Developing a Forest Biomass–to–Hydrogen Bioeconomy in San Bernardino County

California Wood Products Innovation Campus Strategy for Clean Energy and Regional Growth

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EXECUTIVE SUMMARY

California's decarbonization strategy requires scalable, cost-effective solutions for hard-to-abate sectors while simultaneously addressing escalating wildfire risk and persistent environmental justice challenges. This report assesses the technical, economic, environmental, and social feasibility of producing low-carbon hydrogen from forest biomass in San Bernardino County, California, using an integrated geospatial, techno-economic, and policy-analysis framework to inform state and regional policy, planning, and investment decisions.

The analysis begins with a statewide assessment of forest biomass availability using the California Biomass Residue Emissions Characterization (C-BREC) framework. Under a representative 40 percent thin-from-below treatment scenario, California generates an estimated 112.75 million bone-dry tonne (BDT) per year of forest biomass of which 56.37 million BDT per year are technically accessible after applying conservative operational constraints*. While biomass resources are highly concentrated in Northern California and the Sierra Nevada region, Southern California, particularly San Bernardino County, emerges as a strategic location due to its proximity to high wildfire-risk areas, availability of suitable land for facility siting, and access to established transportation and fuel infrastructure.

A spatially explicit multicriteria siting analysis identifies multiple contiguous areas in San Bernardino County that satisfy land-use, environmental, infrastructure, and logistical criteria for clean hydrogen facility deployment. Based on this analysis, a representative candidate site is selected and evaluated alongside a repurposing scenario at the idled Desert View Power (DVP) biomass facility in Riverside County. This approach enables a direct comparison between greenfield and brownfield development pathways.

A detailed techno-economic analysis evaluates a 1,000 BDT per day forest-biomass-to-hydrogen facility employing fluidized-bed gasification, syngas cleanup, water–gas shift conversion, and pressure swing adsorption (PSA) purification. The modeled facility produces approximately 24,707 tonnes H_2 per year at an estimated levelized cost of hydrogen (LCOH) of \$3.52 per kg, below prevailing market prices. Under base-case assumptions, the project generates an estimated gross profit of \$122.1 million per year, with an internal rate of return (IRR) of 12%, a debt service coverage ratio (DSCR) of 1.88-3.12, and a simple payback period of 4.13 years, indicating strong financial performance and investment viability. Repurposing the idled Desert View Power facility with an

* All biomass and hydrogen quantities in this report are expressed in metric tonnes (t), where 1 tonne equals 1,000 kilograms.

assumed 40% capital expenditure (CAPEX) reduction further enhances project economics, reducing LCOH to $2.80 per kg and shortening the payback period to 2.57 years. These results underscore the strategic value of leveraging existing biomass infrastructure to accelerate deployment, reduce capital risk and improve overall financing feasibility.

Beyond financial performance, the project delivers substantial climate, health, and socioeconomic benefits. Diverting forest biomass from wildfire combustion avoids an estimated 466,695 tonnes CO_2-equivalent emissions per year, generating monetized climate benefits ranging from approximately $68 million to $188 million per year, depending on discount rate assumptions. Reductions in wildfire-related $PM_{2.5}$ emissions yield an estimated $1.23 billion per year in statewide health and productivity benefits, with disproportionate improvements in the Mojave Desert Air Basin, a designated environmental justice priority region. In addition, the facility supports 125–164 direct operational jobs and 312–444 total jobs, in addition to significant construction-phase employment and increased regional economic activity.

The report concludes that forest-biomass-to-hydrogen offers a cost-competitive, climate-beneficial, and socially valuable pathway that directly advances California's statutory climate, clean energy, and wildfire-resilience goals. When aligned with wildfire risk reduction programs, repurposing of existing energy infrastructure, and targeted policy support, this pathway can deliver durable emissions reductions while strengthening rural economies and forest management outcomes. Although market volatility, permitting complexity, feedstock competition, and technology scale-up present implementation challenges, these risks are addressable through phased deployment, long-term offtake mechanisms, streamlined permitting, and coordinated incentive design across state agencies. Collectively, the findings support positioning biomass-based-hydrogen as a strategic component of California's clean energy portfolio and a complementary tool within the state's wildfire mitigation and resilience policy framework.


Photo credit: USFS

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1. INTRODUCTION

California's 2022 Scoping Plan outlines one of the most ambitious climate frameworks globally, calling for an 85 percent reduction in greenhouse gas (GHG) emissions below 1990 levels by 2045 and the achievement of statewide carbon neutrality through deep decarbonization, fossil-fuel displacement, and large-scale carbon sequestration [1]. Progress toward these targets, however, is increasingly constrained by climate-driven wildfire activity and declining forest resilience [2].

As of November 2025, 7,689 wildfires had burned more than 523,000 acres (212,000 hectares) across California, destroyed 16,479 structures, and resulted in 31 fatalities statewide [3]. The 2025 Los Angeles fire season, driven by record high temperatures, approximately 30 percent precipitation deficits across Southern California, and early snowpack melts in Sierra Nevada, produced estimated economic losses of $250 to 275 billion. These losses included approximately $75 billion in insured damages and an estimated 0.48 percent reduction in Los Angeles County gross domestic product [4, 5].

These impacts underscore that wildfires now represent not only an ecological and land management challenge but also a systemic macroeconomic, public health, and climate policy risk. Wildfires emit millions of metric tons of carbon dioxide (CO_2) annually, undermining emissions-reduction progress. Fine particulate matter ($PM_{2.5}$) emissions from wildfire smoke frequently exceed those from the on-road transportation sector. Resulting exposure is associated with increased respiratory and cardiovascular disease, reduced life expectancy, and long-term public health costs that disproportionately affect vulnerable populations.

These escalating wildfire impacts are closely linked to long-term structural changes in California's forests. More than a century of commercial timber harvesting and fire suppression has reduced average tree size while increasing stand density, canopy closure, and fuel continuity [6]. When combined with rising temperatures and increasing aridity, these altered forest conditions have significantly amplified fire severity, fire frequency, and spatial extent.

Since 1972, the area burned during summer fire season has increased eightfold statewide [7]. Between 2000 and 2020 wildfire activity contributed an average of 19 million metric tons of CO_2-equivalent (tCO_2e) emissions annually, offsetting a significant share of emissions reductions achieved in other sectors [8]. These large, high-severity fire events not only undermine ecological integrity but also compromise the long-term carbon-storage capacity of California's forests, increasing the risk that the land sector could shift from a net carbon sink to a net emissions source and thereby undermine progress towards net-negative emissions goals [9].

Historically, California forests evolved under frequent, low-intensity fire regimes that maintained structural diversity, supported nutrient cycling, and strengthened overall ecosystem resilience [10, 11]. Decades of fire exclusion and strict logging regulations, however, have disrupted these dynamics, contributing to elevated tree mortality driven by drought, insect outbreaks, and high-severity wildfire [12]. Fuel-reduction treatments, such as mechanical thinning, prescribed fire, and biomass removal, are now widely recognized as essential tools for restoring forest structure, reducing fuel loads, and improving landscape-scale resilience [13]. Achieving the state's forest restoration target of treating one million acres per year can substantially reduce wildfire risk while safeguarding long-term carbon storage and ecosystem function [14, 15]. At the same time, these interventions generate significant quantities of residual woody biomass, creating near-term trade-offs between fuel reduction and carbon retention. How this material is managed has important implications for emissions outcomes, treatment economics, and the overall effectiveness of California's forest health and climate mitigation strategies [16].

To address these interconnected challenges, the California Department of Forestry and Fire Protection (CAL FIRE) administers one of the largest and most comprehensive fuels management programs in the United States. In Fiscal Year 2024–25, CAL FIRE completed 922 forest-health and fuel-reduction projects, treating approximately 179,795 acres statewide. This level of treatment exceeded the program's prescribed fire target of 100,000 acres, while contributing toward California's broader multi-agency goal of treating 500,000 acres annually through a combination of prescribed fire, mechanical thinning, and other fuel-reduction strategies [17]. The subsequent fiscal year began with 232 active projects covering 8,413 acres, indicating continued progress toward the state's Wildfire and Forest Resilience Action Plan. Independent evaluations indicate that approximately 75 percent of treated areas experienced reduced fire behavior and that 60 percent of treatment directly supported wildfire containment efforts [18]. This demonstrates that proactive forest management delivers measurable reductions in wildfire intensity and spread.

Despite these gains, California continues to generate millions of dry tons of residual forest biomass each year, including small-diameter trees, branches, understory material, and sawmill byproducts. A substantial portion of this material is often either pile-burned or left to decompose in situ, resulting in the release of CO_2, methane (CH_4), and particulate matter. Yet this biomass represents a substantial opportunity. When strategically mobilized, residual forest biomass can serve as a renewable, low-carbon feedstock for bioenergy and hydrogen production. Converting excess forest biomass into clean hydrogen has the potential to transform a wildfire and climate management challenge into a decarbonization asset by simultaneously supporting wildfire risk reduction, renewable fuel production, and

rural economic development. This opportunity is particularly relevant for regions such as San Bernardino County, where extensive forest health treatments coincide with emerging hydrogen hub deployment and transportation decarbonization priorities under California's 2045 carbon neutrality mandate.

This report systematically evaluates the technical, economic, environmental, and policy dimensions of deploying forest-biomass-to-hydrogen in San Bernardino County, California. Section 1 outlines the project's motivation, objectives, and the concept of a Biomass-to-Hydrogen Innovation Campus.

Section 2 situates the study within the broader hydrogen market and policy landscape, examining North American and U.S. hydrogen pathways, California's clean hydrogen transition, and the comparative advantages of biomass-derived hydrogen.

Section 3 presents biomass resource assessment and spatial siting analysis, including forest-biomass availability, GIS-based suitability criteria, and weighted overlay results that identify candidate facility locations.

Section 4 presents a comprehensive techno-economic and financial feasibility analysis, detailing system design, mass and energy balances, capital and operating cost estimates, revenue streams, financial performance metrics, sensitivity analyses, and a comparative case study evaluating the potential repurposing of the Desert View Biomass Facility.

Section 5 examines social, environmental, and environmental-justice implications, quantifying avoided wildfire emissions, climate and public health co-benefits, as well as workforce development and regional economic impacts. Section 6 discusses key risks and barriers related to markets, regulatory framework, feedstock availability, and technology readiness.

Finally, Section 7 synthesizes the findings and presents overarching conclusions. Supporting materials, data tables, and detailed methodologies are provided in the Appendices.

1.1. PROJECT AIMS AND GOALS

The California Wood Products Innovation Campus initiative aims to develop a replicable model for advancing wood-based hydrogen production and broader bioeconomy industry clusters in San Bernardino and Fresno Counties. The project seeks to mobilize low-grade woody biomass generated through forest-health treatments and wildfire-risk-reduction activities into high-value, low-carbon products such as hydrogen and biochar. The overarching objective is to transform forest biomass from an environmental liability into a strategic economic asset that supports California's climate mitigation, wildfire resilience, and rural-development goals.

While the broader initiative encompasses both San Bernardino and Fresno Counties, this report focuses exclusively on the San Bernardino County Biomass-to-Hydrogen Innovation Campus. All techno-economic analysis, siting assessment, environmental-justice evaluation, and financial modeling presented herein are specific to the San Bernardino County context. A separate, parallel study has been conducted for Fresno County, applying a similar analytical framework while accounting for distinct feedstock characteristics, infrastructure conditions, air-basin dynamics, and market considerations. Together, the two studies demonstrate the transferability of the Biomass Innovation Campus model across diverse regional settings within California.

The primary goal of this study is to assess the feasibility of establishing a sustainable wood-based hydrogen market that supports forest ecosystem restoration and hazardous-fuel reduction, improves long-term forest health across public and private lands, and strengthens the economic and environmental resilience of underserved and wildfire-impacted communities. To achieve these outcomes, the project evaluates pathways for business development capable of converting forest biomass into low-carbon fuels, identifies critical supply-chain, and examines enabling conditions such as workforce development, innovation capacity, access to capital, and supportive public policy. The San Bernardino Biomass Innovation Campus is evaluated as a potential anchor site for future demonstration, commercialization, and regional expansion of biomass-to-hydrogen systems.

1.2. SAN BERNARDINO COUNTY: BIOMASS-TO-HYDROGEN INNOVATION CAMPUS

San Bernardino County, located within Southern California's Inland Empire, is the largest county in the contiguous United States, spanning 20,105 square miles, of which 82% is federally owned and dominated by public lands, military areas, and conservation zones [19].

This unique landownership structure has important implications for biomass resource mobilization and clean-energy infrastructure siting. The county encompasses major mountain systems including the San Bernardino, San Gabriel (eastern portion), San Jacinto, and Santa Rosa ranges, and contains the 823,816-acre San Bernardino National Forest, a diverse ecological region ranging from desert basins to alpine peaks (600–3,505 m). Eight federally designated Wilderness Areas (151,341 acres) limit mechanized thinning, but extensive treatable acreage remains across wildland–urban interface (WUI) landscapes where wildfire risk is highest [20, 21].

Decades of fire suppression, drought intensification, bark-beetle outbreaks, and climate-driven vegetation stressors have resulted in high forest densities, excessive surface fuels, and widespread tree mortality. Empirical studies show that tree densities in San Bernardino mixed-conifer forests have risen by nearly 80% relative to pre-suppression conditions, with snag densities increasing from ~5 trees ha^{-1} to >120 trees ha^{-1} following drought and pest outbreaks—dramatically elevating wildfire hazard (**Figure 1**) [22–24].

These conditions generate large quantities of woody biomass from CAL FIRE, U.S. Forest Service, and Fire Safe Council treatment projects. Much of this material is currently pile-burned or left to decompose [25], representing both climate liability and a potential feedstock stream for low-carbon or carbon-negative hydrogen.

Persistent smog and particulate matter concentrations are driven by intensive freight and logistics activity, wildfire smoke, and meteorological conditions that trap and concentrate pollutants within the Inland Empire air basin. These exposures disproportionately impact vulnerable populations, including an estimated 35,125 children and 143,727 adults with asthma, nearly 65,000 individuals with COPD, and approximately 284,772 residents living in poverty. Additionally, people of color comprise roughly 1.66 million residents in San Bernardino County, underscoring the significant environmental justice dimensions of regional air quality challenges [26, 27]. These cumulative environmental and public health burdens position the region as a priority area under California Assembly Bill 617 (Community Air Protection Program) and align it with multiple statewide environmental justice frameworks.

The county consistently ranks among the worst air quality regions in the United States. According to the American Lung Association's *2025 State of the Air* report, San Bernardino County ranks #1 nationwide for ozone pollution, with ~153.7 weighted unhealthy ozone days and failing grades (F) for both 24-hour and annual $PM_{2.5}$ [26, 27]. Meanwhile, San Bernardino County anchors one of the nation's most dynamic logistics economies. The Inland Empire supports ~600,000 workers in transportation, warehousing, heavy-equipment operation, mechanics, and industrial maintenance—skills that directly align with biomass supply chains, hydrogen production, and fueling-station operations [28, 29]. The region's transportation network, defined by the convergence of Interstates 10, 15 and 40, State Route 210, major BNSF and Union Pacific rail corridors, and proximity to the Ports of Los Angeles and Long Beach, provides strategic multimodal connectivity for both biomass feedstock logistics and hydrogen distribution [30].

Industrial growth continues to expand into the High Desert (Victorville, Hesperia, Apple Valley, Adelanto), reflecting lower land costs, abundant labor, and the county's strategic role within a $1.8 trillion multi-state economic corridor spanning Los Angeles, San Diego, Phoenix, and Las Vegas [31].

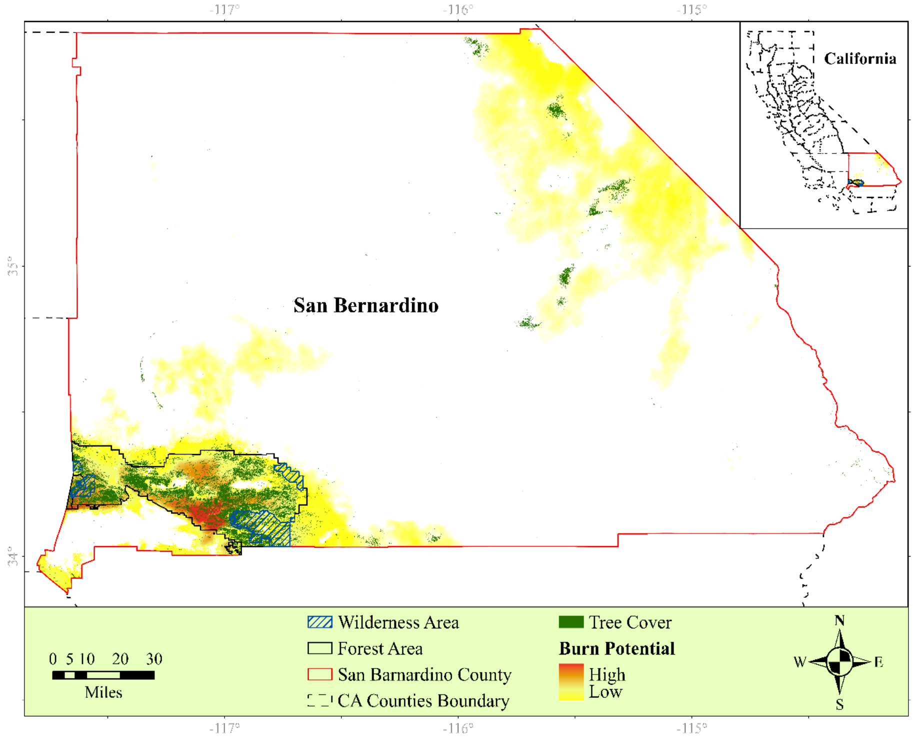

Figure 1. Study area and forest-resource context in San Bernardino County. Map depicting the San Bernardino National Forest, designated wilderness areas, 2023 tree-canopy cover [32], and wildfire burn-potential zones [33]. Together, these spatial layers characterize forest conditions, fuel loads, and biomass availability relevant to the hydrogen production assessment.

Environmental justice concerns coincide with the region's rapid decarbonization efforts. The San Bernardino County Transportation Authority (SBCTA) is piloting North America's first hydrogen-powered passenger train (ZEMU) and deploying zero-emission truck and bus infrastructure—signaling regional readiness for hydrogen adoption [34]. Local support for clean-energy technologies, combined with AB 617 community-benefit requirements and High Road Training Partnerships (HRTP) [35], positions the county as a leading candidate for a biomass-to-hydrogen innovation campus capable of delivering wildfire-risk reduction, low-carbon or carbon-negative fuel production, and equitable workforce development.

Collectively, San Bernardino County's abundant woody biomass, urgent wildfire-mitigation needs, severe air-quality challenges, logistics and workforce strengths, and policy alignment through the California Low Carbon Fuel Standard (LCFS) and AB 617 create a uniquely favorable environment for deploying biomass-derived hydrogen systems. The county exemplifies the convergence of ecological necessity, economic opportunity, and environmental justice, making it an ideal anchor site for a forest-biomass-to-hydrogen demonstration and regional innovation hub.

2. WOOD PRODUCTS INNOVATION CAMPUS (WPIC) FRAMEWORK AND REPLICABILITY MODEL

This section presents a modular industrial architecture blueprint for California's wood-based bioeconomy, centered on the strategic utilization of forest-derived feedstocks and other woody cellulosic materials. It is designed to enable regionally specialized campuses operating under a shared structural, financing, and policy logic. By translating the Fresno and San Bernardino case studies into a unified framework, it defines the California Wood Products Innovation Campuses (WPIC) as a replicable model for statewide bioeconomy cluster development.

2.1 STRUCTURAL ARCHITECTURE OF A WOOD PRODUCTS INNOVATION CAMPUS

The Wood Products Innovation Campus (WPIC) model is designed as a replicable industrial development framework that integrates forest-residue utilization, thermochemical conversion technologies, and multi-output fuel and material pathways within a coordinated regional platform. Rather than focusing on a single technology or fuel type, the WPIC framework establishes a modular campus architecture capable of supporting diverse product configurations based on regional feedstock characteristics, infrastructure availability, and evolving market conditions.

In this structure, individual fuel pathways (e.g., renewable diesel derived from forest residues in the Fresno Region; renewable hydrogen derived from forest residues in the San Bernardino Region) represent regional specializations layered onto a shared thermochemical and supply-chain foundation. This approach enables strategic differentiation across regions while maintaining structural consistency in campus design and deployment methodology.

Overall, the WPIC framework functions as a modular industrial architecture blueprint for California's emerging wood-based bioeconomy, providing a structured yet adaptable platform for scalable implementation.

2.2 MODULAR THERMOCHEMICAL BACKBONE AND DOWNSTREAM PATHWAY FLEXIBILITY

The WPIC model can be conceptualized as three interrelated layers:

(1) Feedstock and Supply-Chain Layer

Sustainable aggregation of forest residues derived from wildfire-risk reduction, ecological restoration, and hazardous-fuel treatment activities. This layer includes harvesting, preprocessing, storage, and logistics infrastructure coordinated with land-management agencies.

(2) Thermochemical Conversion Platform

Commercially established core technologies (e.g., gasification, syngas conditioning, energy integration systems) that convert lignocellulosic biomass into intermediate synthesis gas (syngas). These upstream systems are largely mature in industrial applications and provide the primary energy-conversion backbone of the campus.

(3) Downstream Product Configuration Modules

Fuel-specific or product-specific upgrading systems layered onto the syngas platform, including renewable diesel synthesis, renewable hydrogen purification and compression, sustainable aviation fuel (SAF) pathways, renewable power generation, biochar production, soil amendment streams, and derivative fuel options such as ammonia or methanol.

Because the upstream thermochemical platform is technologically mature relative to certain downstream upgrading pathways, future diversification can often be achieved through incremental integration of modular conversion units rather than redevelopment of core infrastructure. This layered architecture supports phased expansion and adaptive market response while limiting stranded-asset risk.

2.3 REGIONAL SPECIALIZATION WITHIN A STATEWIDE CLUSTER STRATEGY

The Fresno and San Bernardino campuses illustrate how regional conditions inform pathway selection within a shared structural model:

- **Fresno Region (Low-Carbon Renewable Diesel Configuration)**

The Fresno Region campus configuration emphasizes renewable diesel derived from forest residues, with biochar produced as a co-product, aligned with Central Valley agricultural markets, heavy-duty liquid-fuel infrastructure, and established renewable fuel blending and distribution systems. Under biochar-inclusive lifecycle accounting conditions, forest-residue-derived renewable diesel may achieve materially reduced carbon intensity relative to fossil diesel, with the potential for further carbon-intensity reduction depending on sequestration durability, system boundary assumptions, and recognized accounting methodologies. Proximity to agricultural operations, existing fuel terminals, and regional freight corridors create conditions conducive to low-carbon liquid-fuel deployment within California’s transportation and goods-movement sectors.

Biochar production provides an additional value stream associated with soil amendment applications, carbon sequestration potential, and agricultural resilience. Within the WPIC framework, liquid-fuel synthesis modules and carbon-rich material streams are layered onto the shared thermochemical platform, enabling regionally optimized output while preserving flexibility for future pathway diversification (e.g., SAF or renewable power integration).

This configuration reflects local feedstock characteristics and market conditions while maintaining structural alignment with the statewide campus model.

- **San Bernardino Region (Low-Carbon Renewable Hydrogen Configuration)**

The San Bernardino Region campus configuration emphasizes renewable hydrogen derived from forest residues, with biochar produced as a co-product, aligned with Inland Empire freight corridors, heavy-duty vehicle deployment strategies, and emerging hydrogen distribution networks. Under biochar-inclusive lifecycle accounting conditions, forest-residue-derived hydrogen may achieve near-zero or potentially negative carbon intensity, depending on carbon sequestration durability, system boundary assumptions, and recognized accounting methodologies. Proximity to major logistics hubs, interstate transportation corridors, and concentrated Class 8 vehicle activity create conditions conducive to hydrogen-based decarbonization within the goods-movement sector.

Within the WPIC framework, hydrogen purification and compression modules are layered onto the shared thermochemical platform, while carbon-rich solid fractions may be directed toward biochar or other soil-amendment pathways where technically and economically appropriate.

This configuration retains the potential for derivative hydrogen-based products (e.g., ammonia or other hydrogen carriers) as markets evolve.

As with the Fresno configuration, this regional specialization reflects infrastructure conditions and end-use demand patterns while maintaining architectural consistency with the broader WPIC model.

Despite these regional differences, both campuses operate under the same architectural logic: forest-residue supply integration, thermochemical conversion backbone, and modular downstream configuration.

This structure supports the formation of a broader bioeconomy industry cluster by:

- Standardizing campus design principles,
- Enabling inter-regional knowledge transfer,
- Facilitating shared policy, permitting, and financing frameworks,
- Supporting phased scaling across California's forested regions.

2.4 FLEXIBILITY, PHASED DEPLOYMENT, AND MARKET EVOLUTION

Emerging fuel markets in California—particularly hydrogen—demonstrate the importance of infrastructure flexibility and phased deployment strategies. This flexibility allows lifecycle performance to improve over time as carbon accounting methodologies evolve and as biochar sequestration pathways are further validated and standardized. The WPIC model therefore emphasizes:

- Modular capacity additions,
- Co-located or derivative fuel production,
- Integration within multi-facility corridors,
- Adaptation to policy and incentive evolution.

Campus configurations may evolve over time as markets mature, enabling phased expansion, product diversification, or integration of additional conversion modules. This flexibility is particularly important in the context of dynamic federal and state incentive structures, evolving regulatory standards, and changing end-use demand profiles.

2.5 REPLICABILITY AND PUBLIC-DOMAIN VALUE

A defining objective of this grant-funded effort is to establish a replicable model suitable for deployment across multiple California regions. By documenting spatial biomass assessments, techno-economic parameters, workforce impacts, financing structures, and environmental-justice considerations within a unified framework, this report provides a transferable analytical foundation.

"A defining objective of this grant-funded effort is to establish a replicable model suitable for deployment across multiple California regions."

The WPIC model is therefore not limited to the two case-study regions examined here. Instead, it provides a generalizable blueprint that may inform future public and private investment decisions, support interagency coordination, and enable additional wood-products innovation campuses throughout California and potentially beyond.

This framework directly supports the grant objective of establishing a replicable model for wood products innovation campuses capable of promoting regionally specialized bioeconomy industry clusters.

3. HYDROGEN MARKET AND POLICY CONTEXT

Hydrogen is increasingly recognized as a central element of global decarbonization strategies, particularly in hard-to-abate sectors such as heavy industry, petroleum refining, fertilizer production, and long-distance transport. The global hydrogen market was valued at approximately $ 282 billion in 2025 and is projected to reach $ 556 billion by 2034, representing a compound annual growth rate (CAGR) of 7.8 %). This growth is being driven by rapid cost declines in electrolyzers, widespread deployment of fuel-cell technologies, and strong government incentives for low-carbon fuels. Asia–Pacific currently leads global hydrogen deployment (≈36 % of market share), followed by North America (≈29 %) and Europe (≈24 %), reflecting regional differences in industrial demand, clean-energy policy frameworks, and hydrogen-hub investments [36].

3.1. NORTH AMERICAN HYDROGEN LANDSCAPE

North America is one of the world's fastest-growing hydrogen markets, supported by major federal policy initiatives and public–private investment. The U.S. Department of Energy's (DOE) Hydrogen Shot Initiative, the Inflation Reduction Act (IRA), the Infrastructure Investment and Jobs Act (IIJA), and Canada's Clean Hydrogen Strategy collectively provide long-term market certainty through production tax credits (e.g., 45V), hub funding, and R&D investments across the hydrogen value chain [37–40].

As of 2025, North America hosts roughly 225 hydrogen production facilities with a combined capacity of 14.7 Mt H_2 per year, of which 12.2 Mt are operating, and 2.5 Mt are in development. Established industrial uses including oil refining, ammonia and fertilizer production, and chemical manufacturing account for approximately 99% of current hydrogen demand. Emerging segments such as mobility (~1%) and grid-integrated applications (<0.5%) are growing rapidly. Production remains heavily carbon-intensive: about 96% of output is grey hydrogen from natural-gas steam-methane reforming (SMR), with blue hydrogen (SMR/ATR + CCS) contributing ~3% and green hydrogen from renewable electrolysis still <1%. However, project pipelines indicate a structural pivot: nearly 95% of planned new merchant hydrogen capacity is designed as blue or green hydrogen, aligned with net-zero and IRA 45V incentives [41, 42].

3.2. U.S. HYDROGEN MARKET AND TECHNOLOGY PATHWAYS

The United States currently produces approximately 10–11 Mt H_2 per year, corresponding to ~14% of global supply [42–44]. Demand is concentrated in three main segments: petroleum refining (~20 %), ammonia and fertilizer production (~40%), and merchant industrial gas markets (~38%) [43]. Production clusters along the Gulf Coast, Midwest, and California, reflecting co-location with refineries, petrochemical complexes, and existing hydrogen pipelines [36].

Federal incentives are reshaping both the technological and spatial profile of the U.S. hydrogen sector. More than 76 green hydrogen projects totaling ~$36 billion in announced capital are in development, led by states such as Texas, Louisiana, Alabama, and California [45]. These include large blue hydrogen complexes (e.g., Air Products' Louisiana Clean Energy Complex, 750 MMSCF per day with CCS), turquoise hydrogen from methane pyrolysis (e.g., Monolith's Olive Creek 1, produces 13.7 tons per day), and nuclear-coupled electrolysis projects (e.g., Nine Mile Point, 0.6 ton per day "pink" hydrogen). Together, these facilities illustrate a broad technological diversification strategy to decarbonize industrial hydrogen while maintaining energy security.

The U.S. Department of Energy (DOE) estimates that nationwide hydrogen deployment could create approximately 700,000 jobs across the United States by 2030, increasing to up to 3.4 million jobs by 2050, underscoring hydrogen's dual role as both a climate mitigation strategy and a major driver of national economic development [46–49].

3.3. CALIFORNIA'S HYDROGEN TRANSITION

California is the national epicenter of hydrogen innovation, underpinned by ambitious climate legislation, robust clean-fuel incentives, and a large, and diverse industrial base. Policy instruments, including the Low Carbon Fuel Standard (LCFS), Cap-and-Trade Program, California Climate Investments (CCI), and the statewide public-private partnership ARCHES (Alliance for Renewable Clean Hydrogen Energy Systems), collectively support the transition from a fossil-based hydrogen system toward a diversified, low-carbon portfolio consistent with the state's 2045 carbon-neutrality target.

As of 2025, California hosts more than 20 hydrogen production facilities, the majority of which are grey hydrogen plants associated with refineries in the Los Angeles Basin and San Francisco Bay Area [41, 42, 50]. A growing number of low-carbon and renewable hydrogen projects are advancing across the state, including the following:

- **SoHyCal (Kings County):** ~3 metric tonnes per day of green hydrogen from electrolysis.
- **Avina Clean Hydrogen (Vernon):** ~4.4 tonnes per day electrolytic hydrogen (under construction).
- **SGH_2 Lancaster:** ~12 tonnes per day hydrogen via plasma gasification of waste.
- **Ravens SR Richmond:** ~6.5 tonnes per day of waste-derived hydrogen (under construction).

Statewide, California hosts 23 grey and 2 green hydrogen projects, with average production capacities of approximately 267 tonnes per day (grey) and 3.7 tonnes per day (green) (**Figure 2**). This highlights the substantial scale gap between conventional and renewable hydrogen production [41, 50]. Nevertheless, California's regulatory and investment framework is catalyzing diversification toward blue and green hydrogen by supporting carbon capture and storage (CCS) integration, biomass gasification and methane pyrolysis technologies.

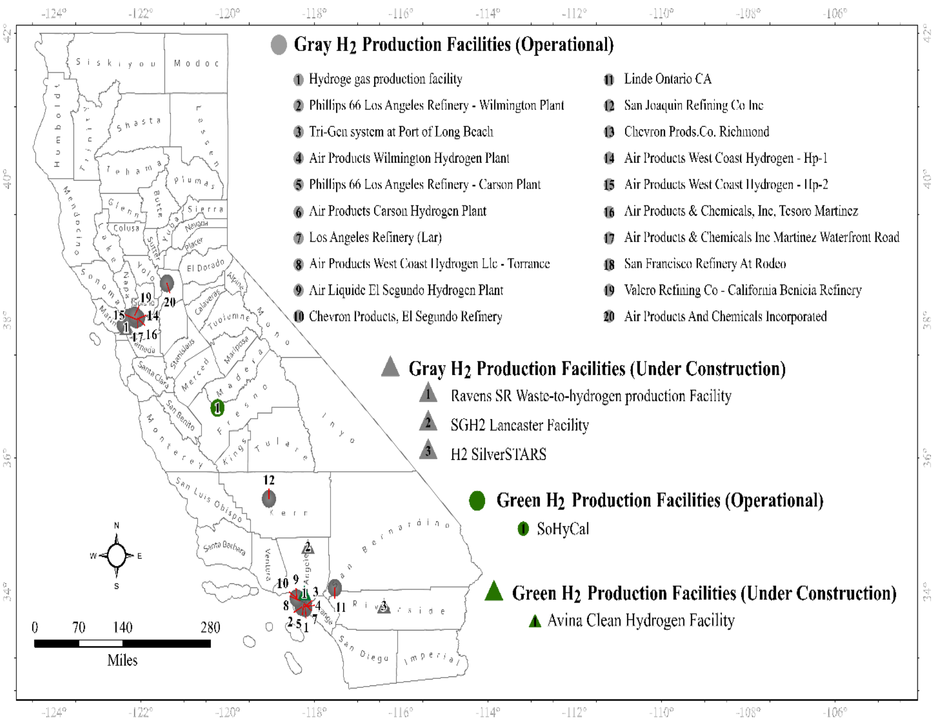

Figure 2. Statewide hydrogen facilities for grey and green hydrogen production, including in operation and under construction.

California's hydrogen strategy can be characterized as a dual transition: (i) decarbonizing existing grey hydrogen infrastructure, and (ii) scaling new low-carbon or carbon-negative hydrogen production technologies. By aligning LCFS credits, Cap-and-Trade revenues, and hydrogen-hub investments, the state is establishing an integral technical and policy blueprint for hydrogen decarbonization that is likely to influence national and international practice.

3.4. POLICY DRIVERS FOR CLEAN HYDROGEN DEPLOYMENT IN CALIFORNIA

California's transition to clean hydrogen is driven by a coordinated suite of federal and state policy instruments that collectively provide financial incentives, regulatory certainty, and market access for low-carbon hydrogen pathways. At the federal level, the Inflation Reduction Act (IRA) has fundamentally reshaped hydrogen production economics through the Section 45V Clean Hydrogen Production Tax Credit, which provides up to \$3.00 per kg H_2 based on lifecycle carbon intensity [51, 52], and the 45Q Carbon Capture Tax Credit, which provides \$85 per tonnes of CO_2 for geologically sequestered carbon [52, 53]. Taken together, these incentives strongly favor carbon-negative biomass-to-hydrogen systems that integrate pre-combustion CO_2 capture. Complementing these tax credits, the Infrastructure Investment and Jobs Act (IIJA) allocate \$8 billion for Regional Clean

Hydrogen Hubs, including ARCHES [54, 55], which supports statewide hydrogen infrastructure and coordinated end-use development.

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State-level policies reinforce and amplify federal support mechanisms. The Low Carbon Fuel Standard (LCFS) remains the most influential statewide policy instrument, assigning credit value to fuels based on lifecycle carbon intensity [56]. Biomass-derived hydrogen with CCS can achieve very low or negative carbon intensity (CI) scores, generating substantial LCFS credit revenue that enhances project viability. Additional state programs, including the California Climate Catalyst Fund, California Climate Investments (CCI) [57], and the California Energy Commission (CEC) Clean Hydrogen Program, provides loans, grants, and cost-sharing support for hydrogen production, fueling infrastructure, and enabling technologies [58]. These federal and state policies establish a robust, multi-layered incentive environment that accelerates clean hydrogen deployment while advancing California's broader climate mitigation, air-quality improvement, and wildfire resilience goals.

3.5. HYDROGEN PRODUCTION TECHNOLOGIES AND TECHNOLOGICAL READINESS LEVELS

Hydrogen can be produced through a wide range of thermochemical, electrochemical, and biological pathways, each characterized by varying levels of commercialization, infrastructure compatibility, and lifecycle carbon intensity. These pathways vary significantly in their current contribution to hydrogen supply, emissions profile, and readiness for large-scale deployment.

Conventional fossil-based hydrogen production routes, primarily steam methane reforming (SMR), autothermal reforming (ATR), and partial oxidation (POX), are fully commercial and operate globally at Technology Readiness Level (TRL) 9. These processes supply the majority of current hydrogen demand. However, in the absence of CCS, they generate substantial CO_2

emissions. When coupled with CCS, these pathways can achieve significant lifecycle emissions reductions, but integration of capture and storage increases system complexity and regulatory exposure. As a result, integrated fossil-based hydrogen with CCS is typically assessed at an overall technology readiness of approximately TRL 5-8 [59–61].

Electrolytic hydrogen production has advanced rapidly in recent years, driven by declining renewable electricity costs and supportive policy frameworks. Alkaline electrolysis (AEL) and proton-exchange membrane (PEM) electrolysis are commercially deployed at multi-megawatt scale and are generally characterized as TRL 8–9. These technologies provide high-purity hydrogen and operational flexibility under variable renewable power conditions, making them well suited to grid-integrated applications [62–64]. Solid oxide electrolysis cells (SOECs) offer the potential for high electrical efficiency but remain at TRL 5–6 due to durability constraints and materials challenges. Emerging hydrogen pathways, including methane pyrolysis (turquoise hydrogen), plasma-assisted conversion, and natural (geologic) hydrogen extraction span TRLs of approximately 3–8 and are currently at early stages of demonstration [65, 66].

Biological and photochemical routes, such as dark fermentation, photo-fermentation, and algal photolysis, remain at low readiness levels (TRL 2–4), constrained by low conversion efficiencies, limited yields, and significant scale-up barriers [62, 67].

Biomass-to-hydrogen pathways occupy an intermediate range of technology readiness, reflecting both their potential to deliver low- or negative-carbon hydrogen and the technical challenges associated with heterogeneous feedstocks and tar management. Among these pathways, thermochemical gasification coupled with water–gas shift (WGS) conversion and hydrogen purification represents the most mature and widely demonstrated approach, particularly for lignocellulosic feedstocks such as forest biomass [67–69]. When integrated with carbon capture, these systems offer a credible pathway to net-negative hydrogen production while leveraging existing expertise in biomass handling and gas processing. A synthesis of assessments from the US Department of Energy (DOE), the International Renewable Energy Agency (IRENA), and recent peer-reviewed literature indicates consistent TRL patterns across hydrogen production pathways (**Figure 3**; full details in **Appendix Table S1**).

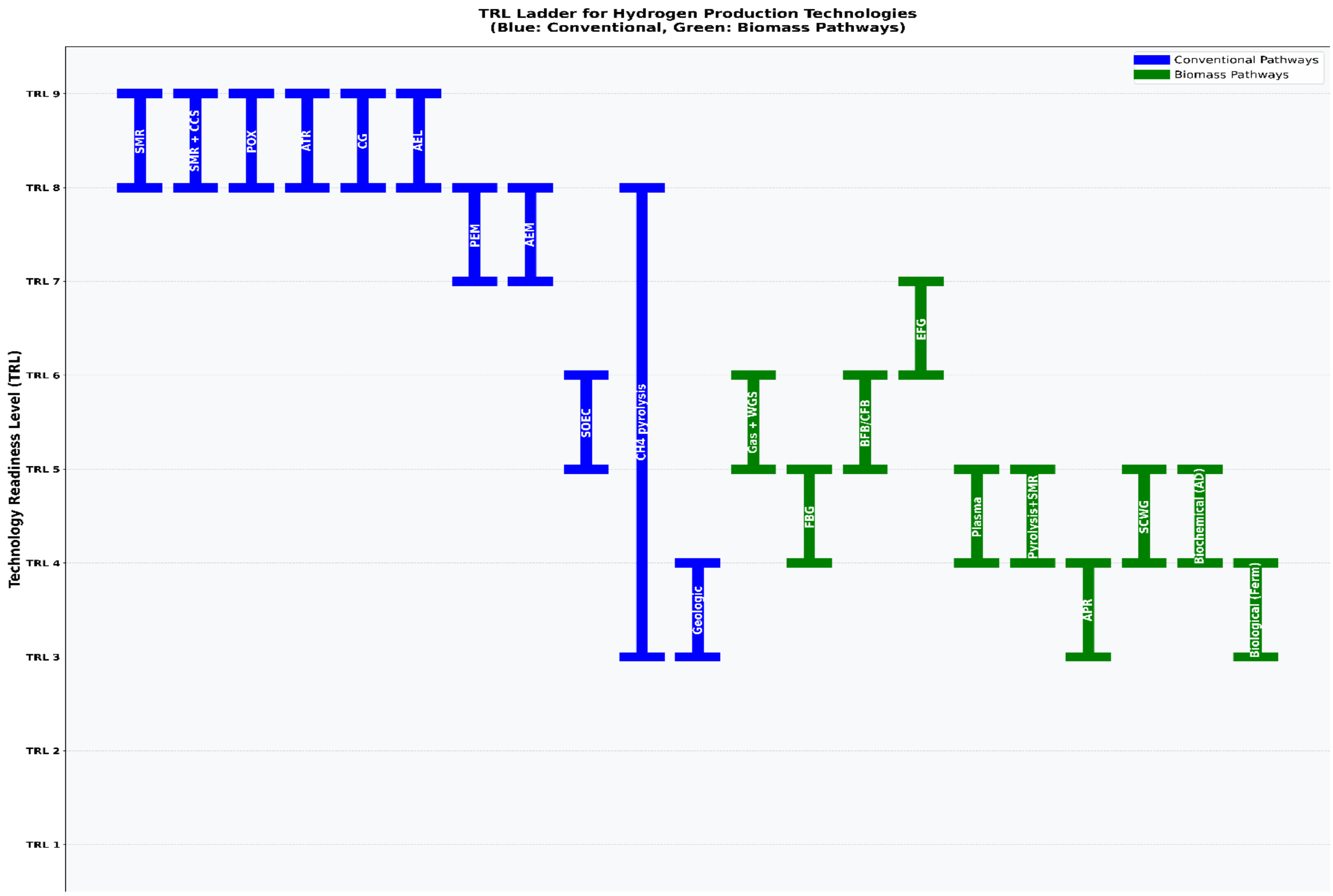


Figure 3. Technology readiness levels (TRLs) of major hydrogen production pathways, comparing mature fossil- and electrolysis-based routes (blue) with biomass-derived systems (green). [SMR = Steam Methane Reforming; SMR + CCS = Steam Methane Reforming with Carbon Capture and Storage; POX = Partial Oxidation; ATR = Auto-Thermal Reforming; CG = Coal Gasification; AEL = Alkaline Electrolysis; PEM = Proton Exchange Membrane Electrolysis; AEM = Anion Exchange Membrane Electrolysis; SOEC = Solid Oxide Electrolysis Cell; CH4 pyrolysis = Methane Pyrolysis (Turquoise Hydrogen); Geologic = Naturally Occurring Hydrogen Extraction; Gas + WGS = Gasification with Water-Gas Shift; FBG = Fluidized Bed Gasification; BFB/CFB = Bubbling/Circulating Fluidized Bed Gasification; EFG = Entrained Flow Gasification; Plasma = Plasma Gasification; Pyrolysis+SRM = Pyrolysis with Steam Reforming; APR = Aqueous Phase Reforming; SCWG = Supercritical Water Gasification; Biochemical (AD) = Anaerobic Digestion; Biological (Ferm) = Biological Fermentation].

3.6. COMPETITIVE ADVANTAGES OF BIOMASS-DERIVED HYDROGEN IN CALIFORNIA

Within California's policy and market context, biomass-derived hydrogen offers several strategic advantages relative to fossil-based and purely electrolytic pathways:

- ***Low- or Negative-Carbon Intensity***

Biomass gasification integrated with pre-combustion CO_2 capture and/or biochar co-production can achieve very low or even negative life-cycle carbon intensities. These systems are well-positioned to generate high-value LCFS credits and qualify for the highest tiers of the Section 45V Clean Hydrogen Production Tax Credit.

- ***Wildfire Risk Reduction and Forest Resilience***

Forest biomass from fuel-reduction treatments represents an underutilized feedstock that contributes to wildfire risk when left unmanaged or pile-burned. Converting this material into hydrogen directly links climate mitigation with forest resilience and wildfire-risk reduction goals.

- ***Rural and Regional Economic Development***

Siting biomass-to-hydrogen facilities in forested counties supports local job creation, lowers biomass disposal costs, and stimulates investment in high-wage industrial and logistics sectors. These facilities typically generate greater local employment multipliers than conventional SMR or electrolytic hydrogen plants.

- ***Grid Independence and Energy Security***

Biomass-derived hydrogen can be produced with minimal reliance on grid electricity, reducing stressors of California's constrained electric system while providing firm, dispatchable low-carbon fuel.

- ***Alignment with Clean Transportation and Freight Strategies***

Hydrogen produced from forest biomass is particularly well-suited to decarbonize heavy-duty trucking, freight and port operations, and potentially off-road and rail sectors, especially in logistics-intensive regions such as the Inland Empire.

These attributes make biomass-to-hydrogen an especially compelling pathway for California, where forest-health management and freight-sector decarbonization are both state-level priorities.

3.7. BIOMASS-TO-HYDROGEN TECHNOLOGIES IN SOUTHERN CALIFORNIA

For a forest-biomass-to-hydrogen system in San Bernardino County, technology selection should be guided by policy objectives that ensure operational reliability, environmental performance and eligibility under California's low-carbon fuel standard. Key considerations include heterogeneity and moisture variability of forest biomass, ash content, the target deployment scale (approximately 1,000 BDT per day), and demonstrated compatibility with low-carbon fuel standard and incentive frameworks. Forest-health and wildfire-risk-reduction treatments in the region generate highly heterogeneous biomass, including branches, tops, small-diameter stems, and mixed species, with substantial variability in particle size, bulk density, and moisture content. These feedstock characteristics pose challenges for fixed-bed gasifiers and entrained-flow systems, which typically require either uniform fuel properties or energy intensive preprocessing such as fine pulverization and strict moisture control, thereby increasing cost and operational complexity.

Fluidized-bed gasification using either bubbling or circulating configurations and integrated with water gas shift and hydrogen purification via pressure-swing adsorption (PSA) or membrane purification, is better aligned with regional feedstock conditions and the modeled scale of 330,000 BDT per year. Fluidized-bed reactors provide strong gas–solid mixing, more uniform temperature control, and greater tolerance to variability in particle size and moisture content, while generally achieving lower tar formation than fixed-bed systems. Operational experience from biomass facilities in Europe and North American biomass plants shows that Bubbling Fluidized-bed (BFB) and Circulating Fluidized-bed (CFB) systems can reliably process several hundred to several thousand bone dry tons per day, consistent with the throughput requirements of a San Bernardino County deployment [69–72].

Syngas cleaning upstream of the water gas shift provides a strategic integration point for pre-combustion CO_2 capture, enabling carbon-neutral or carbon-negative hydrogen when coupled with geologic storage or the production of durable carbon products. This system configuration is particularly well aligned with California's LCFS and applicable federal incentives under Section 45V and 45Q, improving project economics while reducing lifecycle emissions. In contrast, alternative biomass to hydrogen pathways such as pyrolysis with reforming, Aqueous Phase Reforming (APR), Supercritical Water Gasification (SCWG), and biological conversion routes, remain at lower TRLs for lignocellulosic feedstocks, are less compatible with dry forest biomass, or are poorly matched to the scale and infrastructure conditions required for infrastructure [67, 73–76]. For these reasons, this study adopts circulating or bubbling fluidized-bed gasification, coupled with water gas shift and pressure swing adsorption purification, as the reference biomass-to-hydrogen pathway for evaluating forest biomass utilization in San Bernardino County. This reference configuration reflects a technology pathway that is commercially demonstrated, scalable to regional feedstock availability, and well positioned to meet California's policy objectives related to emissions reduction, incentive eligibility, and deployment risk management.

4. BIOMASS ESTIMATION AND SITING ANALYSIS

California possesses one of the most diverse and resource-rich biomass portfolios in the United States, encompassing forest biomass, agricultural byproducts, urban and mill wood waste, municipal solid waste (MSW) organics, and animal manures. Over the past two decades, numerous statewide assessments have sought to quantify this resource base, producing a wide range of estimates that reflect differences in feedstock categories, analytical methodology, and assumptions regarding technical and economic recoverability.

Early statewide assessments by the California Biomass Collaborative estimated approximately 32.2 million BDT per year of technically recoverable biomass from a gross resource base of approximately 82.8 million BDT per year [77]. A more comprehensive synthesis published in 2015 expanded the scope of included feedstock categories and identified 78 million BDT per year of gross biomass potential, of which approximately 35 million BDT per year were considered technically recoverable. This assessment attributes major contributions to forest biomass at approximately 14.3 million BDT per year, agricultural residues at 7 to 8 million BDT per year (**Appendix Table S2 and Table S3**), urban and mill residues at 4 to 5 million BDT per year, and MSW organics at approximately 1.2 million BDT per year [78].

More recent studies reflect California's evolving priorities related to wildfire risk

reduction, waste diversion, and forest health. A statewide inventory conducted by the California Energy Commission identified approximately 76 million BDT per year of technical biomass potential from unused agricultural residues, forest biomass, and urban and MSW feedstocks [79]. Policy-oriented syntheses, such as the Governor's Office of Business and Economic Development (GO-Biz) Interagency Framework, estimate approximately 29 million BDT per year of woody biomass, driven primarily by forest restoration goals and accelerated agricultural orchard turnover in the agricultural sector [80]. Forward-looking scenario analyses project modest long-term growth in statewide biomass availability, reaching approximately 70 million dry tons per year by 2050 under anticipated demographic, agricultural, and environmental trends [81].

These estimates collectively indicate that California's statewide biomass potential spans approximately 30 to 80 million BDT per year, depending on the inclusion of urban waste streams and the assumptions regarding recoverability, as summarized in **Appendix Table S4**. Across all studies, forest biomass consistently represents the largest single category of renewable biomass, particularly under forest-health and wildfire-mitigation scenarios, underscoring the strategic importance of forest biomass in supporting California's decarbonization objectives, wildfire resilience goals, and bioenergy and renewable fuels policy framework.

4.1. FOREST- BIOMASS AVAILABILITY ACROSS EXISTING STUDIES

Forest biomass, including logging slash, thinning materials, small-diameter trees, and biomass derived from tree mortality, have been the focus of several assessments due to their relevance to wildfire risk reduction, carbon removal, and bioenergy production. Estimates vary widely across studies depending on treatment prescriptions, stand conditions, and assumed treatment intensity.

Early forest-focused assessments (**Table 1**) estimated approximately 7.3 million BDT per year of forest biomass under long-term thinning scenarios using Forest Inventory and Analysis (FIA) data in combination with BioSUM, and GBSM modeling frameworks [82]. Saah et al. [83] estimated between 8 and 11 million BDT per year of economically viable forest biomass statewide based on FIA, BioSUM version 5.0, and the Fire and Fuels Extension to the Forest Vegetation Simulator (FFE-FVS) across 25 silvicultural prescriptions. Other studies that constrained biomass availability to High Hazard Zones (HHZs), which are areas prioritized for wildfire fuel reduction, estimated approximately 12.4 million BDT per year of forest biomass of which roughly 3.85 million BDT were classified as unused material [84].

Tree mortality associated with the 2012 to 2017 drought represents an additional but largely one-time source of forest biomass. Tubbesing et al. [85] estimated between 18.4 and 68.9 million BDT of standing dead biomass statewide, with 7.5 to 27.8 million BDT considered potentially recoverable. The Lawrence Livermore National Laboratory *Getting to Neutral* report integrated forest management operations, mill residues, and chaparral treatments and estimated approximately 24 million BDT per year of forest-related biomass under a restoration scenario treating one million acres annually [86].

Across these studies, estimates of annual forest biomass availability in California generally range from 7 to 24 million BDT per year, depending on modeling assumptions, geographic focus, and treatment goals. These values reflect typical forest-management intensities and accessible material under current operational conditions.

Table 1. Summary of Forest Biomass Availability Estimates Across Studies

Year of Estimate	Feedstock Amount (Million BDT/year)	Methodology / Modeling Approach	Source
2015	7.3	FIA, BioSUM, GBSM, 40-yr scenarios	[82]
2016	8 to 11 economically viable	FIA, BioSUM v5.0, FFE-FVS, 25 prescriptions	[83]
2019	12.4 (High Hazard Fuel only; approx. 3.85 unused)	FIA, LEMMA-GNN, Aerial Surveys, FVS	[84]
2020	18.4 to 68.9 (tree mortality, drought 2012–2017); economically viable 7.5 to 27.8	Aerial surveys, LEMMA-GNN	[85]
2020	24 (15 forest ops, plus mill residues & chaparral)	FIA, FVS, BioSUM; Forest Carbon Plan (1M ac/yr)	[86]

4.2. STATEWIDE FOREST BIOMASS ESTIMATION USING THE C-BREC FRAMEWORK

To produce a spatially explicit and policy-relevant estimate of forest biomass availability that aligns with California's wildfire-mitigation objectives, this study applied the California Biomass Residue Emissions Characterization (C-BREC) framework [13, 87]. C-BREC combines high-resolution forest-structure data (TreeMap 2016, 30 m resolution), forest growth simulations from the Forest Vegetation Simulator (FVS), and FIA National Scale Volume and Biomass (NSVB) equations to generate pixel-level estimates of biomass removals under operationally realistic silvicultural treatments [88]. The C-BREC incorporates a suite of 11 treatment methods, including clearcuts, multiple thin-from-below (TFB) and thin-from-above (TFA) intensities ranging from 20 to 80 percent, and Stand Density Index (SDI)–based density treatments, evaluated for two implementation years (2025 and 2030). Among these scenarios, a 40 percent thin-from-below treatment for 2025 (TFB_40_2025) was selected as the reference case because it most closely reflects California's current forest-health and fuel-reduction strategies [89].

Under the 40 percent thin-from-below 2025 scenario (TFB_40_2025) and assuming a 15 percent residue fraction, California's gross forest biomass potential is estimated at 112.75 million BDT per year. Applying a 50 percent technical accessibility screen reduces this to 56.37 million BDT per year of technically accessible biomass. Across all counties, the mean biomass density is 3.45 BDT per acre (median 3.34 BDT per acre), with values ranging from less than 1 BDT per acre (BDT/acre) in intensively agricultural valleys to more than 8 BDT per acre in coastal and mixed-conifer forests. These estimates represent an upper bound conditioned on statewide implementation of a 40 percent thin-from-below treatment and are interpreted as technical potential under an ambitious, sustained forest treatment regime rather than current practice. Biomass availability is strongly concentrated in northern and montane regions (**Figure 4**). Humboldt (12.61 million BDT per year), Siskiyou (11.62 million BDT per year), Mendocino (9.65 million BDT per year), Trinity (8.97 million BDT per year), and Shasta (6.90 million BDT per year) counties together account for 55.3 percent of gross statewide forest biomass. After applying the 50 percent technical accessibility adjustment, these counties remain the dominant sources, contributing 6.31, 5.81, 4.83, 4.49, and 3.45 million BDT per year, respectively. At the regional scale, Northern California contributes 24.67 million BDT per year of technically accessible biomass (54.8 percent of the total), the Sierra Nevada region 9.27 million BDT per year (20.6 percent), and coastal counties 6.87 million BDT per year (15.3 percent). In contrast, urbanized or intensively farmed counties such as San Francisco, Kings, Imperial, Sutter, Sacramento, and San Joaquin each contribute 0.02 million BDT per year or less, reflecting minimal forest cover and low biomass density.

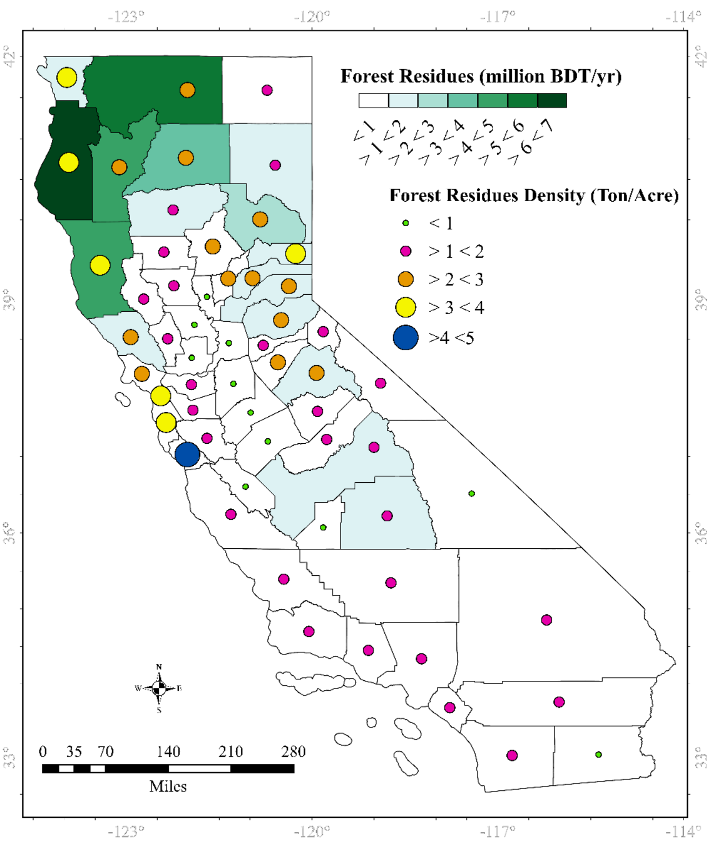


Figure 4. Estimated statewide forest biomass availability (million BDT per year) and biomass density (BDT per acre) based on C-BREC TFB_40_2025 simulations.

These patterns reveal a pronounced urban–rural and north–south gradient in forest biomass availability. Rural, forested counties in Northern California exhibit biomass densities five to ten times higher than urban or intensively farmed counties in Central Valley and Southern California. Overall, the estimate of technically accessible forest biomass confirms that California's forest sector represents a substantial and spatially concentrated resource for bioenergy, biofuels, and bioproducts development. These data provide a robust empirical foundation for the siting and scale assumptions used in subsequent hydrogen-facility analyses.

In San Bernardino County, application of the C-BREC TFB_40_2025 scenario indicates a substantial but more spatially heterogeneous forest biomass resource relative to northern California. Across approximately 241,982 acres of forested land evaluated, mean gross biomass density under a 40 percent thin-from-below treatment is estimated at 16.68 BDT per acre, with a median of 12.65 BDT per acre and a 90th-percentile value of 34.76 BDT per acre, reflecting strong variability driven by elevation, forest type, and stand condition. Applying a 15 percent slash recovery factor and a 50 percent technical accessibility constraint, consistent with statewide assumptions, yields an effective recoverable biomass density of approximately 1.25 BDT per acre. At this level, San Bernardino County provides an estimated more than 0.31 million BDT per year of technically accessible forest biomass. While lower in aggregate magnitude than northern forested counties, this resource is strategically significant due to its proximity to high wildfire-risk landscapes, existing transportation infrastructure, and large end-use energy markets in Southern California. As such, San Bernardino represents a viable regional feedstock base for biomass-to-hydrogen deployment when facility scale and logistics are aligned with realistic biomass recovery rates rather than statewide gross potential.

The quantified biomass inventory demonstrates that California's forest biomass resources are both significant in magnitude and heterogeneous in spatial distribution. This heterogeneity necessitates a systematic assessment of where high resource concentration coincides with conditions suitable for facility development. The siting analysis in the following section integrates biomass availability with critical locational criteria, including land-use compatibility, physiographic constraints, transportation access, regulatory designations, and utility infrastructure, to identify spatially optimal candidate sites for biomass-to-hydrogen deployment. This approach ensures that feedstock potential is evaluated in the context of practical geographic and infrastructural realities that govern project feasibility.

4.3. SITING ANALYSIS

The statewide biomass assessment indicates that while California possesses substantial technical potential for forest biomass feedstock, this resource is unevenly distributed across the state and shaped by strong geographic, ecological, and operational constraints. Counties in northern and interior regions exhibit high concentration of forest biomass, whereas southern and highly urbanized counties contribute comparatively little volumes. These spatial patterns demonstrate that the feasibility of biomass-to-hydrogen development depends not only on the quantity of available feedstock but also on its physical accessibility, landscape configuration, and proximity to enabling infrastructure.

Accordingly, translating biomass potential into viable project opportunities requires a spatially explicit siting analysis that integrates feedstock availability with land-use compatibility, topographic constraints, transportation access, regulatory considerations, and the availability of utility infrastructure. **Appendix Table S5** summarizes the siting criteria applied in this analysis. The following section builds on the statewide biomass inventory to identify locations that best align concentrated resource supply with infrastructure readiness and long-term project feasibility.

4.3.1. AVAILABILITY OF FEEDSTOCK

This analysis evaluates the annual theoretical supply potential of forest biomass under a 40 percent thin-from-below treatment scenario for the year 2025 (TFB_40), consistent with prior applications of the C-BREC model [13, 87–89]. Biomass feedstock supply estimates were derived from the C-BREC model, and the spatial distribution of biomass density (bone dry tons per acre, BDT/acre) was reclassified into a suitability scale to prioritize high-yield areas. The suitability categories include highly desirable (>4 BDT/acre), moderately desirable (3-4 BDT/acre), desirable (2-3 BDT/acre), low desirability (1-2 BDT/acre), and not desirable (<1 BDT/acre) as shown in **Figure 5**.

After applying a 50 percent technical accessibility factor to account for operational and logistical constraints, the total technically accessible forest biomass potential statewide is estimated at 56.37 million bone-dry tons per year. This estimate corresponds to approximately 26.42 million acres of treated forest cover and provides a basis for screening and prioritizing regions with sufficient feedstock density to support biomass-to-hydrogen deployment.

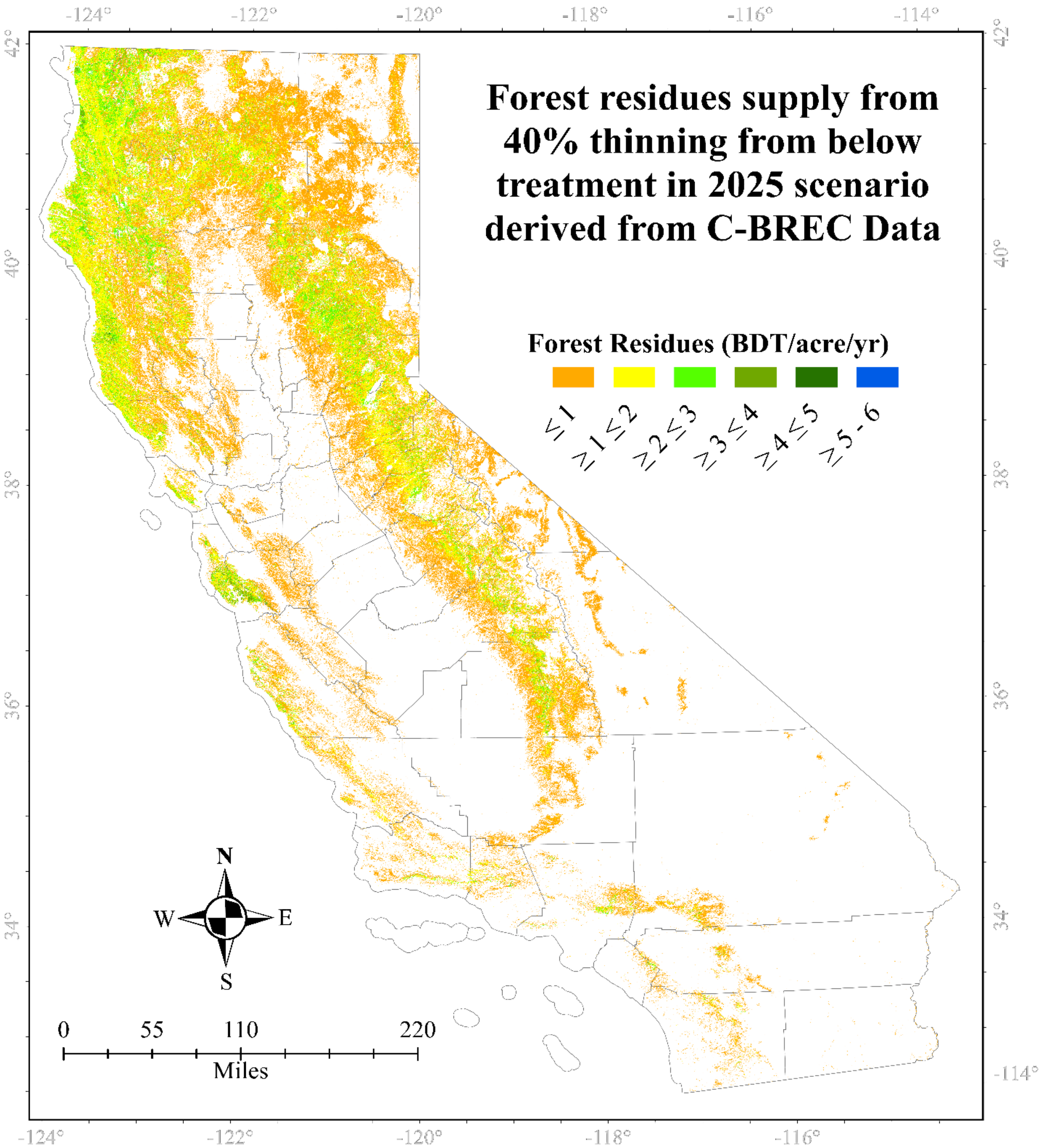


Figure 5. Spatial distribution of forest biomass generated under the 40% thin-from-below (TFB_40) treatment scenario.

4.3.2. TOPOGRAPHIC CHARACTERISTICS

Construction feasibility was assessed by applying slope constraints derived from 30-meter elevation data obtained from the United States Geological Survey (USGS) [90]. To minimize engineering challenges and costs, a graded suitability scale was applied:

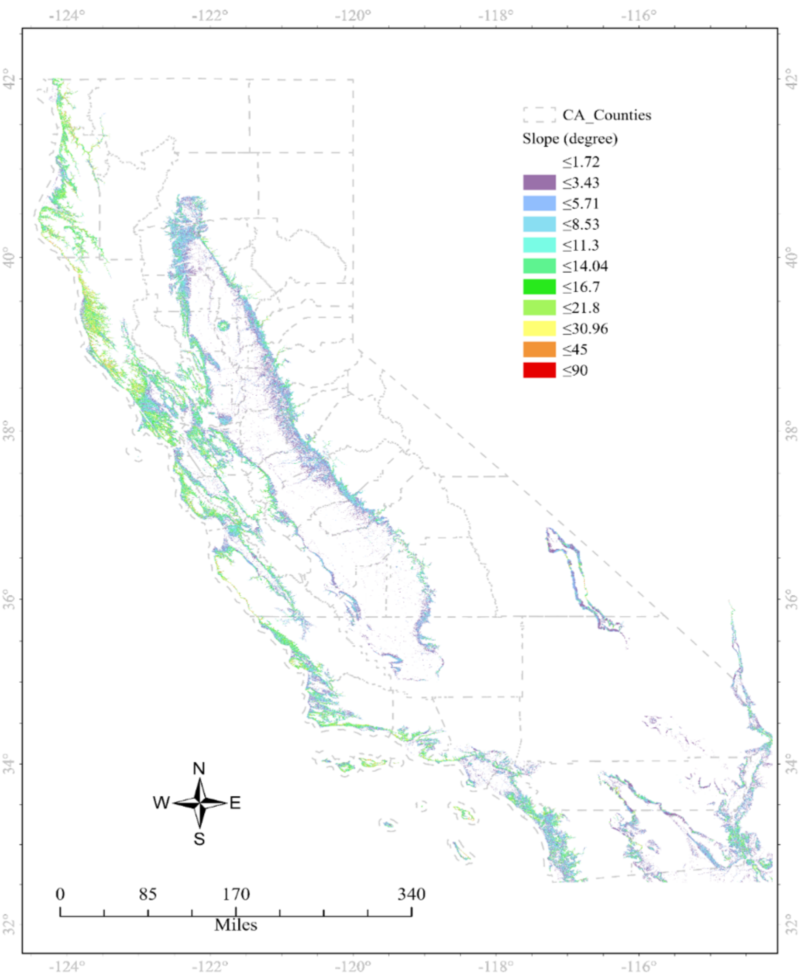


Figure 6. Statewide slope gradients indicating terrain suitability for facility siting, generated from USGS National Elevation Dataset (NED) [90].

highly desirable (<8°), moderately desirable (8-12.5°), and not desirable (>12.5°), effectively filtering out prohibitively steep terrain in **Figure 6**.

4.3.3. LAND USE AND DEVELOPMENT PLAN

The suitability of land for potential biofuel and biomass-to-hydrogen facility development was evaluated using California General Plan land-use data updated in January 2024 and provided by the Governor's Office of Land Use and Climate Innovation [91]. This dataset reflects adopted local planning designations and provides a consistent statewide basis for screening land-use compatibility. Land-use categories considered suitable for industrial biofuel development include Industrial, Low-Density Commercial, Open Space and Public Lands, Planned Development, Very Low-Density Residential, and Other - Not Determined. The "Other – Not Determined" category represents parcels that lack a finalized or clearly specified land-use designation in local general plans or zoning datasets, but that are not explicitly assigned to residential, agricultural, conservation, or environmentally protected uses.

These areas typically include transitional lands, legacy industrial parcels, infrastructure-adjacent zones, or undeveloped tracts with flexible future-use potential, and are therefore treated as conditionally suitable pending site-specific review. Collectively, the included categories correspond to areas with existing or planned industrial activity, lower potential for land-use conflict, or limited residential presence.

Land-use categories excluded from consideration include Agricultural Land, High-Density Commercial areas, all residential designations (High, Medium, and Low Density Residential), Urban Reserves, and Water Bodies. These exclusions prioritize the protection of agricultural productivity, minimize potential community and environmental impacts, and avoid locations with significant development constraints or regulatory protections, as illustrated in **Figure 7.**

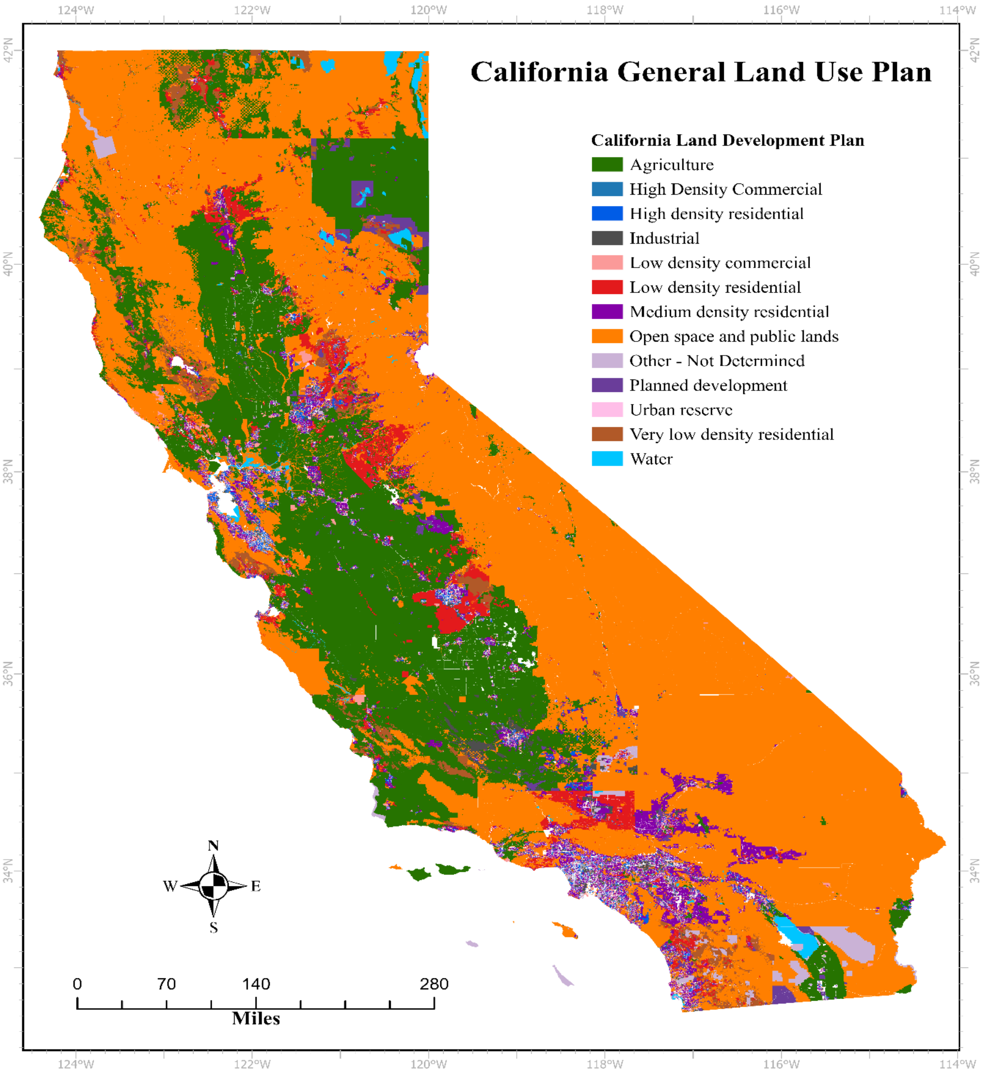


Figure 7. California land-use and development plan, showing spatial categories used to assess suitability for biofuel facility development [91].

4.3.4. PROXIMITY TO SEDIMENTARY BASINS

The siting analysis incorporated proximity to geologic carbon dioxide storage resources as a key screening criterion, drawing on methodologies from the Oak Ridge Siting Analysis for Power Generation Expansion (OR-SAGE) model [92]. OR-SAGE identifies economic feasibility thresholds for carbon capture and storage and indicates that viable saline sedimentary basin resources should be located within approximately 150 miles of a facility to support cost-effective transport and storage of captured carbon dioxide. [93]. Potential facility locations were evaluated based on their distance to mapped saline sedimentary basins using basin data from Brennan et al. [93]. Sites were assigned a relative desirability ranking according to proximity, with categories defined as highly desirable at less than 10 miles, moderately desirable at 10 to 20 miles, desirable at 20 to 30 miles, low desirability at 30 to 40 miles, and not desirable at greater than 40 miles, as shown in **Figure 8**. This proximity-based classification prioritizes locations where integration with carbon capture and storage infrastructure would be more technically feasible and economically viable. Incorporating proximity to sedimentary basins as an early screening factor supports the evaluation of sites that could maximize lifecycle emissions reductions and enhance eligibility for state and federal carbon management incentives.

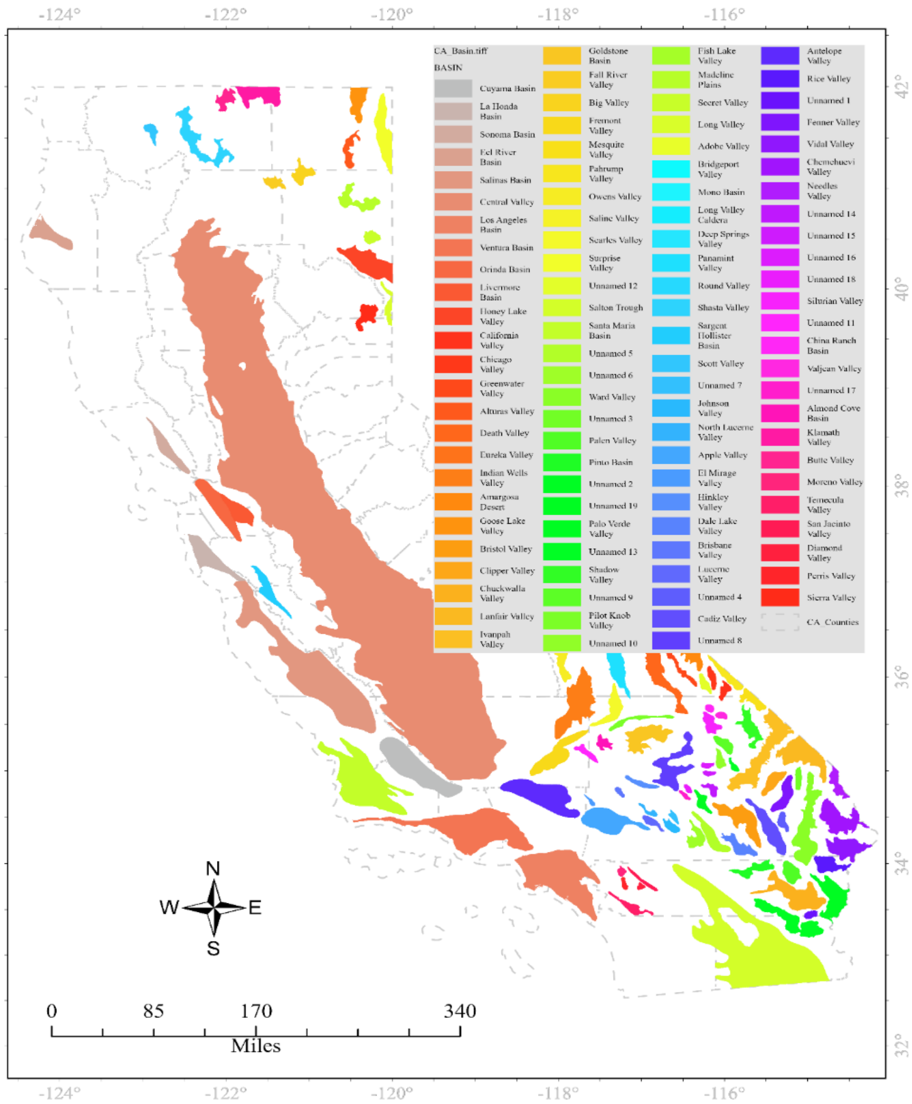


Figure 8. Sedimentary basins in California with potential suitability for geologic CO_2 storage [93].

4.3.5. PROXIMITY TO ROAD NETWORK

Proximity to transportation infrastructure was evaluated using the OR-SAGE siting criterion, which recommends that biomass feedstock be sourced within 100 miles of a biofuel facility, with a strong preference for locations within 20 miles to minimize hauling costs. To implement this criterion, the primary and secondary road networks from the U.S. Census Bureau's MAF/TIGER database (MTS) [94] were used to evaluate potential sites based on distance to road access. Sites were ranked according to the following desirability categories: highly desirable (less than 10 miles), moderately desirable (10 to 20 miles), low desirability (20 to 30 miles), desirable (30 to 40 miles), and not desirable (greater than 40 miles, as shown in **Figure 9.**

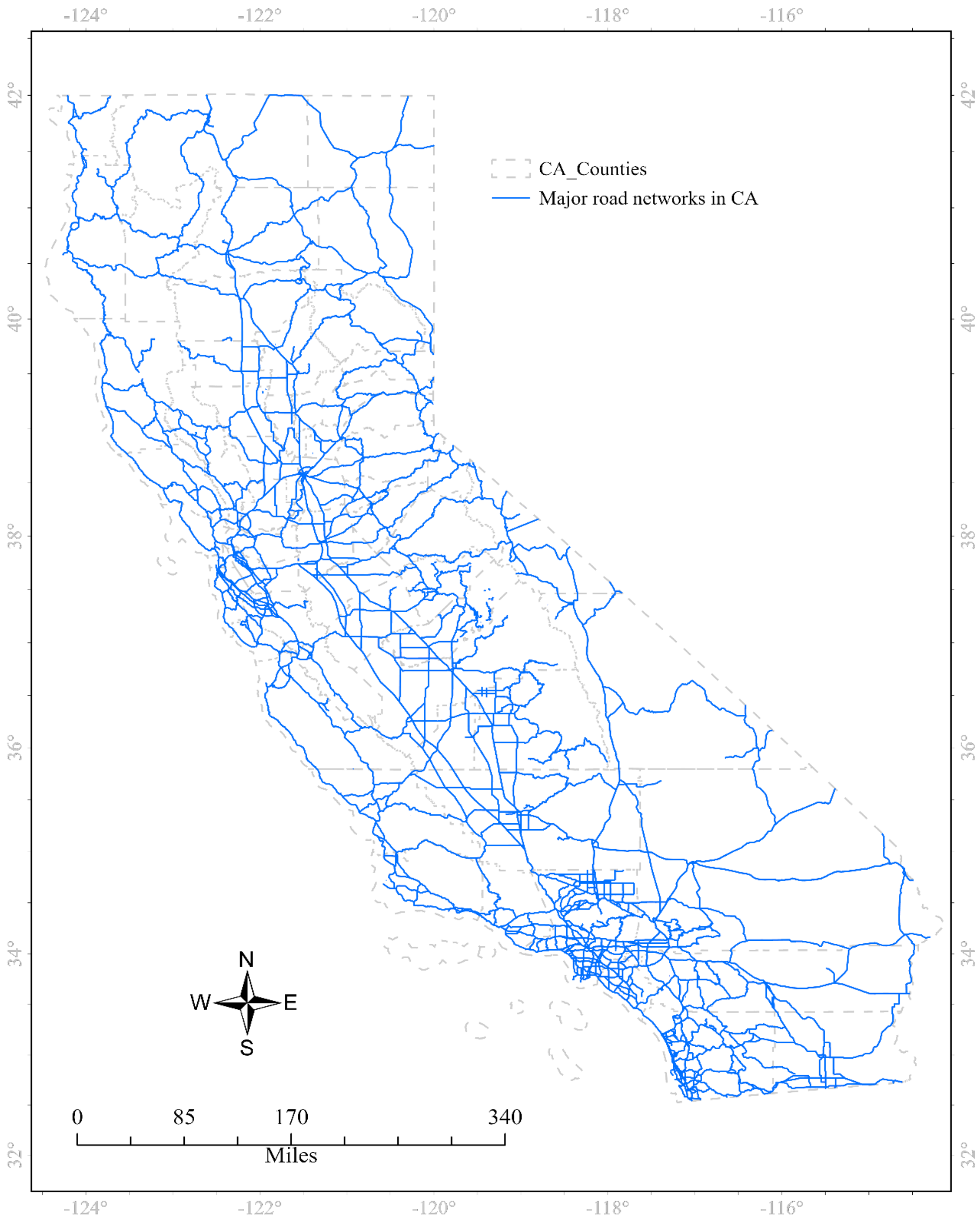


Figure 9. Statewide primary and secondary road network in California, used to evaluate haul-route accessibility for biomass transport [94].

This distance-based classification ensures that candidate locations are logistically feasible for the efficient transport of forest biomass, supporting realistic operational planning for biomass-to-hydrogen development.

4.3.6. POPULATION DENSITY

To minimize potential community impacts, areas of high population density were excluded from the siting analysis. Population density was calculated for each approximately 90m x 90m grid cell using the LandScan USA dataset [95], converting raw population counts into persons per square mile. A spatial filter was then applied systematically: any grid cell with a population density greater than 500 persons per square mile was classified as unsuitable and removed from consideration (**Figure 10**).

The resulting "Suitable Area" mask includes only locations that meet the OR-SAGE criterion for low population density. This ensures that the siting analysis focuses on areas where biomass-to hydrogen facilities could be developed with minimal potential impact on local communities and land-use conflicts.

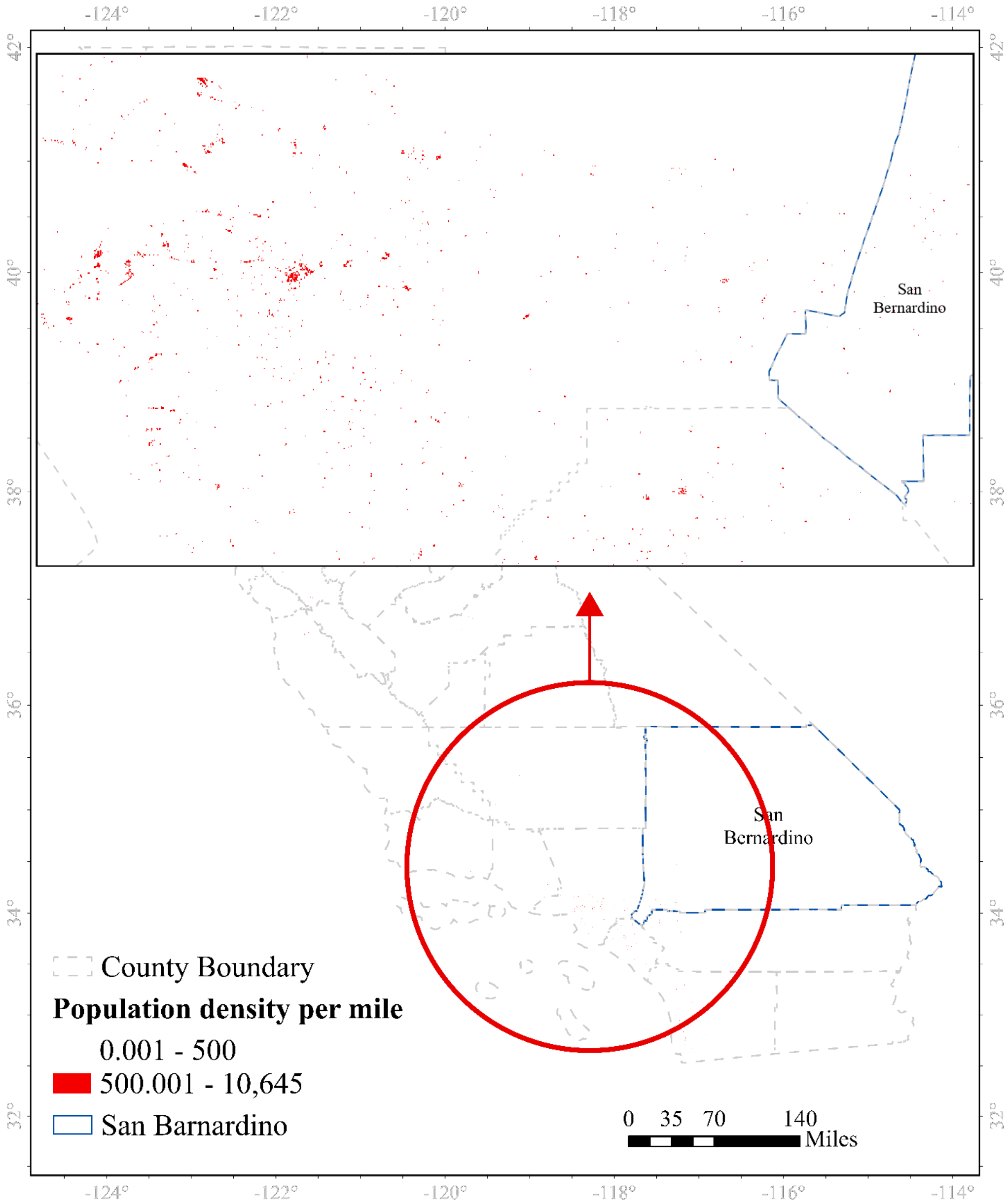


Figure 10. Population density distribution across California used to identify low-impact siting areas [95].

4.3.7. PROXIMITY TO STREAMFLOW

Access to a sustainable water source for cooling purposes was evaluated using the High-Resolution National Hydrography Dataset (NHD) from the U.S. Geological Survey [96, 97]. Following the OR-SAGE siting criteria [92], which recommends that a primary cooling water source be located within 100 miles of a facility, with a strong preference for sites within 20 miles to support closed-cycle cooling systems, the NHD stream network was converted to a 30-meter resolution raster to calculate Euclidean distance **(Figure 11).** Potential sites were then ranked according to the nearest water source: highly desirable (less than 20 miles), low desirable (20 to 100 miles), and not desirable (greater than 100 miles). This classification ensures that candidate locations are operationally viable for necessary cooling requirements while taking into account regional water availability and resource limitations.

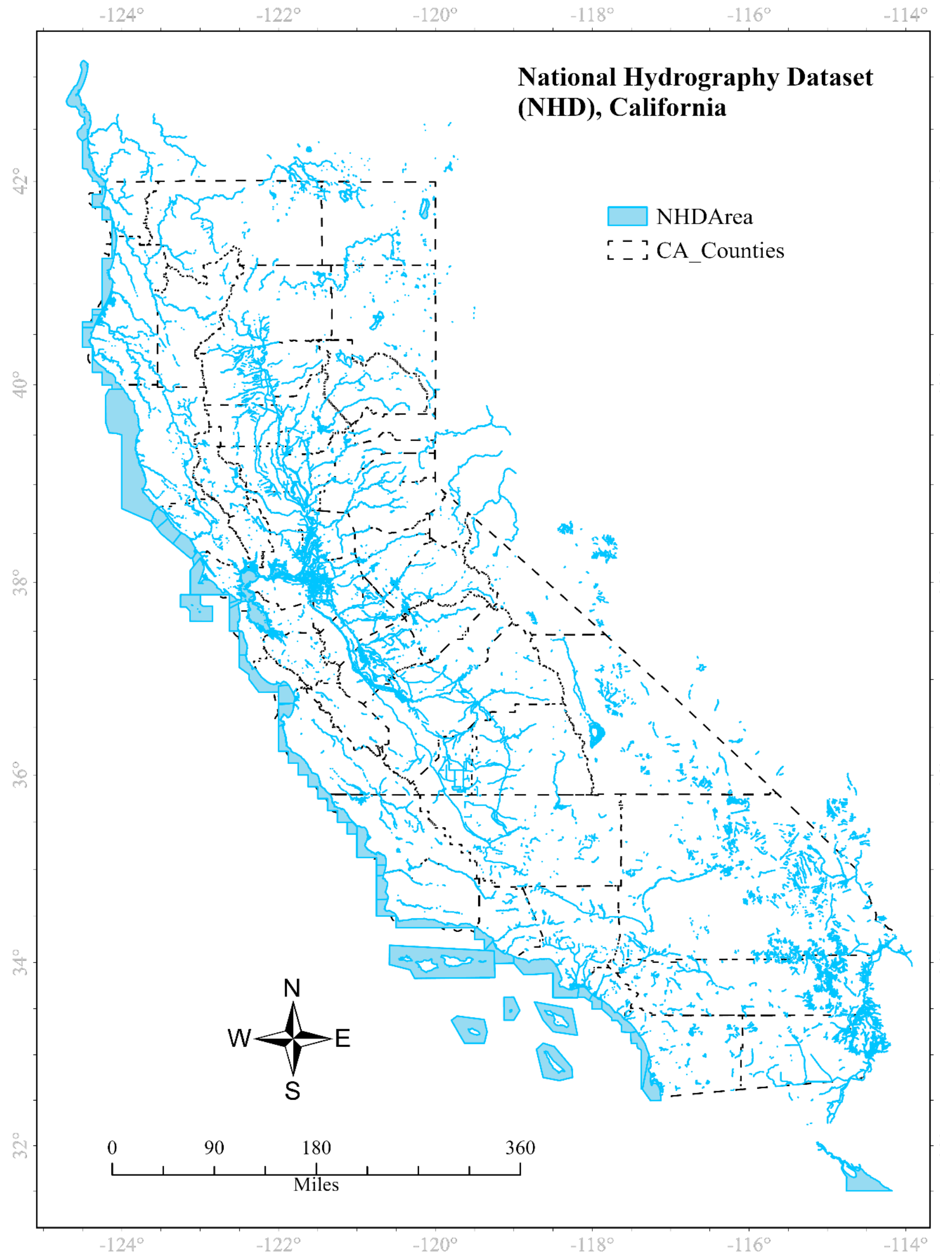


Figure 11. Spatial distribution of surface water resources in California, derived from the USGS NHD, indicating potential cooling-water sources for biomass facility siting.

4.3.8. FUEL INFRASTRUCTURE PROXIMITY

Proximity to existing alternative fuel infrastructure, including CNG refueling stations, LNG refueling stations, refineries (DOE Alternative Fuels Data Center, September 2025) [98], and hydrogen fueling stations [99] were evaluated as a key siting criterion. For each facility type, Euclidean distances from potential plant locations were calculated, and sites were classified using a standardized desirability scale to prioritize locations with close access to fuel infrastructure: highly desirable (less than 1 mile), moderately desirable (1 to 2 miles), low desirability (2 to 3 miles), desirable (3 to 4 miles), and not desirable (greater than 5 miles) **(Figure 12)**. This classification identifies candidate areas where integration with existing alternative fuel networks could support operational efficiency and reduce infrastructure development costs.

A Euclidean distance analysis was performed on the natural gas pipeline network, sourced from the U.S. Energy Information Administration (EIA) [100]. The resulting distances were then reclassified into a standardized desirability scale for site selection: highly desirable (<10 miles), moderately desirable (10-20 miles), low desirability (20-30 miles), desirable (30-40 miles), and not desirable (>40 miles).

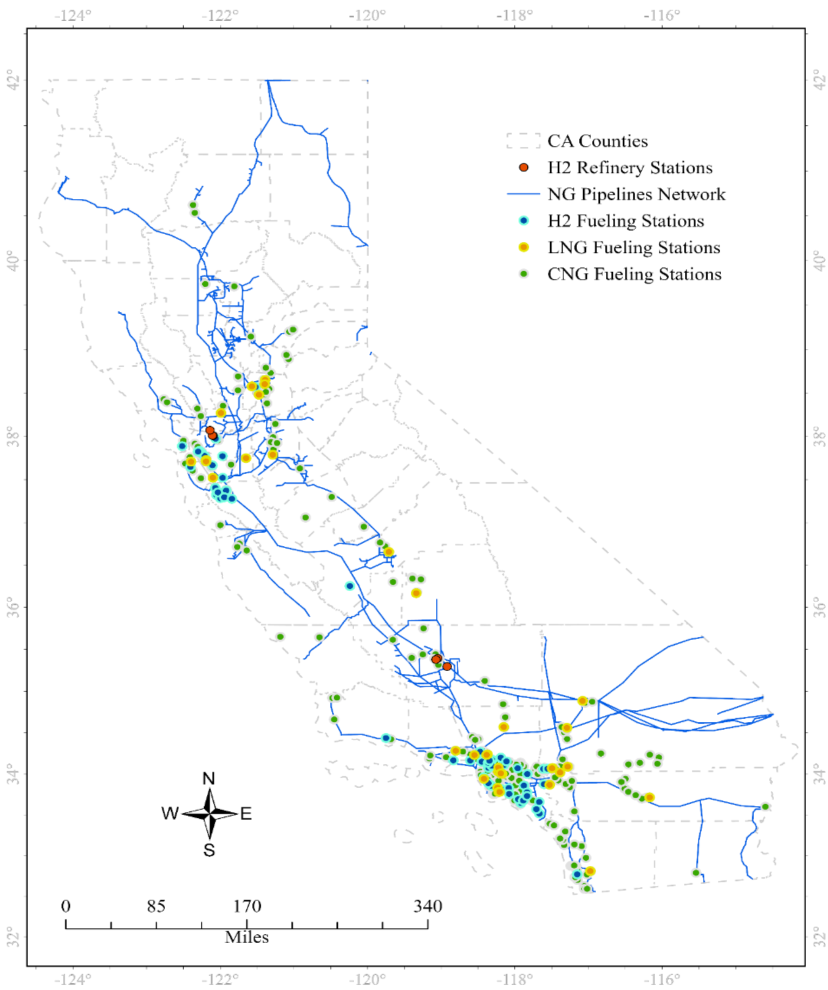


Figure 12. Spatial distribution of alternative fuel infrastructure in California, including CNG and LNG refueling stations, hydrogen refineries, hydrogen fueling stations, and the statewide natural gas pipeline network.

4.3.9. EPA NON-ATTAINMENT AREAS ($PM_{2.5}$ AND OZONE)

In accordance with OR-SAGE facility siting guidelines, which prioritize compliance with air quality regulations, areas designated as non-attainment for federal air quality standards were considered unsuitable for potential biofuel facility development. This analysis used geospatial data from the U.S. Environmental Protection Agency's (EPA) "Green Book," focusing on regions classified as non-attainment for the 8-Hour Ozone (2015 Standard) and $PM_{2.5}$ (2012 Standard) [101] **(Figure 13)**.

Any location within these designated non-attainment boundaries was classified as not desirable and excluded from the siting analysis. This approach ensures that candidate sites do not exacerbate air quality challenges in regions that are already subject to regulatory limitations and public health concerns.

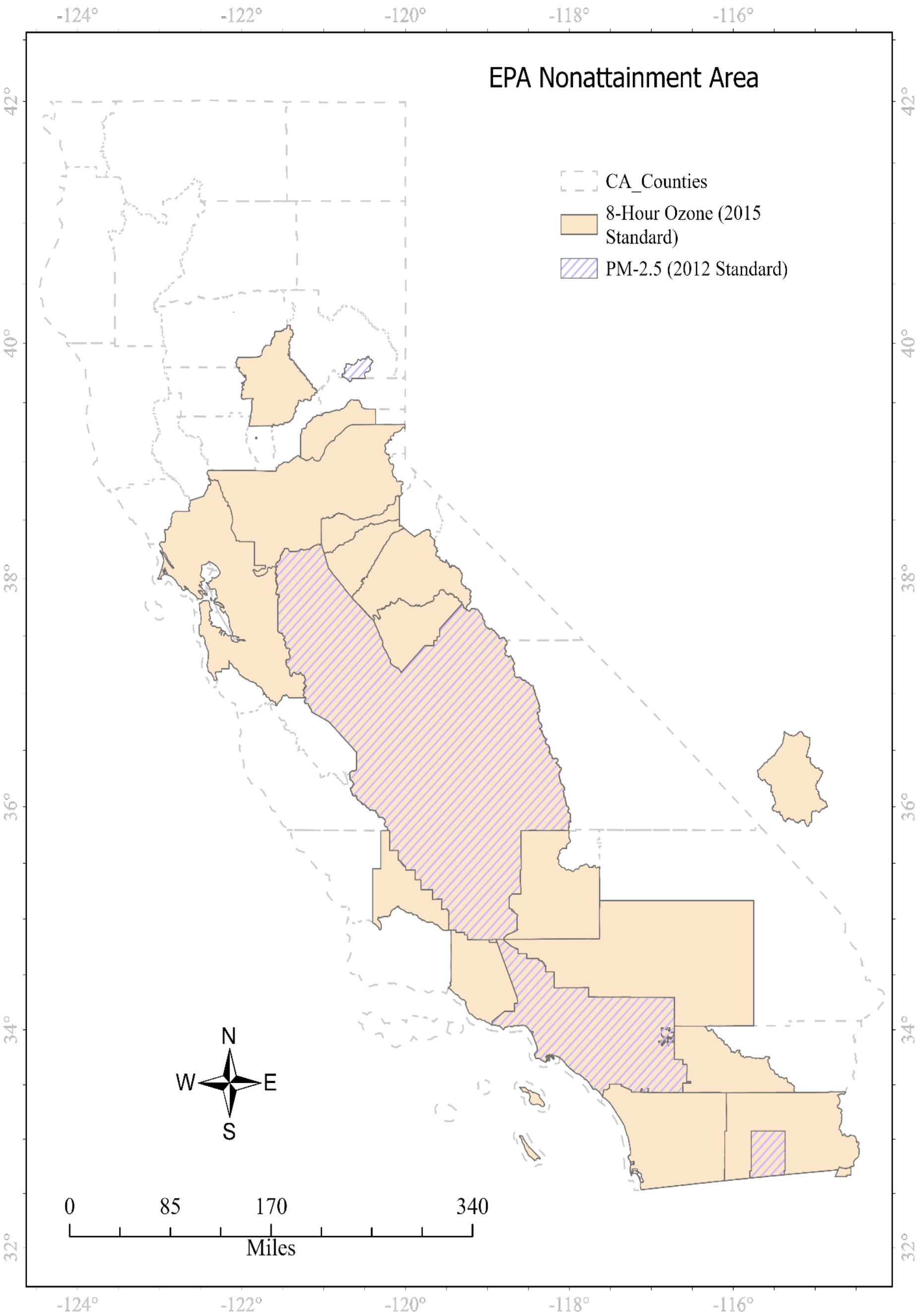
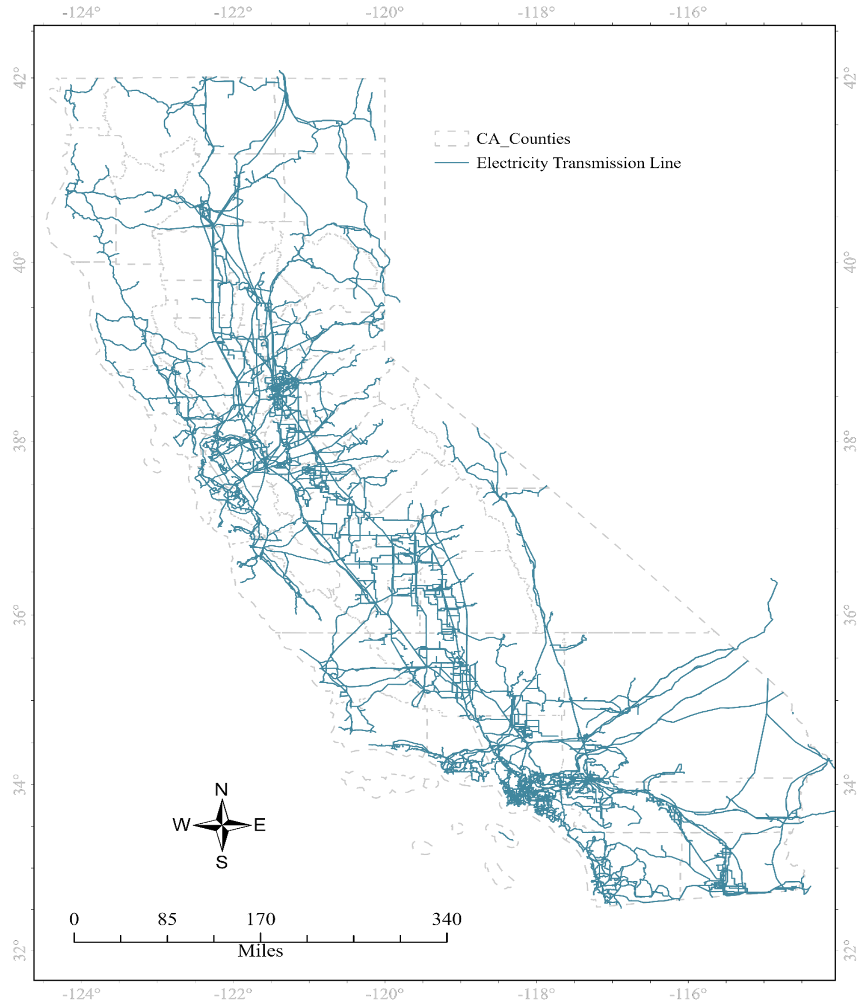


Figure 13. U.S. EPA–designated nonattainment areas for $PM_{2.5}$ and ozone in California [101].

4.3.10. ELECTRIC TRANSMISSION NETWORK

Proximity to existing electrical transmission infrastructure was evaluated as a critical siting criterion due to the substantial electricity requirements of biomass-to-hydrogen systems. Although hydrogen in this study is produced via thermochemical gasification rather than electrolysis, electricity remains a major operational input for air-separation units, syngas compression, hydrogen purification, and balance-of-plant systems, making it one of the largest contributors to operating expenditures (OPEX) after feedstock costs. Reliable and affordable grid access therefore plays a key role in controlling operating cost risk and ensuring continuous plant operation [102, 103]. Prior techno-economic assessments of biomass gasification and centralized hydrogen production consistently identify grid access as a key determinant of capital efficiency, operational reliability, and overall project bankability, even for non-electrolytic hydrogen pathways [104, 105].

Candidate sites were assessed using the California Electric Transmission Lines dataset from the California Energy Commission (CEC) and classified based on distance to existing transmission corridors: highly desirable (<10 miles), moderately desirable (10–20 miles), low desirability (20–30 miles), marginally desirable (30–40 miles), and not desirable (>40 miles) **(Figure 14)**.



14. California electric transmission network showing high-voltage transmission corridors used to evaluate grid interconnection suitability for biomass facility siting [106].

Closer proximity to transmission infrastructure reduces interconnection costs, limits the need for grid upgrades, shortens development timelines, and lowers exposure to electricity supply constraints.

This criterion reflects established techno-economic findings that grid access is a key determinant of capital efficiency, operational reliability, and project bankability for centralized hydrogen production facilities, including thermochemical pathways. Prioritizing sites near existing transmission infrastructure therefore supports realistic deployment and long-term economic performance of biomass-to-hydrogen facilities in California.

4.4. WEIGHTED OVERLAY

The final site-suitability analysis was conducted using a weighted overlay approach in which each siting criterion was assigned a relative importance weight, with all weights summing to 100. Weights were determined through a structured, expert-informed scoring process grounded in techno-economic relevance, operational feasibility, and consistency with prior biomass and hydrogen siting literature [107–117].

Availability of biomass feedstock was assigned the highest weight (16), reflecting its dominant influence on facility viability.

Feedstock availability directly governs plant scale, delivered biomass cost, transportation logistics, and long-term operational reliability, and is consistently identified in the literature as the primary constraint for biomass-based energy systems. As such, it was intentionally emphasized as the principal driver of site suitability.

All remaining criteria were assigned equal secondary weights of 6. These include energy infrastructure proximity (CNG, LNG, and hydrogen stations, and natural gas pipelines), physical constraints (slope and land use), regulatory considerations (EPA $PM_{2.5}$ and ozone non-attainment areas), and essential utilities and logistics (road network access, electric transmission proximity, and surface water availability). Assigning uniform weights to these factors reflects the assumption that, while each is individually important for permitting, construction, and operation, none alone is sufficient to determine feasibility in the absence of adequate biomass supply.

This weighting structure balances realism and transparency: it prioritizes the single most influential factor—feedstock availability—while ensuring that environmental, infrastructural, and regulatory constraints are systematically incorporated. The approach avoids overfitting or subjective fine-tuning of individual weights and is consistent with established multi-criteria decision analysis practices used in regional bioenergy and hydrogen siting studies.

4.5. SUITABLE AREAS FOR SITING

The multi-criteria suitability analysis identified approximately 26.06 million acres statewide as suitable for potential biomass-to-hydrogen and biofuel facility development. Of this total, 25.95 million acres (99.5 percent) fall within the moderate suitability class, while 0.08 million acres (0.3 percent) are classified as high suitability and 0.03 million acres (0.1 percent) as low suitability. The dominance of the moderate suitability class reflects the conservative weighting framework adopted in this study, in which multiple siting constraints—including land use, slope, regulatory designations, infrastructure access, and environmental considerations—must simultaneously align to elevate a location into the high-suitability category. As a result, high- and low-suitability areas appear spatially limited and fragmented, producing relatively subtle visual contrast in the statewide suitability map.

Suitable land is distributed across all 58 counties, but with pronounced geographic variability. Rural, forested counties in Northern California contain the largest contiguous suitable areas, led by Siskiyou County (2.45 million acres), followed by Humboldt (1.84 million acres), Mendocino (1.66 million acres), Shasta (1.60 million acres), and Trinity (1.56 million acres). In contrast, highly urbanized or intensively agricultural counties exhibit minimal suitable land, including San Francisco (0.00068 million acres), Kings (0.0046 million acres), Imperial (0.00997 million acres), and Sacramento (0.0141 million acres). This pattern underscores the strong association between site suitability and rural landscapes characterized by lower population density, fewer land-use conflicts, and greater proximity to forest biomass resources (**Figure 15**).

Within San Bernardino County, the analysis identifies approximately 0.238 million acres (237,775 acres) of land classified as moderately suitable for biomass-to-hydrogen facility siting, with no areas meeting the strict criteria for high or low suitability under the statewide classification scheme. Although San Bernardino County

> “Approximately 0.23 million acres is suitable for potential biomass-to-hydrogen facility development in San Bernardino County.”

contains less suitable land than heavily forested northern counties, the identified moderately suitable areas are strategically important due to their proximity to transportation corridors, existing industrial land uses, energy infrastructure, and major wildfire-prone forest landscapes in the San Bernardino Mountains. These characteristics support the county's role as a viable host region for biomass-to-hydrogen deployment when coupled with targeted site selection and infrastructure reuse, as evaluated in subsequent sections.

The suitability results reveal a clear urban–rural gradient, with the most favorable conditions concentrated in sparsely populated, forested regions, while still identifying meaningful opportunities in Southern California counties such as San Bernardino. These spatial patterns provide a robust foundation for the focused siting evaluation and case-study analyses that follow, ensuring that facility-scale assessments are grounded in statewide resource availability and realistic geographic constraints.

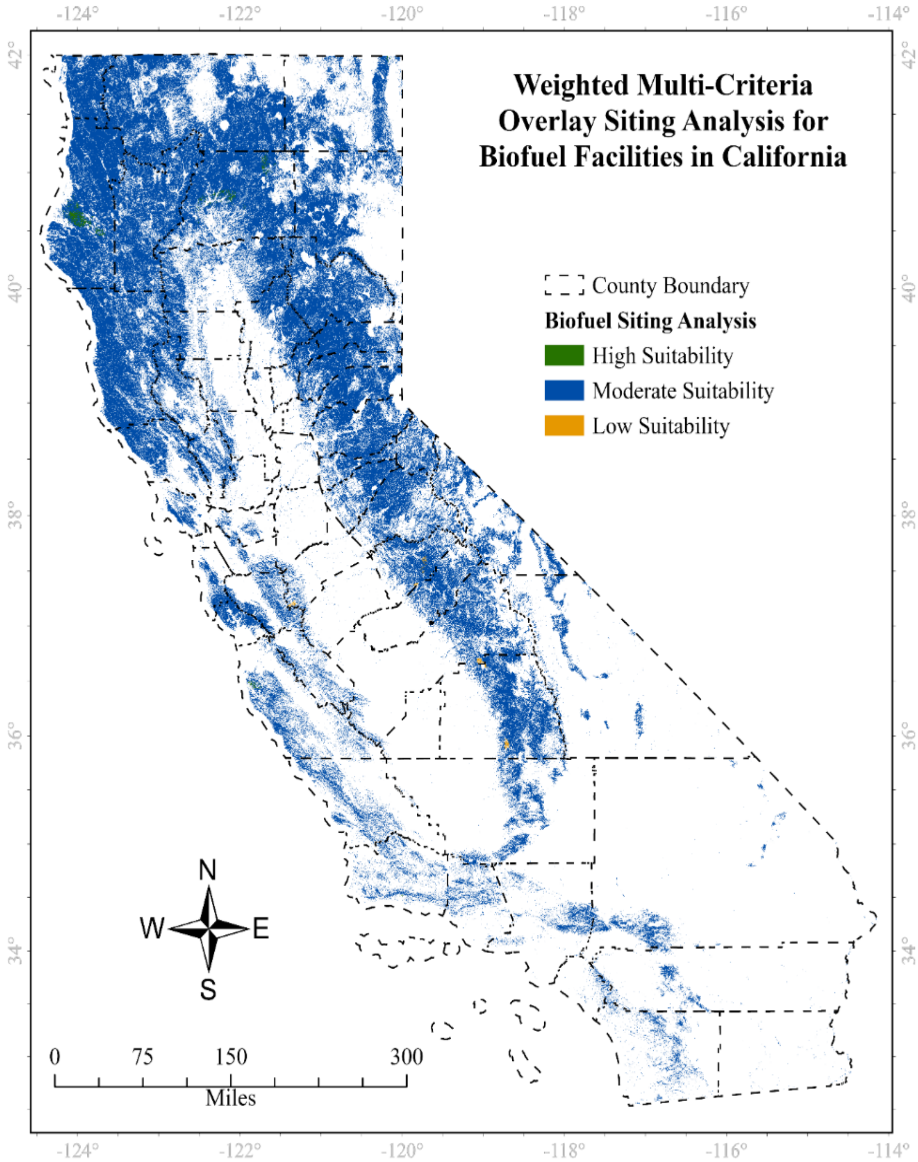


Figure 15. Weighted-overlay suitability map identifying areas ranked from low to high suitability for hydrogen facility development in California based on biomass availability, infrastructure access, physical constraints, and regulatory criteria

5. TECHNO-ECONOMIC AND FINANCIAL FEASIBILITY ANALYSIS

This chapter evaluates the techno-economic and financial feasibility of producing green hydrogen from forest biomass in San Bernardino County (SBC). The analysis integrates spatial biomass availability, suitability siting, transportation logistics, and detailed process and cost modeling. Building directly on the multicriteria siting assessment presented in Chapter 3, this chapter quantifies the economic performance of a 1,000 BDT per day thermochemical hydrogen production facility, including capital investment requirements, annual operating costs, revenue streams, and key financial indicators such as internal rate of return (IRR), levelized cost of hydrogen (LCOH), payback period, debt service coverage ratio (DSCR), and net present value (NPV).

Recognizing that existing bioenergy infrastructure can significantly influence deployment timelines, capital intensity, and project risk, the analysis evaluates two comparative development scenarios. The first considers a greenfield biorefinery site identified within SBC based on the siting results. The second examines a repurposing scenario involving the idle Desert View Power (DVP) biomass facility in Riverside County. These scenarios assess how infrastructure reuse, permitting history, transportation logistics, and spatial feedstock conditions affect overall project economics and investment viability.

The analysis employs a discounted cash flow rate-of-return (DCFROR) framework consistent with U.S. DOE, National Renewable Energy Laboratory (NREL), and National Energy Technology Laboratory (NETL) guidelines. Revenue streams include hydrogen sales, biochar co-product sales, and California Low Carbon Fuel Standard (LCFS) credits. All cost and revenue assumptions reflect California-specific conditions, including electricity prices, biomass transport costs, and regional hydrogen market dynamics.

The purpose of this chapter is threefold. First, it evaluates whether hydrogen production from forest biomass in San Bernardino County is economically viable under current market and policy conditions. Second, it identifies key financial risks and sensitivities related to feedstock cost, hydrogen pricing, capital expenditure, and infrastructure reuse. Third, it provides an integrated financial framework to inform policy decisions related to biomass utilization, wildfire-risk reduction, and clean-energy deployment in Southern California.

5.1. EXISTING BIOENERGY INFRASTRUCTURE AND PROPOSED BIOREFINERY SITE

California's bioenergy sector includes a broad mix of operational, proposed, and legacy facilities that influence feasibility, risk profile, and deployment pathways for new biomass-to-hydrogen systems. As of 2025, the Wood Utilization Group identified 89 bioenergy projects statewide, consisting of 22 operational facilities, 18 projects in active development or proposed stages, and 49 facilities classified as closed, idle, or cancelled [118]. For analytical purposes, these facilities were grouped into three functional categories: Operational, Active Development or Proposed, and Closed or Idle (**Figure 16**).

San Bernardino County emerges as a priority region for evaluation due to the convergence of several enabling conditions identified in the siting analysis. These include extensive areas of suitable land identified through the weighted-overlay assessment, limited overlap with high-density population centers or sensitive land uses consistent with local and regional land-use planning designations, proximity to major transportation corridors, and alternative fuel infrastructure. In addition, the county lies within economically feasible hauling distances of forest-residue resources identified in the C-BREC biomass assessment, supporting its evaluation as a potential regional hydrogen production center.

> "San Bernardino County emerges as a priority region for evaluation due to the convergence of several enabling conditions."

Based on these screening criteria, a proposed greenfield biorefinery location was selected within San Bernardino County at coordinates (–117.584, 34.16722) (**Figure 16**). This location reflects an analytically favorable combination of feedstock accessibility, logistical connectivity, and regulatory compatibility. It is used as a reference site for subsequent techno-economic and financial modeling.

To provide a comparative financial and deployment perspective, an alternative repurposing scenario was evaluated using the idle Desert View Power (DVP) biomass facility in Riverside County. The former 44 MW woody biomass power plant retains key infrastructure assets, including fuel-handling systems, industrially zoned land, grid interconnection, and onsite utilities. Evaluating DVP as a conversion enables comparison of greenfield development with infrastructure-reuse pathways, including potential differences in capital cost, permitting complexity, logistical integration, and overall financial performance

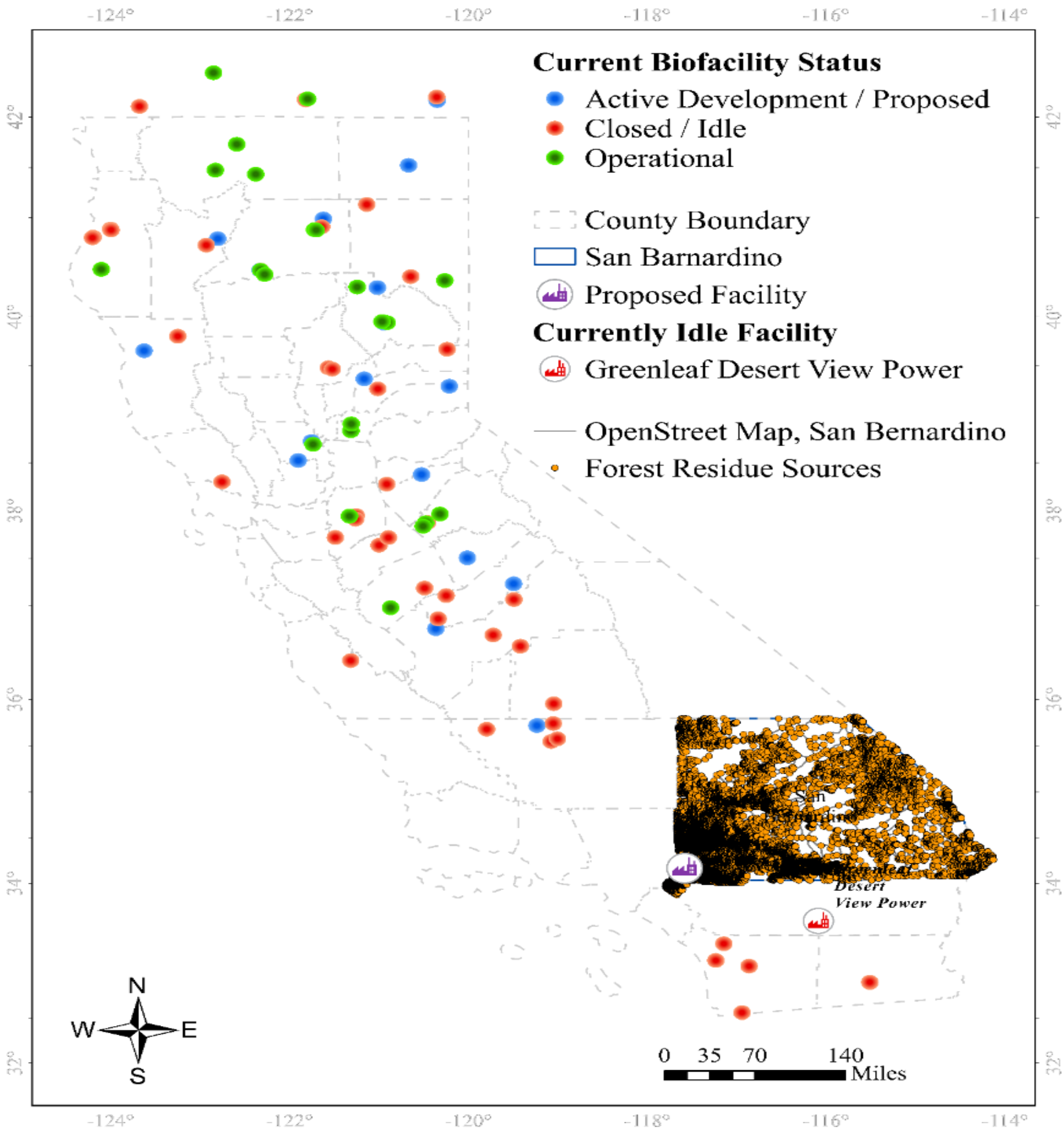


Figure 16. Spatial distribution of forest biomass in San Bernardino County estimated from C-BREC dataset, and locations of proposed and idle biorefinery facilities in California

5.2. TECHNO-ECONOMIC ANALYSIS (TEA) FRAMEWORK

The techno-economic analysis (TEA) evaluates the performance and cost competitiveness of a 1,000 BDT per day forest-biomass-to-hydrogen (H_2) facility located in San Bernardino County. The analysis integrates spatially derived feedstock logistics, process modeling, capital and operating cost estimation, and financial performance metrics to assess the viability of producing low-carbon hydrogen under California-specific market conditions. The TEA follows methodologies established by the U.S. Department of Energy (DOE) [119, 120], the National Renewable Energy Laboratory (NREL) [121], and NETL cost-estimation guidelines [122], supplemented with vendor data and published design references for gasification-based hydrogen production systems [123–129].

The modeled conversion pathway consists of the following major process steps:

- Biomass reception and preprocessing, including weighing, unloading, chipping, secondary size reduction, and drying
- Fluidized-bed gasification of forest biomass into raw synthesis gas (syngas)
- Syngas cooling, cleanup, and conditioning, including cyclones, heat recovery, tar reforming, and acid-gas removal
- High- and low-temperature water–gas shift (WGS) reactors to maximize hydrogen yield
- Pressure swing adsorption (PSA) purification to achieve hydrogen purity of at least 99.97%
- Hydrogen compression and onsite storage for distribution
- Biochar handling and revenue crediting
- Utility systems, including steam generation, nitrogen supply, cooling water, and electricity

Consistent with prior studies [74, 104, 105, 121, 130], hydrogen yields from biomass gasification systems typically range from approximately 70 to 100 kg H_2 per BDT of feedstock, depending on process configuration and overall conversion efficiency, which commonly spans 47–66.8%. In the present study, a conservative overall conversion efficiency of 50% was assumed, resulting in a hydrogen yield of 74.9 kg H_2 per BDT of biomass, which lies within the lower-to-mid range of values reported in the literature and therefore provides a defensible, non-optimistic basis for techno-economic evaluation. The mass and energy balance yields an annual hydrogen production of approximately 24,707 metric tons. Process energy requirements are explicitly quantified and incorporated into capital and operating cost estimation. Revenue streams include hydrogen sales, biochar co-product revenue, biochar carbon removal, and low carbon fuel standard (LCFS) crediting generation.

Capital expenditure (CAPEX), operating expenditure (OPEX), and revenues are evaluated using a discounted cash flow rate-of-return (DCFROR) model. Key financial indicators include net present value (NPV), internal rate of return (IRR), levelized cost of hydrogen (LCOH), debt service coverage ratio (DSCR), and simple payback period. All results are calculated assuming a 20-year project life and financing parameters consistent with industrial energy infrastructure projects in California.

Overall, the TEA framework provides a robust engineering and economic basis for assessing whether hydrogen production from forest residues can be cost-competitive and financially resilient. It also identifies the market and policy conditions under which large-scale deployment of biomass-to-hydrogen systems could support California's decarbonization, wildfire-risk reduction, and clean-energy objectives in Southern California.

5.2.1. SYSTEM BOUNDARY

Techno-economic analysis applies a gate-to-gate system boundary focused on the conversion of mixed forest biomass into hydrogen through thermochemical gasification and downstream gas processing systems. The system boundary is defined to support planning, policy evaluation, and comparative assessment by delineating which costs, emissions, and operational risks are attributable to the hydrogen production facility itself. The modeled system includes all processes from feedstock delivery at the facility gate through hydrogen compression and onsite storage.

Processes included within the system boundary are:

- Forest biomass procurement and transportation, including collection, loading, and trucking to the facility
- Biomass reception and handling, including weighing, unloading, and onsite storage
- Feedstock preprocessing, including primary chipping, secondary size reduction, and drying
- Fluidized-bed gasification, converting biomass into raw syngas and biochar
- Syngas cooling and cleanup, including cyclones, heat-recovery steam generation, tar reforming, and acid-gas removal
- Syngas conditioning, including moisture adjustment, steam addition, and temperature control
- Water-gas shift (WGS) conversion, including high-temperature and low temperature shift reactors
- Pressure swing adsorption (PSA) purification, producing hydrogen with purity of at least 99.97%

- Hydrogen compression and onsite storage
- Biochar quenching, cooling, screening, and packaging
- Utility systems, including electric power, steam generation, nitrogen supply, cooling water, and chilled water
- Thermal oxidation of PSA off-gas to supply internal process heat for feedstock drying and steam generation.

This analysis excludes the following elements:

- Upstream forest management activities, including thinning, harvesting, and residue generation, which are governed by separate forest-health and wildfire-mitigation programs
- Downstream hydrogen distribution infrastructure, including pipelines, refueling stations, and vehicle fleets, which depend on regional market development and deployment decisions
- Biochar end-use pathways and long-term carbon sequestration outcomes, which are recognized as potential co-benefits but are not required for facility-level economic viability
- Carbon capture and storage (CCS), with the base case assuming venting of PSA-separated carbon dioxide; CCS integration is evaluated separately in sensitivity analysis
- End-use hydrogen applications, including transportation, industrial consumption, and power generation

This gate-to-gate system boundary supports policy analysis by isolating cost performance and risk directly attributable to the hydrogen production facility by separating conversion economics from upstream forest-management programs and downstream hydrogen infrastructure deployment.

5.2.2. DESIGN BASIS AND OPERATING CONDITIONS

The design basis establishes the engineering, operational (24/7), and performance assumptions used to model the biomass-to-hydrogen conversion system and quantify mass and energy flows for the techno-economic analysis (**Table 2**). All parameters reflect a commercial-scale facility processing 1,000 BDT per day of mixed forest biomass, consistent with DOE/NREL reference plant designs and vendor-reported process specifications. Feedstock characteristics, including moisture content, particle size, and heterogeneity, are incorporated into preprocessing and gasification assumptions to reflect realistic operational conditions. The system is modeled to operate on a near-continuous basis, accounting for scheduled downtime and maintenance, with process conditions optimized to maximize hydrogen yield while maintaining operational stability. Mass and energy balances from the modeled system are used to estimate hydrogen production, co-product biochar output, and process energy requirements, which in turn inform capital and operating cost estimates.

Table 2. Process design basis for forest-residue hydrogen facility.

Parameter	Value	Basis
Feedstock and Operating Schedule		
Biomass throughput	1,000 BDT per day	Facility design capacity
Annual operating days	330 days per year	[131, 132]
Annual biomass processed	330,000 BDT per year	Throughput × operating days
Moisture content (incoming)	50% wet basis (w.b.)	[81, 133]
Moisture content to gasifier	10% wet basis (w.b.)	[81, 133]
Biomass LHV	18 MJ/kg (dry)	[134]
Conversion Performance		
Hydrogen yield	74.9 kg H_2 per BDT	Derived from mass/energy balance
Annual hydrogen output	24,707 metric tonnes per year	Hydrogen yield × annual biomass
Biochar yield	26,400 metric tonnes per year	8% per BDT
Energy Requirements		
Electricity consumption	2.99 kWh per kg H_2	[135, 136]
Annual electricity use	73.9 GWh per year	Based on total H_2 production
Electricity price	\$0.23 per kWh	[137]
Utility Consumption		
Nitrogen	37.1 million SCF per year	[138, 139]
Steam	Process-integrated; generated via HRSG	Required for WGS, gasifier steam injection
Cooling water & chilled water	Load based on syngas/quench/ exchanger duties	Sized according to heat removal requirements

5.2.3 FINANCIAL AND ECONOMIC ASSUMPTIONS

The financial evaluation of the forest-biomass–to–hydrogen facility is conducted using a discounted cash flow rate-of-return (DCFROR) framework, consistent with DOE and NREL techno-economic analysis guidance. The assumptions presented in this section define the macroeconomic context, project financing structure, and unit costs that drive profitability, levelized cost of hydrogen (LCOH), and overall investment performance.

The project is modeled using a blended debt–equity financing structure representative of commercial-scale energy infrastructure, reflecting a moderate-risk profile suitable for early commercial hydrogen facilities in California. These assumptions balance typical lender requirements with expected project returns and provide a standardized foundation for evaluating financial feasibility, identifying key sensitivities, and informing policy and incentive decisions. Key financial parameters are summarized in **Table 3.**

“The project is modeled using a blended debt–equity financing structure representative of commercial-scale energy infrastructure, reflecting a moderate-risk profile suitable for early commercial hydrogen facilities in California.”

Table 3. Financial parameters, macroeconomic and price assumptions, and output-based revenues.

Parameter	Value	Basis/Notes
Capital Structure and Economic Parameters		
Total Capital Investment (TCI)	\$420.4 million	Derived from detailed CAPEX estimate [104, 105, 121, 123–128, 130, 140–147]
Annual OPEX	\$60.7 million	From fixed + variable O&M model [121, 123–128]
Discount rate (WACC)	10%	[148]
Loan term	20 years	[131]
Equity fraction	40%	Assumed investor contribution [148]
Debt fraction	60%	Commercial debt financing [148, 149]
Corporate tax rate	21%	Federal corporate income tax [148]
Price and Revenue Assumptions		
Hydrogen sales price	\$6.00/kg	Base-case offtake value
Annual hydrogen production	24,707 metric tonnes per year	From design basis
Biochar sale price	\$600 per tonne	[150–152]
LCFS credit price	\$55 per tCO_2e	CARB 2024–2025 average [153]
Biochar carbon credit	\$100 per tCO_2e	Conservative crediting assumption [154]
LCFS credit revenue	\$11.50 million per year	Conservative crediting assumption
Biochar carbon revenue	\$7.26 million per year	\$100 per ton CO_2e removal
Resource and Utility Cost Inputs		
Biomass price	\$50 per BDT	Forest-residue procurement costs in CA [148]
Transportation rate	\$0.15 per metric tonne-mile	Medium-haul biomass trucking [155, 156]
Feedstock insurance rate	2% of feedstock cost	Assumed feedstock supply insurance at 2% of total annual feedstock cost
Electricity price	\$0.23 per kWh	CA industrial rate (2024) [137]
Nitrogen price	\$0.30 million per year	Based on 37 million SCF consumption [138, 139]

5.2.4. DEPRECIATION, TAX, AND CAPITAL RECOVERY

The techno-economic analysis assumes a project-finance structure typical of commercial renewable-energy investments in the United States. The facility is modeled with a capital structure comprising 60% debt and 40% equity, with the debt portion totaling $252.2 million. Debt financing is structured over a 20-year loan term with a fixed interest rate of 10%, reflecting a typical investor expectation for capital-intensive energy infrastructure. Federal corporate income tax is applied at a rate of 21%, and depreciation benefits are incorporated in accordance with standard U.S. tax regulations. Capital recovery is evaluated using a discounted cash flow approach, applying a capital recovery factor (CRF) of 0.12 over a 20-year operating life following construction.

5.2.5. FEEDSTOCK SUPPLY AND TRANSPORTATION LOGISTICS

Feedstock supply and transport were evaluated using a spatially explicit logistics model that integrates the OpenStreetMap (OSM) road network with ArcGIS Pro's Origin–Destination (OD) Matrix tool. Forest residue supply locations identified in Chapter 3 were treated as origin nodes, with candidate plant sites designated as destinations (**Figure 17**). The OD analysis calculated shortest-path road distances for each supply–site pair, from which mean hauling distances and route distributions were derived.

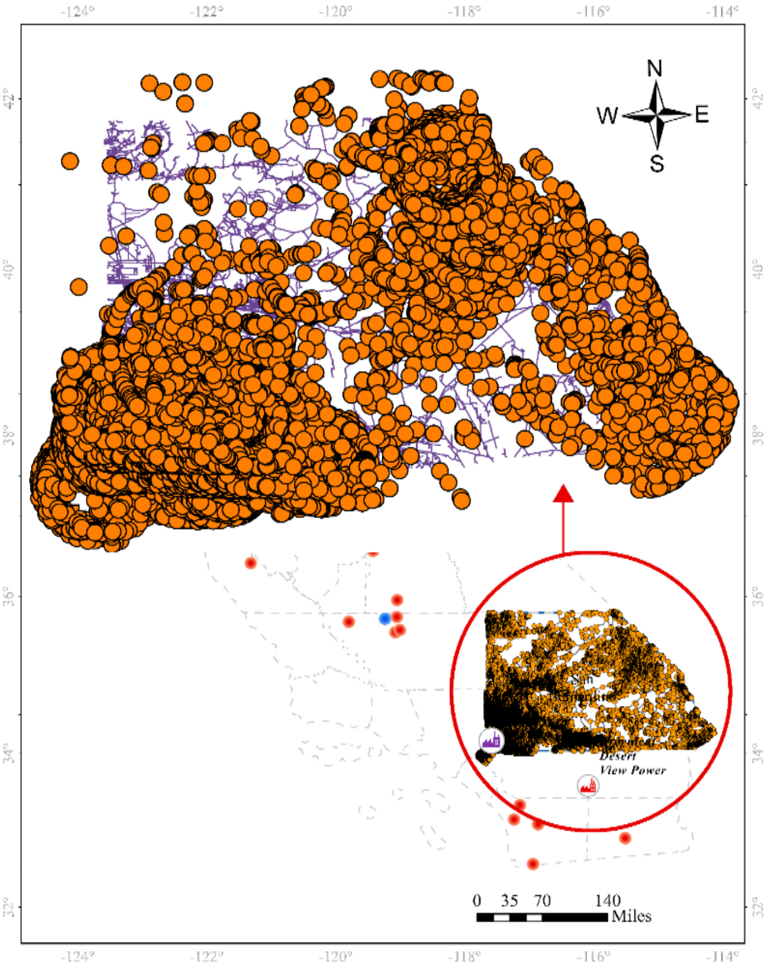


Figure 17. Origin–destination (O–D) matrix–based routing analysis used to calculate forest-residue transportation distances. The enlarged map of San Bernardino County shows individual source points representing forest-residue supply locations, overlaid on the OpenStreetMap road network. Darkened route segments indicate the least-cost road paths used to compute network-based hauling distances from each source location to the proposed biomass-to-hydrogen facility.

For the proposed San Bernardino County (SBC) greenfield site, the modeled mean one-way hauling distance from forest-residue supply locations is 66.7 miles. Conventional chip vans with a payload of about 25 wet tons per load were assumed, resulting in roughly six truck deliveries per day to meet the facility's feedstock demand of 1,000-BDT per day (≈1,150–1,200 wet tons/day).

Transportation costs were calculated using a round-trip rate of $0.15 per ton-mile, representative of medium-haul biomass trucking in California, yielding an annual cost of approximately $1.74 million per year. When combined with an at-source feedstock procurement cost of $16.5 million per year, the total delivered feedstock cost for the San Bernardino County facility is approximately $18.2 million per year. To further mitigate risks associated with feedstock price volatility and potential supply disruptions, a 2% feedstock supply insurance (FSI) premium was incorporated into the operating cost structure. FSI represents an emerging risk-management mechanism designed to de-risk biomass supply chains by stabilizing long-term feedstock availability and pricing, thereby improving project bankability. Even with this risk-mitigation allowance, biomass supply remains the largest contributor to variable operating expenditures, accounting for approximately 30% of total annual OPEX.

5.2.6. PROCESS DESCRIPTION AND MASS–ENERGY BALANCE

This section describes the engineered thermochemical pathway used to produce hydrogen from forest biomass at the San Bernardino County facility. The system includes biomass reception and preprocessing, fluidized-bed gasification, syngas cooling and cleanup, water–gas shift (WGS) conversion, hydrogen purification by pressure swing adsorption (PSA), product handling, and supporting utility systems (**Figure 18**). All mass and energy flows are based on vendor specifications, published feasibility studies, and bottom-up modeling assumptions employed in the techno-economic analysis.

At full design capacity, the plant processes 1,000 bone-dry tons (BDT) of mixed forest biomass per day, corresponding to 330,000 BDT per year, assuming 330 operating days. The incoming biomass has a moisture content of 50% (wet basis) and a lower heating value (LHV) of 18 MJ/kg. Following drying to 10% moisture and conversion through the gasification–WGS–PSA train, the facility produces approximately 24,707 tonnes per year of hydrogen and a gross biochar output of roughly 26,400 tonnes per year, which is credited as a marketable co-product in the TEA. Tail gas and PSA off-gas are combusted on site to supply low-grade heat and steam. These mass and energy flows establish the material and energy boundary conditions for equipment sizing, utility design, capital cost estimation, and operating cost modeling.

FEEDSTOCK RECEPTION, STORAGE, AND PREPARATION

The facility receives approximately 330,000 BDT per year of forest biomass in 25-tonne truckloads, corresponding to roughly six deliveries per day at full operation. Feedstock comprises small-diameter logs, tops, limbs, and pre-chipped material sourced from forest management operations. Upon arrival, trucks are weighed, unloaded, and dispatched to a dedicated storage yard with capacity for three to four weeks of supply. This inventory buffer provides resilience against seasonal harvesting variability, wildfire-related access restrictions, and operational downtime.

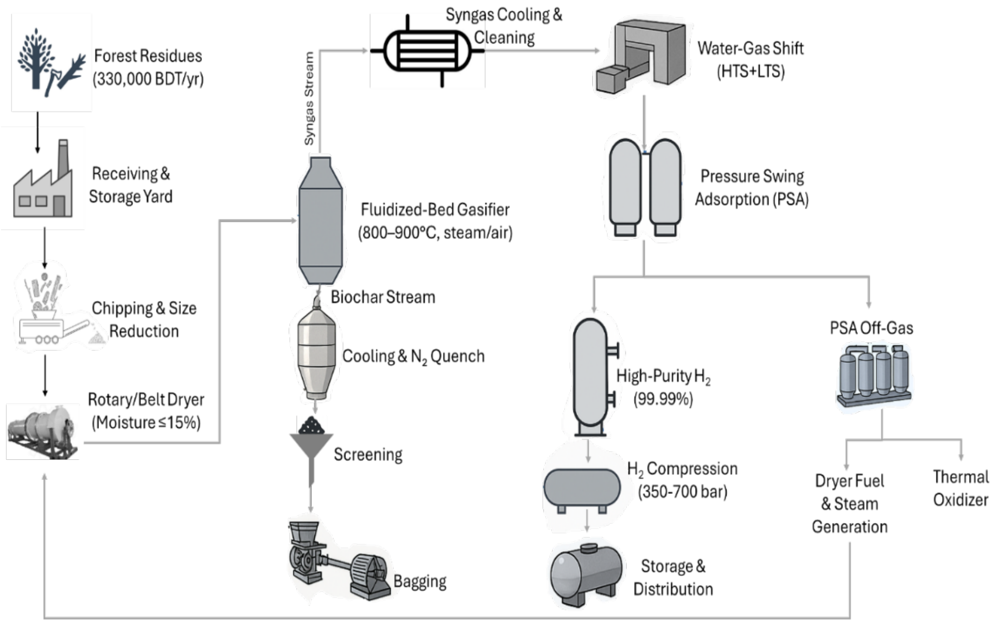


Figure 18. Process flow diagram of hydrogen production from forest biomass via WGS pathway.

On a dry basis, the forest biomass consists of 50.84% carbon, 5.72% hydrogen, 0.66% nitrogen, 0.25% sulfur, 41.46% oxygen, and 5% ash. With moisture content of 10% to the gasifier, the annual energy input to the facility is approximately 5.4×10^9 MJ.

Primary size reduction is performed using a high-capacity industrial chipper, which reduces logs and oversized residues to chips smaller than 3 inches at a nominal throughput of about 6 wet tons per hour. Pre-chipped material bypasses this step and is routed directly to a chip-staging area. All chipped material then passes through a secondary size-reduction system (crumbler) to achieve a uniform particle size of 0.5–0.75 inches. Oversized particles are automatically recirculated, while fines are separated through screening and directed either to biochar handling or disposed of as appropriate.

Following size reduction, the biomass is dried from 50% to approximately 10% moisture using low-grade heat recovered within the plant. The drying system handles ~5443.1 kg (12,000 lb.) per hour (wet basis), yielding ~3323.9 kg (7,328 lb.) per hour of dried biomass. Heat is provided primarily by the combustion of PSA off-gas and tail gas, supplemented by energy recovered from syngas cooling. The resulting prepared feedstock delivers approximately 41,667 kg per hour of dry biomass to the gasification system, ensuring consistent throughput and process stability.

FLUIDIZED-BED GASIFICATION

Dried biomass is fed into a bubbling fluidized-bed gasifier, which serves as the primary thermochemical conversion unit. The reactor operates at temperatures between 800 and 900 °C under oxygen-lean, steam-assisted conditions. Bed material, such as silica sand or olivine, ensures effective mixing, uniform temperature distribution, and rapid heat and mass transfer.

Within the gasifier, the biomass undergoes drying, devolatilization, char gasification, and gas-phase reactions. Key reaction pathways include:

- devolatilization and partial oxidation of organic matter,
- char gasification via

$$\mathbf{C + CO_2 \rightarrow 2CO \text{ and } C + H_2O \rightarrow CO + H_2}$$

- secondary gas reactions that generate additional hydrogen and carbon monoxide.

The primary outputs are a raw syngas composed mainly of CO, H_2, CO_2, CH_4, light hydrocarbons, and condensable tars, together with a solid char fraction. Under model assumptions, biochar represents approximately 8% of the incoming dry biomass, corresponding to a gross production of about 26,400 tonnes per year. Thermal energy contained in the hot syngas and bed material is recovered downstream and reintegrated into the process, improving overall energy efficiency.

A total throughput of 1,000 BDT per day exceeds the typical capacity of a single commercial fluidized-bed gasifier, which is generally in the range of 250–500 BDT per day. In practice, this scale would be achieved using two to four reactors operating in parallel. For the purposes of the techno-economic analysis, the facility is modeled as a single integrated hydrogen production train, with the capital cost and redundancy of multiple gasifiers incorporated into the hydrogen production equipment CAPEX.

SYNGAS COOLING, CLEANING, AND CONDITIONING

Raw syngas exits the fluidized-bed gasifier at near-bed temperatures and must be cooled, cleaned, and conditioned prior to hydrogen production. The first step involves particulate removal using high-efficiency cyclones, which capture entrained bed material and char fines. The gas is then routed through a heat-recovery steam generator (HRSG), where its sensible heat is recovered to produce steam for the water-gas shift (WGS) reactors and to support biomass drying and other thermal loads. This internal heat integration reduces the requirement for external fuel and additional boilers.

Following the HRSG, a catalytic reformer or tar-cracking reactor converts condensable hydrocarbons and heavy tars into additional CO and H_2. This step improves syngas quality and prevents fouling of downstream equipment. The partially cleaned syngas then undergoes multi-stage contaminant removal, including acid gas control (H_2S, NH_3), fine particulate filtration, and water knock-out. Moisture content and temperature are then adjusted to achieve the desired steam-to-carbon ratio and inlet conditions for the WGS reactors.

The resulting conditioned syngas consists primarily of CO, H_2, and CO_2, with trace amounts of CH_4, and meets the specifications required for efficient and stable hydrogen production via water–gas shift conversion and subsequent PSA separation.

WATER–GAS SHIFT (WGS) REACTION SYSTEM

Hydrogen production is achieved through a two-stage water–gas shift reaction system comprising a high-temperature shift (HTS) reactor followed by a low-temperature shift (LTS) reactor. In these reactors, carbon monoxide in the conditioned syngas reacts with steam according to the exothermic reaction:

$$\mathbf{CO + H_2O \rightarrow CO_2 + H_2\ (\Delta H<0)}$$

The HTS reactor operates at elevated temperatures to promote rapid kinetics and convert the majority of carbon monoxide, while the downstream LTS reactor operates at lower temperatures to further shift the equilibrium toward hydrogen formation. Thermal energy released in both stages is recovered through integrated heat exchangers and reused within the process. Effective thermal management through controlled steam addition and inter-stage cooling is essential to maintain catalyst stability, prevent temperature excursions, and ensure long-term system reliability.

Under the modeled operating conditions, the combined WGS system produces an average hydrogen yield of 74.9 kg per BDT of biomass. At full design capacity, this corresponds to approximately 74,869 kg per day of hydrogen, or 24,706,763 kg per year (24,707 t per year). On a lower heating value (LHV) basis, the overall biomass-to-hydrogen conversion efficiency is about 50%, with the remaining chemical energy distributed among tail gas, recoverable biochar, and unavoidable conversion losses.

HYDROGEN PURIFICATION, COMPRESSION, AND STORAGE

The shifted syngas is processed in a pressure swing adsorption (PSA) system to separate hydrogen from carbon dioxide, carbon monoxide, methane, and other trace components. The PSA produces hydrogen at a purity of at least 99.97%, meeting specifications for industrial use, compression, and downstream distribution. The PSA reject stream is rich in CO_2 and contains residual combustibles. This off-gas is routed to onsite burners and thermal oxidizers, where it is combusted to supply thermal energy for biomass drying, steam generation, and emissions control. This internal heat recovery reduces the facility's dependence on external fuels and improves overall system efficiency.

Following purification, hydrogen is compressed to the required delivery pressure using multi-stage compression systems. The compressed hydrogen is stored in high-pressure vessels and can be dispatched via tube trailers or connected to a dedicated hydrogen pipeline, depending on the selected offtake strategy. Electricity demand associated with PSA operation and hydrogen compression represents the largest component of the facility's electrical load and is a key driver of operating costs.

BIOCHAR PRODUCTION AND HANDLING

Biochar generated in the fluidized-bed gasifier is removed continuously through a dedicated solid-handling system designed to ensure safe cooling, stabilization, and storage. Hot char discharged from the reactor is first quenched using a controlled combination of nitrogen and water sprays to rapidly reduce temperature and prevent oxidation. The material then passes through enclosed mechanical cooling equipment, such as screw or drag-chain conveyors, which further lowers the temperature and allows for controlled conveyance to downstream handling units. This staged cooling approach minimizes the risk of auto-ignition and facilitates safe material management.

The cooled biochar is screened to remove oversized fragments and residual contaminants. The conditioned product is then packaged in supersacks or transferred to bulk containers and stored in covered areas prior to shipment. Gross biochar production is estimated at roughly 26,400 tonnes per year, corresponding to 8% of the incoming dry biomass. Assuming a market price of $600 per tonne, biochar sales generate approximately $15.84 million per year in supplemental revenue. Any remaining char is either retained as internally sequestered carbon within the system boundary or managed as a low-value residual material, depending on operational requirements.

UTILITY SYSTEMS (STEAM, NITROGEN, COOLING WATER, AND POWER)

The hydrogen production train is supported by an integrated suite of utility systems designed to enable continuous 24-hour operation over 330 days per year. These systems include electricity, steam, nitrogen, cooling water, and chilled water, and their performance and costs are fully incorporated into the operating cost model.

Electricity represents the dominant non-biomass energy input to the process. Under the defined design basis, the facility exhibits a specific electricity consumption of 2.99 kWh per kilogram of hydrogen produced. At an annual hydrogen output of approximately 24.7 million kg, total electricity demand is estimated at about 7.39×10^7 kWh per year, equivalent to roughly 73.9 GWh per year.

Using a representative California commercial retail electricity price of $0.23 per kWh (September 2024), the resulting annual electricity cost is approximately $17.0 million per year. This substantial power demand reflects the energy requirements of hydrogen compression, PSA operation, biomass handling and drying auxiliaries, blowers, pumps, cooling systems, and other balance-of-plant equipment.

Steam is generated primarily through a heat-recovery steam generator (HRSG) that captures sensible heat from hot syngas streams as well as heat released during the exothermic water–gas shift (WGS) reactions. The recovered steam is used for WGS conversion, gasifier fluidization and steam injection, and other process heating needs. By prioritizing internal heat recovery, the facility minimizes reliance on supplemental fired boilers and reduces external fuel consumption.

Nitrogen is required for reactor inerting, equipment purging, and safe handling and cooling of hot biochar. The annual nitrogen consumption is estimated at approximately 37 million standard cubic feet (SCF per year), corresponding to an annual cost of about $0.30 million per year, based on the assumed unit price. Nitrogen supply will be provided either through bulk liquid storage with onsite vaporization or from a dedicated nitrogen generation system, depending on final system design.

Cooling water and chilled water are employed to remove heat from syngas coolers, WGS inter-stage exchangers, PSA compressors, and other thermal loads. A mechanical chiller with a nominal capacity of 30–35 tonnes, plus redundancy, maintains low-temperature conditions where required (e.g., condensers and select PSA or reformer services), while a conventional cooling tower rejects intermediate-grade heat to the atmosphere. Collectively, the steam, nitrogen, and cooling systems provide thermal stability and operational reliability for the thermochemical conversion pathway and are fully accounted for in the plant's OPEX.

5.2.7. CAPITAL EXPENDITURE (CAPEX) ESTIMATION METHODOLOGY

Capital expenditures for the proposed forest-residue-to-hydrogen facility in San Bernardino County were estimated using a hybrid literature-calibrated and engineering bottom-up approach, consistent with NREL gasification and H2A costing practice and standard chemical-engineering cost scaling. The plant is designed to process 1,000 dry tonnes per day of forest biomass (≈ 330,000 BDT per year), operating 24 hours per day over 330 d per year, with hydrogen produced via oxygen-blown gasification, syngas cooling and cleanup, water–gas shift (HTS/LTS), and hydrogen purification (PSA or membrane). All costs are reported in 2024 dollars.

The capital-cost development followed three steps: (i) Benchmarking total CAPEX from published studies and normalizing all values to 2024 dollars; (ii) Scaling all benchmark costs to the project's 1,000-BDT capacity using a standard exponent; and (iii) Developing a process-level direct-cost breakdown using the NREL framework [105, 121, 145] and integrating site-specific balance-of-plant (BOP) estimates, then applying indirect and owner's costs to obtain Total Plant Cost (TPC) and Total Capital Investment (TCI).

LITERATURE BENCHMARKING AND COST-YEAR NORMALIZATION (CEPCI)

A set of published techno-economic studies representing biomass gasification systems (hydrogen and liquid biofuels) was compiled to establish a defensible capital-cost envelope [104, 105, 121, 130, 140–147]. For each study, the reported total capital investment (or equivalent CAPEX metric), the basis year, and the reference plant capacity were recorded (**Table S6**).

All literature costs were converted to a consistent 2024-dollar basis using the Chemical Engineering Plant Cost Index (CEPCI) (values obtained from Chemical Engineering Magazine) (**Table S7**). For each study, a CEPCI inflator was calculated as:

$$CAPEX_{2024} = CAPEX_{basis} \times \frac{CEPCI_{2024}}{CEPCI_{basis}}$$

This step ensures temporal comparability across studies published in different years and reduces bias from inflation and cost-index drift.

CAPACITY SCALING TO THE 1,000 BDT PER DAY REFERENCE PLANT

Because the source studies span a wide range of plant capacities, each CEPCI-normalized CAPEX value was adjusted to the project design capacity of 1,000 BDT per day. For cross-study benchmarking purposes, a proportional capacity normalization approach was applied to maintain transparency and comparability across heterogeneous literature sources [104, 105]:

$$CAPEX_{1000} = CAPEX_{2024} \times \left(\frac{1000}{Q_{study}}\right)$$

where Q_{study} represents the biomass input capacity (BDT per day) reported in each source study, and $CAPEX_{2024}$ is the capital cost adjusted to 2024 dollars using the Chemical Engineering Plant Cost Index (CEPCI).

This proportional normalization was used solely to derive order-of-magnitude benchmark values from published studies, recognizing that detailed engineering cost functions were not uniformly available across all references. The resulting set of normalized CAPEX values establishes a literature-based capital envelope. The arithmetic mean of these normalized values yields an average CAPEX of approximately $420.68 million (2024$), which serves as a reference benchmark for validating the project-specific bottom-up estimate (**Table S6**).

PROCESS-LEVEL DIRECT CAPEX DEVELOPMENT

For the breakdown of engineering-level cost, capital costs were scaled using a standard capacity-exponent (power-law) relationship, commonly referred to as the six-tenths rule (n = 0.6), consistent with NREL's Swanson et al. [147] biomass gasification framework and chemical engineering practice. NREL's installed costs for key subsystems (feedstock handling and preprocessing, oxygen-blown gasification, syngas cooling/heat recovery, syngas cleanup/AGR, WGS, hydrogen purification, ASU, and BOP) were first escalated from the NREL's Swanson et al. [145] 2010 basis year to 2024 using the relevant CEPCI ratio (2010→2024 CEPCI factor = 1.452).

$$C_{i,2024} = C_{i,2010} \times \frac{CEPCI_{2024}}{CEPCI_{2010}}, \qquad C_{i,1000} = C_{i,2024}\left(\frac{1000}{Q_{NREL}}\right)^{0.6}$$

The exponent-based scaling reflects empirically observed economies of scale in process industries, where capital cost increases less than proportionally with plant capacity.

Using this approach preserves the relative cost contributions of major process islands particularly syngas cleanup/AGR, hydrogen purification, and the air separation unit, while ensuring engineering consistency with validated NREL gasification [147] cost structures **(Table 4)**.

SITE-SPECIFIC BALANCE-OF-PLANT (BOP) AND CIVIL/INFRASTRUCTURE COSTS

Because generic "BOP" percentages can underrepresent actual civil and infrastructure costs, this study developed a site-specific BOP estimate based on a defined facility footprint of 129,600 square feet (ft^2), informed by preliminary layout planning and vendor/civil engineering inputs. The site includes dedicated areas for: security and weigh stations (7,200 ft^2), hydrogen loading and trucking (43,300 ft^2), biochar storage and loading (19,000 ft^2), and biomass laydown (16,500 ft^2), in addition to process buildings, biomass processing and storage structures, administrative and lab facilities, and safety and utility elements. This explicit BOP treatment improves realism relative to literature-only TEAs and strengthens defensibility when responding to reviewer concerns regarding underestimation of non-process infrastructure (**Table 4**).

> "This study developed a site-specific BOP estimate based on a defined facility footprint of 129,600 square feet (ft^2), informed by preliminary layout planning and vendor/civil engineering inputs."

Table 4. Installed equipment costs for the 1,000 BDT per day forest-residue-to-hydrogen facility in San Bernardino County.

Equipment	NREL Swanson et al. [147]			This study	
	2010 $	**$2024 (Estimated)**	**Installed Equipment Cost (%)**	**Estimated Installed Equipment Cost $**	**Percent (%)**
Feedstock handling and preprocessing	22,700,000	32,970,225	9%	21,752,236	9%
Oxygen-blown gasification reactor system	28,200,000	40,958,606	11%	27,022,602	11%
Syngas cooling and heat recovery	29,300,000	42,556,282	12%	28,076,675	11%
Syngas cleanup and acid-gas removal (AGR)	58,700,000	85,257,807	23%	56,249,175	22%
Water–gas shift (WGS) reactors	29,500,000	42,846,768	12%	28,268,325	11%
Hydrogen purification (PSA or membrane)	38,900,000	56,499,637	15%	37,275,859	15%
Air separation unit (ASU)	19,500,000	28,322,440	8%	18,685,842	7%
Balance of Plant (BOP)	27,200,000	39,506,173	11%	32,901,897	13%
Total	**254,000,000**	**368,917,938**	**100%**	**250,232,612**	**100%**

Note: Base-year costs from Swanson et al. (2010), developed by the National Renewable Energy Laboratory, are escalated to 2024 U.S. dollars using the Chemical Engineering Plant Cost Index (CEPCI) and scaled to the target facility capacity using a 0.6 scaling exponent [145].

TOTAL DIRECT COST (TOTAL INSTALLED COST BASIS)

Direct capital cost was computed as the sum of (i) hydrogen-production process equipment derived from the NREL 2010 process-island structure (escalated and scaled to 1,000 BDT per day), and (ii) site-specific BOP and civil infrastructure derived from the 129,600-ft^2 facility layout and associated auxiliary systems. Under this approach, the Total Gross Direct Cost (Direct CAPEX) was estimated as:

$$Direct\ Cost = \sum_i C_{i,1000} + BOP_{site-specific}$$

The resulting direct installed cost (gross direct expense) for the project is $250.23 million (2024 $).

INDIRECT COSTS AND TOTAL PLANT COST (TPC)

Indirect costs were estimated as 40% of the total direct cost to reflect the full set of non-equipment expenditures required to develop and deliver a commercial-scale biomass gasification project under U.S. permitting and EPC conditions [147]. This indirect-cost allowance is consistent with the TEA conventions adopted in this study and is intended to capture three major components: permitting and licensing activities (assumed as 5% of direct cost), engineering and professional services (assumed as 5% of direct cost), and a project contingency (assumed as 30% of direct cost) to account for design maturity, site-specific uncertainty, and technology and execution risk typical of large-scale gasification and hydrogen purification systems. With a direct cost of $250.23 million, indirect costs add approximately $100.1 million, yielding a total plant cost (TPC) of about $350.3 million. This TPC is then used as the base for computing total capital investment (**Table 5**).

TOTAL CAPITAL INVESTMENT (TCI)

Total Capital Investment (TCI) was derived by augmenting the Total Plant Cost (TPC) with owner-related and project-level adders not fully captured in installed plant costs but required to represent a finance-ready capital requirement. In this study, these adders include a design–build fee equal to 5% of TPC, land acquisition and working capital equal to 10% of TPC, and an escalation allowance equal to 5% of TPC. Using this structure, the TCI for the 1,000 BDT per day San Bernardino forest-residue-to-hydrogen facility is $420.4 million (2024 $), which is consistent in order of magnitude with the CEPCI-normalized and capacity-scaled literature benchmark established in earlier sections (**Table 5**).

The resulting TCI is used as the capital basis for subsequent financial analysis (annualized CAPEX, LCOH, IRR, DSCR) and sensitivity testing.

Table 5. Breakdown of total capital investment (TCI) for the 1,000 BDT per day forest-residue-to-hydrogen facility in San Bernardino County, including direct capital costs, indirect costs, and resulting total plant cost (TPC), all expressed in 2024 $

Description	**Total Cost $ million**
General Conditions	0.86
Site Development	15.46
Hydrogen Production Equipment	217.33
Emissions Equipment	0.33
Ancillary Equipment	2.38
Admin/Lab Building	1.67
Process Building – Gasification & Hydrogen Systems	6.03
Biomass Processing Building	1.17
Biomass Storage Building	2.42
Security/Weigh Stations	0.21
Hydrogen Loading & Trucking Area	2.01
Biochar Storage/Loading	0.09
Fire Station	0.02
Water Treatment	0.01
Biomass Laydown Area	0.23
Total Direct Cost	***250.23***
Permitting & Licensing (5% of Direct/construction cost)	12.51
Engineering Services (5% of Direct cost)	12.51
Contingency (30% of direct cost)	75.07
Total Indirect Cost ($) (40% of direct cost)	***100.09***
Total Plant Cost (TPC), (direct cost + indirect cost $ Million)	***350.33***
Design-Build Fee (5% of TPC)	17.52
Land & Working Capital (10% of TPC)	35.03
Escalation (5% of TPC)	17.52
Total Capital Investment (TCI), $ million	***420.4***

5.2.8. OPERATING COST ASSESSMENT (OPEX)

Annual operating expenditures (OPEX) were estimated following established DOE techno-economic analysis methodologies and reflect California-specific conditions, including regional labor rates, feedstock pricing, updated electricity tariffs, and costs associated with nitrogen supply, catalysts, consumables, maintenance, and waste handling. OPEX is divided into fixed and variable components to distinguish expenses that scale with production throughput from those that are largely independent of annual operating rate

Fixed OPEX, estimated at approximately \$24.02 million per year, includes labor, routine maintenance, insurance, and administrative overhead. These costs are largely independent of annual production levels and therefore do not scale with facility throughput (**Table 6**).

Variable OPEX, estimated at approximately \$36.6 million per year, scales directly with biomass throughput and plant utilization. These costs are primarily driven by feedstock procurement and transportation, electricity consumption, nitrogen supply, and other process consumables. Given an electricity requirement of 2.99 kWh per kg H_2 and a California industrial electricity price of \$0.23/kWh, electricity becomes the single largest variable cost component, contributing \$17.0 million per year. (**Table 7**)

Table 6. Fixed operating cost components for the forest-biomass-to-hydrogen production facility.

Cost Category	Annual Cost (\$M/yr)	Notes
Labor	11.35	Operators, engineers, QA/QC, security, admin staff
Maintenance	7.0	≈2% of TPC
Insurance	5.25	1.5% of TPC
Administrative & overhead	0.40	HR, compliance, corporate overhead

Table 7. Total annual operating costs for the forest-biomass-to-hydrogen production facility.

Category	Annual Cost ($M/yr)	Notes
Feedstock procurement	16.50	Based on $50 per BDT
Feedstock transportation	1.74	66.7-mile average haul
Feedstock insurance	0.40	2% of annual feedstock cost
Electricity	17.0	2.99 kWh per kg H_2 and $0.23 per kWh
Catalysts & consumables	0.10	WGS catalysts, filters
Nitrogen supply	0.30	37 million SCF per year
Water & utilities	0.50	Boiler water, cooling makeup
Solid waste & wastewater handling	0.10	Sludge, ash, fines

Combining fixed and variable costs yields a total annual operating cost of $60.7 million. This cost structure reflects the dominant influence of biomass logistics, the energy intensity of thermochemical conversion and PSA purification, and regionally specific electricity prices. This resulting OPEX estimate forms a central input to the hydrogen production cost model and directly influences the levelized cost of hydrogen, project profitability, and overall financial resilience.

5.2.9. HYDROGEN, BIOCHAR, LCFS, AND CARBON REMOVAL CREDIT REVENUE

This section quantifies the revenue streams associated with hydrogen production, sale of the biochar co-product, and potential credit generation under California's Low Carbon Fuel Standard (LCFS) and carbon removal by biochar utilization. Together, these revenue sources define the annual cash inflow of the modeled forest-biomass–to–hydrogen facility and directly affect project profitability, payback period, and financial resilience.

Hydrogen is the principal revenue source for the facility. Based on the modeled mass and energy balance, the plant produces approximately 24,706,763 kg of hydrogen per year from 330,000 BDT of forest biomass, corresponding to an average conversion yield of 74.9 kg H_2 per BDT. Under a base-case hydrogen sale price of $6.00 per kilogram, annual hydrogen revenue is estimated at $148.24 million per year.

Hydrogen sales account for more than 81% of total annual facility revenue, establishing hydrogen price realization as the dominant driver of project financial performance. Consequently, project viability is highly sensitive to H_2 market prices, regional demand growth, offtake arrangements, and policy mechanisms that support low-carbon hydrogen deployment in California.

Gasification produces a significant quantity of biochar—approximately 26,400 tonnes per year, representing 8% of the incoming dry biomass. However, due to uncertainties associated with biochar market demand, certification requirements, and long-term commercial viability, the techno-economic analysis conservatively credits only 23,600 tonnes per year as saleable. At a unit price of $600 per tonne, consistent with emerging carbon-sequestration markets and agricultural soil amendment applications, this yields an annual biochar revenue of approximately $15.84 million per year.

Hydrogen produced from forest biomass qualifies for credit generation under California's Low Carbon Fuel Standard (LCFS) when supplied to eligible transportation fuel pathways. For this modeled facility, LCFS credits are calculated based on the displacement of conventionally produced gray hydrogen from centralized fossil natural gas systems. Consistent with GREET life-cycle assessments and CARB pathway values [56, 157, 158], gray hydrogen is assigned a life-cycle carbon intensity of 118.6 gCO_2e per MJ, while liquid biohydrogen produced via woody biomass gasification is assigned a carbon intensity of 48.2 gCO_2e per MJ, yielding an avoided carbon intensity of 70.4 gCO_2e per MJ. The LCFS credit calculation is expressed as:

$$\begin{aligned} \Delta CI = CI_{gray\ H_2} - CI_{bio-H_2} E_{avoided} \\ = \Delta CI \times E_{H_2} \times 10^{-6} R_{LCFS} \\ = E_{avoided} \times P_{LCFS} \end{aligned}$$

where ΔCI is the avoided carbon intensity (gCO_2e per MJ), E_{H_2} is the annual hydrogen energy output (MJ per year), 10^{-6}converts grams to metric tonnes, $E_{avoided}$ is the annual avoided emissions (tCO_2e per year), and P_{LCFS} is the assumed LCFS credit price ($ per tCO_2e).

Annual avoided GHG emissions (CO_2e) are estimated by multiplying the avoided carbon intensity by the total annual hydrogen energy output, converting grams of CO_2e to metric tonnes. For the modeled San Bernardino facility, this results in approximately 209,028 tCO_2e per year of avoided emissions. Assuming an LCFS credit price of $55 per tCO_2e [153], the corresponding gross annual LCFS revenue is approximately $11.5 million. This estimate is intentionally conservative, as it excludes potential pathway-specific efficiency adjustments, drivetrain multipliers, or additional crediting that could arise under future LCFS rulemaking for biomass-derived hydrogen without carbon capture and storage (CCS). In addition, Renewable Identification Number (RIN) credits are not included in this analysis, as the facility is assumed to source 100% forest biomass from federal lands, which are not eligible for RFS crediting under current regulations.

Durable carbon removal associated with biochar co-production is quantified by converting retained biochar carbon into CO_2-equivalent sequestration. Published estimates of biochar-based carbon removal typically range from approximately 1.9 to 2.7 tCO_2 per tonne of biochar, depending on assumptions regarding carbon stability, fixed-carbon content, and crediting methodology [159–163]. In this study, annual carbon sequestration is calculated based on measured biochar output and an assumed fixed-carbon content of 75% on a dry basis, corresponding to a biochar-specific carbon removal factor of 2.75 tCO_2e per tonne of biochar using the standard 44/12 molecular weight conversion [164, 165].

At an annual biochar production of 26,400 tonnes, representing approximately 8% of incoming dry biomass, the facility achieves 72,600 tCO_2e per year of durable carbon removal. Biochar sequestration is treated as a long-lived carbon removal pathway with a conservative permanence threshold exceeding 100 years, consistent with durable carbon dioxide removal (CDR) accounting frameworks [166, 167]. Carbon removal credits are monetized in the techno-economic analysis at an assumed credit price of $100 per tCO_2e, yielding an annual biochar carbon removal credit value of approximately $7.26 million.

Total annual revenue for the forest-biomass-to-hydrogen facility is derived from four sources: hydrogen sales, biochar sales, LCFS credits, and durable carbon removal (CDR) credits associated with biochar sequestration (**Figure 19**). Based on the modeled mass and energy balances, annual hydrogen production of 24,706,763 kg at a base-case market price of $6.00 per kg H_2 generates approximately $148.24 million per year, making hydrogen sales the dominant revenue stream and accounting for roughly 81% of total project revenue.

Biochar provides an additional and stable co-product revenue stream. With a saleable biochar output of 26,400 tonne per year and an assumed market price of $600 per metric tonne, annual biochar sales total approximately $15.84 million per year, representing about 9% of total revenue.

LCFS credit revenue is estimated using an assumed credit value of $55 per tCO_2e and annual avoided emissions of 209,028 tCO_2e, yielding approximately $11.50 million per year (≈6% of total revenue). This estimate reflects current regulatory uncertainty and conservatively assumes LCFS eligibility for biomass-derived hydrogen without carbon capture and storage (CCS) or Renewable Identification Number (RIN) credits.

Durable carbon removal credits from biochar sequestration provide an additional $7.26 million per year, based on 72,600 tCO_2e per year of verified carbon removal and an assumed credit price of $100 per tCO_2e, contributing approximately 4% of total revenue.

In aggregate, total annual revenue is approximately $182.84 million per year. While hydrogen sales clearly dominate project cash flow, revenues from biochar sales and carbon credit mechanisms provide meaningful diversification and incremental financial support. This total revenue forms the baseline for all subsequent financial performance metrics, including levelized cost of hydrogen, internal rate of return, and debt service coverage analysis.

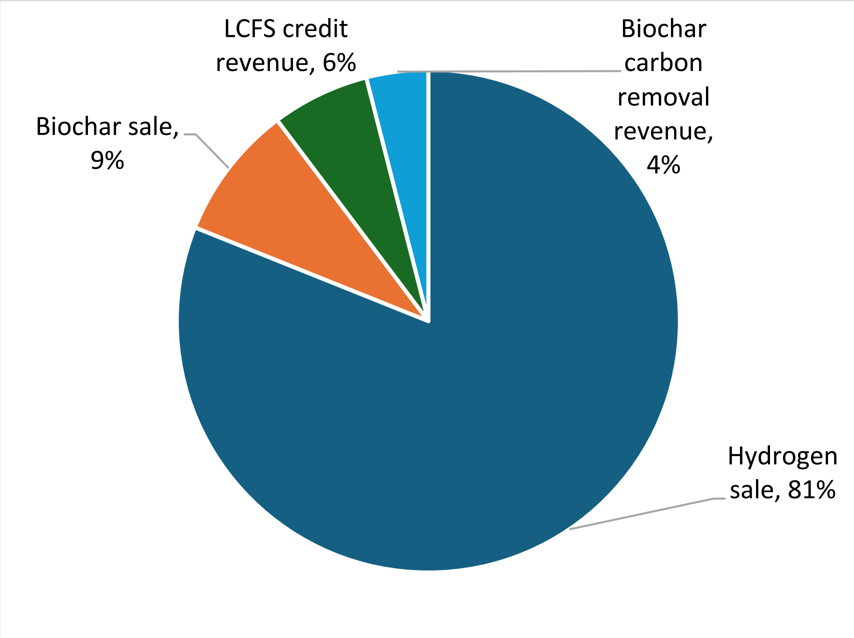


Figure 19. Breakdown of total annual revenue for the San Bernardino forest-residue-to-hydrogen facility, showing contributions from hydrogen sales, biochar sales, Low Carbon Fuel Standard (LCFS) credits, and biochar-based durable carbon removal (CDR) credits.

5.2.10. FINANCIAL PERFORMANCE EVALUATION

The financial performance of the 1,000 –BDT per day forest-biomass–to-hydrogen facility was evaluated using a discounted cash flow rate of return (DCFROR) framework over a 20-year operating life. The analysis integrates capital expenditures, operating costs, and revenue streams, including hydrogen sales, biochar co-product revenue, and LCFS credits—under financing assumptions representative of commercial energy projects in California. The resulting financial indicators provide a comprehensive assessment of project profitability, liquidity, and overall investment attractiveness under the base-case scenario.

Annual gross profit is defined as the difference between total annual revenue and total annual operating expenses (OPEX). With total annual revenues of approximately $182.84 million and total OPEX of $60.7 million per year, the facility generates an annual gross profit of approximately $122.2 million.

This strong operating margin reflects the favorable economics of converting low-value forest biomass into high-value, low-carbon fuel at a base-case hydrogen price of $6 per kg.

Earnings before interest, taxes, depreciation, and amortization (EBITDA) provide a standardized measure of operating performance independent of financing structures. In the first full year of operation, the facility generates approximately $122.2 million per year in EBITDA, reflecting robust cash generation from core operations.

The project's ability to meet its financing obligations is assessed using the Debt Service Coverage Ratio (DSCR), defined as the ratio of net operating income available for debt repayment to the total annual debt service (i.e. scheduled principal and interest payments). After accounting for fixed annual debt service of $29.63 million and applicable tax liabilities, the modeled facility achieves a DSCR of 1.88–3.12 from project year 1 through year 20. A DSCR above 1.2-1.3 is typically required for commercial project finance. The high DSCR calculated here signals a strong capacity to service debt, provides a substantial margin of safety for lenders, and significantly reduces financial risk.

Using a 10% discount rate consistent with energy-sector techno-economic analysis, the discounted cash flow model yields a positive net present value (NPV) of $403.9 million. A positive NPV confirms that the project generates economic value beyond full recovery of capital and operating costs.

The levelized cost of hydrogen (LCOH) represents the minimum hydrogen selling price required for the project to break even over its operating life. Based on updated capital costs, operating expenses, electricity pricing, and financing assumptions, the base-case LCOH is estimated at $3.52 per kg H_2. This value is well below the assumed market sale price of $6 per kg, indicating strong profit margins and resilience to price volatility. The NPV-based LCOH confirms that the project remains financially sustainable even under conservative assumptions regarding policy incentives and market conditions.

"The base-case LCOH is estimated at $3.52 per kg H_2. This value is well below the assumed market sale price of $6 per kg, indicating strong profit margins and resilience to price volatility."

Project-level investment performance was evaluated using internal rate of return (IRR) and net present value (NPV). The calculated IRR of approximately 12% exceeds the return threshold typically required for renewable energy and low-carbon infrastructure investments (generally 8–12%), suggesting that the project delivers competitive returns under prevailing market conditions.

The simple payback period—defined as the time required for cumulative net cash flow to recover the initial capital investment—is approximately 4.13 years. Thermochemical hydrogen production facilities typically exhibit payback periods exceeding 8–10 years due to high capital intensity and system complexity. The relatively short payback period of 4.13 years reflects strong early-stage cash flow generation and efficient capital utilization.

Overall, the financial indicators—strong operating margins, robust cash flow, exceptionally high DSCR, positive NPV, competitive LCOH, and a favorable payback period—demonstrates that a forest-biomass–to–hydrogen facility in San Bernardino County represents a financially viable and investment-ready project under current market and policy conditions.

5.2.11. SENSITIVITY AND SCENARIO ANALYSIS

A structured one-at-a-time sensitivity analysis was performed to evaluate the financial robustness of the forest-biomass–to–hydrogen facility under uncertainty in key techno-economic parameters. The analysis focuses on variables most relevant to policy design, market exposure, and investment risk, including hydrogen sale price, total capital expenditure (CAPEX), feedstock cost, total operating expenditure (OPEX), and the share of debt financing. Each parameter was varied independently over a ±40% range, or within realistic industry bounds, while all other assumptions were held constant (**Table 8**).

For each sensitivity case, changes in internal rate of return (IRR), debt service coverage ratio (DSCR), simple payback period, and levelized cost of hydrogen (LCOH) were quantified. These metrics are selected to capture complementary dimensions of project performance, including investor returns, lender risk, capital recovery time, and long-run cost competitiveness. The sensitivity analysis is intended to identify dominant drivers of financial performance and to evaluate the project's resilience to adverse market and cost conditions.

The simple payback period reported in **Table 8** is calculated on a project-level, pre-financing cash-flow basis and therefore reflects operating performance independent of capital structure.

Table 8. Sensitivity analysis of baseline techno-economic assumptions using a ±40% parameter range.

Parameters	Scenario				
	-40%	-20%	Base	20%	40%
Hydrogen Price					
Hydrogen Selling Price ($/kg H_2)	$4.08	$4.80	$6.00	$7.20	$8.88
Gross Profit ($ million)	$74.74	$92.53	$122.18	$151.83	$193.34
DSCR	1.22–2.02	1.46–2.43	1.88–3.12	2.29–3.81	2.87–4.77
IRR (%)	3%	6%	12%	17%	25%
Payback Period (years)	6.53	5.36	4.13	3.36	2.66
LCOH ($/kg H_2)	$3.52	$3.52	$3.52	$3.52	$3.52
Capital Expense (CAPEX)					
CAPEX ($ million)	252.2	336.3	420.4	504.5	588.5
Gross Profit ($ million/yr)	$122.18	$122.18	$122.18	$122.18	$122.18
DSCR	3.02–5.01	2.30–3.83	1.88–3.12	1.59–2.65	1.39–2.31
IRR (%)	26%	18%	12%	8%	5%
Payback Period (years)	2.53	3.34	4.13	4.90	5.66
LCOH ($/kg H_2)	$2.72	$3.12	$3.52	$3.92	$4.32
Feedstock Cost					
Feedstock cost ($/BDT)	30	40	50	60	70
Gross Profit ($ million/yr)	$128.94	$125.56	$122.18	$118.80	$115.41
DSCR	1.97–3.28	1.93–3.20	1.88–3.12	1.83–3.04	1.78–2.96
IRR (%)	13%	13%	12%	11%	11%
Payback Period (years)	3.92	4.02	4.13	4.24	4.36
LCOH ($/kg H_2)	$3.24	$3.38	$3.52	$3.66	$3.79
OPEX Cost					
OPEX cost ($ million/yr)	$36.4	$48.5	$60.7	$72.8	$84.9
Gross Profit ($ million/yr)	$146.44	$134.31	$122.18	$110.05	$97.92
DSCR	2.22–3.68	2.05–3.40	1.88–3.12	1.71–2.84	1.54–2.56
IRR (%)	16%	14%	12%	10%	7%
Payback Period (years)	3.47	3.77	4.13	4.56	5.09
LCOH ($/kg H_2)	$3.52	$3.52	$3.52	$3.52	$3.52
Debt vs Financing Ratio					
Debt (%)	36	48	60	72	84
Gross Profit ($ million/yr)	$122.18	$122.18	$122.18	$122.18	$122.18
DSCR	3.07–5.10	2.32–3.86	1.88–3.12	1.58–2.63	1.37–2.27
IRR (%)	12%	12%	12%	12%	12%
Payback Period (years)	4.14	4.14	4.13	4.12	4.11
LCOH ($/kg H_2)	$3.52	$3.52	$3.52	$3.52	$3.52

HYDROGEN PRICE SENSITIVITY

Hydrogen selling price is the dominant driver of project viability and financial performance. Across the ±40% sensitivity range (\$4.08–8.88 per kg H_2), annual gross profit increases from approximately \$74.7 million per year to \$193.3 million per year **(Table 8)**. Correspondingly, the internal rate of return (IRR) rises sharply from 3% in the low-price case to 25% under high-price conditions, while the debt service coverage ratio (DSCR) improves from a marginal range of 1.22–2.02 to a highly robust 2.87–4.77.

At the base-case hydrogen price of \$6.00 per kg, the project achieves an IRR of 12%, DSCR values between 1.88 and 3.12, and a simple payback period of approximately 4.13 years, indicating financeable performance under standard infrastructure lending criteria. Importantly, the levelized cost of hydrogen (LCOH) remains invariant at \$3.52 per kg across all hydrogen price scenarios, reflecting its dependence on capital, operating, and financing parameters rather than market price. These results demonstrate that long-term hydrogen offtake agreements priced above the production cost threshold are critical for ensuring stable returns and mitigating revenue volatility (**Figures 20 & Figure 21**).

> "These results demonstrate that long-term hydrogen offtake agreements priced above the production cost threshold are critical for ensuring stable returns and mitigating revenue volatility."

CAPITAL EXPENDITURE (CAPEX) SENSITIVITY

Variations in upfront capital investment exert a strong influence on investment returns and cost recovery. When total CAPEX is reduced by 40% (to \$252 million), IRR increases to 26%, DSCR improves substantially to 3.02–5.01, and the payback period shortens to approximately 2.53 years. Conversely, increasing CAPEX by 40% (to \$589 million) reduces IRR to 5%, compresses DSCR to 1.39–2.31, and extends the payback period to over 5.66 years. Capital escalation also directly affects hydrogen production cost. LCOH increases monotonically from \$2.72 per kg in the low-CAPEX case to \$4.32 per kg of H_2 at the high-CAPEX bound, underscoring the sensitivity of hydrogen cost to upfront investment rather than operational variables (**Figure 20** & **Figure 21**). These results underscore the critical role of capital-risk mitigation strategies in enabling early deployment of biomass-based hydrogen facilities. Instruments such as capital grants, loan guarantees and support for standardized and modular plant designs can materially reduce CAPEX exposure and lower the delivered cost of low-carbon hydrogen.

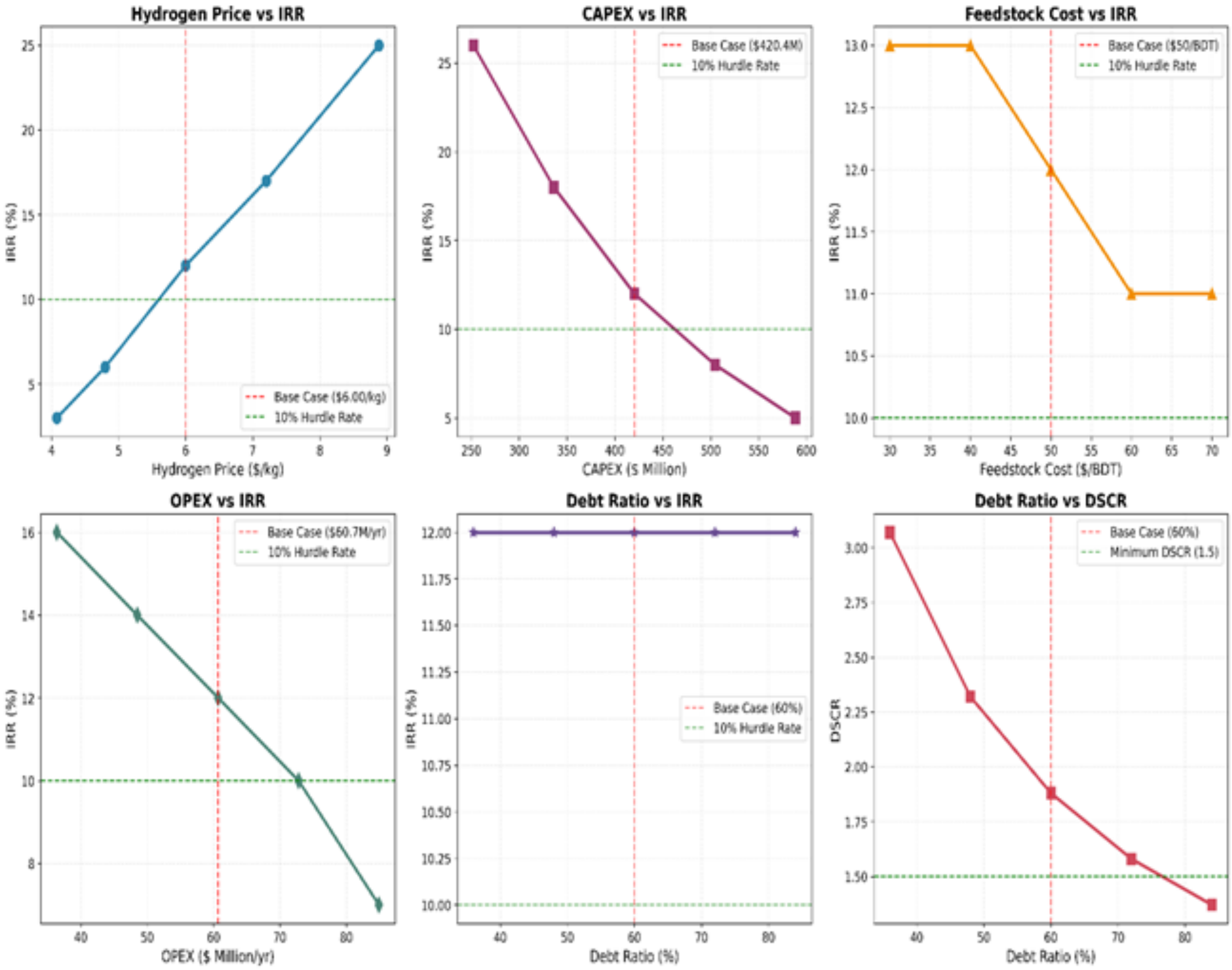


Figure 20. Sensitivity of internal rate of return (IRR) to hydrogen selling price, capital expenditure (CAPEX), and feedstock cost.

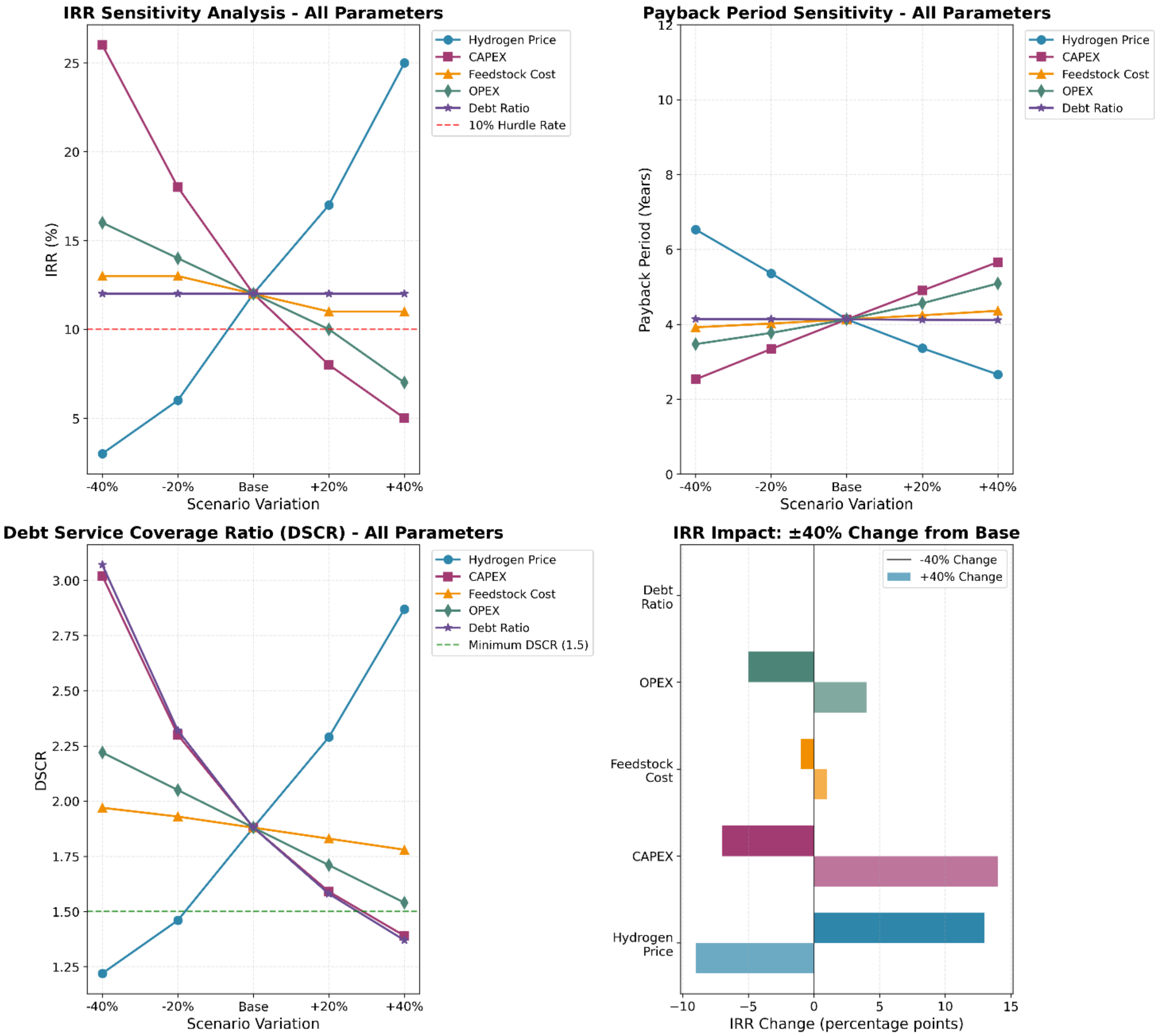


Figure 21. Sensitivity of internal rate of return (IRR), payback period, and debt service coverage ratio (DSCR) to ±40% variations in hydrogen price, capital expenditure (CAPEX), and feedstock cost.

FEEDSTOCK COST SENSITIVITY

Project economics are comparatively insensitive to forest-residue feedstock price variability. Across a wide procurement range of $30–70 per BDT, annual gross profit declines modestly from $128.9 million per year to $115.4 million per year, while IRR decreases only slightly from 13% to 11%. DSCR remains within a stable and financeable range of approximately 1.78–3.28. Over the same range, the simple payback period extends moderately from 3.92 years to 4.36 years (**Figure 20** & **Figure 21**), indicating that feedstock price fluctuations exert a secondary influence on overall project viability relative to hydrogen price and capital investment.

Over the same range, LCOH increases gradually from $3.24 to $3.79 per kg H_2, confirming that feedstock cost plays a secondary role relative to capital investment and hydrogen pricing. This robustness reflects the dominance of CAPEX and fixed operating costs in the overall cost structure and suggests that moderate fluctuations in forest biomass pricing are unlikely to compromise project viability, particularly in regions with established fuel-reduction programs and long-term biomass supply contracts.

OPERATING EXPENDITURE (OPEX) SENSITIVITY

Variation in operating expenditure directly affects both annual cash margins and the levelized cost of hydrogen (LCOH), given that OPEX is included in the annualized cost calculation. Increasing annual OPEX from $36.4 million to $84.9 million reduces gross profit from $146.4 million per year to $97.9 million per year. Over this range, IRR declines from 16% to 7%, while DSCR remains within a financeable range of 1.54–3.68. LCOH increases monotonically with higher operating expenditure, rising from $2.54 per kg H_2 at the low-OPEX case to $4.50 per kg H_2 under the high-OPEX scenario. The base-case LCOH remains $3.52 per kg H_2.

While elevated OPEX reduces operating margins and extends the simple payback period from 3.47 to 5.09 years, the project maintains positive returns and financeable DSCR values across the evaluated range. This outcome reflects the structure of the discounted cash-flow model, in which proportional changes in operating costs directly affect annual net cash flow under a fixed hydrogen sale price assumption, while capital investment parameters remain unchanged. While elevated OPEX reduces financial buffers, it does not materially undermine bankability under stable hydrogen market conditions.

FINANCING STRUCTURE SENSITIVITY (DEBT RATIO)

The project's capital structure significantly affects risk allocation between debt and equity. As the debt share increases from 36% to 84%, DSCR declines from a strong 3.07–5.10 range to 1.37–2.27, while project-level IRR (levered) remains constant at 12% across all financing scenarios. The simple payback period is similarly unchanged at approximately 4.13 years (**Figure 20**), reflecting the fixed operating performance of the facility.

Although all modeled debt ratios remain above minimum lender thresholds, higher leverage reduces the margin of safety against revenue volatility and increases exposure to hydrogen price risk. Intermediate debt shares in the range of 48–60% provide the most balanced outcome, maintaining robust DSCR values while preserving competitive equity returns.

Overall, the sensitivity analysis confirms that hydrogen sale price and capital cost remain the primary drivers of economic performance, while financing structure, feedstock cost and OPEX exert secondary influences. Stable policy frameworks that reduce revenue uncertainty and lower capital costs are therefore critical to enabling financially robust, replicable deployment of forest-biomass-to-hydrogen facilities in California.

5.2.12. CASE STUDY: REPURPOSING THE DESERT VIEW BIOMASS FACILITY

The Desert View Power (DVP) facility, located near Mecca in Riverside County, California, previously operated as a 45-MW woody biomass power plant, processing approximately 360,000–390,000 tons of forest biomass annually. The facility ceased operations in 2024 following sustained operational challenges and the expiration of its EPA permit. Although no longer generating power, the site retains a substantial portfolio of industrial assets, including feedstock handling infrastructure, electrical interconnection, water access, existing buildings, and permitted industrial land. These characteristics position DVP as a strong candidate for conversion to hydrogen production via thermochemical gasification.

Repurposing idle biomass facilities represents a strategic pathway to accelerate low-carbon hydrogen deployment while minimizing siting, permitting, and community-acceptance risks. Existing biomass power plants are typically located in industrial or rural zones, have established biomass supply chains, reduced site preparation costs, and shortened construction timelines.

To assess this opportunity, the techno-economic model developed for the San Bernardino County greenfield facility was adapted to represent site-specific conditions at the Desert View Power (DVP) facility. Modifications were implemented to reflect differences in feedstock supply radius, transportation logistics, and the potential reuse of existing infrastructure, including the fuel yard, material handling systems, utilities, and site development. This comparative case study enables a direct evaluation of how infrastructure repurposing affects capital requirements, operating costs, and overall financial performance relative to a greenfield hydrogen production facility.

FEEDSTOCK TRANSPORT CHARACTERISTICS

Feedstock transportation dynamics represent a key differentiating factor between the Desert View repurposing case and the San Bernardino County greenfield site. Historically, the biomass supply network serving the Desert View facility extended across multiple counties and involved substantially longer hauling distances than the San Bernardino greenfield site. Spatial routing analysis using the OpenStreetMap road network and an Origin–Destination matrix indicates a mean one-way hauling distance of approximately 144.5 miles, more than double the 66.7-mile average assumed for the San Bernardino facility.

This expanded hauling radius increases transportation costs and elevates the delivered cost of feedstock. As a result, feedstock logistics place upward pressure on operating expenses and reduce operating margins relative to the greenfield case, holding all other factors constant.

FINANCIAL PERFORMANCE: BASE REPURPOSING SCENARIO

In the base repurposing scenario, the Desert View facility is evaluated using the same process configuration, production capacity of 1,000 BDT per day, and capital cost structure as the San Bernardino County greenfield facility. The only adjustment incorporated in this case is the longer average feedstock hauling distance associated with Desert View's historical biomass supply network. This approach isolates the economic impact of logistics while holding technology, scale, and financing assumptions constant.

Under these conditions, the repurposed facility generates an annual gross profit of approximately $120.1 million. Although increased transportation distances raise delivered costs, hydrogen output and market pricing remain unchanged, allowing the facility to sustain strong operating margins. The resulting levelized cost of hydrogen (LCOH) is estimated at $3.60 per kg of H_2, slightly higher than the greenfield case but still well below the assumed market sale price of $6.0 per kg of H_2.

Financial performance indicators remain robust. The debt service coverage ratio (DSCR) is 1.85–3.07, indicating substantial capacity to meet loan repayment requirements. The internal rate of return (IRR) remains approximately 12%, reflecting the dominance of capital structure and hydrogen pricing over moderate logistics variability. The simple payback period extends only marginally to 4.19 years. These results indicate that repurposing idle biomass facilities can support economically viable hydrogen production even when feedstock logistics are less favorable than in optimized greenfield locations. The Desert View case underscores the resilience of thermochemical biomass-to-hydrogen systems and suggests that infrastructure-reuse strategies can remain attractive where capital cost savings and permitting advantages offset higher transportation costs.

FINANCIAL PERFORMANCE WITH REDUCED CAPEX

A second repurposing scenario evaluates the economic impact of leveraging existing infrastructure at the Desert View site. In this case, the Total Capital Investment (TCI) is assumed to be reduced by 40%, to $252.2 million, reflecting avoided costs associated with site preparation, civil works, utility interconnections, and permitting. These reductions are consistent with the reuse of an industrially zoned, previously permitted biomass facility with established material-handling systems and grid access. All operating assumptions, hydrogen output, and market pricing remain identical to the base repurposing case, allowing the analysis to isolate the effect of capital efficiency on project performance.

Under this reduced-CAPEX scenario, annual gross profit remains unchanged at $120.1 million, as revenues and operating expenses are unaffected. However, the lower upfront investment substantially improves all capital-sensitive financial indicators. The LCOH declines to $2.80 per kg of H_2, IRR increases to 26%, and the simple payback period shortens to 2.57 years. The DSCR remains high at 2.97–4.93, indicating strong loan repayment capacity and low credit risk even under leveraged financing structures. These results demonstrate that capital cost, rather than feedstock transportation distance, is the dominant driver of economic performance for biomass-to-hydrogen facilities. This finding underscores the importance of mechanisms that reduce upfront investment barriers, including infrastructure-reuse incentives, targeted grants, loan guarantees, and streamlined permitting for facility conversions.

Overall, the reduced-CAPEX Desert View case highlights the strategic value of repurposing idle biomass power plants as a capital-efficient pathway for accelerating clean hydrogen deployment in California. By leveraging sunk infrastructure and existing supply chains, retrofitted facilities can achieve competitive hydrogen production costs, higher investment returns, and faster payback periods. This approach aligns with state priorities related to wildfire-risk reduction, industrial decarbonization, and rapid scaling of low-carbon hydrogen supply.

5.2.13. CASE STUDY: PROTOTYPE MOBILE BIOMASS-TO-HYDROGEN CONVERSION SYSTEM

In addition to centralized, fixed-facility configurations, this study documents an emerging prototype mobile biomass-to-hydrogen conversion technology currently under development by a private-sector technology provider. The inclusion of this system is intended solely to provide contextual insight into alternative deployment concepts currently under development in the biomass-to-hydrogen sector and does not constitute a techno-economic validation, performance verification, endorsement, or comparative competitiveness assessment. The analysis presented here is therefore descriptive and illustrative, based on field visits and direct technical communication with the developer, and reflects the current prototype stage of technology.

The mobile system is designed to operate directly at or near biomass generation sites, thereby reducing or eliminating the need to transport feedstock to centralized facilities. According to the developer, the current prototype consists of a single mobile module capable of processing approximately 1,200 lbs of biomass per hour, equivalent to roughly 13.07 bone-dry tonnes (BDT) per day. At this scale, annual feedstock throughput is approximately 1,320 BDT under continuous operation. The system targets an overall biomass-to-hydrogen conversion efficiency of approximately 50%, with hydrogen as the primary product and biochar as a co-product.

Developer communications indicate that the prototype is intended to be energetically self-sustaining, with a portion of the produced syngas or fuel gas used to meet internal energy requirements. Capital cost estimates provided by the developer suggest that early commercial units could be on order of $1 million per module when manufactured at scale, although the current prototype reflects higher costs typical of first-of-a-kind (FOAK) systems. Operational requirements are expected to be minimal, with small staffing needs and limited auxiliary infrastructure relative to stationary facilities.

Because the system is mobile and deployed at biomass sources, conventional feedstock transportation logistics are not a defining design consideration. Instead, the concept emphasizes operational flexibility, rapid deployment, and potential applicability in locations where permanent infrastructure is not feasible or where biomass availability is spatially dispersed. Potential application contexts discussed with the developer include pilot demonstrations, remote forest-management operations, emergency or temporary fuel-reduction projects, and early-stage market testing.

At its current stage of development, the mobile biomass-to-hydrogen system should be understood as a technology under active refinement, rather than a commercially mature alternative to centralized biomass gasification facilities. Developer feedback indicates that future iterations may pursue modular scaling concepts, in which multiple units are deployed in parallel to increase throughput and improve system economics. As such, the primary relevance of this prototype within the present study is to highlight the diversity of technological approaches being explored for biomass conversion and to inform longer-term innovation pathways, rather than to evaluate near-term financial or market competitiveness.

This prototype mobile system illustrates an emerging, business-driven approach to biomass utilization that prioritizes flexibility and localized operation. While such systems may offer logistical advantages in niche or remote applications, their smaller throughput limits the scale efficiencies achievable by centralized facilities. Continued technology development, scale-up, and operational learning will be required before its role in California's broader hydrogen and bioenergy strategy can be fully assessed.

Photo: Prototype mobile biomass-to-hydrogen conversion system developed by Caribou Biofuels, Inc. (Credit: Sahadat, UCANR)

5.2.14. COMPARATIVE COMPETITIVENESS AND STRATEGIC IMPLICATIONS

The techno-economic results indicate that hydrogen produced from forest biomass via thermochemical gasification can compete favorably with other low-carbon hydrogen pathways currently available in California.

For the San Bernardino County base case, the levelized cost of hydrogen (LCOH) is estimated at \$3.52 per kg H_2, positioning this pathway within the lower end of reported renewable electrolysis costs (\$3–6 per kg H_2 under California electricity prices) and approaching the cost range of steam methane reforming with carbon capture (SMR+CCS).

These results compare favorably with prior National Renewable Energy Laboratory (NREL) and H2A assessments. Swanson et al. [145] nth-plant biomass gasification scenarios report hydrogen production costs of approximately \$2.40–\$3.40 per kg for a 2,000 dry ton per day facility under feedstock prices near \$40–120 per ton, while first-of-a-kind facilities remain substantially higher, exceeding \$7 per kg at smaller scales and higher capital intensity [105, 121, 143, 145, 168]. Similarly, Ramsden et al. [169] identified a Department of Energy (DOE) long-term target of \$2–3 per kg hydrogen (≈ \$2–3 per gasoline-gallon equivalent) delivered, exclusive of compression, storage, and dispensing (CSD) costs, which can add approximately \$1.90 per kg at the forecourt. When these downstream costs are included, total dispensed hydrogen costs for non-fossil pathways typically range from \$3.5 to \$6.0

per kg, depending on technology and maturity [170].

Against this backdrop, the San Bernardino biomass-to-hydrogen pathway performs competitively relative to renewable electrolysis, which currently exhibits levelized production costs of $6–7 per kg on average, with optimistic projections declining toward $2.5 per kg by 2030 and $1.8 per kg by 2040 as electrolyzer costs fall and renewable electricity prices decline [169, 170]. While electrolysis is widely expected to play a dominant role in long-term global hydrogen supply, near-term deployment remains constrained by electricity prices, grid capacity, and capital costs—particularly in California. Biomass gasification therefore occupies a complementary niche, offering dispatchable, infrastructure-ready hydrogen production at costs that approach future green-hydrogen targets without reliance on large volumes of low-cost renewable power.

Beyond cost competitiveness, biomass gasification offers distinct system-level advantages that are not captured fully by LCOH alone. These include the potential for carbon-negative operation through biochar sequestration, the productive use of low-value forest biomass, and direct contributions to wildfire-risk reduction by removing hazardous fuels from overstocked forests. These co-benefits enhance the policy relevance of biomass-derived hydrogen within California's integrated climate, energy, wildfire-risk-reduction, and land-management strategies.

From a financial perspective, the San Bernardino facility demonstrates strong operating performance under base-case assumptions. The project generates an annual gross profit of approximately $122.1 million and achieves a debt service coverage ratio (DSCR) of 1.88–3.12, indicating substantial capacity to meet debt obligations and a high degree of lender protection. The simple payback period of 4.13 years is favorable for a capital-intensive thermochemical hydrogen facility. The internal rate of return (IRR), calculated under conservative financing and revenue assumptions, demonstrates the project's strong sensitivity to realized hydrogen sale prices and capital cost control, reinforcing the importance of long-term offtake agreements and capital-risk mitigation. This reinforces the importance of long-term hydrogen offtake agreements, capital-cost control and stable policy support in enabling investment-grade deployment of forest-biomass-to-hydrogen systems at commercial scale.

Comparison with the Desert View Power (DVP) repurposing case underscores the dominant influence of capital cost in determining overall project viability. Although the DVP site is characterized by substantially longer average feedstock hauling distances, resulting in higher delivered biomass costs, the project remains financially robust when evaluated under comparable operating assumptions. When capital expenditures are reduced through the reuse of existing infrastructure, repurposed facilities achieve materially lower LCOH values and shorter payback periods than greenfield developments, even in regions with less favorable feedstock logistics. This finding confirms that capital efficiency, rather than feedstock transport distance alone, is the primary driver of economic performance for forest-biomass-to-hydrogen systems.

The broader strategic implications are significant for California's hydrogen deployment strategy. Repurposing idle biomass power plants represents a capital-efficient, lower-development-risk pathway for accelerating biomass-to-hydrogen infrastructure. Existing grid interconnections, water access, industrial zoning, and established permitting frameworks can substantially reduce upfront investment and development timelines, while established biomass supply chains enable rapid operational scaling.

Across all sensitivity scenarios evaluated, hydrogen sale price remains the most influential determinant of financial feasibility, followed by capital cost. In contrast, feedstock price variability and operating expenditure exert comparatively modest impacts on overall project economics. Under conservative assumptions, forest-biomass-to-hydrogen systems remain economically viable provided realized hydrogen prices remain above approximately \$2.72–4.32 per kg H_2. These results position thermochemical hydrogen production from forest biomass as a strategically important and economically resilient component of California's clean hydrogen portfolio, with the added benefit of supporting wildfire-risk reduction and forest management objectives alongside statewide decarbonization goals.

> "Existing grid interconnections, water access, industrial zoning, and established permitting frameworks can substantially reduce upfront investment and development timelines."

5.2.15. FINANCING MECHANISMS FOR BIOMASS-TO-HYDROGEN DEVELOPMENT IN CALIFORNIA

The deployment of biomass-to-hydrogen facilities in California depends on a layered financing ecosystem that blends public funding, private capital, and public–private partnerships (PPPs). These mechanisms translate state and federal climate policy into bankable project structures by reducing capital risk, lowering financing costs, and enabling revenue stacking for capital-intensive thermochemical systems.

PUBLIC FINANCING MECHANISMS

Federal Programs

- DOE Hydrogen Hubs (ARCHES): The Alliance for Renewable Clean Hydrogen Energy Systems (ARCHES) was initially awarded up to \$1.2 billion under the U.S. Department of Energy's Regional Clean Hydrogen Hubs program to support coordinated hydrogen deployment across California, including biomass-based hydrogen pathways. ARCHES was structured as a statewide public-private partnership integrating infrastructure development, workforce training, and community benefits [55] [54]. However, in late 2025, DOE withheld this funding as part of broader federal clean-energy budget adjustments, resulting in a suspension of program implementation. While this uncertainty highlights the risk of reliance on discretionary federal appropriations, the ARCHES framework remains a reference model for large-scale hydrogen coordination in California.

- Inflation Reduction Act (IRA) Section 45V Hydrogen Production Tax Credit: The Section 45V credit provides \$0.60–3.00 per kg H_2, scaled to lifecycle carbon intensity (CI). For biomass-derived hydrogen, particularly pathways that incorporate biochar sequestration or CCS, 45V represents the most consequential federal production incentive currently available, materially improving project cash flow, lender confidence, and equity returns. When combined with LCFS revenues, 45V can substantially compress payback periods and lower effective hydrogen production costs [52] [51].

- IRA Section 45Q Carbon Capture and Sequestration Credit: Section 45Q provides \$85 per ton CO_2 permanently sequestered. For biomass gasification systems, this credit enables revenue stacking with 45V and LCFS, creating a powerful financial rationale for integrating CCS. [52] [53]. Eligibility for full credit value depends on lifecycle carbon intensity calculations, applicable Treasury guidance, and evolving federal rulemaking.

- USDA Section 9003 Biorefinery Loan Guarantees: The USDA's Section 9003 program offers loan guarantees covering up to 80% of eligible project debt for biorefineries processing agricultural or forest biomass. This program is particularly relevant for projects in rural and forested counties, where biomass feedstocks are abundant and private capital access may be constrained [171].

- DOE Loan Programs Office (LPO): The DOE LPO provides low-interest loans and loan guarantees through multiple programs, including Title 17 Clean Energy Financing [172], the Advanced Technology Vehicles Manufacturing (ATVM) program [173], the Tribal Energy Finance Program [174], CIFIA support for CO_2 transport infrastructure [175]. These instruments directly reduce weighted average cost of capital (WACC), improve debt service coverage, and enhance bankability for large-scale biomass hydrogen facilities by reducing effective cost of debt and lengthening loan maturities.

State Programs

California's state-level financing and incentive programs play a critical role in complementing federal support and enabling biomass-to-hydrogen projects to reach financial close. These programs primarily function by reducing upfront capital requirements, stabilizing long-term revenue, and aligning hydrogen deployment with California's climate, wildfire mitigation, and rural development objectives.

- The California Energy Commission (CEC) Clean Hydrogen Program, authorized under AB 209, provides competitive grants and cost-share funding for hydrogen production, conditioning, storage, and associated infrastructure. Recent CEC solicitations explicitly include biomass-derived hydrogen technologies, recognizing their dual role in decarbonization and forest-residue utilization [176]. CEC grant funding is particularly impactful during early development and front-end engineering phases, where it can materially reduce capital exposure and improve project bankability.

- The California Infrastructure and Economic Development Bank (IBank) offers low-cost loans, loan guarantees, and bond financing that can support both construction and long-term debt needs for hydrogen facilities [177].

- California's Low Carbon Fuel Standard (LCFS) remains a cornerstone revenue mechanism for low-carbon hydrogen projects. LCFS credits are awarded based on lifecycle carbon intensity, enabling biomass-derived hydrogen, particularly pathways incorporating carbon capture and storage (CCS), to generate higher-value credits due to near-zero or negative emissions [56]. While LCFS revenues are subject to market and regulatory uncertainty, they can provide a recurring and material cash-flow enhancement that improves debt service coverage and equity returns, subject to market conditions and regulatory stability.

- Cap-and-Trade / California Climate Investments (CCI) fund grant programs that support clean fuel production, wildfire-risk reduction, forest biomass utilization, and rural economic development [57] [58]. These funds are well aligned with forest-biomass hydrogen projects, which simultaneously advance emissions reduction and landscape-scale forest management objectives.

PRIVATE FINANCING MECHANISMS

The large-scale deployment of biomass-to-hydrogen systems ultimately depends on mobilizing private capital alongside public incentives. Given the capital-intensive nature of thermochemical hydrogen production, successful projects typically rely on a layered financing structure that combines long-tenor debt equity investment, and monetization of federal tax credits.

- Project finance (non-recourse or limited-recourse debt) is the dominant financing structure for commercial biohydrogen facilities. Debt is underwritten primarily against contracted cash flows from long-term hydrogen offtake agreements, Low Carbon Fuels Standard (LCFS) credit revenues, and monetized federal incentives such as the IRA Section 45V and 45Q. Strong debt service coverage ratio and predictable policy-driven revenue streams significantly enhance lender confidence and reduce the cost of capital. Equity investment is typically provided by strategic energy companies, infrastructure funds, technology developers, and specialized renewable-energy investors seeking exposure to low-carbon hydrogen, gasification, and carbon capture technologies [178]. Early equity participation absorbs development and construction risk, while later-stage infrastructure equity targets stable, long-term cash flows once operations are established.

- Tax equity financing and credit transferability mechanisms, enabled under the Inflation Reduction Act, allow project developers to monetize federal hydrogen and carbon capture tax credits either through traditional tax equity structures or direct credit sales. These mechanisms convert future policy incentives into upfront capital lowering effective project cost and improving internal rates of return without increasing leverage.

- Green bonds and ESG infrastructure funds provide an additional source of capital for mature biomass-to-hydrogen projects with stable revenue profiles. These instruments appeal to institutional investors seeking long-duration, investment-grade assets aligned with decarbonization, climate resilience, and sustainable land-management objectives [179–181].

Across all private financing pathways, long-term hydrogen offtake agreements with creditworthy counterparties—such as fleet operators, ports, utilities, industrial users, and logistics companies—are a critical determinant of project bankability. This is particularly relevant in industrial regions such as California's Inland Empire, where proximity to demand centers can support contractual price certainty and reduce market risk [181] [55].

"Across all private financing pathways, long-term hydrogen offtake agreements with creditworthy counterparties—such as fleet operators, ports, utilities, industrial users, and logistics companies—are a critical determinant of project bankability."

Collectively, these federal and state instruments function as capital-risk mitigators rather than primary revenue drivers, enabling thermochemical biomass-to-hydrogen projects to achieve financeable capital structures despite high upfront investment requirements.

PUBLIC–PRIVATE PARTNERSHIP (PPP) MODELS

California's approach to hydrogen deployment relies heavily on public–private partnership (PPP) models that align public policy objectives with private-sector delivery capacity. Under these arrangements, public entities provide enabling conditions that reduce development risk, while private partners supply capital, technical expertise, and operational capability

- Public-sector participation typically includes access to publicly owned or permitted land, coordinated permitting and environmental review, feedstock aggregation through state and local land-management programs, and co-investment in shared infrastructure such as utilities, grid interconnections, and transportation assets. Public agencies also play a central role in ensuring that projects deliver workforce development, environmental justice, and community-benefit outcomes. Private-sector partners are generally responsible for capital investment, detailed engineering and project design, construction management, technology deployment, and long-term operational management.

- Blended-finance structures are a defining feature of California's PPP model. These structures combine federal tax credits, state grants and LCFS revenues, loan guarantees from entities such as the DOE Loan Programs Office or California IBank, and private debt and equity financing.

The integration of public and private capital lowers overall financing risk by reducing capital exposure, stabilizing revenue streams, and improving access to long-term debt. This blended-capital approach improves project bankability and accelerates deployment timelines while advancing regional economic development, wildfire-risk reduction, forest-resilience objectives, and statewide decarbonization goals.

6. SOCIAL AND ENVIRONMENTAL JUSTICE IMPLICATIONS

6.1. ENVIRONMENTAL JUSTICE AND SOCIETAL CO-BENEFITS

This chapter evaluates the social, environmental, and public-health implications of redirecting forest biomass from wildfire-prone landscapes to low-carbon hydrogen production in San Bernardino County, California. The analysis is grounded in the California Air Resources Board (CARB) Cap-and-Trade Standardized Regulatory Impact Assessment (SRIA) framework [182], and integrates avoided wildfire emissions, lifecycle greenhouse gas (GHG) displacement, and monetized health-damage benefits to quantify annualized climate and environmental-justice benefits. By linking hazardous fuel reduction with renewable hydrogen production, the modeled system addresses two intersecting policy priorities: wildfire risk mitigation and deep decarbonization of the transportation and industrial energy sectors. Forest biomass that would otherwise be burned in open piles or contribute to high-severity wildfires are instead utilized as a productive energy resource, reducing uncontrolled emissions of particulate matter, nitrogen oxides, and other hazardous air pollutants. These avoided emissions yield localized air-quality improvements that are particularly relevant for the Mojave Desert air basin, where communities already experience elevated pollution burdens and heightened vulnerability to respiratory and cardiovascular health impacts.

6.1.1. STUDY DESIGN AND SCENARIO.

The environmental justice assessment is based on a scenario in which 1,000 bone-dry tons (BDT) of forest biomass per day (equivalent to approximately 330,000 BDT per year) are diverted from wildfire-prone landscapes and converted to renewable hydrogen. Using a modeled conversion efficiency of 74.9 kg H_2 per BDT, this feedstock throughput yields an annual hydrogen production of approximately 24,707 metric tonnes.

Spatial analysis drawing from a 40% thin-from-below (TFB_40) forest treatment scenario indicates that only half of the technically available forest biomass density is assumed to be recoverable, resulting in an accessible biomass density of approximately 1.25 BDT per acre, based on an underlying average availability of 2.50 BDT per acre across treated forest stands. At this effective recovery rate, supplying 1,000 BDT per day requires treatment of roughly 800 acres per day, corresponding to approximately 263,861 acres annually.

This scale of treatment is significant from both land-management and public-health perspectives. It directly reduces hazardous fuel loads across a large, forested area, lowering the probability and severity of high-intensity wildfires, while simultaneously supporting sustained production of low-carbon hydrogen. The scenario therefore establishes a direct and quantifiable linkage between wildfire risk reduction, emissions avoidance, and clean-energy deployment, forming the analytical basis for evaluating environmental justice and societal co-benefits under California's climate and forest-resilience policy frameworks.

6.1.2. WILDFIRE EMISSION FACTORS

Wildfire emission intensities for carbon dioxide (CO_2), fine particulate matter ($PM_{2.5}$), and inhalable particulate matter (PM_{10}) were derived using empirical data from CARB's statewide wildfire emissions inventory covering the period 2000–2023 [183]. Annual wildfire emissions were regressed against total burned areas to estimate pollutant-specific emission factors on a per-acre basis. This approach is consistent with CARB's Standardized Regulatory Impact Assessment (SRIA) methodology, as it links emissions directly to fuel consumption and the spatial extent of wildfire activity. The regression analysis variation of approximately 27–37% reflect interannual variability driven by meteorology, fuel moisture, and the disproportionate influence of extreme wildfire years (**Figure 22**).

"By linking hazardous fuel reduction with renewable hydrogen production, the modeled system addresses two intersecting policy priorities: wildfire risk mitigation and deep decarbonization of the transportation and industrial energy sectors."

demonstrates strong linear relationships between burned area and emissions for all pollutants (CO_2: $R^2 = 0.955$; $PM_{2.5}$: $R^2 = 0.904$; PM_{10}: $R^2 = 0.905$), supporting the assumption that wildfire emissions scale approximately proportionally with area burned and justifying the use of area-based emission factors for avoided-emissions accounting. Long-run mean emission intensities were estimated as 23,892 kg CO_2 per acre (95% CI: ±6286.1), 224.8 kg $PM_{2.5}$ per acre (95% CI: ±83.0), and 265.2 kg PM_{10} per acre (95% CI: ±97.9). Coefficients of

The emission factors were applied to the treated-area equivalent associated with forest-residue diversion (approximately 263,861 acres per year) to estimate avoided wildfire emissions. The resulting avoided emissions provide the quantitative foundation for subsequent climate-damage valuation and public-health impact monetization under the CARB SRIA framework.

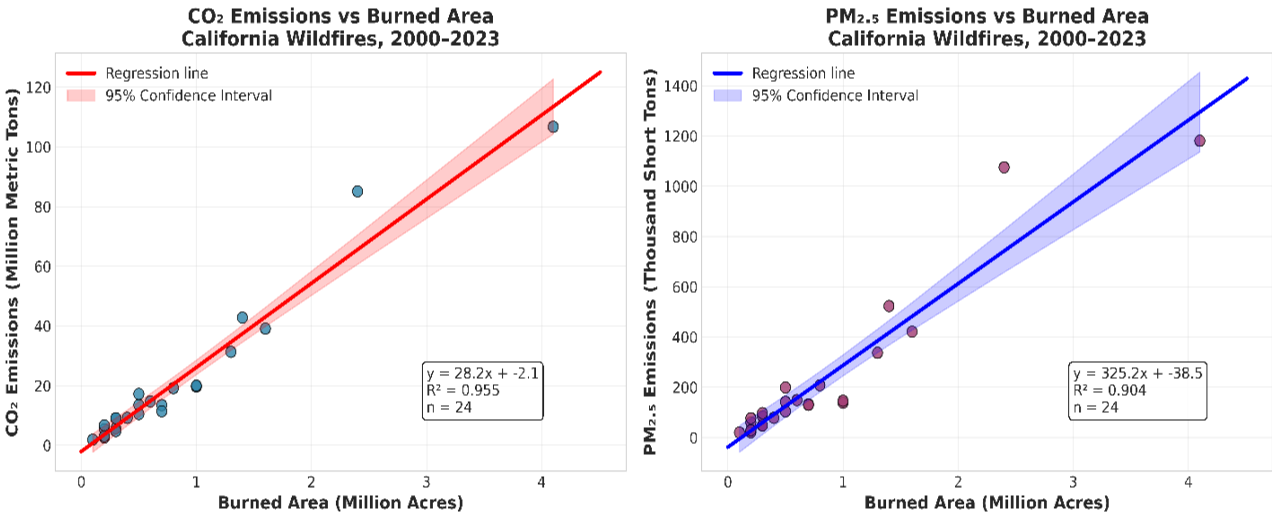


Figure 22. Regression relationships between burned area against wildfire emissions in California (2000–2023), showing (a) CO_2 emissions and (b) $PM_{2.5}$ emissions as functions of total area burned, used to derive empirical wildfire emission factors.

6.1.3. CO_2 DISPLACEMENT FROM HYDROGEN PRODUCTION AND USE

Lifecycle greenhouse-gas (GHG) reductions from forest-biomass-derived hydrogen were quantified using a displacement-based accounting approach consistent with the California-modified CA-GREET 4.0 well-to-wheel (WTW) methodology. Avoided emissions were calculated based on annual hydrogen production, hydrogen lower heating value (120.21 MJ kg^{-1}), and the carbon-intensity differential between conventional steam-methane-reforming gray hydrogen and the biomass gasification pathway (ΔCI = 70.4 g CO_2e per MJ). This WTW displacement captures upstream and conversion-stage emission reductions while avoiding double counting of end-use benefits.

Separately, transport-sector displacement was evaluated using a tank-to-wheel (TTW) approach to quantify tailpipe emissions avoided when hydrogen replaces diesel in heavy-duty fuel -cell electric vehicles (FCEVs). Assuming a hydrogen LHV of 33.3 kWh kg^{-1}, a 60% fuel efficiency, and a vehicle efficiency of 3.5 miles per kWh, each kilogram of hydrogen enables approximately 69.93 vehicle-miles. Applying a diesel tailpipe emission factor of 0.0008 t CO_2 per mile (≈ 1.6 lb. CO_2 per mile), the resulting CO_2 displacement is reported independently of the GREET lifecycle estimate to ensure accounting integrity.

6.1.4. MONETIZED CLIMATE BENEFITS

Monetized climate benefits were quantified using the Social Cost of Carbon (SC-CO_2), which represents the global economic damages avoided per metric ton of CO_2

emissions reduced, including impacts on human health, agricultural productivity, infrastructure, and ecosystem services. Valuation follows the California Air Resources Board (CARB) Standardized Regulatory Impact Assessment (SRIA) framework [182] and is consistent with guidance from the U.S. Environmental Protection Agency (EPA) and the Interagency Working Group (IWG) on the Social Cost of Greenhouse Gases [184, 185] (**Appendix Table S8**).

SCOPE OF MONETIZATION AND ACCOUNTING

Total avoided CO_2 emissions associated with the project comprise two physically distinct components (i) avoided wildfire emissions resulting from forest fuel-load reduction, and (ii) lifecycle and end-use (well-to-wheel, WTW) CO_2 displacement from hydrogen production and use in transportation.

To ensure accounting consistency and avoid double counting, only avoided wildfire emissions are monetized using the Social Cost of Carbon in this section. The WTW CO_2 displacement associated with renewable hydrogen use is already internalized in the techno-economic analysis through Low Carbon Fuel Standard (LCFS) credit revenues and is therefore excluded from the baseline SCC monetization. The hydrogen-related displacement is reported separately for completeness and sensitivity analysis but is not double-counted in the economic valuation presented here.

AVOIDED WILDFIRE CO_2 EMISSIONS

Avoided wildfire emissions are credited only to the slash fraction that is removed and technically accessible, rather than to total stand-level wildfire combustion emissions. Using CARB's mean wildfire CO_2 emission intensity of 23.583 tCO_2 per acre burned, the effective avoided CO_2 per acre is calculated by applying the same accessibility and slash fractions used in the residue accounting:

$$E_{acre} = E_w \times f_a \times f_s$$

Where E_w is the wildfire CO_2 emission factor (23.583 tCO_2 per acre), f_a is the technically accessible residue fraction (50%)., and f_s is the removable residue fraction (15%).

Equivalently, this can be expressed on a per-BDT basis by dividing by the accessible residue density (1.25 BDT per acre):

Total annual avoided wildfire CO_2 emissions are then:

$$E_{\mathrm{CO2,yr}} = A_{\mathrm{yr}} \times E_{\mathrm{CO2,acre}}$$

This approach is intentionally conservative: although multiplying the full treated acreage by 23.583 tCO_2 per acre would imply a much larger theoretical value, the analysis credits only the portion of wildfire emissions attributable to the removable and technically accessible slash stream approximately 466,695 tCO_2 per year that is actually diverted and utilized by the facility.

HYDROGEN-RELATED CO_2 DISPLACEMENT

Lifecycle CO_2 displacement from hydrogen production and use was quantified using

California-modified CA-GREET well-to-wheel accounting and reflects the displacement of fossil-based grey hydrogen in heavy-duty transportation. This component contributes an additional 209,028 tCO_2 per year of avoided emissions. As noted above, this benefit is monetized through LCFS crediting in the TEA and is therefore excluded from the baseline SCC valuation presented in this section.

> "This approach integrates epidemiological concentration-response relationships with economic valuation to estimate avoided premature mortality, hospital admissions, asthma incidence, and productivity losses resulting from improved air quality."

MONETIZED CLIMATE BENEFITS

Monetized climate benefits from avoided wildfire emissions were calculated as:

$$Monetized\ Climate\ Benefit = E_{wildfire} \times SC_{CO_2}$$

where SC_{CO_2} is the social cost of carbon expressed in 2022 $ per metric ton of CO_2.

Applying EPA SCC values yields annual monetized benefits ranging from approximately $68 million per year at a 2.5% discount rate to $188 million per year at a 1.5% discount rate. Under the IWG SCC framework, corresponding estimates range from $9.8 million per year at a 5% discount rate to $46.7 million per year at 2.5%.

For sensitivity purposes, if the hydrogen WTW displacement were additionally monetized using SCC values—rather than captured via LCFS credits—it would contribute an incremental $4.4–20.9 million per year, depending on sthe valuation framework and discount rate.

Overall, combined avoided emissions from wildfire mitigation and hydrogen displacement total approximately 675,724 tCO_2 per year, but only wildfire-related reductions are monetized here to maintain clear separation between policy-based valuation (SCC) and market-based compliance mechanisms (LCFS). This approach ensures transparency, avoids double counting, and provides a conservative yet policy-relevant estimate of climate benefits.

The wide range of monetized outcomes highlights the sensitivity of climate benefit valuation to SCC assumptions and discount rates, reinforcing the importance of range-based reporting rather than reliance on a single point estimate for decision-making and policy evaluation (**Figure 23**).

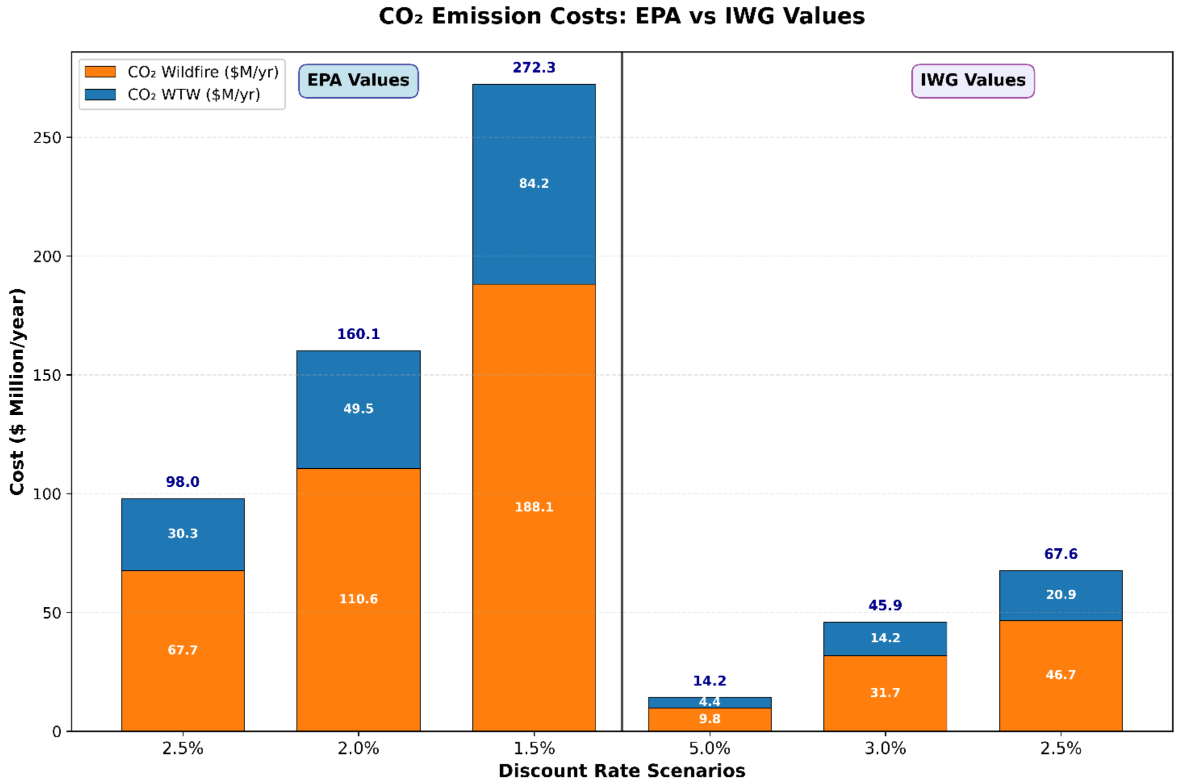


Figure 23. Monetized annual climate benefits from avoided CO_2 emissions due to forest-biomass-to-hydrogen deployment, based on Social Cost of Carbon estimates from the U.S. Environmental Protection Agency (EPA) and the Interagency Working Group (IWG) across multiple discount rates.

6.1.5. HEALTH AND PRODUCTIVITY BENEFIT FROM $PM_{2.5}$ AVOIDANCE

Health and productivity co-benefits from reduced fine particulate matter ($PM_{2.5}$) exposure were quantified using the CARB standardized regulatory impact assessment framework [182], informed by BenMAP-CE–based valuation methods [186]. This approach integrates epidemiological concentration-response relationships with economic valuation to estimate avoided premature mortality, hospital admissions, asthma incidence, and productivity losses resulting from improved air quality.

CARB's statewide analysis estimates a total monetized benefit of approximately $73 billion associated with a 47,600-t reduction in $PM_{2.5}$ emissions, corresponding to an average benefit of $1.53 million per ton of $PM_{2.5}$ abated (2022 $). This per-ton valuation reflects population-weighted exposure modeling across California and is constructed to avoid double counting among correlated health endpoints.

Applying this valuation to the modeled avoidance of 4,383 t $PM_{2.5}$ per year through forest-residue utilization yields approximately $6.7 billion per year in statewide health and productivity benefits. Because this estimate is derived from integrated population-exposure modeling rather than site-specific incidence counts, it provides a consistent and policy-relevant basis for comparison across mitigation strategies and sectors within California's climate and air-quality planning framework. This valuation reflects population-weighted exposure modeling and should be interpreted as a marginal damage estimate rather than a direct cash-flow equivalent.

6.1.6. MOJAVE DESERT AIR BASIN DIAGNOSTIC: INCIDENT-BASED MICROANALYSIS

Because San Bernardino County lies within the Mojave Desert (MD) Air Basin, a basin-level diagnostic was performed to capture localized health co-benefits from reduced wildfire-related $PM_{2.5}$ exposure. While the CARB standardized regulatory impact assessment (SRIA) framework [182] applies a statewide average valuation of $1.53 million per ton $PM_{2.5}$, aggregating mortality and morbidity impacts into a single metric to avoid double counting, this approach can obscure distributional effects relevant to regional and environmental-justice decision-making.

To address this limitation, an incident-based microanalysis was performed for the Mojave Desert Air Basin using CARB SRIA methods.

This diagnostic quantifies and monetizes individual health endpoints (e.g., premature mortality, hospital admissions, asthma exacerbations) at the air-basin level, providing greater transparency into localized public-health impacts. Results from this basin-specific analysis are reported separately and are not aggregated with the statewide $PM_{2.5}$ valuation, ensuring methodological consistency and avoiding double counting of benefits.

The analysis followed the SRIA [182] incident-level valuation method, applying endpoint-specific concentration-response function and unit damage values for each health outcome *i* within air basin *b*, as described below:

$$r_{(i,b)} = \frac{D_{(i,b)}^{total}}{PM_{(2.5,b)}^{total}},$$

$$D_{(i,b)}^{proj} = r_{(i,b)} \times \Delta PM_{(2.5,b)}^{proj} Monetized_{(i,b)} = D_{(i,b)}^{proj} \times V_i$$

Where $D_{(i,b)}^{total}$ represents the total number of avoided health incidents for endpoint *i* within air basin *b*, $PM_{(2.5,b)}^{total}$ is the total $PM_{2.5}$ reduction reported under the CARB SRIA framework for basin *b*, $\Delta PM_{(2.5,b)}^{proj}$ is the project-attributable $PM_{2.5}$ reduction within the Mojave Desert Air V_i is the CARB-assigned monetary value per incident for endpoint *i.* Monetary values follow SRIA guidance and include, for example, a value of statistical life of approximately $13.45 million for premature mortality and endpoint-specific valuations for hospital admissions, asthma exacerbations, and work-loss days as reported in SRIA estimation [182].

Applying this framework to the Mohave Desert Air Basin yields an estimated 27,702 avoided health incidents per year, corresponding to approximately $1.23 billion per year (2022 $) in monetized health benefits. Cardiopulmonary mortality overwhelmingly dominates these benefits, accounting for about $1.21 billion or roughly 98 % of the total. Non-fatal but economically meaningful outcomes included avoided asthma onset ($11.2 million), asthma symptom days ($4.47 million), and work-loss days ($2.23 million) (**Table 9**). Remaining benefits arise from reductions in hospital admissions, emergency-department visits, and chronic disease-related endpoints such as lung cancer and neurodegenerative illnesses.

Table 9. Incident-based estimates of avoided morbidity and mortality and associated monetized health benefits from reduced $PM_{2.5}$ exposure attributable to forest-biomass-to-hydrogen deployment in the Mojave Desert Air Basin.

Health Category	Avoided Cases	Cases %	Health Benefits ($M)	Benefits %
Cardio- pulmonary mortality	90	0.33%	$1,211.75	98.39%
Hosp. for cardiovascular disease	14	0.05%	$0.28	0.02%
Cardiovascular ED visits	28	0.10%	$0.04	0.00%
Acute myocardial infarction	10	0.04%	$0.82	0.07%
Hospitalized for respiratory disease	2	0.01%	$0.03	0.00%
Respiratory ED visits	52	0.19%	$0.08	0.01%
Lung cancer incidence	6	0.02%	$0.18	0.01%
Asthma onset	194	0.70%	$11.20	0.91%
Asthma symptoms	16,446	59.37%	$4.47	0.36%
Work loss days	10,829	39.09%	$2.23	0.18%
Hospitalized for Alzheimer disease	28	0.10%	$0.43	0.04%
Hospitalized for Parkinson disease	5	0.02%	$0.08	0.01%
Total	**27,702**	**100.00%**	**$1,231.59**	**100.00%**

Because many morbidity and mortality endpoints are interrelated, the estimated $1.21 billion per year in Mojave Desert Air Basin health benefits should be interpreted as an upper-bound diagnostic, not an alternative to the statewide valuation. The per-ton BenMAP-CE–derived average value of $1.53 million per ton $PM_{2.5}$ metric remains the appropriate, non-overlapping aggregate metric used by CARB at the statewide level. The Mohave Desert diagnostic instead provides spatial and epidemiological resolution—identifying which health outcomes dominate locally and illustrating reductions in wildfire-related $PM_{2.5}$ from forest-biomass-to-hydrogen deployment can generate disproportionately large health gains in overburdened desert air basins. This dual-scale approach, statewide aggregation paired with basin-level diagnostics, preserves methodological integrity while strengthening the evidence-base for regional climate, air-quality, and environmental justice decision-making in Southern California.

6.2. WORKFORCE AND REGIONAL ECONOMIC IMPACTS

Deployment of a 330,000 BDT per year (1,000 BDT per day) forest-biomass-to-hydrogen facility in San Bernardino County would generate substantial and durable employment benefits across the Inland Empire (**Appendix Table S9**). Sustained facility operations create predictable demand for forest biomass removal, stabilizing employment in hazardous-fuel reduction activities that are otherwise episodic and funding-dependent. Based on sector-specific labor intensities, hydrogen-industry staffing benchmarks, and regional input–output multipliers, the project is estimated to support 125–164 direct full-time equivalent (FTE) jobs during steady-state operations.

Direct employment is concentrated in labor-intensive upstream activities. Feedstock harvesting and aggregation account for 40–53 FTE, while biomass transportation and logistics contribute 32–39 FTE, reflecting the scale and geographic dispersion of forest-residue supply chains. The hydrogen production facility itself supports 33–38 FTE, consistent with DOE BETO biorefinery staffing norms and adjusted for the added operational complexity of gasification, syngas cleanup, and hydrogen purification. Downstream activities such as hydrogen distribution, fueling operations, and FCEV fleet maintenance add 10–17 FTE, based on ARCHES workforce guidance [187, 188], DOE H_2@Scale benchmarks [98, 119], and CARB zero-emission freight maintenance analyses [187, 189]. Administrative, environmental-compliance, and community-benefit staffing required under ARCHES participation [190] and California LCFS and CI reporting frameworks [187, 191–193] contributes an additional 10–18 FTE, yielding total direct employment of approximately 125–164 FTEs.

Including supply-chain (indirect) and household-spending (induced) effects substantially amplifies regional employment impacts. Applying established industrial bioeconomy multipliers (indirect = 1.7–1.9; total = 2.5–2.7) [192, 193], the facility is estimated to support 87–148 indirect jobs and 100–131 induced jobs, resulting in 312–444 total long-term FTEs across the regional economy. These multipliers reflect the strong employment spillover associated with forest management, biomass logistics, and hydrogen-infrastructure investment in California, where each direct job supports an additional 1.5–1.7 jobs in upstream manufacturing, engineering services, and local retail and service sectors. During the 3–4-year construction period, the facility is projected to generate 600–1,000 job-years, based on construction labor intensities of 0.6–1.0 job-years per unit of installed capacity (BDT per day) derived from DOE BETO and biomass EPC benchmarks [194–196] (**Table 10**)

Table 10. Estimated direct, indirect, and induced employment impacts associated with a 1,000 BDT per day forest-biomass-to-hydrogen production facility in San Bernardino County.

Job creation impact	**Estimated jobs**
Feedstock supply	≈ 40–53 FTEs
Biomass transport & logistics	≈ 32 - 39 FTEs
Hydrogen conversion facility (O&M)	≈ 33 - 38 FTEs
H_2 distribution, fueling, and FCEV maintenance	≈ 10 - 17 FTEs
Engineering, compliance, administrative, and community-benefit	≈ 10 - 18 FTEs
Total Direct employment	***≈ 125-164 FTEs***
Total Indirect employment	***≈ 87–148 FTEs***
Induced jobs	***≈ 100 - 131 FTE***
Total Employment	**≈ 312–444 FTEs**
Construction-phase jobs (3–4 yr build-out)	≈ 600 - 1000 FTEs
Revenue from H_2 selling	≈ \$74 - \$124 million yr^{-1}
Direct annual labor income	≈ \$10 - \$15 million yr^{-1}
Total annual labor income	≈ \$25 - \$40 million yr^{-1}
Annual regional economic output impact	≈ \$45 - \$88 million yr^{-1}
Revenue from taxes	≈ \$6-\$16 million yr^{-1}

Labor-income effects are substantial. Applying a blended regional wage of \$80,000–\$90,000 per year [192, 193], direct employment generates approximately \$10–15 million per year in wages. When indirect and induced employment effects are included, total annual labor income rises to \$25–40 million per year. Using output-to-labor-income ratios typical of industrial bioeconomy sectors (ϕ = 1.8–2.0) [192, 193, 197], the facility supports an estimated \$45–\$88 million per year in total regional economic output.

Hydrogen production generates substantial gross revenues of approximately \$100.80–\$219.40 million per year across the modeled hydrogen price range (\$4.08–8.88 per kg). Federal corporate income taxes were estimated based on taxable income rather than gross revenue. Taxable income was calculated as earnings before interest and taxes (EBIT), defined as EBITDA minus depreciation, less interest expense. Under the base-case financing structure, this results in taxable income of approximately \$76–98 million per year during operating years, corresponding to federal corporate income tax payments of approximately $15.95 – 20.68 million per year at the current 21% statutory rate.

7. RISKS & BARRIERS

The commercialization of hydrogen produced from forest biomass in San Bernardino County is subject to a range of interrelated risks and barriers that influence project bankability and deployment timelines. Drawing on recent assessments, California policy analyses, transportation sector studies, and biomass supply chain literature, four primary barrier categories are identified: (i) market uncertainty; (ii) regulatory and permitting complexity; (iii) feedstock availability and competition; and (iv) technology readiness limitations.

7.1. MARKET UNCERTAINTIES

Market volatility represents a primary barrier to large-scale hydrogen deployment in California. Clean hydrogen prices remain highly unstable, with observed retail prices of $25–$30 per kg [42, 48, 198], well-above the $5–6 per kg threshold generally required for cost parity in heavy-duty transport applications. While state and federal policy targets (e.g., DOE Hydrogen Earthshot goals of $2 per kg by 2026 and $1 per kg by 2031) signal long-term ambition, their realization depends on rapid and coordinated scale-up of production, delivery, storage, and end-use infrastructure [69].

Revenue uncertainty is further amplified by dependence on policy-driven incentives. LCFS credit values exhibit historical volatility, eligibility rules for biomass-derived hydrogen remain under development, and the durability of federal incentives such as the IRA 45V production tax credit is subject to regulatory interpretation and political risk [190, 199]. The late-2025 revocation of up to $1.2 billion in federal funding for California's ARCHES hydrogen hub illustrates the uncertainty associated with discretionary federal funding streams and has increased perceived risk for early biomass-to-hydrogen projects [54]. Although hydrogen demand projections for Class 8 trucks, transit fleets, and port drayage are robust, forecasting nearly twenty-fold growth by 2030, deployment remains concentrated in coastal metropolitan corridors [55, 189, 190]. Inland regions such as San Bernardino face slower fleet turnover, uncertain OEM delivery schedules, and fragmented procurement behavior, which collectively exacerbate first-mover risk. Across U.S. hydrogen roadmaps, the challenge of synchronizing supply and demand at commercial scale is consistently identified as a dominant barrier to market formation [48].

7.2. REGULATORY AND PERMITTING CHALLENGES

Regulatory fragmentation is widely regarded as one of the most consequential barriers to hydrogen project development in the United States. Forest-biomass-to-hydrogen facilities must comply with overlapping and, in some cases, uncoordinated regulatory regimes, including South Coast Air Quality

Management District (SCAQMD) air permitting [191], California Environmental Quality Act (CEQA) review [200], hazardous materials handling requirements, land-use and zoning restrictions, NFPA-2 hydrogen safety standards [201], California Fire Code amendments [202], and potential federal oversight when feedstock originates from national forest lands. While California has enacted SB 1418 and SB 1291 to streamline hydrogen fueling-station permitting, these reforms do not yet fully extend to biomass-based hydrogen production facilities.

Permitting timelines for integrated gasification and hydrogen systems commonly range from 18–36 months or longer, with uncertainty exacerbated by evolving emissions thresholds, hydrogen purity requirements, and limited familiarity among local permitting authorities with thermochemical conversion and hydrogen handling technologies [203]. This regulatory learning curve increases schedule risk and financing uncertainty, particularly for first-of-a-kind or early commercial deployment.

Eligibility, lifecycle accounting, and compliance requirements for key incentive programs introduce additional complexity. LCFS credit certification, IRA Section 45V lifecycle carbon-intensity accounting, and federal financing through DOE's Loan Programs Office (DOE LPO) each impose distinct methodological, reporting, and timing requirements that are not always aligned across project development stages [68].

Finally, land management objectives, such as wildfire-risk reduction, ecological restoration, and sustainable biomass removal may impose additional constraints on feedstock sourcing activities in the San Bernardino Mountains. These considerations can affect both facility siting and long-term feedstock contracting, underscoring the need for coordinated planning across forestry, environmental, and energy agencies.

Collectively, these regulatory and institutional complexities highlight the importance of early interagency coordination and phased project development to reduce schedule risk and enhance financing certainty.

7.3. FEEDSTOCK AVAILABILITY AND COMPETITION

Although forest biomass constitutes a substantial and underutilized resource for wildfire mitigation in Southern California, they are increasingly subject to competition from other biomass-utilization pathways, including electricity generation, composting, soil amendments, and biochar production. Overlapping state and federal incentive structures—such as LCFS credits, biogas and RNG subsidies, and emerging carbon removal markets—can create localized demand "hot spots" that elevate residue prices and introduce volatility into long-term feedstock contracts [68, 69, 107, 204, 205].

Supply-chain reliability is further constrained by the spatially dispersed and seasonally variable nature of forest biomass in the San Bernardino Mountains. Collection often occurs in steep, remote terrain, increasing hauling distances, transportation costs, and operational safety risks. In addition, regional infrastructure for biomass aggregation, preprocessing, and storage remains limited. Developing centralized depots or preprocessing hubs would improve logistics efficiency but would require additional capital investment, permitting, and interagency coordination among CAL FIRE, the U.S. Forest Service, and local jurisdictions [69, 81, 206–208].

Because thermochemical hydrogen production requires continuous, year-round feedstock availability to maintain capacity utilization and financial performance, disruption in residue supply—arising from weather constraints, access limitations, wildfire events, shifting land-management priorities and treatment schedules, contracting delays, or competing utilization pathways—represent a material operational and revenue risk. These constraints underscore the importance of diversified feedstock sourcing strategies, long-term procurement agreements, and integration with wildfire-resilience planning to ensure reliable biomass supply.

Notwithstanding these risks, regional forest-treatment targets and fuel-reduction objectives indicate that sufficient theoretical biomass volume exists to support multiple utilization pathways, provided that contracting and logistics frameworks are coordinated effectively.

7.4. TECHNOLOGY READINESS AND INFRASTRUCTURE GAPS

Forest-biomass-to-hydrogen conversion systems (e.g., gasification with water-gas shift and pressure swing adsorption) are generally assessed at TRL 6–7 for integrated hydrogen production configurations. Although individual subsystem components—such as gasification, water-gas shift, and PSA separation—are commercially mature technologies in other industrial applications, their integrated application for dedicated hydrogen production has seen only limited commercial-scale deployment to date [59, 209].

While biomass gasification is well-established for heat and power generation, achieving fuel-cell-grade hydrogen requires advanced tar reforming, rigorous syngas cleanup, and high-purity separation to meet SAE J2719 specifications [62, 210, 211]. These downstream conditioning systems are capital-intensive, sensitive to feedstock variability, and introduce residual scale-up and operational risks.

By contrast, hydrogen end-use technologies—especially heavy-duty fuel-cell electric vehicles (FCEVs), transit buses, and port drayage trucks—are approaching commercial maturity, with multiple OEM platforms in service and documented pilot-to-early-commercial transitions [189, 212]. In San Bernardino County, the principal constraint is therefore not vehicle readiness, but the lack of cost-effective hydrogen infrastructure, including production integration, compression, storage, liquefaction (where applicable), and distribution networks [64, 68, 69, 204, 213].

The DOE/U.S. DRIVE Hydrogen Delivery Roadmap indicates that hydrogen delivery systems achieve economic efficiency only at sustained throughput levels typically exceeding 150 tons per day [212]. A 330,000 BDT per year biomass facility producing approximately 24,707 tons H_2 per year (~74.9 tons per day) falls below this threshold, resulting in higher per-unit delivery costs unless regional hydrogen demand scales rapidly or shared infrastructure is developed. However, co-location strategies, phased capacity expansion, or integration within multi-facility hydrogen corridors could mitigate these scale disadvantages.

Finally, California's codes, standards, and interconnection requirements for hydrogen production and fueling infrastructure remain in flux, particularly for heavy-duty stations, renewable hydrogen crediting, and safety certifications. Absent harmonized and stable regulatory frameworks, early biomass-to-hydrogen projects face heightened risks of permitting delays, post-approval design modifications, increased capital costs, and potential underutilization of infrastructure during the transition from pilot-scale to commercial deployment.

8. CONCLUSION

This study demonstrates that producing hydrogen from forest biomass in San Bernardino County is technically feasible, economically viable, and strongly aligned with California's climate, wildfire-mitigation, and environmental-justice objectives. By integrating spatial biomass assessments, facility siting analysis, techno-economic modeling, and social-benefit valuation, the report provides a comprehensive, decision-relevant framework for evaluating biomass-to-hydrogen deployment in Southern California.

The analysis shows that forest biomass—often treated as low-value waste or hazardous wildfire fuel—can be converted into a high-value, low-carbon energy carrier at competitive cost. A commercial-scale facility processing 1,000 BDT per day achieves a levelized cost of hydrogen (LCOH) of \$3.52 per kg, generates strong operating margins, and delivers attractive investor returns (IRR = 12%) under conservative assumptions. Sensitivity and scenario analyses indicate that hydrogen sale price and capital expenditure are the dominant drivers of economic performance, while feedstock price, operating costs, and transport distance exert comparatively smaller impacts. Notably, repurposing idle biomass facilities, such as Desert View Power, can reduce capital costs by ~40%, lowering LCOH to \$2.80 per kg, increasing IRR to 26%, and shortening payback periods to 2.57 years, highlighting a strategic pathway for cost-efficient deployment.

Beyond private returns, the societal and environmental benefits are substantial. Forest-residue diversion reduces wildfire emissions by an estimated 466,695 tCO_2e annually and mitigates 4,383 t $PM_{2.5}$ per year, translating to monetized climate and health benefits of $68–188 million per year (EPA framework) and $10–47 million per year (IWG framework). Health co-benefits accrue disproportionately to overburdened inland air basins, including the Mojave Desert, where incident-level analysis indicates ~27,702 avoided morbidity and mortality cases per year, corresponding to $1.23 billion per year in localized health gains. These results underscore the potential of forest-residue hydrogen as a potentially carbon-negative energy pathway that simultaneously advances environmental justice, air-quality improvement, and public-health protection.

The economic and regional development impacts are equally compelling. Steady-state operations are projected to support 125–164 direct FTE jobs, with supply-chain (indirect) and household-spending (induced) effects expanding total employment to 312–444 FTEs, alongside $25–40 million per year in total labor income and $45–88 million per year in regional economic output. Construction-phase employment contributes an additional 600–1,000 job-years, demonstrating the potential for forest-residue hydrogen to serve as a regional economic catalyst, supporting rural development, workforce equity, and industrial capacity in the Inland Empire.

From a policy and financing perspective, biomass-to-hydrogen deployment in California is supported by a robust mix of public and private mechanisms, including federal incentives (IRA 45V, 45Q, DOE loan guarantees), state programs (CEC Clean Hydrogen Program, IBank loans, LCFS credits), and public–private partnerships (PPPs) that leverage infrastructure, land access, and community benefits. Project bankability is further enhanced through long-term offtake agreements, blended financing structures, and strategic siting that exploits existing biomass processing infrastructure. While market volatility, regulatory complexity, feedstock availability, and technology readiness pose risks, scenario modeling demonstrates that these barriers are manageable with coordinated policy support, predictable revenue streams, and phased infrastructure development.

In conclusion, forest-biomass-to-hydrogen systems represent a high-impact, resilient, and scalable solution for California's clean-energy transition. They offer a rare convergence of climate mitigation, wildfire-risk reduction, regional economic development, and public-health improvement within a single deployable infrastructure strategy. Prioritizing capital-efficient retrofits of existing biomass facilities, securing long-term hydrogen offtake agreements, and integrating biomass hydrogen into California's broader renewable-fuel planning can enable coordinated progress across these objectives. In doing so, California can advance its clean hydrogen ambitions while simultaneously addressing pressing environmental, social, and economic challenges, positioning forest-biomass hydrogen as a strategically important component of the state's decarbonization and rural-resilience strategy.

APPENDIX

Table S1: Technology Readiness Level (TRL) for Hydrogen Production Pathways. The diagram compares conventional (blue) and biomass-based (green) hydrogen production technologies across the TRL spectrum from TRL 1-9.

TRL Definitions:

TRL 1 = Basic principles observed

TRL 2 = Technology concept formulated

TRL 3 = Experimental proof of concept

TRL 4 = Technology validated in laboratory environment

TRL 5 = Technology validated in relevant environment

TRL 6 = Technology demonstrated in relevant environment

TRL 7 = System prototype demonstration in operational environment

TRL 8 = System complete and qualified

TRL 9 = Actual system proven in operational environment

Hydrogen Production Pathway	TRL	Readiness Summary	Sources
Steam methane reforming (SMR)	9	Fully commercial, dominant global pathway; cost-competitive but carbon-intensive unless paired with CCS. SMR + CCS (blue H_2) demonstrated at scale; competitive cost (~$1.8–2.5/kg with incentives); regulatory hurdles remain the TRL 8.	[59, 213]
Partial oxidation (POX)	9	Mature, industrial scale; CCS integration lowers TRL to 5–8 depending on capture efficiency.	[60]
Autothermal reforming (ATR)	9	Commercial for syngas; CCS integration lowers TRL to 5–6.	[61]
Coal Gasification (CG)	9	Commercial for syngas; CCS integration lowers TRL to 5–6.	[214]
Alkaline electrolysis (AEL)	8-9	Long-established, reliable, scaled, mature technology with global deployment. Applicable for grid-connected renewables, but not residue-specific.	[62, 64]
Proton exchange membrane (PEM) electrolysis	7-8	Commercial but scaling; high purity, responsive to variable renewables; cost still high. Applicable for renewable integration, not residue-specific.	[62–64]
Anion Exchange Membrane (AEM) Electrolysis	7	Emerging, cost-effective, flexible water sources; pilot stage. Limited applicability.	[215]

Solid Oxide Electrolysis (SOEC)	5–7	High efficiency potential (85–90%); durability challenges; pilot stage. Not residue-specific.	[62, 64]
Methane pyrolysis (turquoise H_2)	3-8	Range depends on process; some pilots, but most at demo stage. Not residue-specific.	[66]
Natural (geologic) hydrogen	3	Early exploration; natural subsurface hydrogen, very low TRL.	[65]
Biomass gasification + Water-Gas Shift	5–6	Most mature biomass route; pilot plants >50% efficiency; tar removal/logistics barriers. Scalable, carbon-negative with CCS/biochar.	[67–69, 204]
Fixed-Bed Gasifiers (Updraft/Downdraft)	4–5	Simple, low-cost, decentralized; higher tar content; suited for small-scale pilots. Suitable for small, rural pilots only.	[76]
Fluidized-Bed Gasifiers (BFB/CFB)	6	Best balance of efficiency, scalability, and feedstock flexibility; promising for forest biomass. Most viable for CA residues; scalable, efficient, flexible.	[71, 72]
Entrained-Flow Gasifiers	6–7	High-temperature, largescale, low tar; higher CAPEX; suited for CCS integration. Applicable for large, centralized plants with CCS.	[70]
Plasma Gasification	4–5	Very high temperature, minimal tar; high energy cost limits commercial use. Too costly.	[67, 74, 216]
Pyrolysis + Steam Reforming of Bio-Oil	4–5	Two-step, modular/distributed systems; easier storage; still demonstration stage. Useful for distributed/modular systems.	[68, 75, 217]
Aqueous Phase Reforming (APR)	3–4	Lab/pilot stage; efficient for wet feedstocks; avoids drying; not yet scaled. Not recommended for forest biomass (better for wet waste).	[73, 218]
Supercritical Water Gasification (SCWG)	4–5	High yield for wet biomass; pilot stage; materials/cost challenges at >22 MPa. Not recommended for forest biomass (better for sewage/sludge).	[68, 219, 220]
Biochemical Conversion (Dark Fermentation)	3–4	Emerging, low yield, requires pre-treatment, sustainable but immature. Low yield.	[67, 68, 213, 221]
Biological Conversion (Photolysis, Algae)	3–4	Lab-scale only; low efficiency, long cycles; significant R&D needed.	[67, 213, 222, 223]

Table S2. Total Acres and Total Biomass (BDT) of Agricultural Residues within 45 km, 80 km, and 160 km of the Proposed San Bernardino Wood Products Innovation Campus.

Species	Total Acres	Biomass Factor (BDT/acre)	Total BDT
45 km radius			
Citrus	2,059.50	18	37,071.0
Dates	0.60 + 5.29 = 5.89	25	147.4
Avocados	241.86	18	4,353.5
Apples	69.23	12	830.8
Cherries	0.08 + 3.16 = 3.24	14	45.4
Pecans	5.57	23	128.0
Vineyards (annual)	53.41	0.83–2.39	44.3–127.7 t/yr
80 km radius			
Species	Total Acres	Biomass Factor	Total BDT
Citrus	1,658.90	18	29,860.3
Dates	5.21	25	130.2
Avocados	447.70	18	8,058.6
Apples	33.03	12	396.4
Walnuts	0.31	25	7.8
Pistachios	2.90	22	63.8
Vineyards (annual)	1,858.13	0.83–2.39	1,542–4,441 t/yr
160 km radius			
Citrus	4,104.64	18	73,883.5
Dates	933.55	25	23,338.8
Avocados	8110.53	18	145,989.5
Apples	48.02	12	576.3
Cherries	0.22	14	2.2
Pecans	17.62	23	405.3
Apricots	25.98	10	259.8
Peaches & Nectarines	9.11	14	127.5
Plums	5.80	9	52.2
Pistachios	25.18	22	553.9
Pomegranates	9.11	15	136.7
Vineyards (annual)	5,721.71	0.83–2.39	4,749–13,675 t/yr

Table S3. Total Biomass by Scenario. Summary of total retreeing biomass (BDT) and annual vineyard residues available within 45 km, 80 km, and 160 km of the proposed San Bernardino Wood Products Innovation Campus.

Scenario	Total Retreeing Acres	Total Retreeing Biomass (BDT)	Vineyard Biomass (t/yr)
45 km	2,385 acres	42,576 BDT	44–128
80 km	2,147 acres	38,517 BDT	1,542–4,441
160 km	13,282 acres	245,325 BDT	4,749–13,675

Note: Agricultural residue availability was quantified by intersecting statewide 2023 land-use geodatabase parcels with three trucking-distance buffers (45 km, 80 km, and 160 km) around the proposed San Bernardino Wood Products Innovation Campus and applying UCANR productive lifespans and species-specific biomass generation factors to identify parcels expected to undergo re-treeing. Annual vineyard pruning were estimated using published low–high yield factors. Across all three distance scenarios, agricultural residues represent a substantial and spatially scalable biomass resource. Within the 45 km radius, re-treeing of citrus, avocados, apples, and other woody crops yields roughly 42,600 BDT, supplemented by 44–128 tons/year of vineyard pruning. Expanding the boundary to 80 km increases species diversity and acreage, producing about 38,500 BDT of re-treeing biomass and 1,500–4,400 tons/year of vineyard residues. The 160 km scenario delivers by far the largest supply, with more than 245,000 BDT of re-treeing biomass—dominated by avocados, citrus, and dates—and 4,700–13,700 tons/year of vineyard pruning (Manzone et al. 2016). Overall, while vineyard residues provide a steady but relatively small annual stream, orchard removal events generate episodic but very large biomass pulses that scale sharply with distance, offering a robust feedstock base for thermochemical conversion at regional scale.

Table S4. Statewide Biomass Feedstock Availability Estimates for California

Year of Estimate	Biomass Amount (million BDT/yr)	Biomass Types Included	Methods Used	Sources
2007	32.2 (technical) Gross production 82.8	Forestry, agriculture, mill residues, urban wood, MSW organics, manure	Bottom-up statewide resource assessment; recovery factors applied	[77]
2013 (summarized 2019)	78 gross; 35 technical (~45%)	Forest (~14.3), agricultural (~7–8), urban/mill (~4–5), MSW (~1.2)	USFS inventory, harvest statistics, residue-to-product ratios	[78]

2015	7.3	Forest biomass	FIA, BioSUM, GBSM, 40-yr scenarios	[82]
2016	8–11 economically viable)	Forest operations residues	FIA, BioSUM v5.0, FFE-FVS, 25 prescriptions	[83]
2019	12.4 (HHZ total); ~3.85 unused	Forest biomass (HHZ)	FIA, LEMMA-GNN, Aerial Surveys, FVS	[84]
2020	18.4–68.9 (one-time stock); 7.5–27.8 economically viable	Mortality-derived woody biomass	Aerial surveys, LEMMA-GNN	[85]
2020	24	Forest ops (15M), mill residues, chaparral	FIA, FVS, BioSUM; Forest Carbon Plan (1M ac/yr)	[86]
2021 (2015–2019 data)	~76 (technical unused residues)	Agriculture (19.5), forestry (18.5), urban/MSW (38)	Statewide inventory + recoverability screens	[79]
2022	~29 woody feedstock	Forest + agricultural tree crops + orchards	Policy-driven synthesis	[80]
2050 projection	~70 (≈16% increase)	Agriculture, forestry, urban waste, manure	Scenario-based modeling	[81]
2025	~47 potential)	Forest, agricultural, and urban biomass	Multi-study synthesis	[224]
2025 (This Study)	56.35 technical (from 112.75 gross)	Forest biomass only	C-BREC; TreeMap 2016, FVS, FIA NSVB; 40% thin-from-below	[225]

Table S5: Input variables, exclusion constraints, and suitability thresholds applied in the weighted overlay analysis for forest-residue-to-biomass facility siting.

Variable	Restricting criteria
Access to forest biomass	< 2 ton BDT per acre = Not desirable
CA land use development plan	Ag =0 (=not suitable for plant); High Den Comm=0; High density residential=0; Industrial=1; Low density commercial=1(=suitable for plant); Low density residential=0; Medium density residential=0; Open space and public lands=1; Other - Not Determined=1; Planned development =1; Urban reserve=0; Very low density residential=1; Water=0
Slope	< 8 degrees = Highly desirable 8-12.5 degrees = Moderately desirable >12.5 degree = Not desirable
Access to road network	<10 miles = Highly desirable 10-20 = Moderately desirable

	20-30 = Low desirable 30-40 = Desirable > 40 miles = Not desirable
CO2 basin area	<10 miles = Highly desirable 10-20 = Moderately desirable 20-30 = Low desirable 30-40 = Desirable >40 miles = Not desirable
Electricity transmission network	<10 miles = Highly desirable 10-20 = Moderately desirable 20-30 = Low desirable 30-40 = Desirable >40 miles = Not desirable
Population density	<500 within 1 mile = Desirable >500 within 1 mile = Not desirable
EPA non-attainment areas (PM & O3)	Not desirable
NHD	<20 Miles = Highly desirable 20 – 100 miles =low desirable >100 miles = Not desirable
Proximity to natural gas pipeline	<10 miles = Highly desirable 10-20 = Moderately desirable 20-30 = Low desirable 30-40 = Desirable >40 miles = Not desirable
Proximity to hydrogen fueling stations	<10 miles = Highly desirable 10-20 = Moderately desirable 20-30 = Low desirable 30-40 = Desirable >40 miles = Not desirable
LNG Refineries	<10 miles = Highly desirable 10-20 = Moderately desirable 20-30 = Low desirable 30-40 = Desirable >40 miles = Not desirable

Table S6: Capital cost normalization and scaling of literature-reported biomass-to-fuel and biomass-to-hydrogen facilities to a common 2024 $ basis and a reference capacity of 1,000 BDT per day using CEPCI adjustment and a 0.6 scaling exponent.

Study	Plant size (BDT per day)	TCI ($MM)	Basis year	CEPCI inflator	Estimated CAPEX $2024	Scaling Factor	Scaling to 1000 BDT per day CAPEX (2024 $ M)	Product & Plant Stage
Tijmensen et al. [104]	1920	387	2000	2.03	785.59	0.52	409.16	FT product, 1st plant, indirect gasifier
Swanson et al. 2010 [145]	2205	498	2007	1.52	758.28	0.45	343.89	FT product, nth plant, indirect gasifier
Swanson et al. 2010 [145]	1920	339	2000	2.03	688.15	0.52	358.41	FT biofuel, Nth plant
Mann and Steward 2020 [121]; Ruth 2011 [105]	500	214	2009	1.53	328.03	2.00	656.06	Adjusted for Hydrogen, 1st plant
Mann and Steward 2020 [121]; Ruth 2011 [105, 130]	2000	344	2009	1.53	527.30	0.50	263.65	Hydrogen, nth plant
Commercial Project 1 [105, 121, 130, 143, 144]	2000	548	2009	1.53	840.01	0.5	420.00	FT product, 1st plant, indirect gasifier
Commercial Project 2 [105, 121, 130, 143, 144]	500	455	2009	1.53	697.45	2.00	1394.90	FT product, 1st plant, indirect gasifier

Commercial Project 3 [105, 121, 130, 143, 144]	2000	432	2009	1.53	662.20	0.50	331.10	FT product, 1st plant, indirect gasifier
Tijmensen et al. [104]	2000	542	2009	1.53	830.81	0.50	415.41	hydrogen, 1st plant, indirect gasifier
Spath et al. 2005 [142]	2000	565	2009	1.53	866.07	0.50	433.03	hydrogen, 1st plant, indirect gasifier
Swanson et al. 2009 [147]; Anex et al. 2010 [146]	2000	331	2009	1.53	507.38	0.50	253.69	FT, nth plant, direct gasifier
Swanson et al. 2009 [147]; Anex et al. 2010 [146]	2000	250	2009	1.53	383.22	0.50	191.61	FT, nth plant, direct gasifier
Tijmensen et al. [104]	2000	638	2009	1.53	977.97	0.50	488.98	hydrogen, 1st plant, direct gasifier
Tijmensen et al. [104]	2000	474	2009	1.53	726.58	0.50	363.29	hydrogen, 1st plant, direct gasifier
Tijmensen et al. [104]	2000	559	2009	1.53	856.87	0.50	428.43	hydrogen, 1st plant, direct gasifier
Phillips et al. [141]	2,000	191	2005	1.70	325.50	0.50	162.75	Ethanol, nth plant
Larson et al. [140]	4,540	541	2003	1.99	1076.62	0.22	237.14	Diesel, gasoline, nth plant
Average CAPEX ($MM 2024)							**420.68**	

Table S7: Chemical Engineering Plant Cost Index (CEPCI) values used to inflate literature-reported capital costs to a common 2024 $ basis (data from Chemical Engineering Magazine).

Basis Year	CEPCI value
2000	394
2001	394.3
2002	395.6
2003	402
2004	444.2
2005	468.2
2006	499.6
2007	525.4
2008	575.4
2009	521.9
2010	550.8
2011	585.7
2012	584.6
2013	567.3
2014	576.1
2015	556.8
2016	541.7
2017	567.5
2018	603.1
2019	607.5
2020	596.2
2021	708.8
2022	816
2023	797.9
2024	800

Table S8: Values for the SC-CO2 (in 2022$ per metric ton of CO_2)

Emissions Year	EPA Values			IWG Values		
	2.5% Discount rate	2% Discount rate	1.5% Discount rate	5% Discount rate	3% Discount rate	2.5% Discount rate
2025	145	237	403	21	68	100
2030	161	257	430	23	73	107
2035	177	277	456	26	81	115
2040	194	299	482	31	88	123

2045	211	321	510	34	94	131
2050	229	345	539	38	101	139

Table S9: Potential job estimation from 1000 BDT per day forest biomass to hydrogen production facility job impact and regional economic impacts.

Impact metric	Estimated value	Calculation / formula
Feedstock supply	≈ 40–53 FTE	$$J_{feedstock} = \frac{M_{BDT}}{1000} \times EI_{forestry}$$ Where $M_{BDT} = 330{,}000\ BDT\ yr^{-1}$ (annual forest–residue supply), and $EI_{forestry} = \ Employment\ intensity$ $0.12 - 0.16\ FTE\ per\ 1{,}000\ BDT$ for Western U.S. forest operations [192].
Biomass transport & logistics	≈ 32 - 39 FTE	$$N_{trucks} = \frac{T_{trips,\ day}}{N_{trips,\ truck}}$$ Where $T_{trips,\ day} = 65 - 75\ haul\ trips\ day^{-1}$ ($1000\ BDT\ day^{-1}\ at\ {\sim}13 - 15\ BDT\ load^{-1}$), $N_{trips,\ truck}$ = 2.3–2.5 trips per truck per day (Inland Empire heavy–duty fleet productivity [226]). Non-driver logistics staffing is estimated as: $$J_{non-driver} = J_{mechanics} + J_{dispatch} + J_{supervision}$$ With *Mechanics* 1 FTE per 10–15 trucks, *Dispatch* 1 FTE per 15–20 trucks, and *Supervision/Administration/Safety* 2–3 FTEs per fleet as California's goods-movement studies [227, 228]. Total logistics employment, $J_{transport,\ total} = N_{trucks} + J_{non-driver}$
Hydrogen conversion facility (O&M)	≈ 33 - 38 FTE	$$J_{plant} = \left(\frac{E_{H_2\,plant}}{E_{ref}}\right) \times J_{ref} \times \emptyset_{complexity}$$ Where J_{ref} = 45 FTE reference staffing for a 100 $Mgal\ yr^{-1}$ corn ethanol biorefinery [195], $\frac{E_{H_2\,Plant}}{E_{ref}}$ ≈ Ratio of annual energy throughput (0.35) of the modeled forest-residue-to-hydrogen facility to a standard 100-Mgal ethanol plant [197, 229], $\emptyset_{complexity}$ ≈ Adjustment factor (1.8-2.0) for added operational complexity associated with gasification, syngas cleanup, hydrogen purification, high-pressure compression, and enhanced process safety requirements (relative to fermentation-based ethanol) [230, 231].

H_2 distribution, fueling, and FCEV maintenance	≈ 10 - 17 FTEs	$$J_{H_2\,use} = J_{load} + J_{station} + J_{FCEV}$$ Where J_{load} = Personnel required (3-6 FTEs) for hydrogen handling, compression, loading, and storage management at the plant (ARCHES workforce guidelines [187]; clean-transport handling norms [188]). $J_{station}$= Operators and technicians (3-5 FTEs) for hydrogen refueling station(s) servicing heavy-duty trucks (based on California H_2 station staffing standards [98] and DOE H2@Scale benchmarks [119]). J_{FCEV} = Maintenance technicians (4-8 FTEs) supporting the heavy-duty fuel-cell electric vehicle (FCEV) fleet, including fuel-cell system checks, high-pressure storage inspection, and powertrain servicing (ARCHES planning documents [190]; CARB ZE freight maintenance studies [189].
Engineering, compliance, administrative, and community-benefit	≈ 10 - 18 FTEs	$$J_{overhead} = J_{O\&M} \times r$$ Where $J_{overhead}$ = overhead and administrative staff (FTE) [192, 194, 196], $J_{O\&M}$ = total operations and maintenance staffing for the hydrogen conversion facility (FTE) r = overhead ratio of 0.25-0.40 ,consistent with industrial bioeconomy staffing structures [193, 195]. $$J_{ARCHES} = \sum J_{WN} + J_{CC} + J_{DE}$$ Where J_{ARCHES} = ARCHES-required workforce and community-engagement staff [187, 190], J_{WN} = Workforce Navigator (1 FTE), J_{CC}= Community-Benefits Coordinator (1 FTE), J_{DE} = Data & Equity Reporting staff (0.5–1.0 FTE). $$J_{env} = \sum J_{LCFS} + J_{CARB} + J_{GHG}$$ Where J_{env} = environmental and regulatory compliance staff (FTE) [187, 191–193], J_{LCFS} = LCFS/CI pathway development and fuel-reporting support (0.5–1.0 FTE), J_{CARB} = CARB/AQMD air-quality and facility-permitting staff (1.0 FTE), J_{GHG} = GHG monitoring, verification, and annual reporting (0.5 FTE). The total administrative component of direct employment (J_{admin}): $$J_{admin} = J_{overhead} + J_{ARCHES} + J_{env}$$

Total Direct employment	≈ 125-164 FTEs	Total direct employment across all supply-chain segments (FTE): $$J_{direct} = \sum_{high\ case}^{low\ case} J_{feedstock} + J_{transport,total} + J_{plant} + J_{H_2\ use} + J_{admin}$$
Total Indirect employment	≈ 87–148 FTEs	$$J_{indirect} = J_{direct} \times (m_{indirect} - 1)$$ Where $J_{indirect}$ = indirect employment (FTE), $m_{indirect}$ = indirect employment multiplier, typically 1.7–1.9, based on industrial bioeconomy input–output modeling [193] and biomass power sector multipliers [192].
Induced jobs	≈ 100 - 131 FTE	$$J_{induced} = (m_{total} - m_{indirect})J_{direct}$$ Where $J_{induced}$ = total induced employment (FTE), J_{direct} = direct employment (FTE), m_{total} = total employment multiplier, typically 2.5–2.7 for regional bioenergy sectors [193], $m_{indirect}$= indirect employment multiplier (1.7–1.9) [193].
Total Employment	≈ 312–444 FTEs	$$J_{total} = m_{total} \times J_{direct}$$ J_{total} = total Long-Term Employment (direct + indirect + induced), J_{direct} = direct full-time equivalent (FTE) jobs, m_{total} = total employment multiplier (2.5–2.7) derived from regional bioenergy and industrial bioeconomy sectors [193].
Construction-phase jobs (3–4 yr build-out)	≈ 600 - 1000 FTEs	$$J_{construct} = C \times EI_{const}$$ Where $J_{construct}$ = total construction-phase employment (job-years) [194–196], C = plant processing capacity (BDT day^{-1}), EI_{const} = construction employment intensity (0.6-1.0 job-years per BDT day^{-1}) for biomass power benchmarks for construction labor.
Revenue from H2 selling	≈ \$99 - \$148 million yr^{-1}	$$O_{direct} = Q_{H_2} \times P_{H_2}$$ Where, O_{direct} = direct annual plant output (annual H_2 revenue), Q_{H_2} = annual H_2 production ($kg\ H_2 yr^{-1}$) P_{H_2} = plant-gate H_2 price (\$3-\$5 kg^{-1})
Direct annual labor income	≈ \$10 - \$15 million yr^{-1}	$$Income_{direct} = J_{direct} \times W$$ Where $Income_{direct}$= total direct annual labor income (US \$ yr^{-1}), J_{direct}= total number of direct full-time equivalent jobs (FTEs), W = average annual wage (\$80,000-\$90,000) per FTE [192, 193].
Total annual labor income	≈ \$25 - \$40 million yr^{-1}	$$Income_{total} = J_{total} \times W$$ $Income_{total}$ = combined annual labor income from direct, indirect, and induced employment (US \$ yr^{-1}), J_{total} = total number of jobs supported by the project (direct + indirect + induced FTEs), W = average annual wage per FTE (US \$ yr^{-1}).

Annual regional economic output impact	≈ \$45 - \$88 million yr^{-1}	$$O_{total} = Income_{total} \times \emptyset_{\frac{O}{T}}$$ Where O_{total} = total estimated regional economic output (US \$ yr^{-1}), $Income_{total}$= total annual labor income from all jobs supported by the project, ($\emptyset_{\frac{O}{T}}$ = output-to-labor-income ratio (1.8-2.0) for bioenergy and industrial bioeconomy sectors [192, 193, 197].
Revenue from taxes	≈ \$6-\$16 million yr^{-1}	$$O_{taxes} = \int_{P_{H_2}=3}^{5} (Cash_{inflow} - Cash_{outflow}) \times \tau_{federal}\, dP_{H_2}$$ Where O_{taxes}= annual federal tax payments generated by project operations (US \$ yr^{-1}), $Cash_{inflow}$= annual hydrogen sales revenue (US \$ yr^{-1}), $Cash_{outflow}$= annual operating expenses (OPEX) (US \$ yr^{-1}), $\tau_{federal}$= federal corporate income tax rate (21%) P_{H_2}= plant-gate hydrogen price (scenario range: 3–5 US \$ kg^{-1}).

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