CARB, 2022d, Figure 4-12). As discussed in **Section 5**, California's Low Carbon Fuel Standard (LCFS) allows dairy/livestock operators and landfills to generate "carbon-negative" credits if they capture methane that would otherwise be emitted from their operations into the atmosphere and use the captured biomethane to displace fossil-fuel combustion.

One major concern is that hydrogen producers who make hydrogen in the conventional way—via steam methane reforming of natural gas—will be able to purchase carbon offsets from California dairy farms and landfills and claim that the hydrogen they produce is green. This type of book-and-claim accounting system fails to tackle the real-world impacts of SMR hydrogen production, including not only the carbon emissions associated with it, but also the emissions of harmful air pollutants impacting nearby communities, including NO_x, particulate matter, and volatile organic compounds (Sun et al., 2019).

Another concern about book-and-claim practices is that they may create perverse incentives for livestock operators to manage their manure and operations in ways that increase their methane emissions in order to earn more LCFS credits from capturing them. Incentivizing biogas production at large concentrated animal feeding operations creates the additional issue of how to dispose of the vast amounts of liquid residue that are often loaded with antibiotics and other chemicals. Spreading the residue on land requires long-distance transport, leading to increased on-road emissions along trucking corridors.

6.2.3 Ammonia

While hydrogen can be converted to ammonia for transport and storage (as discussed in **Section 3.1**), ammonia has the potential to contribute significantly to $PM_{2.5}$ and ozone pollution levels if used directly, as it contributes to the formation of NO_x emissions (Rathod et al., 2023; Ma et al., 2021; Pedersen et al., 2023). This concern is alleviated if ammonia is converted back to hydrogen before use. However, ammonia is still toxic, corrosive, and flammable, with a detectable smell at even low atmospheric concentrations (DOE, n.d.-g). Although used safely in industrial and agricultural applications, ammonia poses occupational health and safety risks during handling, such as damage to the skin and lungs (Ma et al., 2019; IEA, 2019; National Institute for Occupational Safety and Health, n.d.) Additionally, using ammonia as an energy-dense carrier for hydrogen may lead to ammonia odor in neighborhoods where trucks carrying ammonia either sit in traffic or unload their product. It also increases the risk of ammonia spills, which are particularly damaging to aquatic environments such as lakes and rivers (DOE, n.d.-g). Finally, ammonia combustion can increase the emissions of nitrous oxide (N_2O), a powerful greenhouse gas (Pedersen et al., 2023).

7. Case Study: Repowering Scattergood with Hydrogen

Scattergood Generating Station, Los Angeles

The Los Angeles Department of Water and Power (LADWP) plans to repower its four in-basin gas plants with hydrogen by 2035, starting with the Scattergood Generating Station in 2029 (LADWP, 2022a). Scattergood, built in the 1950s on the coastline next to the Los Angeles International Airport, currently uses sea water in a once-through cooling process. Current regulations require phasing out this process by the end of 2029 to mitigate harms to marine wildlife (State Water Board, 2023b). LADWP's 2022 Strategic Long-Term Resource Plan (SLTRP) plans to meet this target by replacing its once-through cooling units at Scattergood with 688 MW of hydrogen-burning combined cycle units. This plan stands in contrast with the Scoping Plan, which only relies on hydrogen combustion turbines for backup in the power sector. LADWP aims to begin with a 30 percent hydrogen blend at Scattergood in 2029, phasing up to 100 percent by 2035. However, limited details are provided about LADWP's plan, and LADWP highlights numerous potential risks and challenges, ranging from a lack of technology maturity to the absence of green hydrogen infrastructure in Los Angeles. We outline these and some additional challenges and unknowns below, as well as possible alternative strategies to meet Los Angeles's peak power demand.

Technology Maturity. Although many companies are currently working on creating hydrogen-burning power plants, to our knowledge no commercial power plants exist that can run on 100 percent hydrogen. Mitsubishi developed a commercial turbine that can run on 30 percent hydrogen, and says it is aiming to complete "rig tests" on a turbine that can run on 100 percent hydrogen by early 2025, although it is unclear when they hope to bring a commercial turbine to market (Mitsubishi Heavy Industries Group, n.d.). GE Vernova (n.d.) has also commercialized a turbine that runs on a 50 percent hydrogen blend. Other companies, such as Siemens, are developing similar technologies but they are still under development and timelines are uncertain (Siemens Energy, n.d.). The LADWP plan for Scattergood aims to rely on a "fast-ramping combined-cycle unit" to burn hydrogen that will begin operation in 2029, but highlights "technology maturity" as a potential risk (LADWP, 2022a). The CEQA analysis for the Scattergood Modernization Project proposes a 3.5-year project construction timeline beginning in early 2026 (LADWP, 2023).

A handful of demonstration projects have briefly blended hydrogen at existing plants, including up to 38 percent by volume (about 17 percent by energy) at a combined cycle gas plant in Alabama in 2023 and 44 percent by volume (21 percent by energy) at a simple cycle combustion turbine in New York (Constellation Energy, 2023; EPRI, 2022). These demonstrations have highlighted a few concerns and limitations. The demonstration at a Wärtsilä gas turbine in Michigan blended up to 25 percent hydrogen into its fuel—but had to drop this to 17 percent to run at full load (Wärtsilä Corporation, 2023). It is unclear if this limitation applied to the other demonstrations as well. The demonstration in New York highlighted the need to greatly increase the pressure of the gas in order to increase the hydrogen blend fraction, but there is a dearth of data on what the long-term impact might be of this increased pressure on power plant equipment. Similarly, there is a lack of data on what the long-term impact of hydrogen blending might be on power plant equipment, given the well-known problem of hydrogen-induced embrittlement of steel pipelines.

It is also worth noting that the 44 percent blend of gas *by volume* at the New York turbine described above is only equivalent to about 21 percent from an energy standpoint. As a result, blending hydrogen into gas at relatively high volumes has a much lower impact on total CO_2 emissions than burning pure hydrogen. The New York Brentwood demonstration project, for example, found that at a 35 percent hydrogen blend, CO_2 emissions were only reduced by 14 percent (EPRI, 2022). Applying data from this same study to Scattergood suggests that a 30 percent by volume blend in 2029 is likely to only reduce CO_2 emissions by about 12 percent.

Green Hydrogen Supply. To power Scattergood with green hydrogen, the power plant would need to secure supply by 2029. There is general agreement that there is insufficient in-basin renewable energy capacity to produce green hydrogen in Los Angeles itself, although potentially some curtailed renewables could be dedicated to this purpose. LADWP released a Request for Information on green hydrogen to address this and other challenges, and the CEQA analysis for the Scattergood Modernization Project states that supply will be addressed in a future CEQA analysis (LADWP, 2023). It is unclear exactly how much hydrogen is expected to be needed for Scattergood. The CEQA analysis states that Scattergood will run at a "low capacity factor" compared to today (which is approximately 27 percent) but does not give a value. In contrast, the SLTRP shows a base case capacity factor of over 40 percent for Scattergood in 2030 (Case 1) (LADWP, 2022a).

We can use these values to estimate the amount of green hydrogen required to power Scattergood. Since the conversion of Scattergood is staged, only 346 MW is expected to be hydrogen-ready by 2030. At a 40 percent capacity factor, this means that the Scattergood hydrogen unit would need to produce 1.2 million MWh of electricity in 2030. At a 30 percent blend, hydrogen is responsible for only about 12 percent of the MWh generated. Given efficiency losses, this would still require approximately 300 MW of solar (at 30 percent capacity factor) to produce sufficient hydrogen for the plant in 2030, and likely more when the plant expands to 688 MW and is expected to burn 100 percent hydrogen in 2035 (although the capacity factor at this point is uncertain).

All of this solar to produce green hydrogen would have to be produced somewhere. SoCalGas's proposed Angeles Link suggests exploring locations such as the Central Valley, Mojave/Needles, and Blythe as candidate locations—which are approximately 100+, 150+, and 225 miles from Scattergood, respectively (SoCalGas, 2022b). SoCalGas has even considered pipeline routes extending to Utah. However, there are no commercial green hydrogen production sites at these locations. Providing green hydrogen to Scattergood via AngelesLink would therefore be contingent on the siting, permitting, and construction of green hydrogen production facilities somewhere outside of the Basin, as well as a hydrogen pipeline connecting those sites to Los Angeles, all within five years. If the latter is not built, hydrogen could potentially be trucked in. Given a number of potential off-takers—including the Ports of Los Angeles and Long Beach—this lack of extant supply raises concerns about supply reliability as well as price volatility if there are production, delivery, or storage choke points.

Infrastructure. In addition to supply infrastructure, there is a lack of green hydrogen delivery and storage infrastructure, also highlighted by the SLTRP. There are currently no green hydrogen transmission and distribution pipelines nor storage facilities in Los Angeles. The SLTRP notes that: "Space constraints preclude onsite production and storage of hydrogen at the generating stations" and that there are significant space constraints in the surrounding communities. If appropriate siting is found for such infrastructure, it frequently takes a significant amount of time to permit and build. For example, LADWP notes the 12-year period it took to permit and build an 11.5-mile-long underground electric transmission line in West Los Angeles. As noted above, if Angeles Link were to deliver hydrogen to Los Angeles in time to supply Scattergood, it would likely need to build more than 100 miles of pipeline—and perhaps more than 200 miles—in less than five years. In addition, local transmission, storage, and subsequent distribution infrastructure would likely be necessary. The SLTRP states that a "continuous" hydrogen supply is necessary to deliver hydrogen to LADWP power plants since "on-site storage is impractical." It is unclear if a lack of pipeline capacity could be solved with trucking in hydrogen in the near term (LADWP, 2022a).

One of the additional risks associated with building out this infrastructure is the risk of stranded assets. For example, if hydrogen trucking and delivery infrastructure is needed to deliver fuel by 2029 but is phased out by 2035 if a pipeline is built, the associated investment might not be fully recovered. Moreover, as noted above, the predicted amount of hydrogen needed is wildly variable. Scattergood might operate at capacity factors of over 40 percent according to the SLTRP (LADWP, 2022a). Across all Los Angeles plants, without transmission upgrades, the SLTRP projects an average capacity factor of 18 percent between 2028–2045. And with transmission upgrades, that average drops to two percent, because larger transmission capacity would enable more electricity imports into the Los Angeles Basin and displace the need for local power generation. This calculation implies both a wide range of potential outcomes, as well as the potential for a significant drop in demand over this time frame. Building out the infrastructure to deliver sufficient hydrogen to power Scattergood at a 40 percent capacity factor, with the potential for this to rapidly drop to only two percent, suggests that these infrastructure investments might quickly become stranded assets as well. These are not purely hypothetical concerns. As noted previously, Shell Global, which had begun building out passenger vehicle hydrogen fueling infrastructure across California, canceled 48 planned stations in 2023, and shut down its remaining seven operational light-duty vehicle (LDV) fueling stations in early 2024 due to supply and market barriers—such as the very low adoption rates of hydrogen LDVs (Martin, 2024).

Successfully building hydrogen production, transmission, and storage infrastructure will also require significant ongoing monitoring for safety risks, in particular due to its immaturity as a technology. Insufficient inspections and upkeep of natural gas infrastructure has contributed to significant events in the past, such as the Aliso Canyon gas leak in 2015. Near-term hydrogen maintenance and inspections will likely require even more intensive attention due to the current lack of long-term operational and degradation data for hydrogen infrastructure. This need will likely require significant additional workforce training and development to ensure there are enough workers to conduct inspections and maintain infrastructure. In addition, safety and emergency management plans will require ensuring communication about risks, and any incident messaging, is provided in numerous languages and across a broad range of platforms in order to adequately reach Los Angeles' diverse population.

Air Pollutant Emissions. Replacing natural gas with hydrogen in power plants has the potential to provide some broad natural gas system air pollutant benefits, including the reduction of upstream health-damaging air pollutant emissions associated with gas production, processing, and transmission infrastructure (Michanowicz, 2021). However, co-firing hydrogen at the New York demonstration project described above led to an *increase* in NO_x emissions at the stack. These can be mitigated by air pollution control technology, which will be required under air quality regulations, but there is no reason to believe that NO_x emissions per MWh of generation will be any lower than what is currently permitted for gas. Moreover, if the capacity factor of Scattergood increases from 27 percent to 40 percent, these emissions will likely go up. There is limited data on NO_x emissions during start-up and shut-down of hydrogen gas turbines—partly due to the lack of maturity of the technology—but NO_x emissions do increase for gas turbines during start-up and shut-down operations. From 2010–2018, Scattergood ran an average of 610 hours every time it was turned on, suggesting it was running in relative steady state rather than having frequent start-ups (Krieger, 2020). However, the proposed Scattergood turbine is fast ramping, suggesting that LADWP plans to operate it to flexibly respond to load, rather than at steady state, and therefore suggesting a risk that its operation might lead to an increase in emissions.

Power plants in Los Angeles currently contribute a relatively low fraction of total NO_x emissions in the Basin, but they do tend to operate simultaneously on hot summer days (when ozone is often high) to meet peak cooling demand, suggesting an ongoing risk that these plants will continue to cumulatively exacerbate air quality on some of the worst air quality days. In 2018, for example, Scattergood only operated at a capacity factor of 17 percent, but 48 percent of its total generation occurred on days exceeding the EPA's National Ambient Air Quality Standards (NAAQS) for ozone, and six percent on days exceeding NAAQS standards for particulate matter.

There are also some concerns related to site-level construction emissions at the Scattergood facility. The CEQA analysis suggests that during construction, up to 40 off-site trucks may serve the site per day, risking an increase in diesel pollutant emissions (LADWP, 2023). The census tract Scattergood is located in has insufficient population to have a full CalEnviroScreen 4.0 score, but it is ranked as more polluted than 97 percent of census tract in California (OEHHA, 2023).

Alternatives. While a full analysis of alternatives to the repowering Scattergood with hydrogen is beyond the scope of this report, we will note a few technologies that were not fully considered in the SLTRP. For example, LADWP did not fully consider long-duration energy storage technologies, which are also under development but are beginning to build real-world demonstration projects (CEC, 2023c). One study has suggested that all of California's gas plants could be replaced with long-duration energy storage (Go et al., 2023). While these projects will certainly face scale and deployment challenges, much like hydrogen, they should be included in the potential resource deployment mix as candidates for helping reach peak demand. In addition, LADWP did not fully explore the potential for demand management—in particular, utilizing the rapidly electrifying vehicle fleet—to mitigate peak demand. Finally, the state is rapidly moving forward with offshore wind, including sites off the coast of Southern California, which tend to have the highest wind speeds on summer evenings, which aligns relatively well with LADWP's identified time of projected peak demand (Wang et al., 2019; Musial et al., 2016; LADWP, 2022a). It would be valuable to model the impact of integrating this offshore wind supply into LADWP's modeling to identify its impacts on LADWP's identified need for in-basin hydrogen combustion.

8. Key Findings, Policy Considerations, and Recommendations

We discuss the key findings from our report in **Section 8.1** below. These findings reflect significant unknowns and uncertainties about the benefits and impacts of green hydrogen deployment to achieve California's climate targets, due in part to the nascent nature of the industry alongside inconsistent policy goals from decision-makers across the state. Therefore, in **Section 8.2**, we highlight important policy considerations and guiding questions that can help inform hydrogen-related decision-making in the context of these unknowns. Finally, in **Section 8.3**, we provide recommendations and suggest future research areas that can help inform decision-making while California continues to develop decarbonization strategies.

8.1 Key Findings

Decision-Makers in California are Not Aligned on Hydrogen. California's agencies, utilities, and other decision-makers have limited alignment on the role of hydrogen in a decarbonized California. Across the state, decision-makers have set a wide range of targets for hydrogen deployment, with different primary end-uses, timelines, and definitions of what makes hydrogen "clean" or "green." This lack of alignment is illustrated in variation in hydrogen goals proposed by CARB, ARCHES, and LADWP, as well as scenarios explored in the 2023 IEPR from the CEC between numerous local and state planners. Unless addressed, these divergent proposals may encounter energy security and supply challenges, or risk undermining cross-California decarbonization efforts.

Existing Hydrogen Plans Lack Detail. Many of the proposed "green" hydrogen plans lack sufficient detail, including locations and methods of hydrogen production, energy sources for hydrogen production (whether in-state or imported energy, grid electricity, or off-grid renewables), delivery methods, and the impacts of these factors on the ability to meet other energy demands. As a result, it is impossible to determine the total cost of the proposed build-out of hydrogen infrastructure and the appropriate safety measures. This lack of detail raises questions about the feasibility of many hydrogen deployment proposals and inhibits alignment between stakeholders. These unknowns also make it difficult to fully characterize the potential system-level impacts of hydrogen use, including equity, public health, environmental, climate, and economic concerns.

California Will Need to Rapidly Accelerate Hydrogen Infrastructure Deployment to Meet Proposed Goals. Achieving proposed hydrogen deployment goals across California will require the rapid deployment of associated infrastructure, including of technology that is not yet commercial. For example, LADWP is aiming to begin to repower its gas plants with hydrogen in 2029, leaving five years to identify a hydrogen supply, build a means of hydrogen transport and storage, and install and operate hydrogen combustion technology that is not yet on the market. The proposed rapid adoption of emerging technologies without adequate operational, performance, safety, and longevity data suggests the need for planning and funding to support accompanying monitoring and safety measures over the lifespan of these projects.

Renewable Energy Deployments Will Need to Increase Multifold to Meet Hydrogen and Direct Air Capture Goals. To meet the energy demands for hydrogen production and direct air capture as laid out in the Scoping Plan (CARB, 2022d), renewable energy (e.g., wind and solar) must nearly quadruple the historic annual average build rate, and more than double the maximum annual historic build rate every year from now through 2045. These estimates may change as direct air capture technology matures and energy requirements become clearer. But this compounding effect on renewable energy builds highlights the need to look at deployment goals *comprehensively* and to assess their implications at an economy-wide level, rather than on individual technologies or sectoral deployments.

Green Hydrogen Production Inefficiencies Make Direct Electricity Use More Suitable for Many Applications. Electrolytic hydrogen production is roughly 60–70 percent efficient, depending on the technology and associated processes, and hydrogen produced via biomass gasification is roughly 40–70 percent efficient depending on the moisture content of the biomass. Certain applications, such as burning hydrogen in power plants to generate electricity, compound inefficiencies, resulting in roundtrip efficiencies of less than 30 percent. As a result, using hydrogen in certain applications, such as electricity production, home heating, or in light duty vehicles, would require a significantly larger buildout of renewable energy than if these renewables could be used directly or stored in batteries. However, for some applications, such as long-duration energy storage where lithium-ion batteries are considered too expensive at present, hydrogen may still be an appropriate option.

California May Benefit from Prioritizing Certain Hydrogen End-Uses Over Others. Given uncertainties in the ability to rapidly scale hydrogen production and delivery infrastructure, and viable alternatives for many proposed hydrogen end uses, it may make sense to prioritize certain hard-to-electrify end-uses over others. For example, prioritizing the use of hydrogen for certain high-heat applications that typically require fossil fuels, rather than blending hydrogen in gas pipelines to decarbonize residential heating, which could be done via electrification using efficient heat pumps. Given unknown future costs of both hydrogen and other decarbonization infrastructure (e.g., long duration energy storage), such prioritization will likely have to be frequently revisited.

Hydrogen Buildout as Planned Poses Stranded Asset Risks. Unknown future demand for hydrogen—in particular for end uses that have viable or proposed alternative technologies—presents a risk that the build-out of hydrogen production and delivery infrastructure may become stranded assets, as has already been seen for light duty vehicle fueling stations in California. Prioritizing certain hydrogen end uses and focusing initial production and delivery infrastructure on only the hardest-to-abate sectors may help manage such risks. Aligning, clarifying, and adding detail to these plans may also help hydrogen stakeholders minimize the risk of stranded assets.

Hydrogen Pipeline Blending Presents Safety Risks and Limited Climate Benefits. Proposed blending of hydrogen in existing gas pipelines presents safety risks due to hydrogen embrittlement of pipelines, hydrogen leakage, and other factors. Proposed hydrogen blending levels—up to approximately 20 percent by volume—result in a fuel blend that is only seven percent hydrogen on an *energy* basis because hydrogen is less dense, meaning that the *maximum* climate benefit of such a blend would be at most a seven percent reduction in greenhouse gas emissions. This benefit would be further eroded if the hydrogen production pathway has any associated greenhouse gas emissions, such as those associated with hydrogen leaks or using biogas as a feedstock.

Hydrogen Use Poses Climate Risks. Hydrogen has indirect climate warming effects in part because its presence in the atmosphere affects atmospheric concentrations of methane, ozone, and water vapor, resulting in an estimated global warming potential of roughly 37 times that of CO_2 over 20 years and 8–12 times that of CO_2 over 100 years. Any hydrogen leakage therefore undermines the benefit of fuel switching to hydrogen. Studies of hydrogen leakage rates are preliminary and have not been studied across all proposed applications, making it difficult to accurately characterize the scale of leakage across proposed hydrogen deployment scenarios, but they have demonstrated that leakage does occur. Hydrogen produced from biogas is likely to have increased climate impacts due to the risk of methane leakage from the biogas supply chain, although these values are also poorly characterized. Additionally, using biomass to produce hydrogen requires the transport of that feedstock to hydrogen production facilities. Unless transport methods are zero-carbon (e.g., using zero-emission vehicles), this biomass transport could have impacts as well.

Hydrogen Combustion Perpetuates Public Health Impacts from NO_x. Hydrogen combustion produces NO_x and may even increase NO_x emissions compared to gas combustion unless mitigation strategies are put in place. Scrubbers may be used at power plants to limit NO_x emissions to permitted levels, but even permitted levels can continue to have public health impacts. Studies on NO_x emissions from hydrogen use in commercial and residential appliances show mixed results but appear to indicate these emissions either stay constant or increase, meaning they would contribute to poor indoor air quality and associated public health impacts much like natural gas combustion in homes.

Equity Impacts from Hydrogen Use Vary by Application. The use of hydrogen holds equity implications, although these vary significantly by application. For example, expanding hydrogen combustion at existing gas power plants risks perpetuating NO_x emissions in the state's disadvantaged communities. Similarly, risks may be posed by industrial facility use of hydrogen combustion. Use of hydrogen fuel cells in trucks, which also disproportionately release diesel particulate matter into disadvantaged communities, is likely to help reduce pollution burdens. The build-out of hydrogen fueling infrastructure along busy transportation corridors will require significant community input, safety measures, emergency response preparations and messaging in multiple languages, and other efforts to ensure that safety risks are mitigated in places that have historically faced numerous environmental health burdens due to fossil fuel transportation. The full lifecycle of hydrogen production and use should be evaluated when addressing potential equity impacts, in particular because some proposed feedstocks—such as biomass and biogas—have known potential environmental and public health risks, and production-related impacts on exposed populations should be considered.

The System-Level Impacts of Hydrogen Pathways and Possible Alternatives Are Unclear. The system-level impacts of proposed hydrogen use are difficult to evaluate given the lack of detail in hydrogen proposals, but these system-level impacts are important for fully understanding the benefits and impacts of hydrogen use for various applications. For example, "green" hydrogen fuel cells might have a *direct* climate benefit if used to replace gas in a power plant. However, if that power could have been replaced with renewable energy stored in a lithium-ion battery, then using hydrogen would have incurred a significant opportunity cost—the hydrogen pathway requires nearly twice as much wind or solar energy as the battery pathway, and those surplus renewables could have been used to displace fossil fuels elsewhere. Understanding these *indirect* impacts and opportunity costs requires an expansion of economy-wide decarbonization modeling to better incorporate the renewable energy inputs for hydrogen production.

8.2 Key Policy Considerations and Guiding Questions to Address Unknowns

Our findings highlight numerous policy and regulatory considerations that state and local planning processes have not fully addressed. The largest of these include lack of detail in plans and lack of alignment between planners. A number of assumptions and requirements regarding the scale of hydrogen production and use in California may prove to be unrealistic and/or not fully supported by science. These gaps pose multiple risks in the rollout of hydrogen across the state, including that multiple competing demands for hydrogen might undermine the ability of any individual organization or agency to achieve its hydrogen goals and associated climate targets; that lack of coordination may result in inefficient infrastructure investments and potential stranded assets; and that lack of coordination and prioritization around the many needs for renewable electricity, including direct use, hydrogen production, CCS, and direct air capture, may lead to inefficient build-out of energy resources. Moreover, these competing plans may have indirect system-level impacts (e.g., on greenhouse gas emissions, workforce needs, etc.) that are impossible to model and address without coordinated planning.

Moving forward with plans without clear certainty on details also leaves significant unknowns about the public health, equity, and climate implications of hydrogen infrastructure buildout—and inhibits the ability to address or mitigate any unexpected impacts. In addition, many decarbonization planning goals are reliant on being able to deploy renewable energy and hydrogen rapidly and at previously unachieved scales, and there is limited contingency planning for what to do if these goals are not achieved. Below, we highlight: 1) Key questions that will help better characterize the impacts of hydrogen policies and projects, 2) Important unknowns and contingencies that need to be addressed before moving forward, and 3) Additional policy considerations.

Key Questions to Better Characterize the Impacts of Hydrogen Policy and Deployment Proposals

- **Alternatives.** What alternatives exist for any proposed application for hydrogen? When evaluating the impacts and benefits of a project, how do you define a counterfactual scenario? *Example: How do the cost, infrastructure, public health, climate, equity, and environmental impacts of burning hydrogen in power plants compare to meeting flexible power demand with renewable energy and batteries?*
- **Lifecycle Impacts.** What are the lifecycle energy, water, and climate implications for any proposal, and how does this compare to alternatives? *Example: What are the lifecycle greenhouse gas impacts of using biogas-derived hydrogen? How much water is needed, and is this available in the places where—and the seasons when—biogas-derived hydrogen is expected to be produced?*
- **System Impacts.** How does any proposal affect the energy system as a whole? How do these impacts change when you simultaneously consider multiple hydrogen proposals or other goals for California's energy system? *Example: How does hydrogen use in heavy duty transportation affect the renewable energy build rate and the required build-out of hydrogen pipeline and storage infrastructure? How might this build rate for renewables impact the ability to meet direct air capture goals? How does the capital cost expenditure on hydrogen projects affect the capital available for other decarbonization efforts?*
- **Stranded Infrastructure Risk.** What is the likelihood an investment, such as a hydrogen production facility, will be needed in the future? What happens and who pays for it if it is not needed? If an investment is not made, will it turn an associated investment, such as a hydrogen storage facility, into a stranded asset? *Example: Who covers the costs if a pipeline is built and there are insufficient off-takers?*
- **Safety and Public Health.** What do we know and not know about the safety and public health risks of hydrogen production, transportation, and use for various applications? Who is most likely to be affected by an adverse outcome? *Example: If hydrogen blended into gas pipelines accelerates pipeline degradation at a faster rate than expected, who lives nearby and faces the greatest associated safety risks if there are high levels of leakage or an explosion? What are the in-home public health risks of hydrogen combustion?*
- **Investments in Priority Communities.** How should hydrogen investments be targeted towards—or not targeted towards—disadvantaged communities (as defined by SB 535), or other priority communities? What counts as a "benefit" to a disadvantaged community (rather than just being located in a disadvantaged community) and what could be considered a "risk" for that community? Who gets to determine what community benefits are or how they should be defined? *Example: Should policy incentivize hydrogen infrastructure in specific communities?*

And if it is, how can policymakers ensure the community is receiving tangible benefits such as long term, local job creation for existing members of the community?

- **Competing Demands.** What are the competing demands for hydrogen, particularly at early stages of deployment? How do these change over time? If hydrogen is directed towards one application, would that preclude its use elsewhere? What are the opportunity costs of any given hydrogen use case? What are the energy security implications of these competing demands? *Example: If green hydrogen is used at power plants in Los Angeles, will this limit the quantity or reliability of the hydrogen supply available to the Port of Los Angeles to decarbonize its operations?*
- **Sensitivity to Assumptions.** Given the many unknowns and uncertainties in hydrogen infrastructure and deployment, what is the sensitivity of project success to input assumptions? *Example: See next subsection.*

Unexplored Sensitivity Scenarios and Implications for Contingencies

- **Definition Scenarios.** Policymakers are still considering different definitions for green (or clean) hydrogen. What is the sensitivity of lifecycle climate benefits of hydrogen adoption to the definition of green hydrogen? How much does adherence to the three pillars (co-location, additionality, and hourly time matching) affect climate benefits at a system level?
- **Demand Scenarios.** CARB's Scoping Plan includes a reduction of vehicle miles traveled per capita to 30 percent below 2019 levels by 2045 and California is targeting widespread electrification. What are the implications for hydrogen demand if reductions in vehicle miles traveled are or are not achieved? What is the magnitude and location of power sector impacts if electrolytic hydrogen blended into gas pipelines is replaced with electrification?
- **Technology, Infrastructure, and Scaling Scenarios.** If proposed technologies do not mature as quickly as expected (e.g., hydrogen combustion turbines; direct air capture) or if renewable energy resources cannot scale as quickly as expected, what are the implications for meeting climate targets? If supporting infrastructure is not built quickly enough, what are the climate, cost, and energy security implications of switching end-use applications to hydrogen? (E.g., if Angeles Link is not built quickly, what are the implications for price volatility at Scattergood?) Additionally, what is the sensitivity of the climate benefit of various hydrogen production and use pathways to different levels of fuel leakage (e.g., biogas, hydrogen)?
- **Biomass Scenarios.** Biomass inputs may prove hard to scale (either through state-based programs or imports from out of state) and the location of hydrogen production facilities is still an open question. If biomass inputs are lower than anticipated, what are the implications for renewable energy buildout to support hydrogen production? What are the implications of incentivizing biofuels, particularly biomethane, for hydrogen production to increase their

availability?[83] How sensitive are energy, cost, and environmental health outcomes to whether small hydrogen production facilities are co-located with biomass source locations, or if biomass is transported to larger centralized production facilities?

8.3 Recommendations

- **Develop Stringent, Consistent Definitions for "Green" or "Clean" Hydrogen.** Adopting the three pillars of green hydrogen production—namely, additionality, hourly-matching, and co-location of renewable energy generation with hydrogen production—will help minimize unintended climate and system impacts of green hydrogen production. This will also require a consistent definition of "renewable" energy specifically addressing how biofuels are categorized.
- **Better Characterize Hydrogen Leakage Rates Before Investing in Infrastructure.** Given the huge uncertainty in hydrogen leakage rates, it is important to improve our understanding of these leaks, as well as develop comprehensive processes to monitor for and mitigate them before greatly expanding hydrogen infrastructure. Comprehensive and ongoing monitoring at pilot projects may help improve this understanding.
- **Improve Interagency Coordination on Hydrogen Planning.** Investing in significant hydrogen infrastructure expansion, or over-relying on hydrogen to meet climate targets, without proper coordination between California agencies, utilities, and other decision-makers increases the risk of failure.
- **Build Safety into Hydrogen Infrastructure Development.** Ensure sufficient funding is allocated to maintain and monitor hydrogen infrastructure and mitigate safety risks in the near- and long-term. This includes funding for equity-focused considerations such as developing emergency preparedness and response communication in multiple languages. Novel technologies (including hydrogen, DAC, and CCS) should require an additional level of stringency—including requirements related to community input, community benefits, and extra protections for historically disinvested and vulnerable populations—as well as data collection of the long-term operation and risks associated with each technology.
- **Consider System and Lifecycle Implications in Policy Planning.** Any cost-benefit or other analysis of the impact of hydrogen infrastructure adoption should consider lifecycle and system-level impacts (e.g., cost, equity, climate, public health) in addition to application-specific benefits.
- **Evaluate Alternative Technologies and Deployment Scenarios.** Ensure that planning efforts fully evaluate alternative technologies for various end uses, alternative deployment scenarios,

[83] California is not currently considering purpose-grown biofuels for hydrogen production. This is good, as biofuel-based hydrogen pathways that use purpose-grown biofuels are emissions- and water-intensive.

and sensitivity to assumptions regarding future costs and technology maturities before investing in hydrogen projects.

- **Ensure There are Strict Emissions Controls and Enforcement for Hydrogen Production and its Input Fuels (e.g., Biofuels).** Ensuring both biofuel-based hydrogen production and biogas production facilities have strict and enforced emissions limits in place—and that facility siting minimizes impacts on environmentally overburdened communities and sensitive receptors (e.g., schools) and is conducted with meaningful community input and engagement—will help reduce unintended emissions from this hydrogen production pathway.
- **Avoid Hydrogen Pipeline Blending.** The minimal potential climate benefits of hydrogen pipeline blending do not justify the unknown safety, cost, and public health risks associated with blending hydrogen in existing gas pipelines.
- **Prevent Book-and-Claim Schemes.** Ensure that hydrogen producers who make hydrogen in the conventional way—via steam methane reforming of natural gas—are not eligible to receive incentives or subsidies for green hydrogen when they purchase biomethane "carbon-negative" credits.

Additional hydrogen-focused research, as well as an exploration of how its potential adoption interacts with other proposed climate mitigation strategies, will help drive better-informed decision-making about hydrogen deployment strategies and trade-offs. Although there is preliminary research on some of these issues, we find that a few key emergent research questions that merit attention include:

- **Comprehensive Energy Modeling.** How would the inclusion of both electrolytic hydrogen and direct air capture within energy demand modeling affect the optimal mix and magnitude of renewable energy resources and energy storage in the coming decades. How does this compare to the resource mix in models (e.g., in the Scoping Plan) that exclude this energy demand?
- **Electrolyzer Efficiency.** How does a variable renewable energy supply affect electrolyzer efficiency and the required installed capacity of various electrolyzer types, and what are the cost and infrastructure trade-offs between using energy storage to provide a steady power supply to electrolyzers, or oversizing electrolyzers to accommodate a variable supply? Put simply, is it better to build fewer electrolyzers that each have storage, or more electrolyzers, if they are powered by variable renewable energy?
- **Curtailed Electricity.** How much curtailed electricity might be available for either hydrogen (or direct air capture) from now through 2045? Given the inconsistent nature of this supply, how does including curtailed energy in economy-wide electricity system optimization affect the optimal use of curtailed energy for hydrogen, direct air capture, and other purposes? How does this affect system costs, including given irregular electrolyzer use described in the previous question? How does the *reason* for the curtailment (e.g., excess supply, transmission

constraints, etc.) affect the ability to utilize this energy source for various proposed applications?

- **Water Use.** Water consumption estimates for hydrogen production are quite variable. Can we develop better water use estimates for hydrogen produced from wind, solar, and various biofuel sources? How do water resources align with the proposed requirements for hydrogen, DAC, and CCS, and are these aligned geographically across California? Do we expect to see competing demands? Will shifts in seasonal water availability impact the cost or availability of hydrogen?
- **Land Use.** What are the land use impacts of "off grid" renewable resources proposed to support hydrogen and DAC?
- **Prioritization.** Where would clean hydrogen deployment be most beneficial, both in 2045 and in the near term, to support decarbonization? If there is a limited supply, what sector should get it first?
- **Economic Risks.** How do we better characterize the economic risks associated with supply volatility and stranded assets while building out hydrogen infrastructure?
- **Leakage, Safety, and Climate.** What are the long-term safety and climate impacts of using hydrogen in pipelines, industry, appliances, and other infrastructure? How does leakage evolve over time?
- **Opportunity Costs.** What is the opportunity cost of investing in hydrogen blending or otherwise ongoing use of fossil fuel infrastructure as compared to investments in renewables or other decarbonization efforts such as direct electrification of home heating heat pumps?
- **Hydrogen Storage.** What is the technical and economic potential for bulk hydrogen storage across California, and how does this potential interact with competing demand to use these sites for CO_2 storage? How do these relate to safety, equity, and public health concerns?
- **DAC Energy Needs.** It is difficult to characterize the competing energy and water needs of hydrogen and DAC without a better understanding of DAC energy and water requirements. How much geothermal, waste, and solar thermal energy could reasonably be dedicated to direct air capture to minimize wind + solar photovoltaic energy input requirements? Which direct air capture technologies have the lowest energy and water inputs?

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