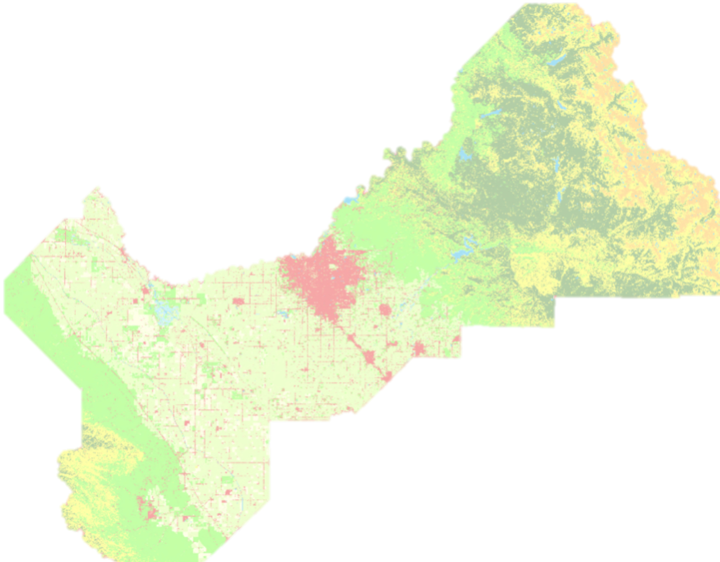

Fresno Wood Products Innovation Campus:

A Siting and Techno-Economic Assessment of Forest Biomass–to–Renewable Diesel and Biochar Pathways

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EXECUTIVE SUMMARY

California's climate, wildfire, air quality, and transportation challenges are increasingly interconnected. The state's climate strategy, articulated in the 2022 Scoping Plan developed by the California Air Resources Board, targets an 85% reduction in greenhouse gas emissions below 1990 levels by 2045, alongside statewide carbon neutrality. Progress toward these goals is constrained by intensifying wildfire activity, declining forest resilience, and persistent air-quality nonattainment—particularly in the San Joaquin Valley (SJV). At the same time, diesel remains the dominant fuel for freight, agriculture, and off-road equipment, where near-term electrification faces cost and infrastructure barriers.

These conditions underscore the need for scalable, near-term solutions that integrate forest management, low-carbon fuels, and rural economic development. A wood-based bioeconomy pathway offers such an opportunity by utilizing low-value forest and agricultural residues generated through restoration and hazardous-fuels reduction, displacing petroleum diesel with a drop-in alternative, producing carbon-management co-products beneficial to forestry and agricultural systems in the Central Valley.

This report evaluates a renewable diesel–oriented Wood Products Innovation Campus (WPIC) in Fresno County. The proposed configuration is based on a thermochemical platform comprising oxygen-blown gasification, syngas cleanup and conditioning, Fischer–Tropsch synthesis and upgrading to finished renewable diesel. Biochar is produced as a co-product from clean biomass streams via slow pyrolysis. The analysis is designed as a replicable WPIC model that is financeable, permittable, and operationally viable, with adaptability to regional variation in feedstock availability, infrastructure, and market conditions.

A key system design principle is strict product-stream segregation to maintain product quality and eligibility for environmental credit programs. Forest and agricultural residues are eligible feedstocks for both renewable diesel and biochar production, while municipal solid waste (MSW), modeled as specification-controlled refuse-derived fuel (RDF), is routed exclusively to the renewable diesel pathway. This approach protects biochar integrity and supports defensible carbon-crediting frameworks.

Feedstock availability was assessed for the three primary supply streams used in the scenario analysis: forest residues, agricultural residues, and MSW-derived RDF. Forest residue availability was quantified using the California Biomass Residue Emissions Characterization (C-BREC) framework under the 2025 "thin-from-below" 40% treatment case (TFB_40_2025), interpreted as technical potential under sustained forest management rather than current practice. Results indicate that Fresno County has an estimated gross forest residue potential of approximately 3.01 million bone-dry tons (BDT) per year, with approximately 1.51 million BDT/yr remaining after applying a

50% technical accessibility screen; average residue density is estimated at 3.75 BDT per acre across mapped forestlands. Agricultural woody biomass availability was estimated from orchard/vineyard residue inventories within defined haul buffers (e.g., re-treeing removals and annual pruning streams), aggregated by crop type and planting cohort and converted to BDT using species- and practice-specific yield factors (BDT/acre). MSW availability was estimated using county- and facility-scale solid waste generation and characterization data, with MSW assumed to be preprocessed into specification-controlled refuse-derived fuel (RDF); in the TEA, MSW contributes only through the RDF fraction that meets conversion specifications and is available within the assumed sourcing shed. Together, these three feedstock estimates support the feasibility of supplying commercial-scale facilities within practical haul radii, contingent on coordinated aggregation, preprocessing infrastructure, and alignment with land-management and materials-recovery stakeholders. A statewide siting analysis integrates geographic information systems (GIS) screening with multi-criteria decision analysis (MCDA). Twenty-three criteria layers were normalized to a 0–1 suitability scale and combined to generate a composite suitability surface (range 2.17–14.50). High-suitability areas were identified using percentile-based thresholds, refined by minimum developable area and spatial dispersion constraints. Under representative assumptions (top 10% suitability, ≥10-hectare minimum site area and 50-mile spacing), the analysis identifies 77 candidate sites statewide, including nine in Fresno County. One representative location (36.710608, −119.778176) is selected for detailed techno-economic modeling. Proximity to legacy bioenergy infrastructure, such as the Rio Bravo Fresno Biomass Power Plant, is recognized as a potential advantage for redevelopment and risk reduction, although the base analysis assumes a greenfield integrated facility.

The techno-economic assessment models a 1,000 BDT/day facility operating 330 days per year over a 20-year project life using a levered discounted cash flow framework. Key performance indicators include net present value (NPV), internal rate of return (IRR), debt service coverage ratio (DSCR), payback period, and levelized cost of renewable diesel. Four feedstock scenarios are analyzed to reflect realistic procurement strategies and associated operational considerations: (1) 100% forest residues; (2) a 50/50 blend of forest and agricultural residues; (3) a mixed portfolio including 20% MSW (RDF); and (4) a high-MSW scenario (50% RDF). A ±40% capital expenditure (CAPEX) sensitivity range is applied to reflect first-of-a-kind deployment.

Under base assumptions, results indicate a clear performance hierarchy. Scenario 1 (100% forest residues) demonstrates the strongest financial and operational performance, producing ~17.3 million gal/yr of renewable diesel and ~9,570 t/yr of biochar, with IRR ~19%, NPV ~$158M, DSCR ~2.20, and payback ~8.2 years. Importantly, the forest case is not modeled as zero-RIN: we apply a conservative eligibility screen assuming 26% of forest residues are sourced from federal lands and therefore do not generate RINs, while the remaining 74% is eligible and does generate RIN value under the adopted pathway assumptions. Scenario 1 remains dominant despite this partial RIN eligibility because clean woody feedstock yields higher fuel output (and therefore sales and LCFS value) and maximizes biochar/CDR revenues, while avoiding the added preprocessing, contaminant-control, and yield penalties associated with higher agricultural-residue and MSW/RDF blends. This scenario also achieves the lowest levelized fuel cost (~$2.58/gal).

Blended feedstock scenarios show reduced performance due to lower conversion yields and constrained biochar production. Scenarios 2 and 3 produce similar fuel volumes (approximately 14.3–14.6 million gallons per year) and approach breakeven under baseline assumptions (IRR ~9%, DSCR ~1.3), suggesting that moderate improvements in capital costs, operational efficiency, or credit realization could enable investment viability. The high-MSW scenario (Scenario 4) performs weakest, with limited financial attractiveness under base assumptions (IRR ~5%, DSCR ~1.03), indicating a need for additional risk mitigation, cost reductions, or enhanced revenue streams. Sensitivity analysis confirms that the forest-residue scenario remains robust across CAPEX variability, while blended scenarios require tighter cost control to maintain positive returns.

The report also evaluates environmental justice (EJ) and regional economic impacts in Fresno County and the broader San Joaquin Valley. Wildfire risk reduction and smoke-related health benefits scale with forest-residue utilization, making the forest-residue-dominant scenario the most impactful. Employment analysis indicates that the facility would support approximately 102–139 direct full-time equivalent (FTE) positions and 255–375 total long-term jobs, including indirect and induced effects. Construction activities are estimated to generate 600–1,000 job-years over a 3–4 year development period. While facility operations employment remains relatively constant across scenarios, upstream supply-chain employment declines as MSW share increases due to reduced biomass handling requirements and increased reliance on RDF logistics.

Overall, the analysis demonstrates that a renewable diesel–oriented WPIC model in Fresno County can serve as a viable and scalable pathway to align forest management, low-carbon fuel production, and regional economic development objectives. Policy alignment, capital cost management, and feedstock strategy are identified as key determinants of successful deployment.

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1. INTRODUCTION

California faces an increasingly interconnected set of challenges at the intersection of climate, forest, waste, and transportation systems. The state's 2022 Scoping Plan establishes a pathway toward an 85% reduction in greenhouse gas emissions below 1990 levels by 2045 and statewide carbon neutrality through deep decarbonization, fossil-fuel displacement, and expanded carbon sequestration [1]. Progress toward these targets is increasingly influenced by climate-driven wildfire activity and declining forest resilience across the Sierra Nevada and other forested regions. Since 2010, more than 10 million acres have burned statewide, resulting in significant episodic carbon emissions and widespread exposure to hazardous fine particulate matter ($PM_{2.5}$) [2, 3]. Escalating wildfire severity, prolonged drought, and forest overstocking have intensified the need for large-scale fuel-reduction and ecological restoration. State and federal initiatives are advancing landscape-scale treatments—on the order of approximately one million acres annually—through mechanical thinning, prescribed fire, and cultural burning [4]. When strategically implemented, these interventions can reduce hazardous fuel loads while enhancing forest health, ecosystem resilience, and community protection [5, 6].

A key implementation challenge is the management of low-value woody biomass—typically consisting of small-diameter trees, understory vegetation, and other non-merchantable residues—is often pile-burned or left to decay, leading to rapid carbon release with limited economic return. As a result, biomass utilization represents a critical opportunity to align wildfire mitigation with climate objectives, rural economic development, and renewable energy production [7–9]. At the same time, California's transportation sector remains the largest contributor to greenhouse-gas emissions statewide, accounting for approximately 40% of total emissions.

Diesel-dependent freight, agriculture, and off-road equipment are particularly challenging to decarbonize in the near term due to cost, infrastructure, and operational constraints [10]. These conditions have elevated the role of low-carbon drop-in fuels as a pragmatic pathway for near-term emissions reductions in hard-to-electrify sectors.

Policy frameworks such as the Low Carbon Fuel Standard (LCFS), administered by the California Air Resources Board, provide a durable market signal by crediting verified reductions in fuel carbon intensity (CI). This mechanism has accelerated the deployment of renewable diesel and other low-carbon fuels across the state [1, 11]. In recent years, renewable diesel has experienced rapid market growth, supplying an increased share of California's diesel pool and contributing meaningfully to transportation fuel decarbonization [12–14].

These pressures are particularly acute in the San Joaquin Valley (SJV), including Fresno County, where persistent air-quality nonattainment intersects with elevated baseline vulnerability and recurring wildfire smoke exposure. The SJV is among the most $PM_{2.5}$-burdened air basins in the United States and remains out of compliance with federal fine particulate standards under the National Ambient Air Quality Standards [15, 16]. Chronic exposures to elevated $PM_{2.5}$ concentrations are associated with increased respiratory and cardiovascular morbidity, with disproportionate impacts on low-income and historically underserved communities in this economically and demographically diverse region [17, 18]. During severe wildfire events, smoke can dominate regional air quality by introducing large quantities of primary particulate matter and precursor compounds that contribute to secondary aerosol formation, amplifying basin-wide pollution episodes and exacerbating existing public health and environmental justice challenges [17, 19–21].

Within this context, forest biomass-to-renewable diesel systems present a multi-benefit pathway aligned with state and federal priorities. Such systems can convert hazardous-fuels biomass through controlled thermochemical processes rather than open burning or unmanaged decomposition, thereby reducing emissions associated with traditional disposal practices. At the same time, they can displace petroleum diesel in sectors that are difficult to electrify in the near term, while supporting economic activity in forest-adjacent and rural communities. When coupled with biochar co-production, these systems can further deliver durable carbon storage and produce soil-enhancing amendments relevant to Central Valley agriculture, strengthening linkages between forest management, low-carbon fuel production, and land stewardship outcomes.

This report evaluates the feasibility of establishing a renewable diesel–oriented Wood Products Innovation Campus (WPIC) in Fresno County. The proposed facility is designed to convert primarily forest-derived biomass from restoration and fuels-reduction activities into renewable diesel using thermochemical conversion, including gasification and the Fischer–Tropsch process, with biochar produced as a co-product from clean biomass streams. The analysis is conducted within the broader framework of the California Wood Products Innovation Campuses initiative, which seeks to evaluate scalable and replicable bioeconomy cluster models across diverse regions of the state. While a parallel campus configuration in San Bernardino County has already been completed, this report focuses specifically on the Fresno County context and the renewable diesel–plus–biochar pathway.

1.1 Project Aims and Analytical Focus

The Fresno County analysis evaluates whether a renewable diesel–oriented campus model can convert low-value forest residues, currently a byproduct of wildfire mitigation, into a strategic asset that advances California's climate, forest-resilience, and rural economic development goals, while remaining financeable and implementable at commercial scale. Specifically, the report:

(i) ***assesses*** the availability, spatial distribution, and reliability of forest-derived biomass generated through fuel-reduction and ecological restoration activities.

(ii) ***evaluates*** the technical and economic feasibility of biomass-to-renewable diesel conversion via thermochemical pathways, including gasification and Fischer–Tropsch process, with sensitivity to feedstock composition and operational constraints.

(iii) ***characterizes*** lifecycle greenhouse gas performance, including the contribution of biochar co-production to carbon intensity and long-term carbon storage outcomes.

(iv) ***examines*** infrastructure compatibility with Central Valley fuel demand, logistic networks, and distribution systems; and

(v) ***identifies*** workforce requirements, siting considerations, and policy and regulatory factors relevant to scalable deployment in Fresno County and comparable regions.

1.2 Fresno County Context: Renewable Diesel Innovation Campus

Fresno County occupies a strategic position at the interface of Sierra Nevada forest landscapes and the Central Valley agricultural and freight economy.

Forested lands in the eastern portion of the county and adjacent Sierra regions face increasing wildfire risk driven by fuel accumulation, prolonged drought, insect-related mortality, and broader climate stressors. Restoration activities such as mechanical thinning, fuel-break construction, and prescribed fire generate significant volumes of woody biomass residues that require cost-effective and scalable management pathways.

Concurrently, Central Valley remains one of the most diesel-dependent economic corridors. Agriculture, food processing, goods movement, and heavy-duty transportation rely extensively on compression-ignition engines to power tractors, harvesting equipment, irrigation systems, and freight fleets. Renewable diesel's drop-in compatibility with existing engines and fuel-distribution infrastructure creates a strong structural alignment between restoration-derived biomass resources and established energy demand systems.

The Fresno Renewable Diesel Innovation Campus is designed to operate within this alignment. The configuration emphasizes: (i) primary reliance on forest-derived feedstocks associated with wildfire mitigation and landscape resilience; (ii) renewable diesel synthesis as the defined downstream fuel pathway; (iii) biochar co-production to stabilize a portion of biomass-derived carbon and support soil enhancement in regional agricultural systems; and (iv) integration with existing fuel terminals, freight corridors, and heavy-duty transportation networks. While the campus is centered on forest-based feedstocks, site-specific conditions may allow limited incorporation of supplemental cellulosic materials—such as certain agricultural residues or organic fractions—where they align with lifecycle and regulatory performance requirements.

Beyond wildfire mitigation and carbon-intensity considerations, the campus model can generate regional economic benefits by establishing a stable demand center for restoration-derived biomass, supporting contractor capacity, skilled-trade employment, and industrial operations aligned with California's evolving forest-resilience priorities. Certain deployments within the broader Innovation Campus framework may involve collaboration with tribal governments, which can introduce governance structures and development pathways consistent with sovereign authority; such partnership structures represent a replicable design element but are not a prerequisite for implementation in Fresno County. Overall, the model is designed to redirect biomass that would otherwise be burned or left to decay into value-added products, with revenues that can help reinforce ongoing landscape management and long-term forest stewardship.

1.3 Report Organization and Structure

This report provides a Fresno County-specific, scenario-based evaluation that is both finance-facing and implementation-oriented. It is designed to support the Wood Products Innovation Campus (WPIC) scope of work by turning alternative feedstock configurations into investable pathway comparisons and linking those outcomes to workforce, environmental, and public-value considerations.

The analysis is structured to move from system context and a replicable campus framework to technology selection, siting feasibility, and ultimately to economic viability and public-interest alignment under California's policy and environmental justice priorities.

Section 1 introduces the integrated climate, wildfire, air-quality, and drivers underpinning the case for a renewable diesel campus in Fresno County and defines the project's analytical objectives.

Section 2 presents the Wood Products Innovation Campus (WPIC) as a modular and replicable development model, demonstrating how a shared thermochemical platform can support region-specific product pathways – renewable diesel in Fresno County and renewable hydrogen in San Bernardino – while maintaining design consistency.

Section 3 reviews the biomass-to-liquids (BtL) technology landscape and technology readiness and identifies gasification combined with the Fischer–Tropsch process as the most suitable pathway for Fresno's feedstock characteristics. Key technical risks and corresponding de-risking strategies are also summarized.

Section 4 details the statewide siting analysis, including the GIS and multi-criteria decision analysis (MCDA) framework, evaluation criteria (feedstock availability, logistics, infrastructure access, environmental constraints, hydrology, environmental justice and workforce indicators), composite suitability mapping, and candidate site selection. It also explains the rationale for selecting the Fresno site, including proximity to existing bioenergy infrastructure.

Section 5 presents the core techno-economic and financial feasibility analysis for a 1,000 BDT/day facility. This includes scenario definitions, system boundaries, process configuration, mass, energy, and carbon accounting, capital and operating cost estimation, policy credit treatment, and discounted cash flow modeling. Key performance metrics —levelized cost of renewable diesel (LCORD), net present value (NPV), internal rate of return (IRR), payback period, and debt service coverage ratio (DSCR) are reported alongside a ±40% capital cost sensitivity analysis.

Sections 6 and 7 extend the analysis beyond plant-level economics by quantifying environmental justice and public health co-benefits, particularly wildfire risk reduction and $PM_{2.5}$ exposure, as well as regional economic impacts, including employment, labor income, and economic output.

Section 8 synthesizes key deployment risks and constraints, including feedstock supply, logistics, capital execution, policy and carbon accounting, and permitting considerations, and identifies priority levers for risk reduction. The report concludes with an integrated assessment of siting, economic feasibility, and public-value outcomes, supported by detailed appendices and references to ensure transparency and reproducibility.

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

This section presents an industrial development blueprint for California's wood-based bioeconomy. The framework is built around 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, while using a common supply-chain and thermochemical platform to support diverse downstream product pathways. By synthesizing insights from the Fresno and San Bernardino case studies, this model defines the WPIC as a replicable approach for building statewide bioeconomy cluster development.

2.1 Structural Architecture of a WPIC

The WPIC model provides a replicable industrial development framework that integrates three core elements, including (i) forest-residue utilization, (ii) thermochemical conversion, and (iii) multi-output fuel and material production pathways within a coordinated regional platform. Rather than prescribing a single technology or product, the WPIC establishes a modular campus architecture capable of supporting diverse product configurations based on regional feedstock characteristics, infrastructure availability, and market demand. Within this structure, individual pathways—such as renewable diesel derived from forest residues in the Fresno Region and renewable hydrogen derived from forest residues in the San Bernardino Region—are treated as regional modules built on top of a shared thermochemical and supply-chain foundation.

2.2 Modular Thermochemical Backbone and Downstream Pathway Flexibility

The WPIC model can be conceptualized as three interrelated layers:

2.2.1 Feedstock and Supply-Chain Layer

This layer focuses on the sustainable aggregation of forest residues generated through wildfire-risk reduction, ecological restoration, and hazardous-fuel treatments. It encompasses harvesting, preprocessing, storage, and logistics coordinated with land management agencies, contractors and other supply-chain partners.

2.2.2 Thermochemical Conversion Platform

This layer focuses on commercially established core systems, such as gasification, syngas cleanup and conditioning, and energy integration systems, that convert lignocellulosic biomass into an intermediate synthesis gas (syngas). These upstream systems provide the primary energy-conversion backbone of the campus and serve as a shared platform across regions.

2.2.3 Downstream Product Configuration Modules

This layer focuses on product-specific upgrading units added onto the syngas platform, such as renewable diesel synthesis, renewable hydrogen purification and compression, sustainable aviation fuel (SAF) pathways, renewable power generation, and carbon-rich co-products such as biochar and soil amendments.

Because the upstream thermochemical backbone is typically more standardized than downstream product modules, this layered architecture supports phased expansion and adaptive market response. Modular integration of downstream units enables incremental growth while limiting stranded-asset risk.

2.3 Regional Specialization Within a Statewide Cluster Strategy

The Fresno and San Bernardino campuses illustrates how regional conditions inform optimized product-pathway selection within a shared WPIC structural model.

2.3.1 Fresno Region Low-Carbon Renewable Diesel Configuration

The Fresno configuration emphasizes renewable diesel production from forest residues using gasification and Fischer–Tropsch upgrading, with biochar co-production from clean biomass streams. This pathway aligns with Central Valley agricultural markets and the region's diesel demand for agriculture and goods movement. It leverages existing heavy-duty liquid-fuel infrastructure and established renewable fuel blending, storage, and distribution systems. Biochar creates an additional value stream through soil-amendment applications and potential carbon stabilization benefits, improving lifecycle performance depending on operational boundaries and durability assumptions.

2.3.2 San Bernardino Region Low-Carbon Renewable Hydrogen Configuration

The San Bernardino campus emphasizes renewable hydrogen production from forest residues with biochar co-production. This pathway aligns with Inland Empire freight corridors, heavy-duty vehicle deployment strategies, and emerging hydrogen distribution networks. Hydrogen purification and compression modules are added to the thermochemical platform.

Despite these regional differences, both campuses follow the same architectural logic: treatment-aligned forest-residue supply, a shared thermochemical conversion platform, and modular downstream configuration. This structure supports a broader, statewide bioeconomy cluster by standardizing campus design principles, enabling inter-regional knowledge transfer, and facilitating shared policy, permitting, and financing frameworks.

2.4 Flexibility, Phased Deployment, and Market Evolution

The WPIC model is designed for flexibility in response to dynamic market and policy conditions. The WPIC model therefore emphasizes modular architecture supporting phased capacity additions, co-located product options, and integration within multi-facility corridors where infrastructure and end-use demand are concentrated. As regulatory standards and carbon accounting evolve—particularly for carbon-rich co-products such as biochar—the campus structure allows lifecycle performance and product portfolios to improve over time without redevelopment of the core conversion backbone.

2.5 Replicability and Public-Domain Value

The primary objective of this grant-funded effort is to establish a replicable model suitable for deployment across multiple California regions. By documenting geospatial feedstock

assessments, siting criteria, techno-economic parameters, workforce considerations, and environmental-justice indicators within a unified framework, this report provides a transferable analytical foundation for future wood utilization projects. WPIC is not limited to the Fresno and San Bernardino case studies. 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.

3. BIOMASS-TO-BIOFUEL (BTL) AND TECHNOLOGY READINESS

Biomass-to-liquid (BtL) fuel technologies include several conversion pathways that transform solid biomass and waste-derived feedstocks—such as forest residues, agricultural residues, and municipal solid waste (MSW)—into liquid transportation fuels compatible with existing distribution systems and end-use engines. In contrast to first-generation biofuels, which are mainly produced from food-based sugars, starches, or oils, BtL pathways valorize lignocellulosic and heterogeneous residues, reduce direct competition with food crops, and produce fuels suitable for high blend ratios, including 100% utilization when upgraded to specification [22–25].

While biochemical routes, such as enzymatic hydrolysis followed by fermentation, remain important for producing oxygenated fuels such as ethanol, BtL systems targeting drop-in diesel, jet fuel, and naphtha markets are predominantly thermochemical. Thermochemical pathways generate hydrocarbon intermediates that can be hydro-processed into paraffinic, infrastructure-compatible fuels [24, 26]. Thermochemical BtL is commonly organized into two "platforms": (i) ***Syngas platform*** converts feedstocks via gasification to synthesis gas ($CO + H_2$), followed by syngas cleanup and conditioning and catalytic fuel synthesis—most notably Fischer–Tropsch (FT)—to produce paraffinic hydrocarbons that can be refined into renewable diesel and jet fractions [23, 27]; (ii) ***Bio-oil platform*** generates a liquid intermediate first—either fast pyrolysis oil (through rapid thermal decomposition of dry biomass) or hydrothermal liquefaction (HTL) biocrude (produced through high-pressure processing that can better tolerate wet feedstocks)—and then upgrades this intermediate via hydrotreating and hydrocracking to remove oxygen and meet fuel specifications [24, 25, 28]. In practice, the main distinction between these platforms is where the technical complexity is concentrated: syngas routes demand catalyst-grade gas (i.e., placing stringent requirements on cleanup and conditioning), whereas bio-oil routes shift complexity to deep deoxygenation, hydrogen management, and long-duration upgrading stability [24, 29, 30].

3.1 Market Maturity and Technology Readiness

The commercial maturity of biomass-to-liquid (BtL) technologies varies significantly by conversion pathway and by the underlying feedstock platform. At one end of the spectrum, first-generation biofuels (e.g., corn and sugarcane ethanol) and lipid hydrotreating to renewable diesel (hydrotreated vegetable oil/hydrogenation-derived renewable diesel, HVO/HDRD) are fully commercial (approximately TRL 9). These systems are supported by established supply chains, standardized product specifications, and substantial installed production capacity [24, 31, 32]. These mature pathways serve as important market benchmarks for scale and operability. However, lipid-based renewable diesel and sustainable aviation fuel (SAF) remains constrained by limited and price-volatile lipid feedstocks, as well as competing demand across renewable diesel and SAF markets.

"Advanced" BtL routes that utilize lignocellulosic residues and waste-derived feedstocks (forest residues, agricultural residues, and MSW) remain less mature at the fully integrated system level. Cellulosic ethanol has reached commercial-scale demonstrations (typically characterized as TRL 7–8), but early deployments have revealed persistent challenges related to feedstock logistics, enzyme and catalyst cost, and sustained conversion performance [24, 25] (**Figure 1**). For thermochemical drop-in fuels, a consistent maturity pattern emerges across major assessments: core conversion chemistry (e.g., FT synthesis and hydro processing) is relatively mature, while front-end conversion system integration – encompassing

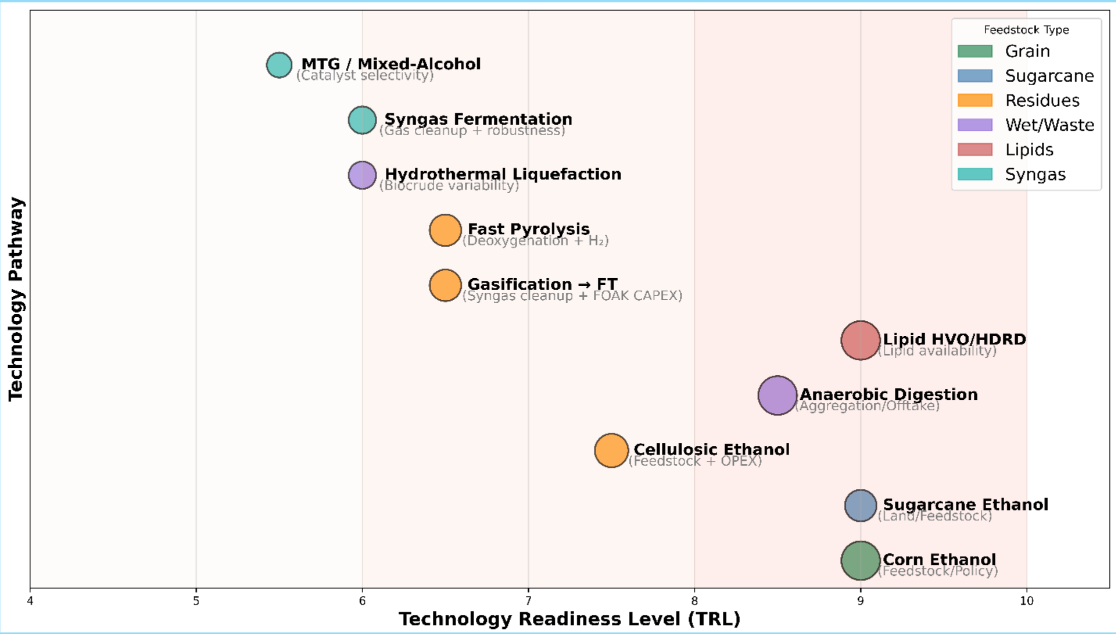

Figure 1. Technology Readiness vs Primary Constraints, Bubble size indicates deployment status

gasification, pyrolysis or hydrothermal liquefaction (HTL), along with syngas or intermediate cleanup and conditioning – remains the primary source of technical and financial risk. These integration challenges directly affect long-duration operability, capital intensity, and overall project bankability [24, 29, 30].

Among residue-based drop-in pathways, gasification coupled with Fischer–Tropsch synthesis (BtL-FT) is widely regarded as the most commercially advanced near-ready option for producing diesel- and jet-range hydrocarbons from lignocellulosic feedstocks, given the established track record of FT synthesis in gas-to-liquid (GTL) and coal-to-liquid (CTL) applications (**Figure 2**). However, the fully integrated biomass-to-FT system generally falls within a near-commercial TRL range (approximately TRL 6–7). This reflects its dependence on the reliable, continuous production of catalyst-grade syngas, which requires stringent contaminant control and consistent

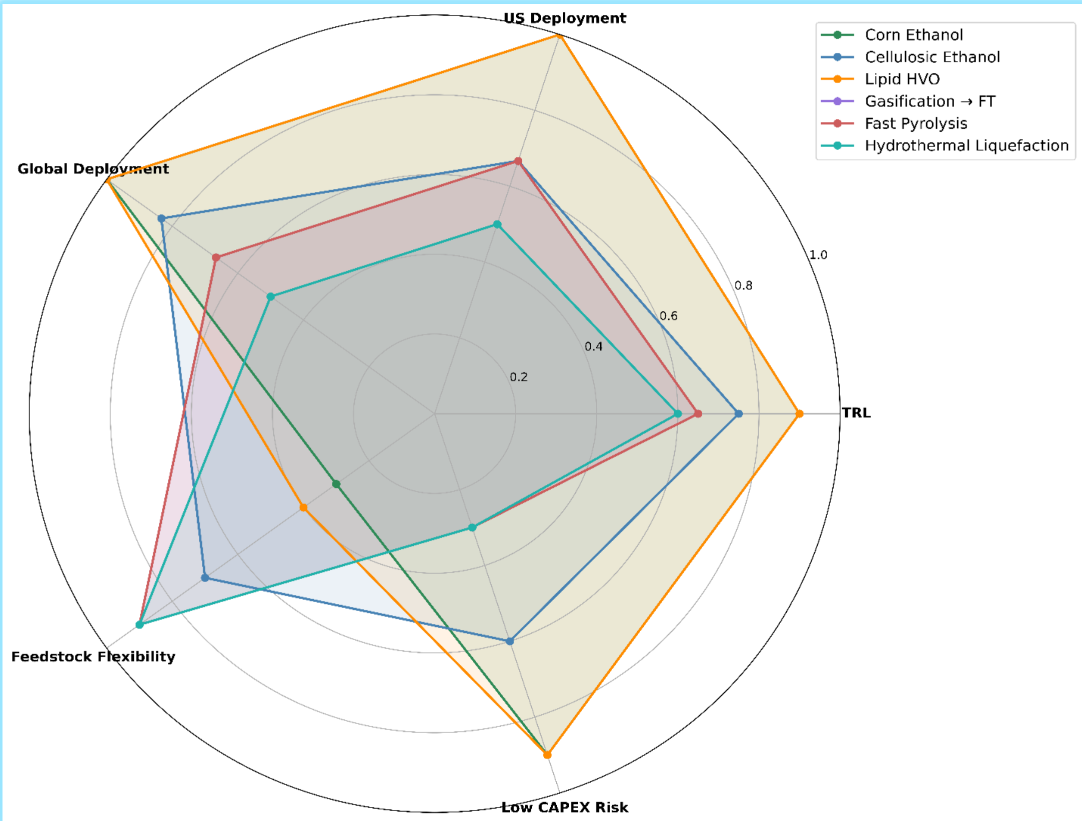

Figure 2. Technology Attribute Radar Chart for Selected Biomass-to-Liquid (BtL) Pathways (Normalized Scores). Normalized scores compare CAPEX risk (low = higher score), feedstock flexibility, TRL, and global and U.S. deployment.

operational performance across variable feedstocks and operating conditions [27, 33] (**Appendix TS1**). Recent project experience further underscores that system integration and sustained operability—rather than FT chemistry itself—remain the primary constraints to commercial deployment.

3.3 Biomass-To-Renewable Diesel Production Technologies

In this report, renewable diesel (RD) refers to *drop-in*, paraffinic diesel-range hydrocarbons that are chemically similar to petroleum diesel and can be used at any blend ratio (up to 100%) in existing engines and infrastructure [31]. This distinguishes RD from fatty acid methyl ester (FAME) biodiesel, which is oxygenated, blend-limited (typically ≤B20), and may exhibit different storage stability and cold-flow properties [23].

Multiple technology pathways can produce RD. For Fresno County, the primary screening criterion is feedstock suitability. The region's resource base is dominated by forest residues, orchard and agricultural residues, and MSW. This feedstock generally favors thermochemical pathways (e.g., gasification–FT and bio-oil upgrading) over lipid hydrotreating. Lipid-based pathways are less applicable unless large, low-cost feedstock supplies can be secured under reliable contracts [24, 29] **(Table 1)**.

Table 1. Renewable diesel pathways: feedstock compatibility and indicative readiness

RD pathway	Best-suited feedstocks	Typical products	Indicative system TRL	Fresno fit	Primary constraint for Fresno
Lipid hydrotreating (HVO/HDRD)	Used cooking oil, tallow, vegetable oils	RD (drop-in) + (optional) jet/naphtha	~9	Low–Medium	Limited local lipid supply; price volatility and competing demand [24, 31]
Fast pyrolysis oil + upgrading	Cleaner lignocellulosic residues preferred	RD and jet blend stocks	~5–6 (to early 6–7 depending on system scope)	Medium	Deep deoxygenation, catalyst life, high H_2 demand / logistics [24, 28]
Gasification + FT (FT-RD)	Forest and Ag residues; MSW with preprocessing	RD + wax (upgraded) + naphtha/jet	~6–7 (integrated); FT sub-step ~8–9	High	Syngas cleanup reliability; FOAK CAPEX; contaminant variability [23, 24, 29, 33]

3.5 Technology Readiness of Fischer–Tropsch Renewable Diesel

Authoritative assessments from DOE, NREL, NETL, PNNL, IEA Bioenergy, and peer-reviewed literature converge on a consistent conclusion: FT synthesis and hydro processing are mature, while gasification and syngas cleanup/ conditioning drive most of the integration risk for biomass- and waste-to-FT systems (**Figure 3**; **Appendix TS2**, and **Appendix TS3**) [23–25, 28, 29, 33–35].

At the subsystem level, technology readiness can be summarized as follows:

- Feedstock logistics (forest and agricultural residues): Generally high readiness (≈TRL 7–8), though delivered cost and variability remain site-sensitive [27].

• MSW preprocessing: ≈TRL 6–7, with dependent on contaminant control and feedstock consistency [24].

• Gasification (indirect or dual fluidized bed for FT applications): ≈TRL 6–7, based on demonstration experience and scale-up history [24, 25, 27].

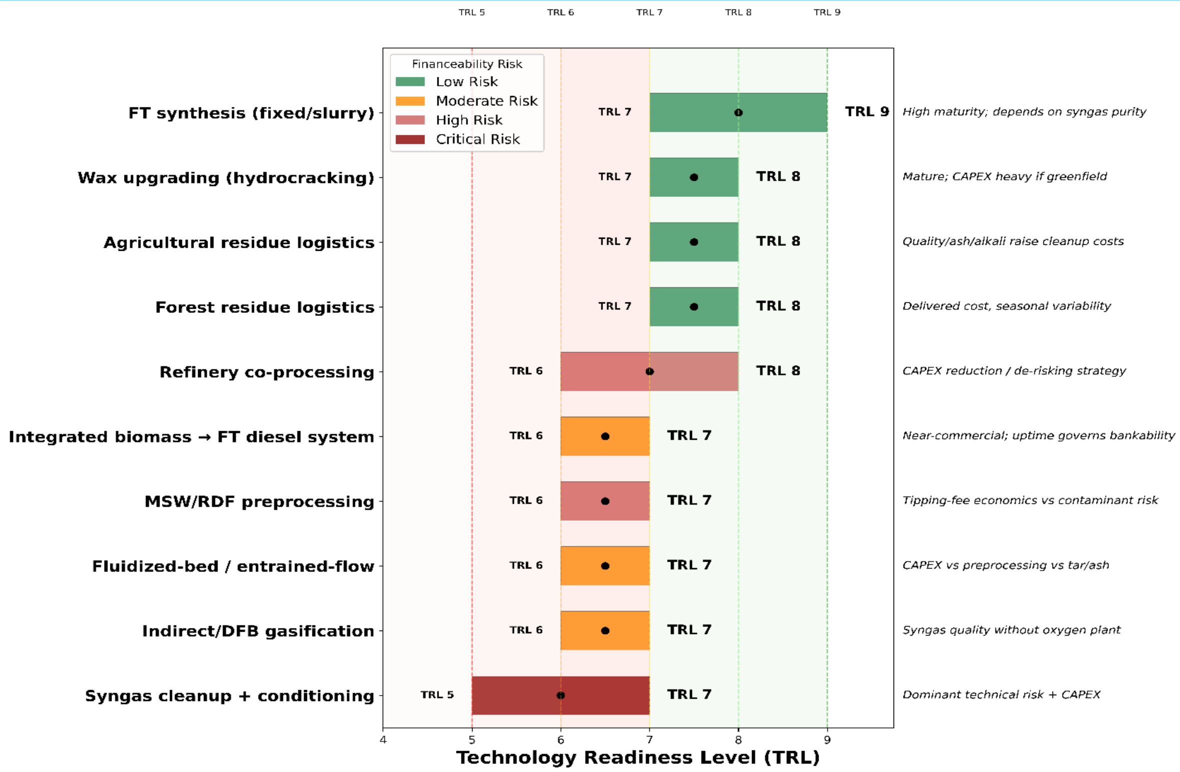

Figure 3. Technology Readiness Across Biomass-to-FT Renewable Diesel Chain (Subsystem View) and Financeability Implication.

• Syngas cleanup and conditioning: ≈TRL 5–7), the *lowest-readiness* system and most cost- and operability-sensitive block, duo to strict contamination limits for FT catalysts. [29, 33].

• FT synthesis: Mature (≈TRL 8–9) in CTL and GTL analogs; performance in biomass systems depends on consistent syngas purity and stable H_2:CO ratios [24, 25].

• Refinery co-processing: ≈TRL 6–8, increasingly recognized as a commercialization enabler by reducing standalone upgrading CAPEX requirements and accelerating deployment [35].

The integrated biomass-to-FT RD chain is near-commercial-ready (≈TRL 6–7), while FT synthesis itself is mature (≈TRL 8–9) [24, 25, 27, 35]. Gasification with syngas cleanup and conditioning are the primary bottlenecks, driving operability and CAPEX risk due to tar and trace contaminants that affect catalyst protection [29, 33]. Refinery co-processing serves as a practical first deployments enabler by reducing greenfield upgrading CAPEX and supporting blending and offtake strategies [35].

The four-scenario structure – from forest residues to agricultural residues to MSW blends – is technically justified, as contaminant profiles directly influence cleanup system design, consumables, maintenance, and catalyst longevity [24, 25, 33]. Environmental performance is strongly favorable compared to petroleum diesel and can be further enhanced with carbon capture and storage (CCS) or durable carbon co-products, depending on system boundaries and crediting frameworks [34, 36–38].

3.6 Rationale for Fischer–Tropsch Renewable Diesel Deployment in Fresno County

Fresno County is a strong candidate for biomass-to–Fischer–Tropsch renewable diesel (FT-RD) due to convergence of key enabling conditions:

(i) Feedstock availability: Treatment-driven forest residues from Sierra-Nevada Forest restoration and hazardous-fuel reduction, supplemented by other cellulosic residues.

(ii) Public-policy drivers: High-priority objectives including wildfire resilience, air quality improvement, and waste diversion

(iii) Logistic connectivity: Access to California's fuel distribution system and existing fuel distribution infrastructure

(iv) Policy and market support: Established compliance markets and incentive structures that monetize low-carbon attributes and co-benefits [39–41].

Together, these factors support a practical and decision-ready configuration for the Fresno Biomass Innovation Campus: a gasification → syngas cleanup/conditioning → FT synthesis → upgrading pathway, with biochar co-production from clean biomass streams.

3.6.1 Feedstock Landscape and Scenario Optionality

The Fresno campus configuration is primarily supplied by forest-derived woody biomass sourced from Sierra Nevada landscape management activities, including ecological restoration, thinning, hazardous-fuel reduction, and WUI treatments across State Responsibility Areas (SRA), Federal Responsibility Areas (FRA), and adjacent lands. State and federal agencies have emphasized the need to expand annual treatment acreage to reduce wildfire intensity, protect watersheds and communities, and enhance long-term carbon storage (**Figure 4**).

Achieving this treatment scale requires economically viable outlets for low-value woody biomass that does not meet conventional wood-products specifications. Without such outlets, material is often pile-burned, broadcast burned, or left to decompose, resulting in rapid carbon release and minimal economic return on restoration investments.

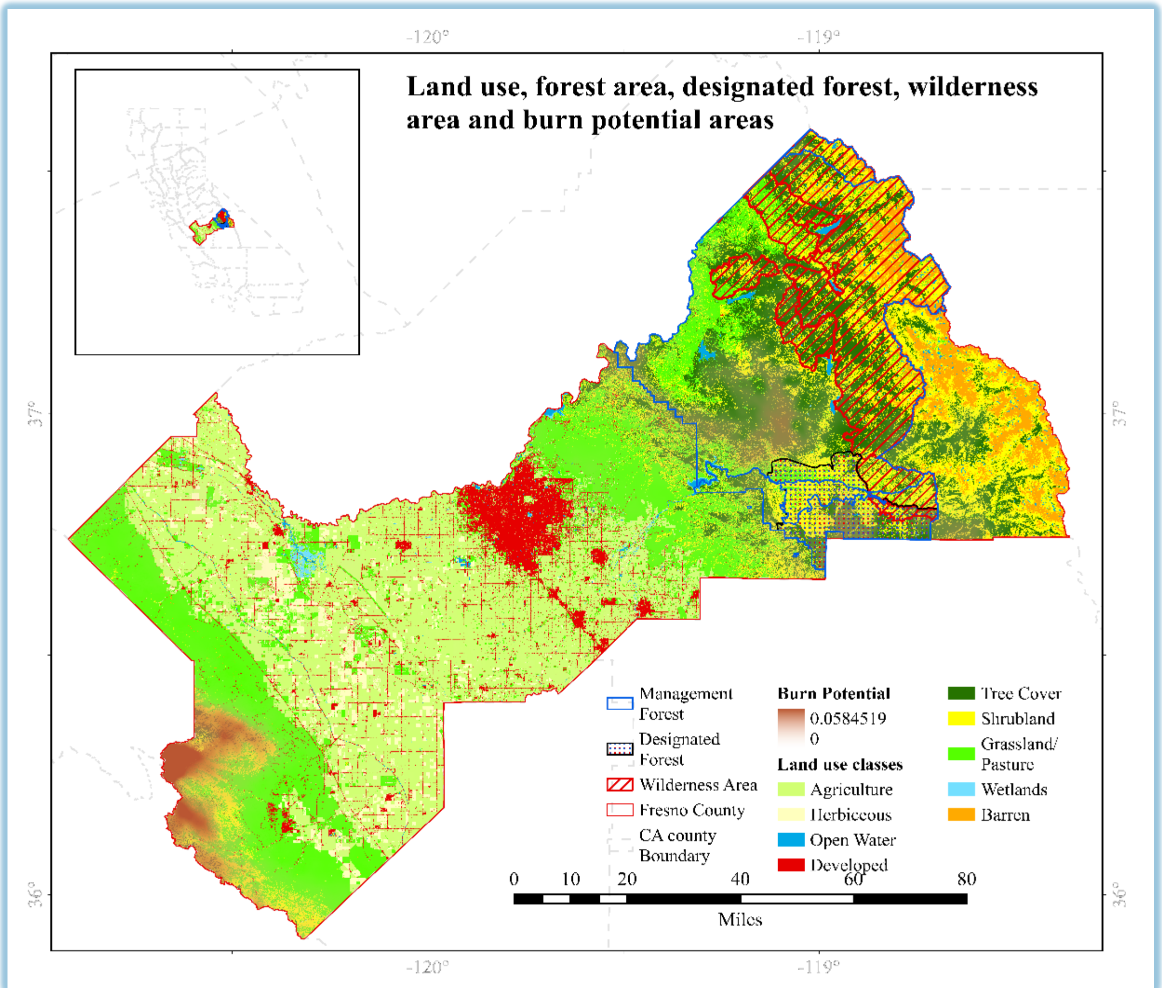

Figure 4. Map showing the wilderness area, management and designated forest, burn potential and land use classes in Fresno County.

3.6.1.1 Forest-Derived Feedstock

Forest residue supply for the Fresno campus is based on the C-BREC biomass layer under a 40% thin-from-below =(TFB_40_2025) scenario for 2025 [42–44]. C-BREC integrates high-resolution forest-structure data (TreeMap 2016, 30 m resolution), 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 [45]. The 40% thin-from-below scenario was selected as the reference case because it aligns with current California forest-health and fuel-reduction strategies [43].

Under TFB_40_2025 scenario and assuming a 15 percent residue fraction, California's gross forest biomass potential is 112.75 million BDT per year. Applying a 50 percent technical accessibility screen yields 56.37 million BDT per year of technically accessible biomass. Average biomass density is 3.45 BDT per acre, with highest densities in

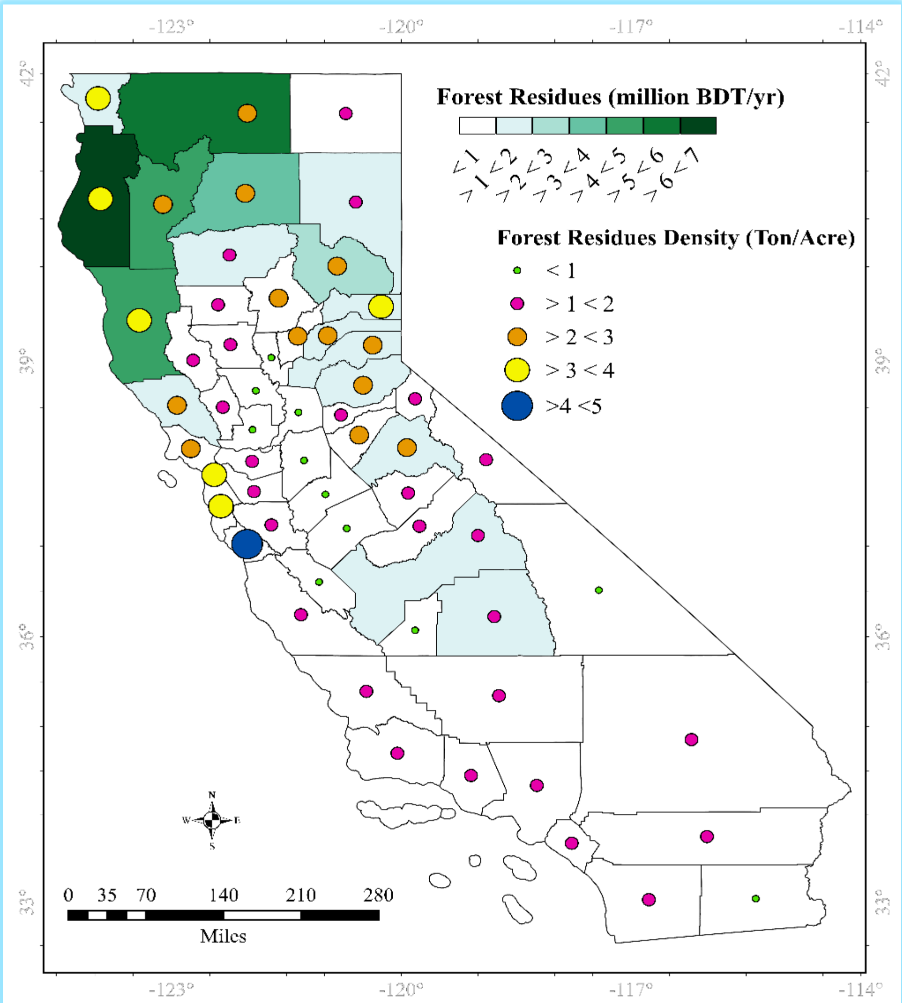

Figure 5. Estimated statewide forest biomass availability (million BDT per year) and biomass density (BDT per acre) based on C-BREC TFB_40_2025 simulations.

mountain and coastal mixed-conifer forests and lowest in intensively farmed valleys. These estimates are interpreted as an upper-bound technical potential, conditioned on statewide implementation of a 40 percent thin-from-below treatment, rather than as a representation of current realized practice.

Biomass availability is concentrated in northern and montane regions (**Figure 5**): Humboldt, Siskiyou, Mendocino, Trinity, and Shasta counties account for 55% of gross biomass and remain dominant after accessibility adjustments. Regionally, Northern California contributes 24.7 million BDT/year (55% of total), Sierra Nevada 9.3 million BDT/year (21%), and coastal counties 6.9 million BDT/year (15%). Urbanized or heavily farmed counties contribute minimally (<0.02 million BDT/year).

"Regionally, Northern California contributes 24.7 million BDT/year (55% of total), Sierra Nevada 9.3 million BDT/year (21%), and coastal counties 6.9 million BDT/year (15%)."

County-scale C-BREC TFB_40_2025 results indicate Fresno County contains approximately 802,399 forested acres contributing to residue availability. Mean biomass density across contributing pixels is 3.75 BDT per acre (median 2.76 BDT per acre); 90th-percentile 8.11 BDT per acre; max 18.79 BDT per acre). Gross annual forest residue availability is estimated at 3.01 million BDT per year, with 1.51 million BDT/year technically accessible after applying a 50% accessibility screen. These values represent upper-bound technical potential under sustained treatment and residue recovery assumptions. Sierra National Forest spans ~1.3 million acres in the Fresno supply shed and requires annual treatment of approximately 15,000–20,000 acres to reduce hazardous fuel loads [46, 47]. Typical treatments can generate approximately 100,000 BDT per 5,000 acres treated, sufficient for approximately 8 million gallons of renewable diesel [40, 48].

Currently, only a fraction of residues is recovered; the WPIC model addresses this by establishing a stable demand center and coordinating aggregation, preprocessing, and transport logistics to maximize residue utilization [23, 27].

3.6.1.2 Agricultural Residues in San Joaquin Valley

Fresno County's ~1.8 million acres of farmland generate additional woody biomass from orchards and vineyards [49]. Agricultural residues can be cost-competitive for thermochemical pathways, although delivered costs remain sensitive to collection, preprocessing, and ash and alkali constraints [34, 50].

Vineyards typically undergo trimming twice annually (winter pruning, summer hedging) and generate between 0.83 and 2.39 tons per acre [51]. Tree crops (citrus, tree nuts, stone fruits, pomegranates, pears) have a productive life ranging from 18 to 50 years. When orchards are removed and replanted, this re-treeing process generates from 9 bone-dry tons (BDT) per acre (peaches and nectarines) to 25 BDT per acre (walnuts).

Biomass potential was calculated using the California Department of Water Resources crop mapping geodatabase [52], aggregated within 40- and 80-km

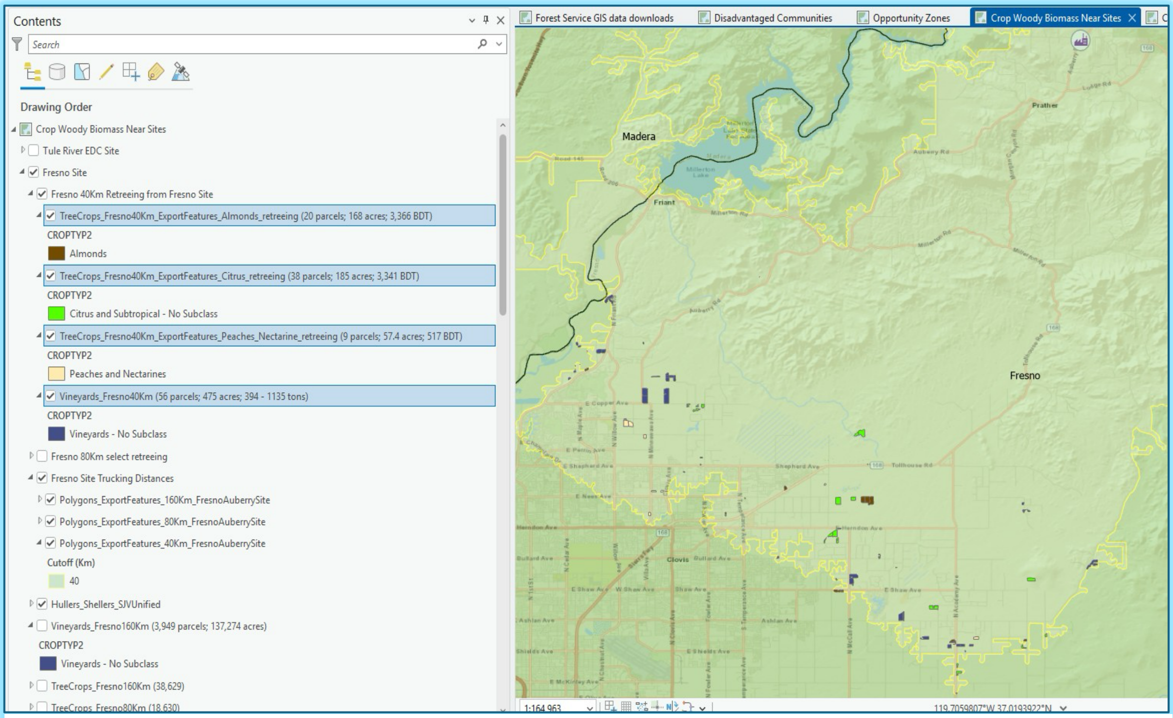

Figure 6. Fresno 40 km re-treeing: almonds, citrus, peaches nectarines, vineyard trimmings.

trucking distances from the proposed campus.

Appendix **Tables ST4 and ST5** summarize re-treeing and vineyard pruning volumes, **Figures 6 and 7** show the spatial distribution of potential feedstock parcels.

Within a 40-km radius of the Fresno site, orchard re-treeing across 11 tree-crop parcels totalling 5,522.5 acres, yielding 41,158.7 bone-dry tons (BDT) of recoverable biomass over crop lifespans. The resource is dominated by pistachios (24,151.1 BDT; 58.7%) and almonds (9,487.1 BDT; 23.0%), together accounting for ~82% of the total, while citrus contributing 5,464.7 BDT (13.3%).

Supply availability follows two waves: legacy plantings from the 1980s–1990s, which imply near-term removals (notably almonds, walnuts, some citrus), and more recent pistachio plantings (2014–2022), offering a predictable, longer-term supply. Minor crops (peaches/nectarines, apples, dates) contribute minimally due to limited acreage [57–60].

Expanding the catchment to 80 km encompasses a larger, more diverse agricultural landscape (16 crop types), increasing available biomass roughly

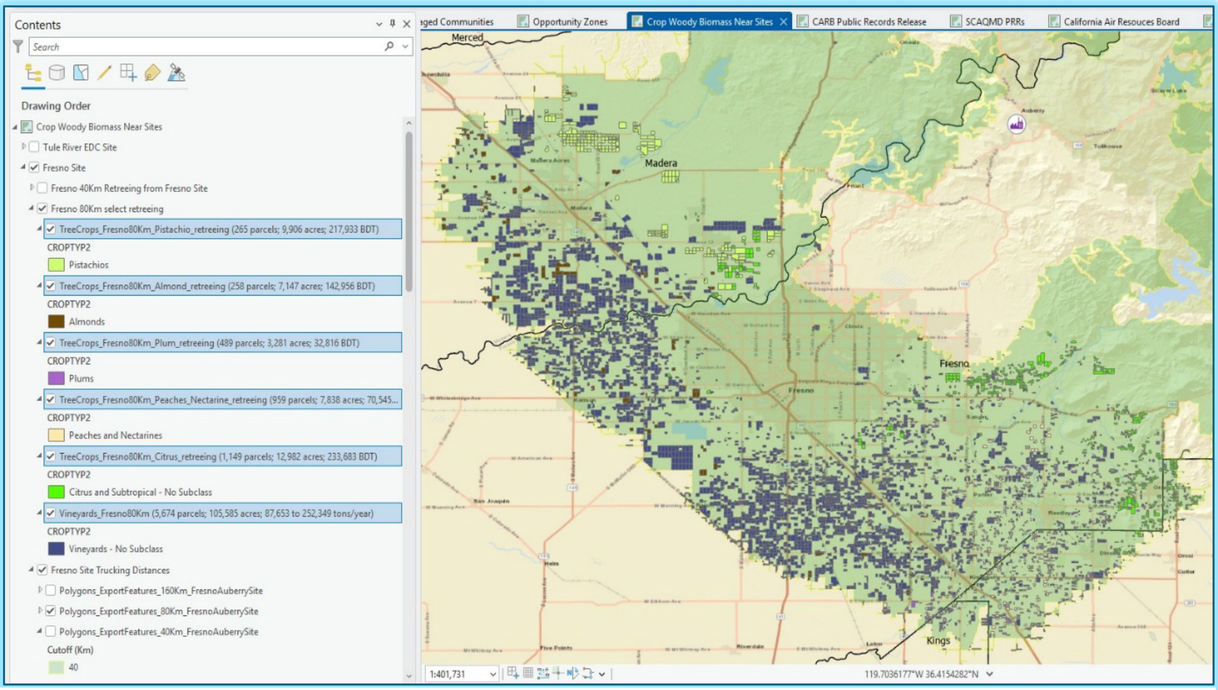

Figure 7. Fresno 80 km re-treeing: pistachios, almonds, plums, peaches nectarines, citrus and vineyard trimmings.

tenfold. Vineyards dominate the recurring residue stream: 5,674 parcels covering 105,585 acres yield87,635–252,349 tons per year of pruning and hedging biomass under low-high yield assumptions (0.83–2.39 tons/acre/yr). Among re-treeing biomass, almonds are the largest end-of-life resource, supported by extensive post-2000 plantings (e.g., a 2016 cohort >20,000 acres), with pistachios and walnuts also providing significant future supply. Overall, the 80-km inventory represents hundreds of thousands of acres in rotation, supplying a continuous, multi-decadal source of woody residues (~9–25 BDT/acre) that can materially supplement forest residues for a commercial FT renewable diesel supply chain [57–60].

3.6.1.3 Municipal Solid Waste (MSW)

Fresno County generates ~1.5 million tons of MSW annually with an estimated 50–60% organic fraction, creating an RDF and organics stream that can provide low-cost, or potentially negative-cost feedstock via tipping fees and methane-avoidance credits, consistent with California's SB 1383 diversion mandate [57–59]. FT-RD is well-suited to heterogeneous lignocellulosic and MSW feedstocks, provided preprocessing and syngas cleanup address contaminants [24, 60]. The feedstock framework incorporates three replicable elements for other regions:

(1) Treatment-driven supply linked to planned restoration activities rather than opportunistic residue collection.

(2) Aggregation and preprocessing infrastructure (staging, chipping, moisture control) to stabilize supply and reduce haul inefficiencies.

(3) Multi-jurisdiction coordination across SRA and FRA lands, with collaboration where applicable with tribal entities and private landowners.

3.6.2 Renewable Diesel Market and Infrastructure Alignment

Renewable diesel (RD) is fully compatible with California's existing diesel infrastructure, allowing transport, storage, blending, and use without modifications. Fresno County lies within a diesel-intensive corridor, where agriculture, food processing, freight, and heavy-duty equipment rely heavily on compression-ignition engines.

For many of these applications, near-term electrification is limited by energy density, duty cycles, and charging infrastructure. This existing diesel dependence positions RD as a low-risk, near-term decarbonization option, minimizing market-adoption barriers compared with fuels or technologies that require new fueling infrastructure or specialized vehicles.

3.6.2.1 U.S. and California Renewable Diesel Market Scale

U.S. renewable diesel capacity has expanded rapidly and is concentrated in coastal and Gulf refining and logistics regions. As of January 1, 2025, total U.S. renewable diesel and other biofuels plant capacity is 4,718 million gallons per year (MMgal/yr; 308 Mb/d). Capacity is largest in PADD 3 (Gulf Coast: 2,129 MMgal/yr; 139 Mb/d), followed by PADD 5 (West Coast: 1,799 MMgal/yr; 117 Mb/d), indicating that the West Coast is already a major renewable diesel production and logistics region.

Within PADD 5, California accounts for 1,684 MMgal/yr of capacity, concentrated in large-scale facilities in the Bay Area and Southern California (e.g., Rodeo: 767 MMgal/yr; Martinez: 731 MMgal/yr), and additional capacity in Bakersfield and Paramount **(Table 2)**. This existing scale is relevant to Fresno because it implies a mature downstream ecosystem for renewable diesel handling, including terminals, blending, and distribution. These conditions reduce offtake and market integration risk for early biomass-to-liquids deployments [61]. The distribution of capacity also supports the commercialization logic of integrating FT intermediates with existing terminal integration[35].

3.6.3 Feedstock-Linked Co-Benefits and Policy Relevance

For Fresno County, the case for FT-RD is strengthened by co-benefits that are directly linked to feedstock selection and can influence permitting, funding competitiveness, and potential value of environmental credit:

- ***Wildfire risk reduction and air quality***

Converting forest residues into fuels, rather than open burning, pile burning, or unmanaged decomposition, supports hazardous fuel reduction strategies and can reduce localized emissions from residue management. The 2020 Creek Fire (~380,000 acres) illustrates the scale of wildfire impacts in the region, including significant emissions and acute $PM_{2.5}$ exposure in Fresno [62]. Within a project framework, FT-RD can serve as (i) a demand anchor for fuels-reduction biomass and (ii) a pathway that reduces reliance on higher-emitting residue management practices [63].

- ***MSW diversion and methane avoidance***

Where MSW is integrated, diversion and methane-avoidance benefits can strengthen the overall climate value proposition and may enhance credit value, depending on accounting boundaries and policy structures [24, 25, 38]. These benefits are most robust when paired with enforceable diversion requirements and credible feedstock specification and control strategies [24, 57, 58].

Table 2. U.S. Renewable Diesel Fuel and Other Biofuels Plant Production Capacity as of January 1, 2025 [61].

Location	Respondent	Production capacity (MMgal/yr)
Hugoton, Kansas	Seaboard Energy Kansas LLC	85
Dickinson, North Dakota	Dakota Prairie Refining LLC	192
Wynnewood, Oklahoma	CVR Renewables WYN LLC	121
Norco, Louisiana	Diamond Green Diesel LLC	982
Geismar, Louisiana	REG Geismar LLC	108
Norco, Louisiana	Shell Oil Products U.S.	54
Chalmette, Louisiana	St Bernard Renewables	307
Artesia, New Mexico	HF Sinclair Renewables Holding Co LLC	141
Port Arthur, Texas	Diamond Green Diesel LLC	537
Great Falls, Montana	Montana Renewables LLC	184
Cheyenne, Wyoming	Cheyenne Renewable Diesel Company LLC	92
Sinclair, Wyoming	Wyoming Renewable Diesel Co.	117
Bakersfield, California	Bakersfield Renewable Fuels LLC	138
Bakersfield, California	Kern Oil & Refining	6
Rodeo, California	Phillips 66 Co.	767
Martinez, California	Martinez Renewables LLC	731
Paramount, California	Altair Paramount LLC	42
Blaine, Washington	BP Products North America	111
Tacoma, Washington	US Oil & Refining Co.	5

3.6.4 Alignment with De-Risked Commercialization Pathways

DOE guidance consistently emphasizes that early biomass-to-liquids deployments can reduce risk by separating front-end conversion from final upgrading. In this model, FT intermediate (e.g. wax or Syncrude blend stock) is produced at or near biomass conversion sites and subsequently co-processed in existing refinery assets (e.g.

FCC units and hydrocrackers). This approach reduces greenfield upgrading CAPEX and improves overall project bankability [35]. DOE peer-review summaries report successful FCC co-processing at ~20–40% FT wax co-feed with demonstrated incorporation of biogenic carbon into finished fuels [35].

For Fresno, this "distributed-depots plus refinery-upgrading" architecture is particularly relevant given California's existing refining and terminal infrastructure and established fuel distribution systems.

The Sierra Tribal Energy (Auberry) concept—planned at ~90,000 BDT/yr with an estimated $164 million capital cost—provides a regional example consistent with depot-oriented approach. More broadly, blending and co-processing strategies support commercialization in two keyways:

(1) Refinery co-processing of FT intermediates, which can reduce CAPEX and accelerate deployment timelines [35]

(2) Terminal blending of finished FT-RD into diesel pools, enabling flexible logistics and specification compliance during market entry [23, 31].

3.6.5 Policy Alignment Supporting Bankability

FT-RD economics are strongest where both (i) low-carbon fuel credit value and (ii) resilience and waste-related co-benefits can be monetized. California's Low Carbon Fuel Standard (LCFS) and federal mechanisms such as the Renewable Fuel Standard (RFS), 45Q (where applicable), and IRA-related incentives, are widely recognized as critical enablers for thermochemical drop-in fuels during early-stage deployment [24]. In addition, public funding rationales linked to wildfire resilience, air quality improvement, and environmental justice align closely with the WPIC framework. These policy drivers can support blended financing approaches and public–private partnership models, improving overall project bankability and facilitating early deployment.

4. SITING ANALYSIS FRAMEWORK FOR WPIC

For a forest biomass–to–Fischer–Tropsch (FT) renewable diesel project, facility location is a primary determinant of financeability, permissibility, and operability, not simply the presence of biomass resources. Across the bioenergy siting literature, the dominant factor is the delivered feedstock system, including availability, spatial distribution, accessibility, and hauling cost. This reflects the physical characteristics of biomass, which is bulky, dispersed, and costly to transport [64–67].

In California, siting must also address regulatory feasibility (including CEQA and air permitting), wildfire exposure, water availability, and community impacts. These factors can significantly affect project timelines, capital costs, and overall implementation risk [68–70].

Within the California Wood Products Innovation Campuses (WPIC) framework, siting is therefore not solely a cost-minimization exercise. It is a strategic process aimed at enabling a replicable campus model that can: (i) anchor long-term forest-residue utilization, (ii) connect suppliers, service providers, and infrastructure, (iii) support workforce and training, and (iv) reduce permitting and development risk for near-term deployment [70, 71].

4.1 Screening Method: Multi-Criteria Decision Analysis (MCDA)

A defensible statewide siting analysis follows a transparent, multi-step workflow combining (1) geospatial screening, (2) weighted suitability mapping, and (3) logistics/economic verification. This hybrid approach is widely applied in forest biomass siting and aligns with best practices in the literature [64, 66, 67, 71, 72].

A harmonized geodatabase – using consistent projection and resolution – was developed to integrate biomass supply, transportation networks, infrastructure, environmental constraints, and socio-economic and environmental justice indicators [70–72]. Non-buildable and high-conflict areas (e.g., protected lands, wetlands, floodplains, steep slopes) were excluded, while permitting-sensitive zones were retained and flagged for later risk scoring.

Remaining buildable areas were evaluated using standardized criteria scaled from 0 to 1 and weighted using structured methods such as Analytic Hierarchy Process (AHP) or Best–Worst Method (BWM) [73, 74]. Weighted overlay methos were applied to generate composite suitability scores, offering a transparent and auditable framework that can be updated as stakeholder priorities evolve [71, 72].

High-scoring candidate sites were then validated through transportation-cost modeling and, where appropriate, location-allocation or mixed-integer linear programming (MILP) optimization. These steps confirm that selected sites can support target throughput at economically viable delivered feedstock costs [64, 67, 75, 76].

4.2 Proposed Siting Criteria for California Biomass Innovation Campuses

Feedstock-related criteria are designed to capture both the magnitude and spatial distribution of available biomass resources, while ensuring long-term operability aligned with forest-resilience and fuel reduction programs [69–71, 77]. These criteria reflect the central role of sustained, treatment-linked biomass supply in supporting commercially viable WPIC deployments.

4.2.1 Forest Residue Availability

Delivered feedstock cost is typically the primary feasibility constraint for commercial FT renewable diesel systems. Accordingly, a site is unlikely to be financeable unless sufficient residues can be secured within an economically viable haul radius [66, 72, 76]. Forest residue availability was quantified using the C-BREC biomass layer for 2025 under a 40% thin-from-below treatment scenario (TFB_40) (**Figure 8**) [42–45]. The C-BREC dataset reports biomass density in bone-dry tons per acre (BDT/ac). A statewide 70-mile-radius fishnet overlaid on the raster, and zonal statistics were calculated for each polygon. Total forest residue availability within each sourcing shed was computed derived using the zonal sum (area-weighted aggregation of BDT per acre across pixels, converted to total BDT using pixel area where required).

"…a site is unlikely to be financeable unless sufficient residues can be secured within an economically viable haul radius."

To support integration into the weighted overlay MCDA, availability values were normalized to a 0–1 suitability scale using min–max normalization:

$$s_j = \frac{X_j - X_{\min}}{X_{\max} - X_{\min}}$$

where X_j is total forest residue availability (BDT) for zone j. Zones with zero biomass were retained with a suitability score of $s_j = 0$.

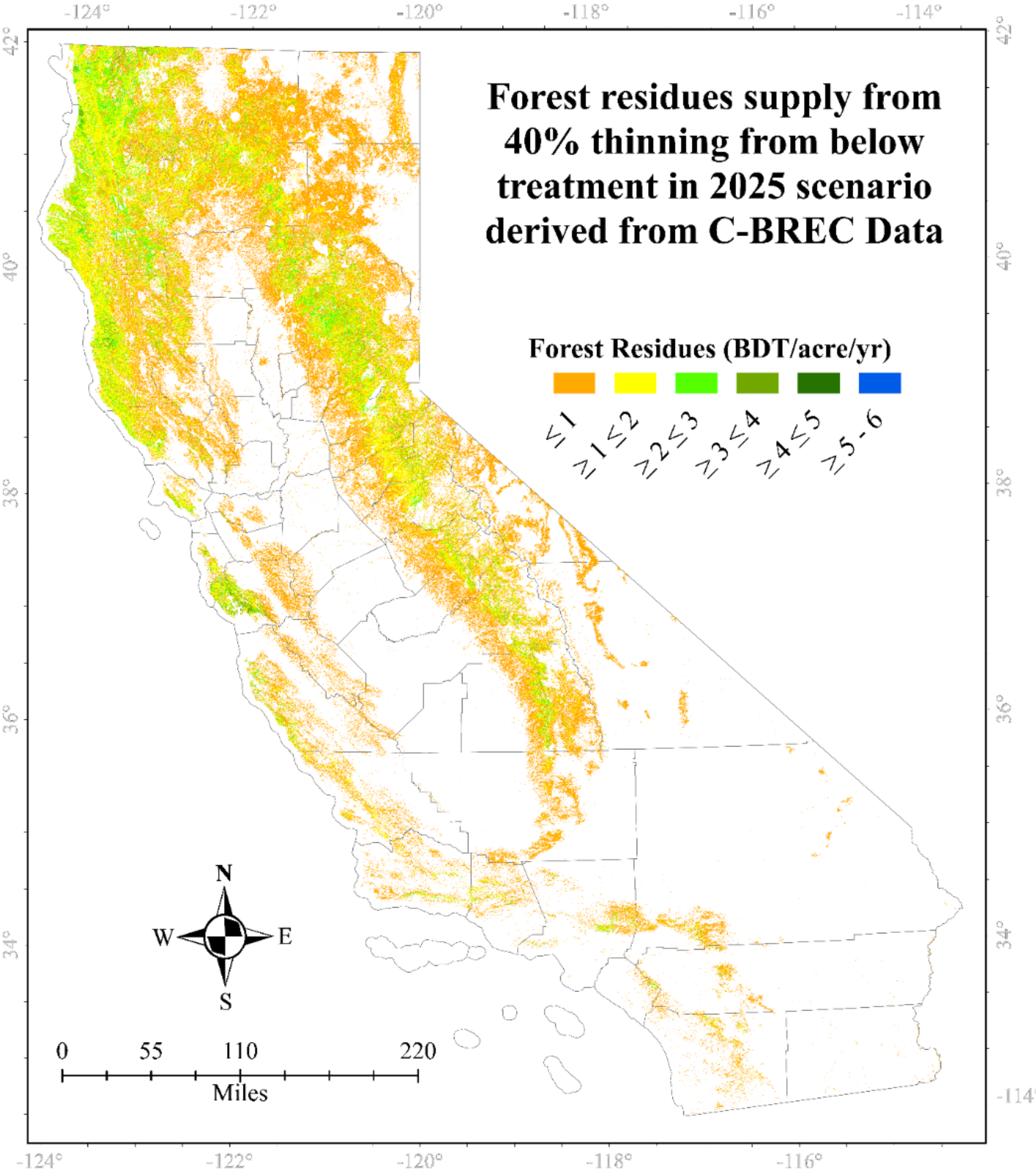

Figure 8. Spatial distribution of modeled forest biomass availability generated under the 40% thin-from-below (TFB_40) treatment scenario (2025).

4.2.2 Feedstock Density (Clustering)

In addition to total supply, the spatial concentration of biomass is a key determinant of delivered cost and operational reliability. High-density clusters reduce collection effort and transportation distances, support depot-based aggregation strategies, and improve procurement consistency— factors that are critical for a replicable Innovation Campus model [67, 71].

Clustering was quantified using a hotspot-based statistic derived from the same 70-mile-radius fishnet zonal framework, using the 90th percentile biomass density (PCT90) within each polygon — representing high-yield areas—was used as the primary metric (**Figure 9**). Higher PCT90 values indicate that a greater share of biomass is concentrated in fewer, high-density locations, thereby reducing logistics complexity and improving supply reliability.

For integration into the MCDA framework, the clustering metric was normalized to a 0–1 suitability scale using the same min–max normalization. It was evaluated as a distinct criterion from total availability to

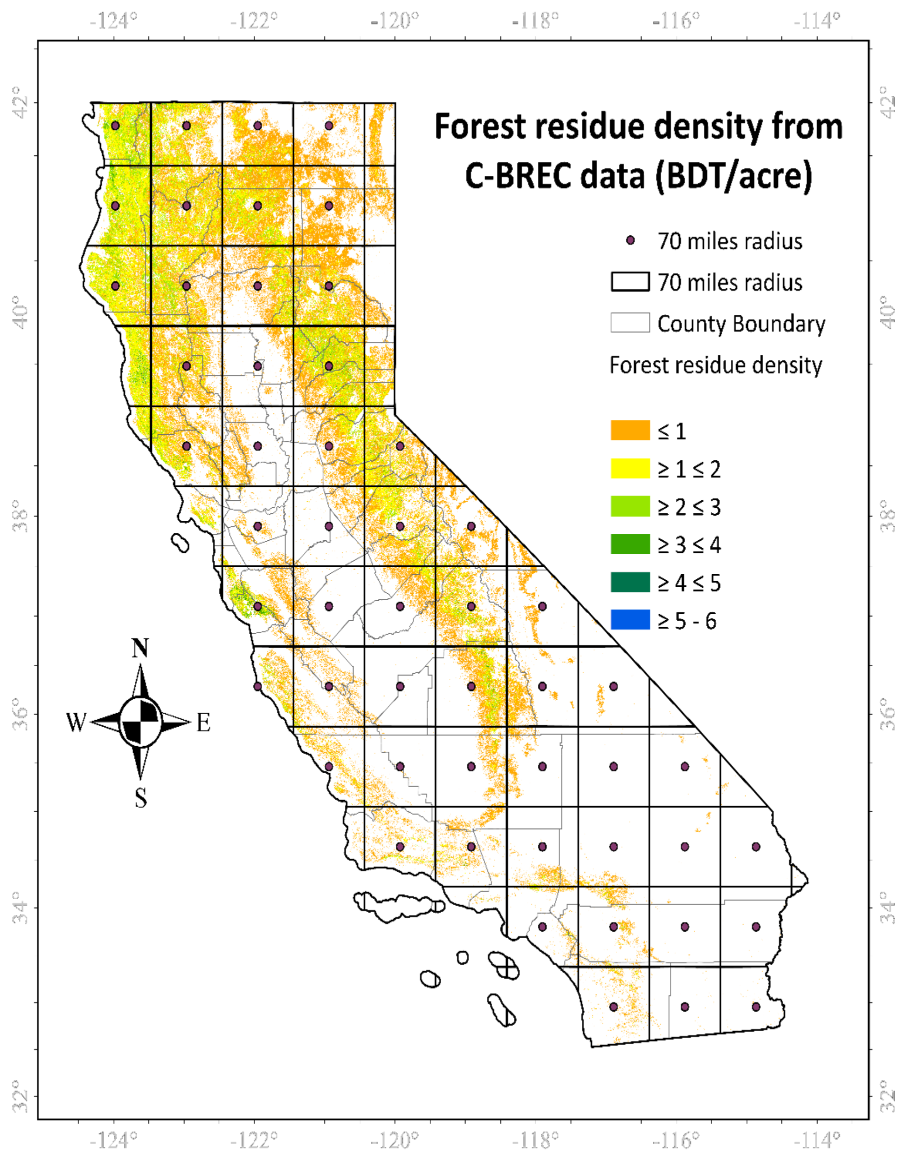

Figure 9. Spatial clustering forest residue density within 70-miles sourcing radius.

differentiate between overall resource magnitude (“how much biomass exists”) and spatial concentration (“how efficiently it can be collected and delivered”).

4.2.3 Sustainable Treatment Alignment

Aligning biomass procurement with designated treatable areas supports long-run operability, strengthens sustainability claims, and links project development to established to forest-resilience programs [64, 78]. Treatable areas were identified using the California Vegetation Treatment Program (CalVTP) PEIR web map [79]. The dataset was converted to a raster and reclassified into a binary mask (treatable = 1; non-treatable = 0). This mask was then applied within each 70-mile-radius sourcing shed to quantify the share of biomass located in treatable areas (e.g., treatable supply fraction or treatable BDT) **(Figure 10)**. The resulting alignment metric was incorporated as a siting criterion to prioritize locations where biomass availability is consistent with treatment eligibility and programmatic implementation constraints.

4.2.4 Transportation and Logistics

Because biomass is bulky and costly to transport, logistics are a primary determinant of delivered feedstock cost and overall plant scale feasibility [67, 76, 77]. The transportation domain was evaluated using proximity-based GIS metrics designed to: (i) represent least-cost haul potential along the road network, and (ii) capture access to high-capacity freight corridors, as well as optional rail or intermodal infrastructure.

Consistent with OR-SAGE screening approaches for biomass systems, logistics were assessed using a “preferred near or feasible far” framework, which prioritizes sites with proximity to transportation infrastructure while retaining flexibility for locations that remain viable under longer-distance haul scenarios.

4.2.4.1 Road Network Proximity

Because biomass logistics often dominate delivered feedstock cost and constrain feasible plant scale, road access was included as a primary transportation siting criterion [67, 76, 77]. The U.S. Census Bureau MAF/TIGER road network (primary and secondary roads) [80] was used to represent trucking access. A Euclidean distance-to-road surface was computed in GIS to evaluate proximity. Candidate areas were then screened using a 10-mile distance threshold: locations within ≤10 miles of the road network were classified as suitable for facility siting (assigned a value of 1), while locations beyond 10 miles were excluded (assigned 0) (**Figure 11**). This binary road-access layer ensures that candidate sites have practical proximity to truck routes required for inbound biomass delivery and outbound product transport.

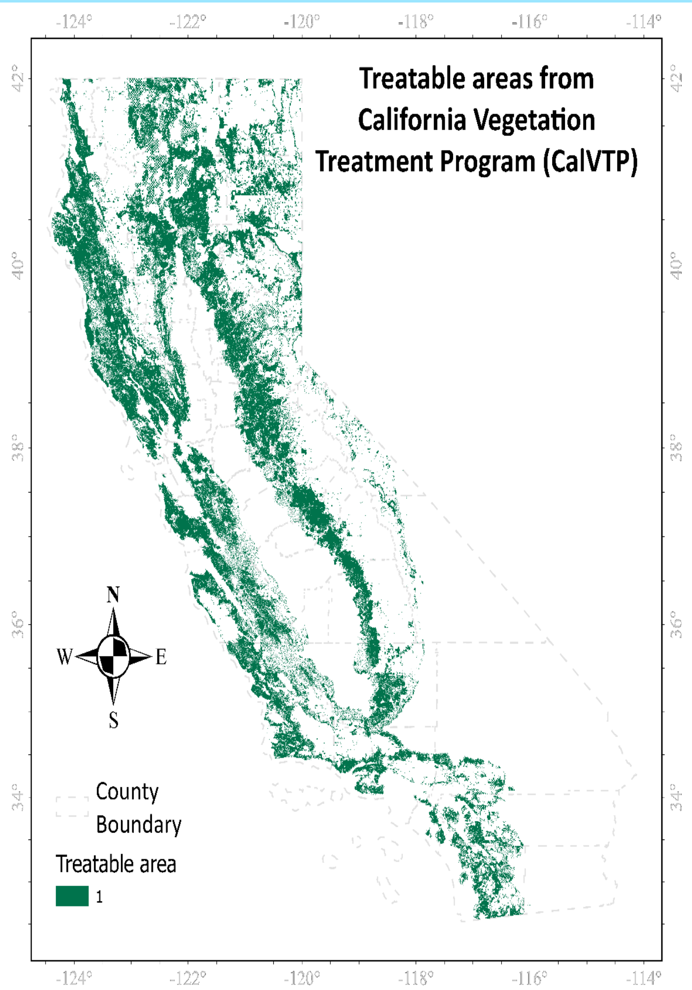

Figure 11. Spatial distribution of treatable forest areas eligible for commercial thinning under CalVTP guidelines.

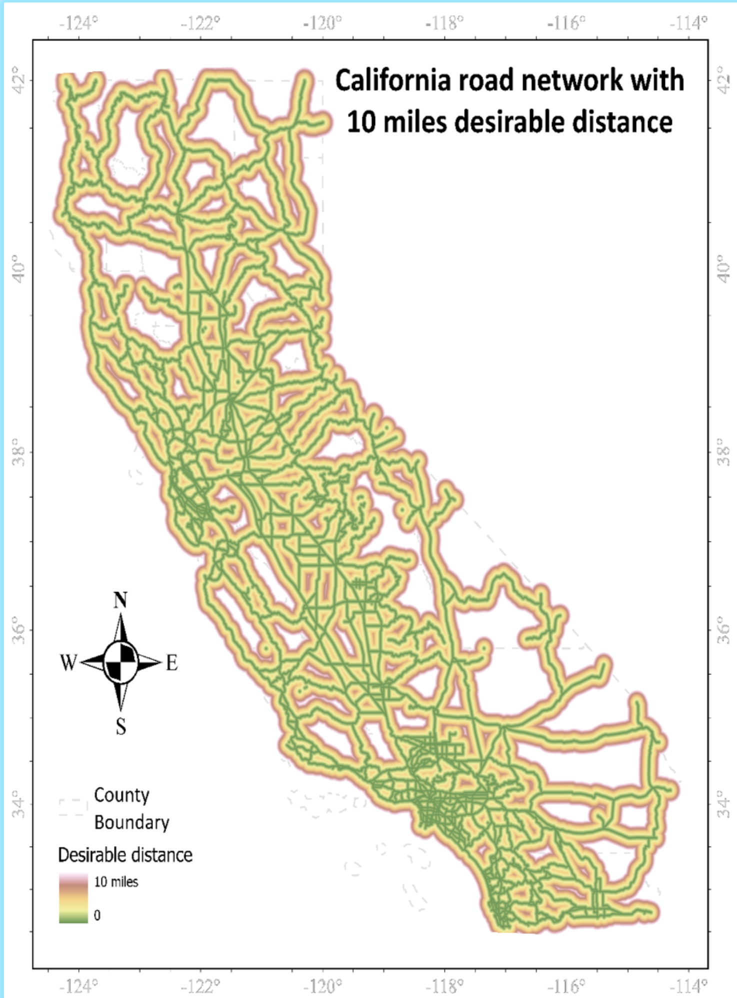

Figure 10. Major road network in California with 10-miles proximity buffer used for transportation screening.

4.2.4.2 Rail or Intermodal Proximity

Rail access was included as an optional, logistics-enabling criterion, as proximity to rail infrastructure can reduce outbound transportation constraints and support campus-scale cluster-based logistics strategies [71]. The California Rail Network dataset (Caltrans) [81] was used to represent rail infrastructure. A Euclidean distance-to-rail surface was computed in GIS to assess proximity. Locations within ≤10 miles of the rail network were classified as suitable (assigned a value of 1), while locations beyond 10 miles were excluded (assigned 0) (**Figure 12**). This binary rail-access layer identifies sites with potential access to alternative freight modes, which can enhance logistics flexibility and support future scaling or integration with regional supply chains.

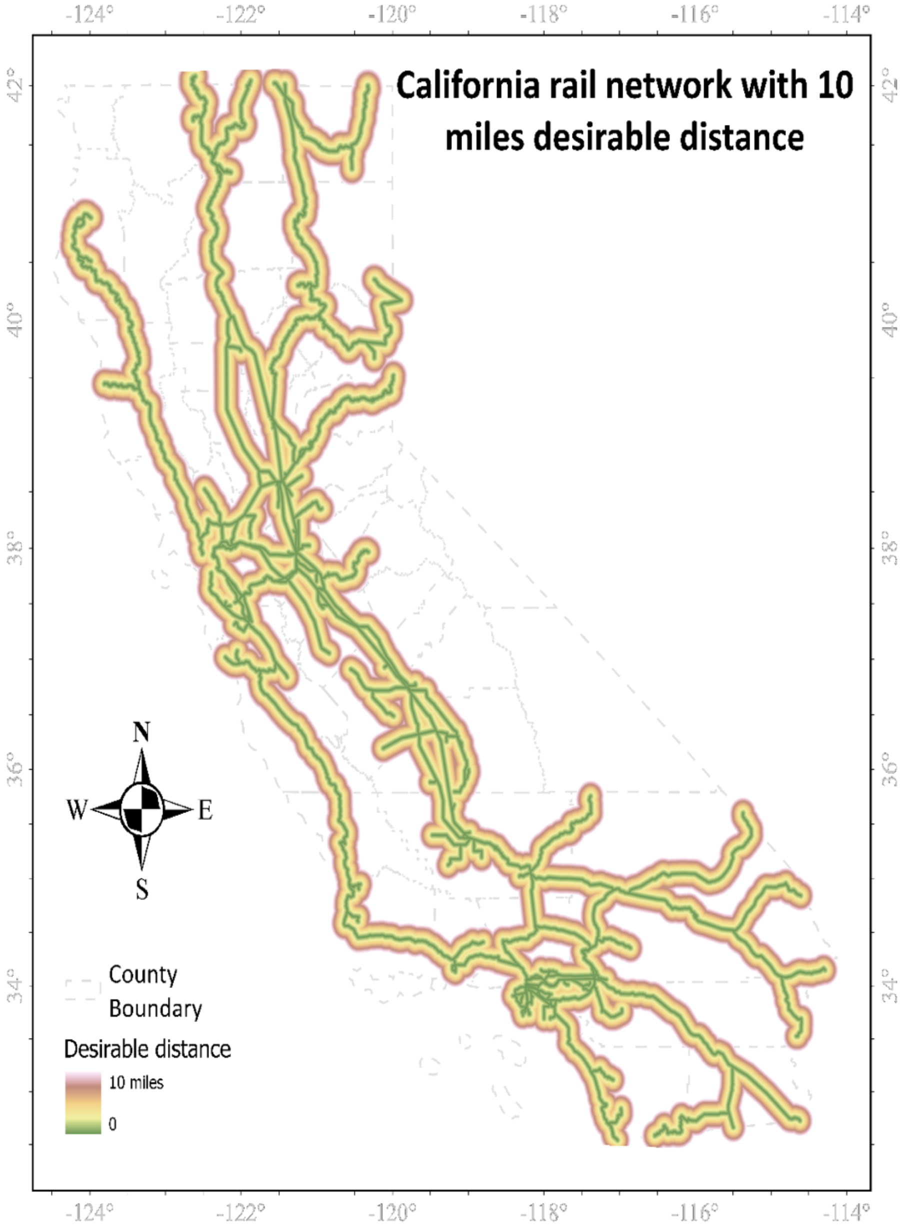

Figure 12. California rail network with a 10-miles proximity buffer.

4.2.4.3 Forest Motor Vehicle Routes

Forest road accessibility is a critical factor for efficient residue recovery and transport. To capture this, the U.S. Forest Service Motor Vehicle Use Map (MVUM) roads layer was used, which identifies National Forest System routes open to motorized vehicles under the Travel Management Rule (36 CFR 212.56) [82]. A Euclidean distance-to-MVUM surface was generated, and areas within 2 miles of MVUM-designated roads were classified as suitable for biomass transportation (assigned a score of 1), while areas beyond 2 miles were considered as less

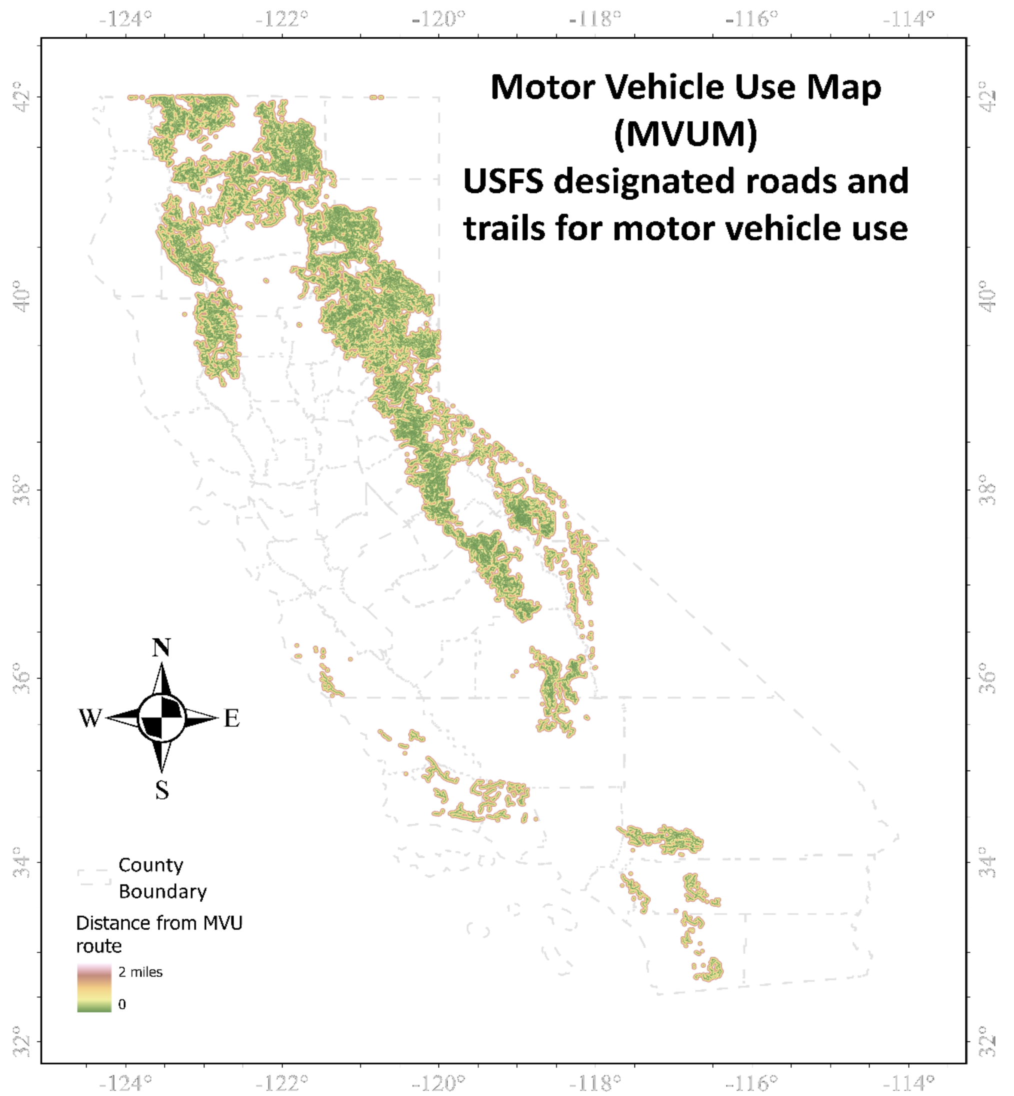

Figure 13. USFS MVUM showing designated motorized roads and trails for biomass access.

suitable (assigned 0) (**Figure 13**). This criterion helps prioritize candidate site location with practical access to biomass supply areas and reduced collection and haul constraints. forest biomass, minimizing collection effort and haul costs.

4.3.5 Infrastructure and Built Capital

4.3.5.1 Land Use Compatibility

The biomass innovation campus siting requires industrial land with expansion potential and minimal land-use conflicts. Land-use compatibility was assessed using the California General Plan land-use dataset (January 2024) [66, 78] [83], which reflects adopted local planning designations and provides statewide basis for identifying parcels suitable for industrial biofuel infrastructure.

A binary suitability mask was generated by reclassifying land-use categories as suitable (1) or unsuitable (0). Suitable categories included Industrial, Low Density Commercial, Open Space, Planned Development, Very Low Density Residential, and Other—areas with existing or planned industrial activity or low land-use conflict. Excluded categories included Agricultural Land, High Density Commercial, all other residential, Urban Reserves, and Water Bodies (assigned 0) (**Figure 14**). This approach protects agricultural land, minimizes community conflict, and avoids areas with major development constraints.

4.3.5.2 Grid Access: Transmission and Substation Proximity

Access to reliable electricity is a critical infrastructure criterion for biomass gasification–to–Fischer–Tropsch (FT) renewable diesel systems. Key plant components, including the air separation unit (ASU), syngas compression and cleanup systems, pumps and blowers, plant controls, and balance-of-plant utilities, depend on continuous power. Proximity to existing transmission lines and substations reduces interconnection costs, minimizes schedule risk, and enhance operational reliability, all of which are important considerations for project bankability [69, 71, 72, 84, 85].

For siting analysis, the statewide electrical transmission network was mapped [86], and a Euclidean distance-to-grid surface was generated in GIS. Areas within 10 miles of transmission infrastructure were classified as suitable (assigned a value of 1), while areas beyond 10 miles were classified as unsuitable (assigned 0) (**Figure 15**). This binary suitability layer highlight locations where grid access supports practical and cost-effective deployment of an Innovation Campus facility.

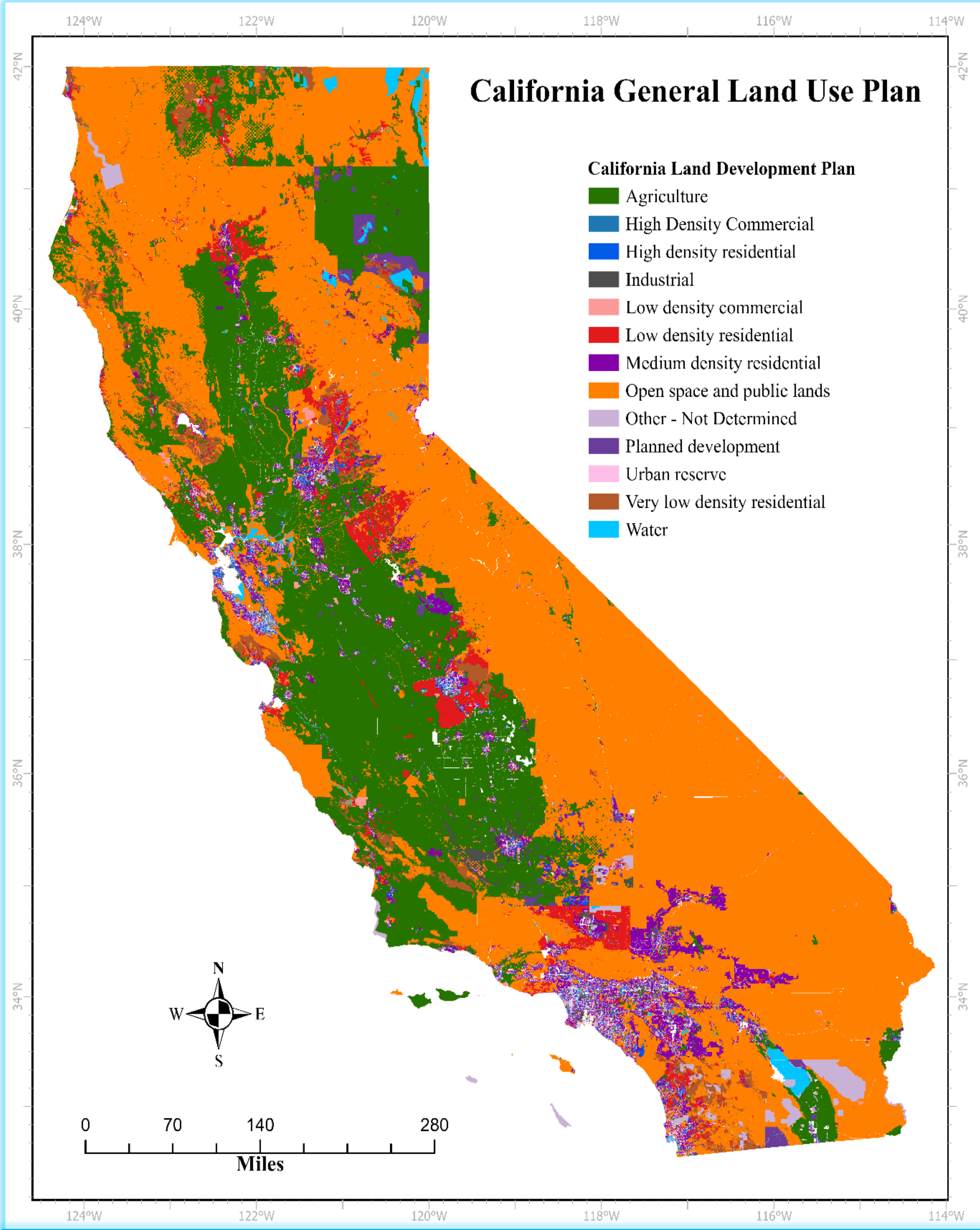

Figure 14. Land use suitability mask *for* biofacility siting, highlighting areas included (suitable) and excluded (unsuitable) from analysis.

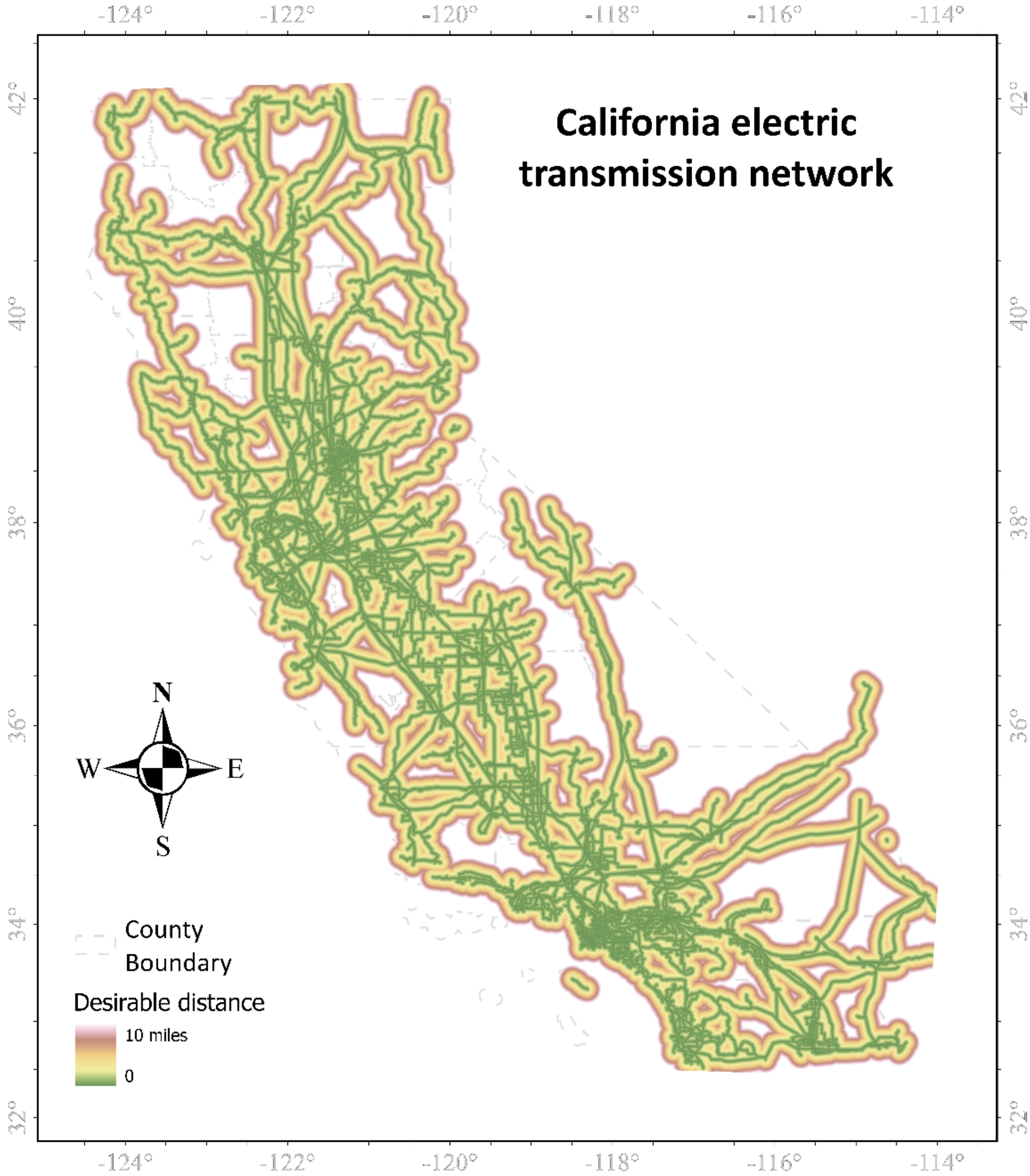

Figure 15. California electric transmission network and areas within 10 miles of existing infrastructure suitable for Innovation Campus siting.

4.3.5.3 Water Supply and Wastewater Access

Access to reliable water supply and wastewater discharge was included as a core infrastructure criterion because thermochemical gasification–to–Fischer–Tropsch (FT) renewable diesel facilities require process and cooling water, as well as permitted wastewater management. In California, limited water availability can pose significant schedule, permitting and cost risks [69, 72]. To evaluate this, the California Drinking Water System Area Boundaries dataset [87] was used as a proxy for water-service accessibility. A Euclidean distance-to-water-service surface was generated in GIS, and areas within 2 miles of a drinking water system boundary were classified as suitable (assigned a value of 1), while areas beyond 2 miles were classified as unsuitable (assigned 0) (**Figure 16**). This approach prioritizes sites with feasible utility connections, reducing potential development delays and cost exposure.

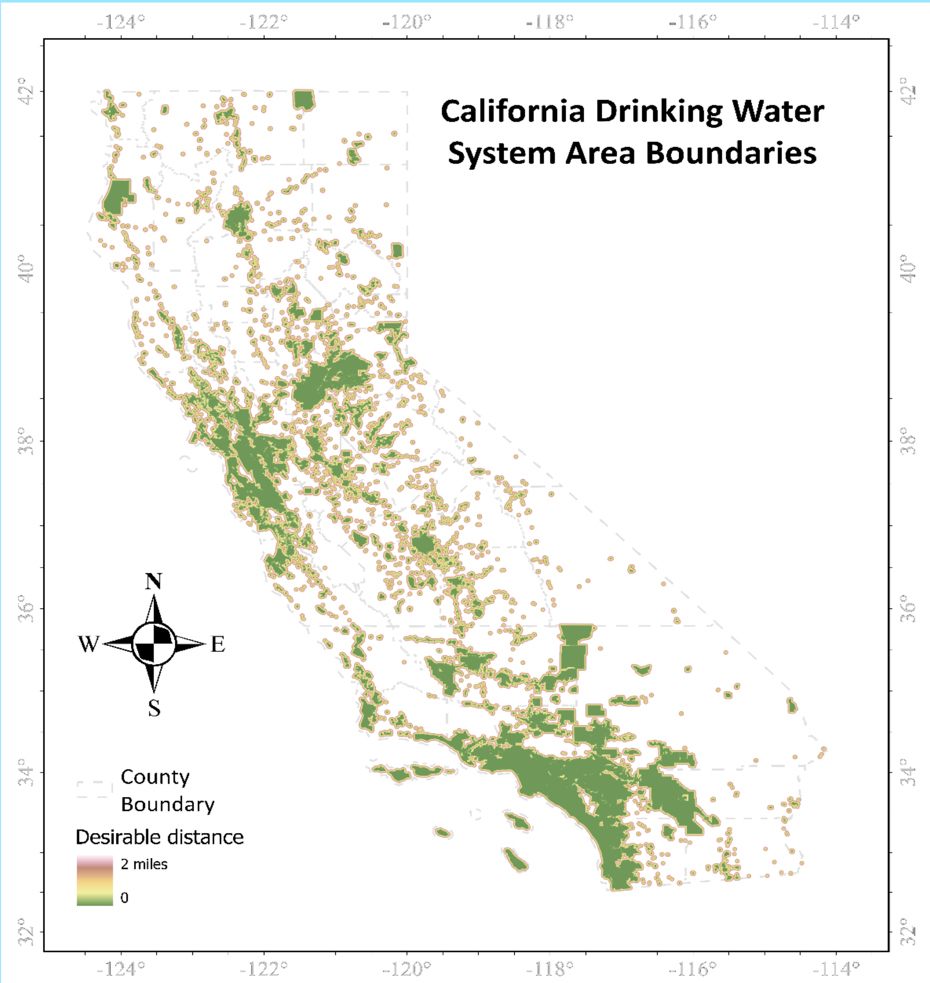

Figure 16. California drinking water service areas used to assess suitability for industrial biofuel facility siting

4.3.5.4 Repurposing Potential: Mills, Industrial Sites, and Brownfields

Repurposing existing industrial sites can shorten development timelines, reduce greenfield civil and utility costs, and improve overall bankability. This approach aligns with the innovation campus concept of leveraging existing wood-products infrastructure and regional industrial ecosystems [70, 71]. To assess repurposing and co-location potential, statewide point data were compiled for bioenergy facilities and sawmills from the 2025 Wood Utilization Group inventory [88]. Facilities were categorized as Operational, Active Development/Proposed, or Closed/Idle/Cancelled to capture both active industrial anchors and legacy sites that may retain transferable assets (e.g., industrial zoning, utility interconnections, access roads). Sawmill proximity was also included as an indicator of potential access to mill residuals (e.g., sawdust, shavings) and a supporting supplier/service ecosystem.

This criterion was implemented as a binary proximity indicator (not a graded surface): a Euclidean distance raster was generated from all bioenergy and sawmill locations, and cells within 10 miles of any listed site were classified as suitable for repurposing/co-location potential (assigned 1), while cells beyond 10 miles were classified as not suitable under this criterion (assigned 0) (**Figure 17**). The 10-mile threshold was selected to represent a practical radius for shared

infrastructure access, workforce and services proximity, and short-haul transfer of mill residuals within a campus-style clustering strategy.

4.3.5.5 Refinery Proximity as a Strategic Siting Factor

Proximity to existing refineries and petroleum terminals was included as a strategic siting criterion because it directly supports a key de-risking commercialization approach for biomass-to-liquids projects: producing FT intermediates (e.g., FT wax or Syncrude blend stock) near biomass depots and leveraging existing refinery upgrading and distribution infrastructure. Access to these assets can reduce greenfield upgrading requirements, lower capital expenditures, and improve bankability and deployment speed [75]. Facility locations were obtained from the California Energy Commission Oil Refineries and Terminals dataset (California Office of Emergency Services GIS Data Manager; July 2, 2019) [89], which includes refineries, tank farms and oil terminals used for storage, transfer and processing of petroleum products. A Euclidean distance-to-refinery and terminal surface was generated, and areas within 20 miles of an existing refinery, terminal, or depot were classified as strategically favorable (assigned a value of 1), while areas beyond 20 miles were classified as less favorable (assigned 0) (**Figure 18**). This criterion identifies locations with direct access to established upgrading and fuel logistics hubs, supporting efficient handling, upgrading, blending, and distribution of FT intermediates and finished renewable diesel.

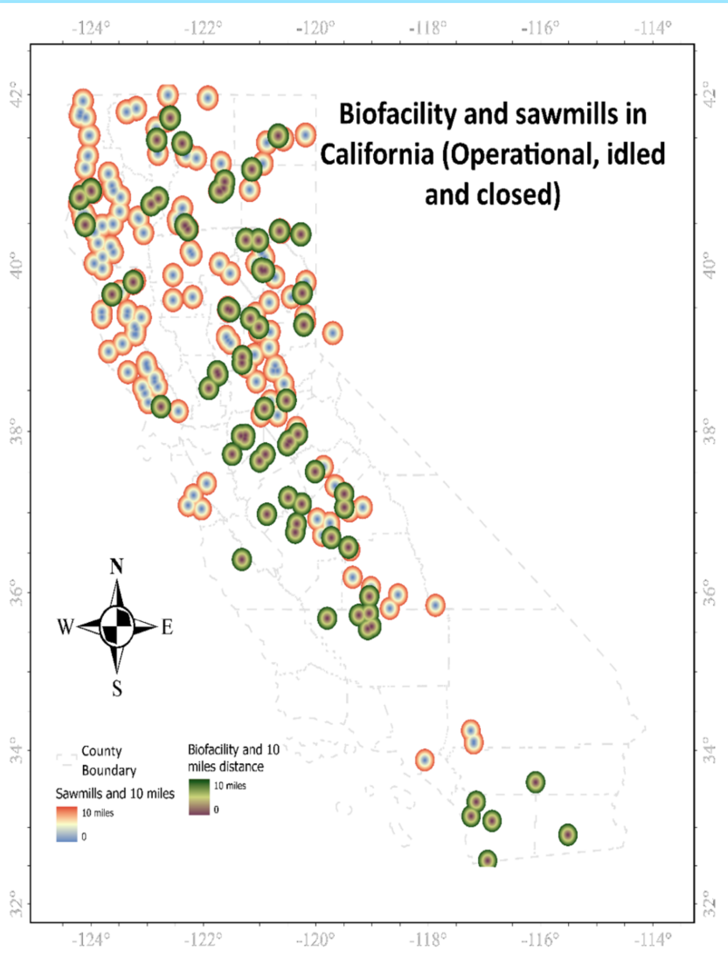

Figure 17. Location of existing bioenergy facilities and sawmills, including active, idled and closed sites.

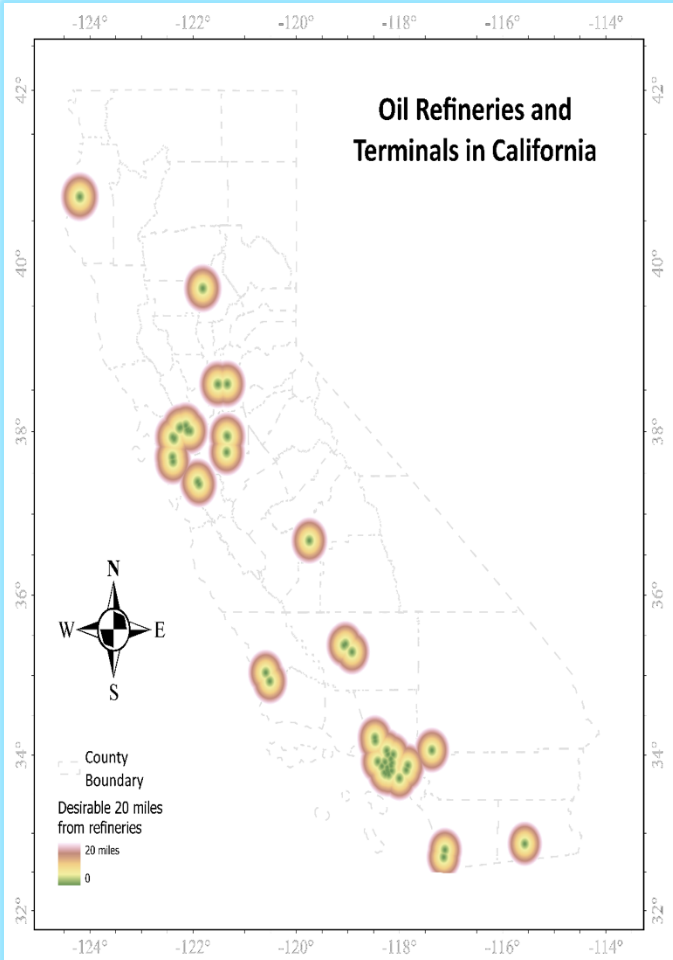

Figure 18. California refineries and petroleum terminals with a 20-mile strategic proximity radius.

4.3.6 Environmental and Regulatory Feasibility

4.3.6.1 Protected Lands and Sensitive Habitat Exclusions

Protected lands were treated as a fatal-flaw criterion because locating large thermochemical facilities within these areas can create insurmountable permitting conflicts and compromise ecological protection goals. Excluding protected lands is standard practice in bioenergy siting analysis [66, 78].

Protected areas were delineated using the California Protected Areas Database (CPAD), the authoritative statewide GIS inventory of parks and protected open-space lands managed by public agencies and non-profit organizations (GreenInfo Network) [90]. CPAD polygons were used as an exclusion mask: all designated protected areas were classified as unsuitable for facility siting (assigned a value of 0) and removed from the buildable land set prior to MCDA scoring (**Figure 19**). This conservative approach was applied regardless of access designation (Open, Restricted, No Public Access, or Unknown), to ensure avoidance of sensitive habitats and protected open-space areas.

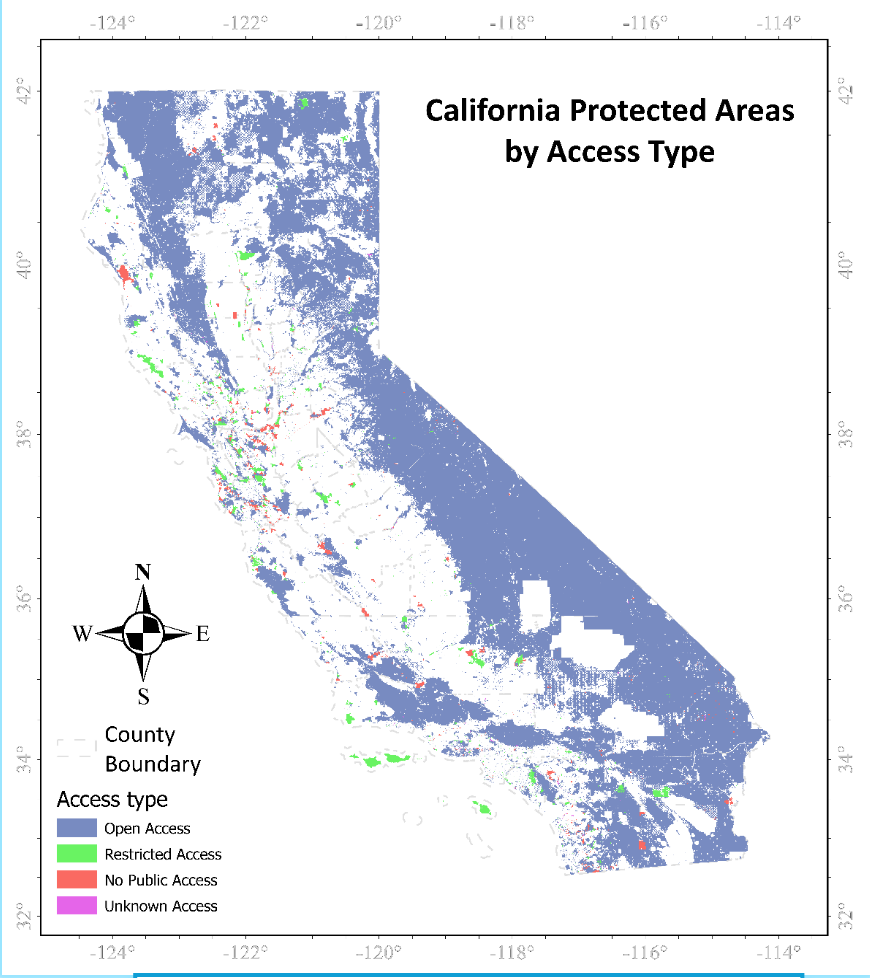

Figure 19. Protected and restricted-access areas—including public and private parks—excluded from facility siting analysis.

4.3.6.2 Slope and Terrain Thresholds

Slope was included as a key terrain feasibility criterion because steep slopes increase construction complexity, earthwork, safety risks, hauling costs, potentially constraining operations [66, 67].

Using 30-m U.S. Geological Survey (USGS) elevation data [91], a slope raster was generated, and areas were classified using a conservative threshold: slopes under 12.5° were considered suitable for facility siting (assigned a value of 1), while slopes of 12.5° or greater were excluded (assigned 0) (**Figure 20**). This approach ensures that candidate sites are technically feasible and aligned with long-term project reliability and cost-efficiency objectives.

4.3.7 Hydrology Proximity Screen (Floodplains, Wetlands, and Water Buffers)

Hydrologic constraints were incorporated to avoid high-risk parcels, minimize potential flood damage, reduce impacts to wetlands, and limited mitigation and permitting obligations, in line with standard bioenergy siting practice [66, 78].

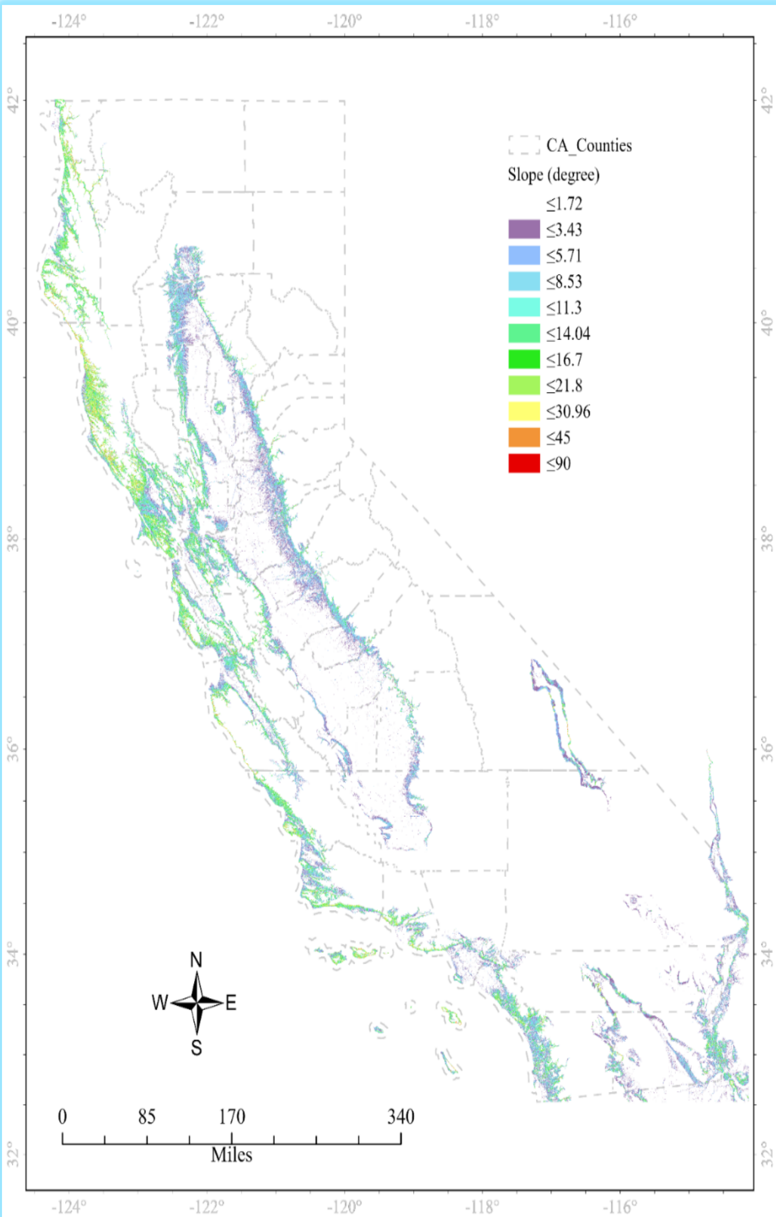

Figure 20. Terrain slope in California, with areas steeper than 12.5 degree excluded from facility siting analysis

4.3.7.1 California Flood Hazard Areas

Flood exposure was assessed using the National Flood Hazard Layer (NFHL) for California, specifically the S_Fld_Haz_Ar feature class (version November 29, 2023). To ensure consistency with FEMA and Esri representations and optimize GIS performance, non-informative designations (e.g., “Area Not Included,” “Open Water,” “D,” “NP,” and NoData) and Zone X (Area of Minimal Flood Hazard) were removed. Remaining flood hazard polygons, including both 1% and 0.2% annual chance flood zones, were aggregated into standardized classes consistent with Esri Living Atlas symbology.

For siting purposes, flood-prone areas were treated as a fatal-flaw constraint. Polygons were converted to a raster and reclassified so that all flood hazard zones were assigned 0 (unsuitable for biofacility development), while areas outside mapped flood hazard zones were retained as potentially developable (**Figure 21**).

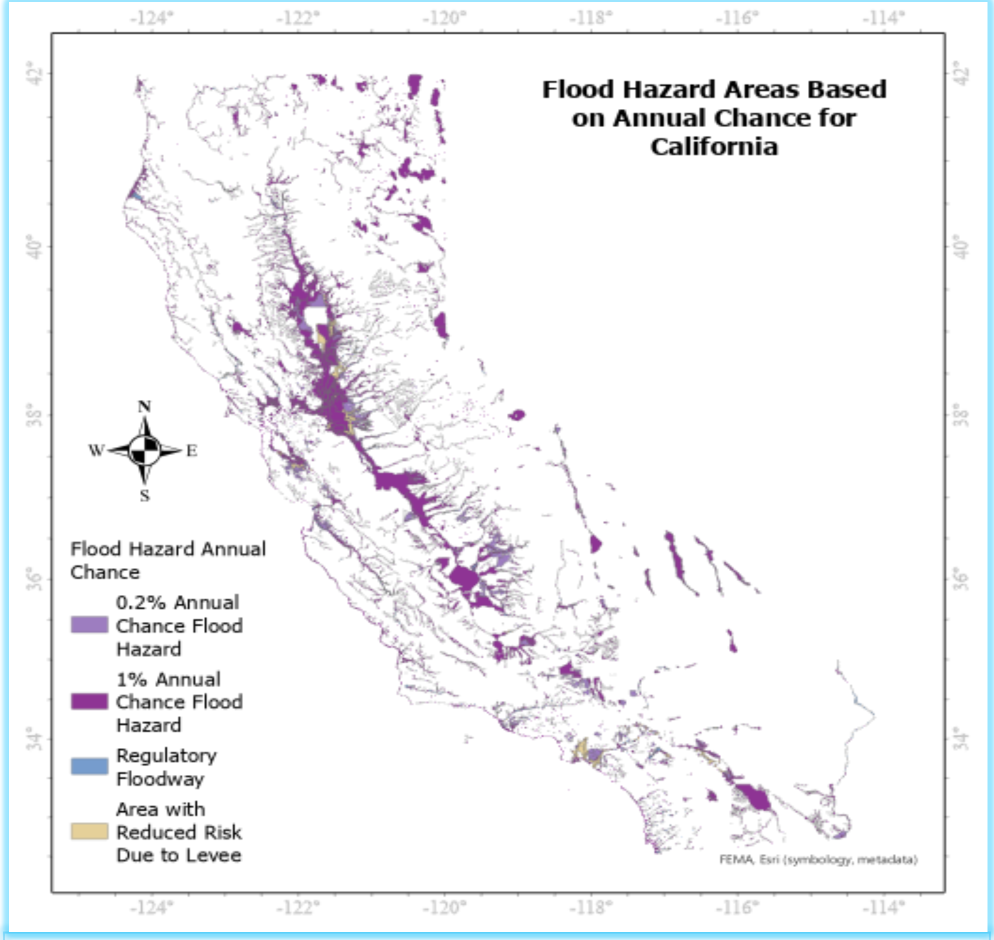

Figure 21. California flood hazard *layer:* areas in 1% and 0.2% annual chance zones excluded.

4.3.7.2 Proximity to Streamflow

Proximity to surface-water features was included to support process and cooling water for a thermochemical gasification–to–Fischer–Tropsch (FT) facility. Following the OR-SAGE siting guidance [92], sources within 100 miles are feasible, with a preference for sites within 20 miles to enable closed-cycle cooling. Using the U.S. Geological Survey High-Resolution National Hydrography Dataset (NHD) [93, 94], the stream network was converted to a 30-m raster, and a Euclidean distance-to-stream surface was generated. Areas within ≤2 miles of a mapped stream were classified as suitable (assigned a value of 1), while areas beyond 2 miles were classified as unsuitable (assigned 0) (**Figure 22**). This threshold-based screen prioritizes sites with practical surface-water access while accounting for regional water constraints.

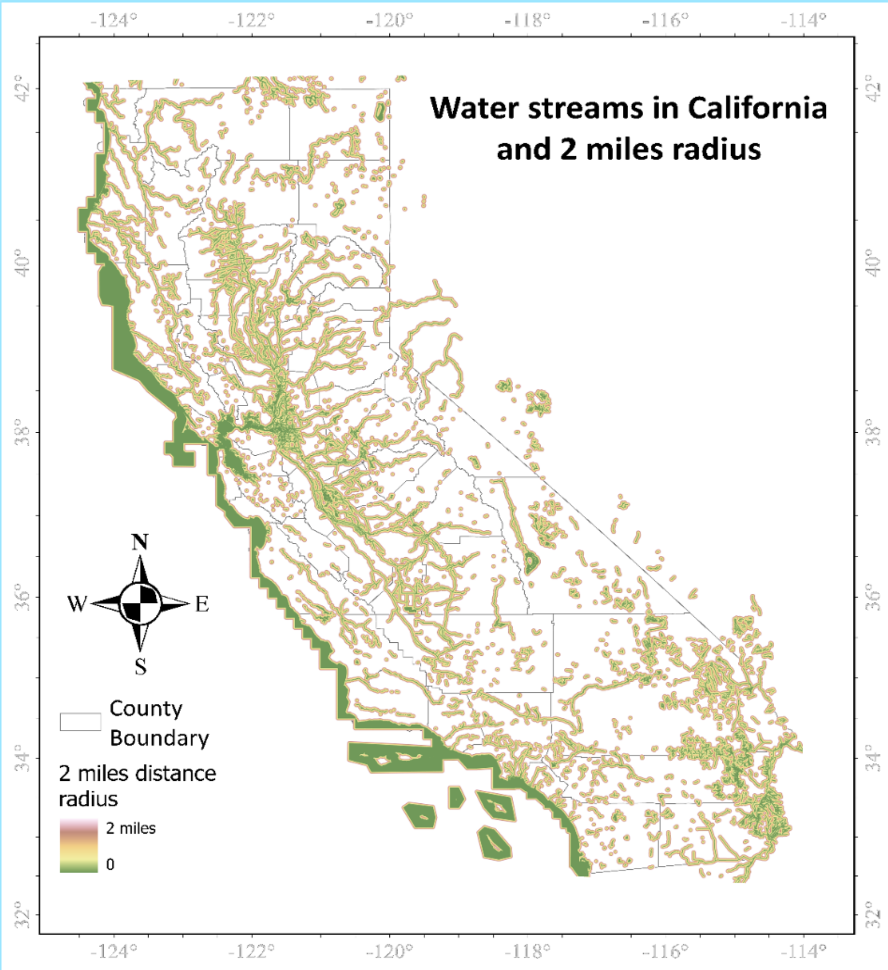

Figure 22. California surface-water streams with a 2-mile proximity buffer.

4.3.7.3 Proximity to Sedimentary Basins in California

To maintain optionality for future carbon management, such as integration carbon capture and storage (CCS) into a biomass-to-–Fischer–Tropsch (FT) facility, proximity to geologic CO_2 storage resources was included as a screening criterion. Consistent with OR-SAGE siting logic, saline sedimentary basins should ideally be located within roughly 150 miles of a facility to support cost-effective CO_2 transport and storage. [92].

Saline sedimentary basin polygons were obtained from Brennan et al. [95] and a Euclidean distance-to-basin surface was generated to classify candidate locations by proximity. Areas located within 20 miles of a mapped sedimentary basin were treated as highly desirable or suitable for biofacility (assigned a value of 1), reflecting higher technical feasibility and lower expected CO_2 transport barriers (**Figure 23**). This early-stage screening prioritizes locations where CCS deployment is more plausible, supporting deeper lifecycle emissions reduction potential and improving eligibility for carbon management incentives if CCS is pursued during later phases of the project.

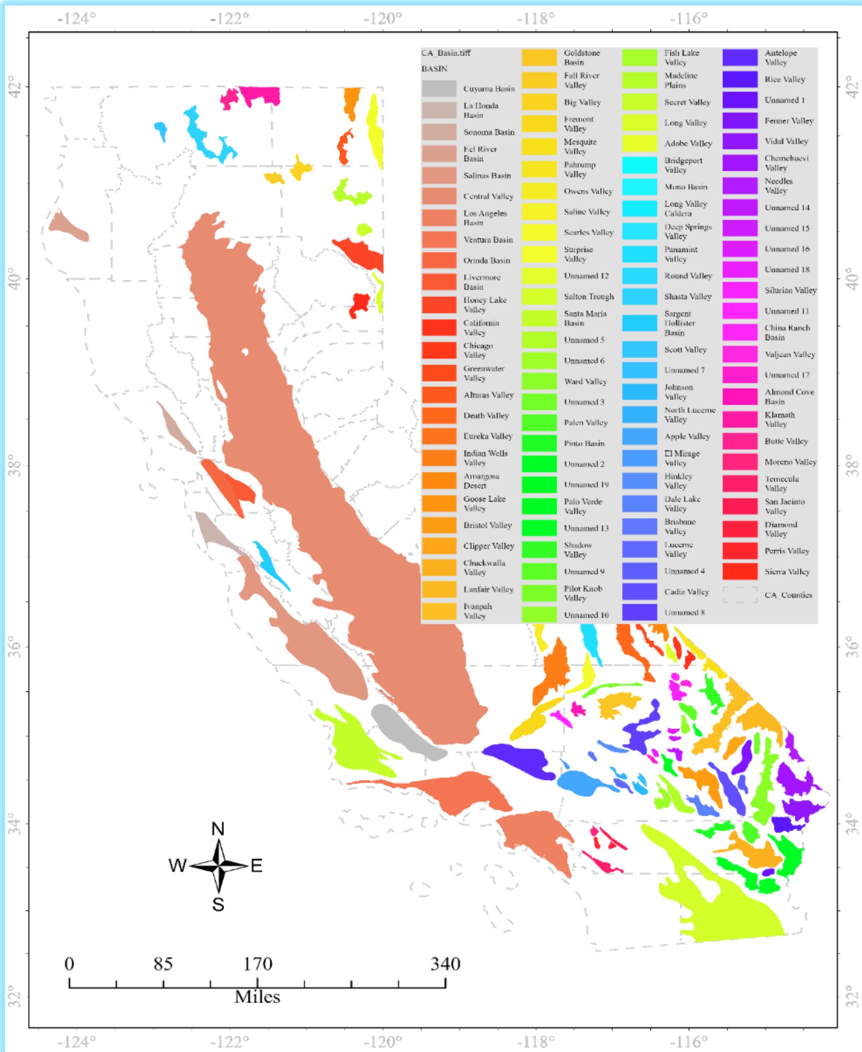

Figure 23. California sedimentary basins showing areas with potential suitability for geologic CO_2 storage [93].

4.3.8 Social and Environmental Justice Alignment

4.3.8.1 Community Vulnerability to Pollution Burden

Environmental justice (EJ) considerations were included because cumulative pollution exposure and community vulnerability can affect project feasibility, including permitting complexity, community acceptance, and alignment with equity-focused public-financing objectives [70]. EJ vulnerability was quantified using CalEnviroScreen 4.0 (CES 4.0), the California Office of Environmental Health Hazard Assessment (OEHHA) census-tract screening tool [96] that evaluates communities based on combined indicators of environmental exposures, environmental effects, sensitive populations, and socioeconomic factors. Higher CES scores indicate higher cumulative burden and vulnerability. In the CES 4.0 dataset, Fresno County ranks highest with a score of 93.18, followed by San Joaquin (86.65) and Los Angeles (82.39). The lowest-burden counties include Marin (1.03), San Mateo (1.10), and Contra Costa (1.25). These values contextualize the statewide burden gradient; the siting model uses tract-level normalized scores.

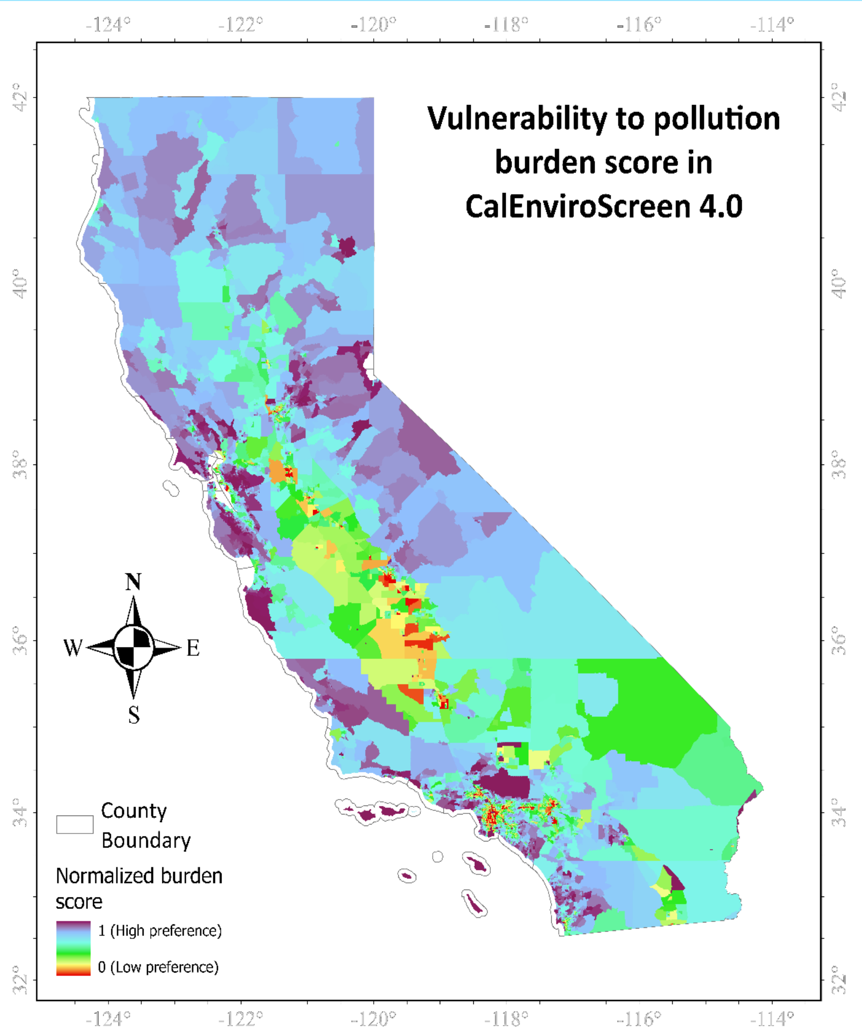

Figure 24. California census-tract vulnerability to pollution burden (CalEnviroScreen 4.0).

CES 4.0 scores were joined to census-tract geography and incorporated as an inverse suitability criterion, so that lower-burden areas receive higher siting priority. Scores were normalized to a 0–1 scale with the highest-burden tracts near 0 and the lowest-burden tracts near 1 (**Figure 24**).

4.3.8.2 Air Basin Nonattainment or Permitting Sensitivity

Air-permitting feasibility is a critical siting consideration because locating new industrial processing facilities within California air basins that already have nonattainment designations can significantly increase emissions-control requirements, extend permitting timelines, and elevate implementation risk. Early identification of nonattainment areas ensures that potential siting conflicts are addressed proactively rather than discovered late in development [69, 73].

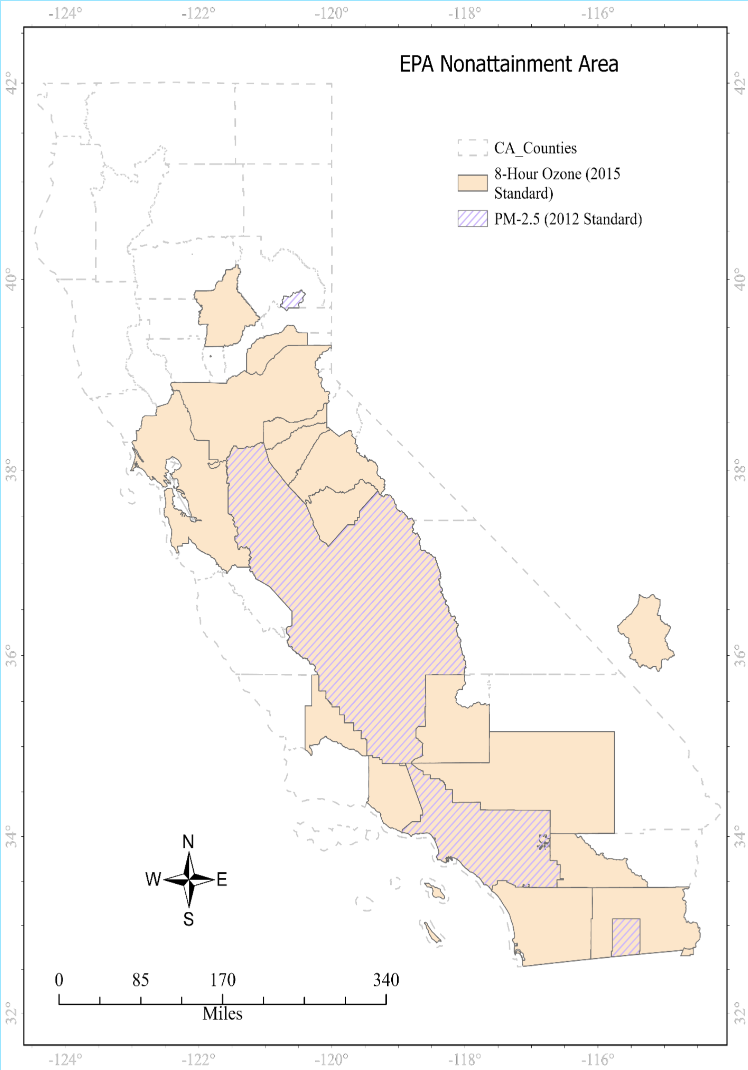

Figure 25. U.S. EPA–designated nonattainment areas for $PM_{2.5}$ and ozone in California [101].

Following OR-SAGE siting guidance, a fatal-flaw screening layer was applied using the U.S. EPA Green Book nonattainment boundaries. The analysis focused on areas designated as nonattainment for 8-hour ozone (2015 standard) and $PM_{2.5}$ (2012 standard) [101]. Candidate locations within these polygons were classified as unsuitable (assigned 0) and excluded from the siting analysis (**Figure 25**). This approach ensures that proposed facilities avoid regions with heightened regulatory constraints and public-health concerns, thereby reducing air-permitting risk during site selection.

4.3.8.3 Wildfire Hazard Potential (WHP)

Wildfire exposure was included as a siting criterion because high wildfire hazard increases development risk, affecting construction and operations, raises insurance and financing costs, and can disrupt year-round biomass logistics. Wildfire risk was quantified using the Wildfire Hazard Potential (WHP) index developed by the USDA Forest Service. WHP maps the relative likelihood of high-intensity wildfire that are difficult to manage, integrating burn probability (from the FSim large-fire simulator), expected fire intensity (flame length), vegetation and fuels (e.g., LANDFIRE), and topographic factors. WHP does not represent structure vulnerability.

Data were sourced from Scott et al. [98]. To incorporate wildfire risk into the siting model, WHP values were converted to an inverse 0–1 suitability score, where the maximum WHP value (85,758) was assigned 0 (not suitable) and the minimum value (0) was assigned 1 (most suitable) using inverse min–max normalization (**Figure 26**). This approach prioritizes locations with lower wildfire hazard, supporting safer and more resilient Innovation Campus siting.

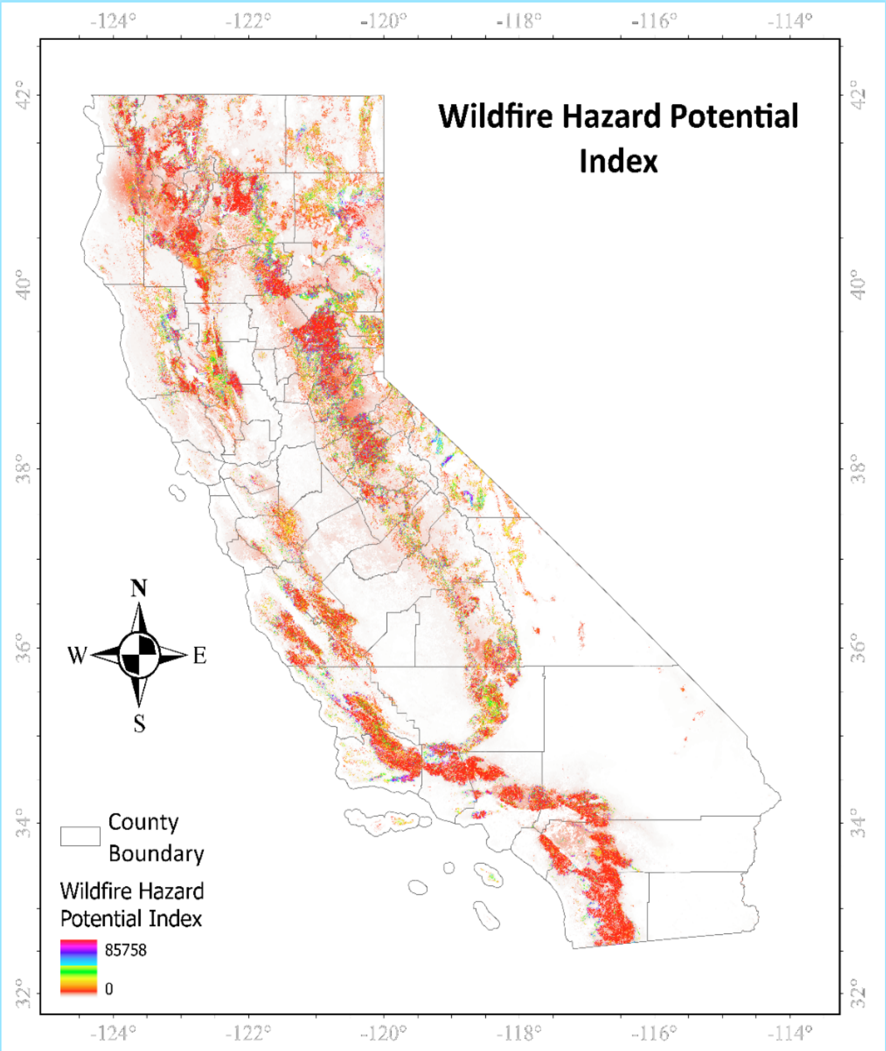

Figure 26. Wildfire Hazard Potential Index.

4.3.9 Population Density and Community Impact Screening

To minimize potential community impacts and land-use conflict, population density was included as a social siting constraint. Population density was calculated at ~90 m × 90 m resolution using the LandScan USA dataset [99], converting gridded population counts to persons per square mile. A binary exclusion filter was applied: grid cells with population density greater than 500 persons/mi^2 were classified as unsuitable (assigned a value of 0) and removed from consideration, while cells at or below this threshold were retained as suitable (assigned 1) (**Figure 27**).

The screening produces a "suitable area" mask aligned with OR-SAGE-style low-population siting logic, prioritizing locations where a biomass–to–Fischer–Tropsch (FT) renewable diesel facility is less likely to create community exposure concerns or land-use conflicts.

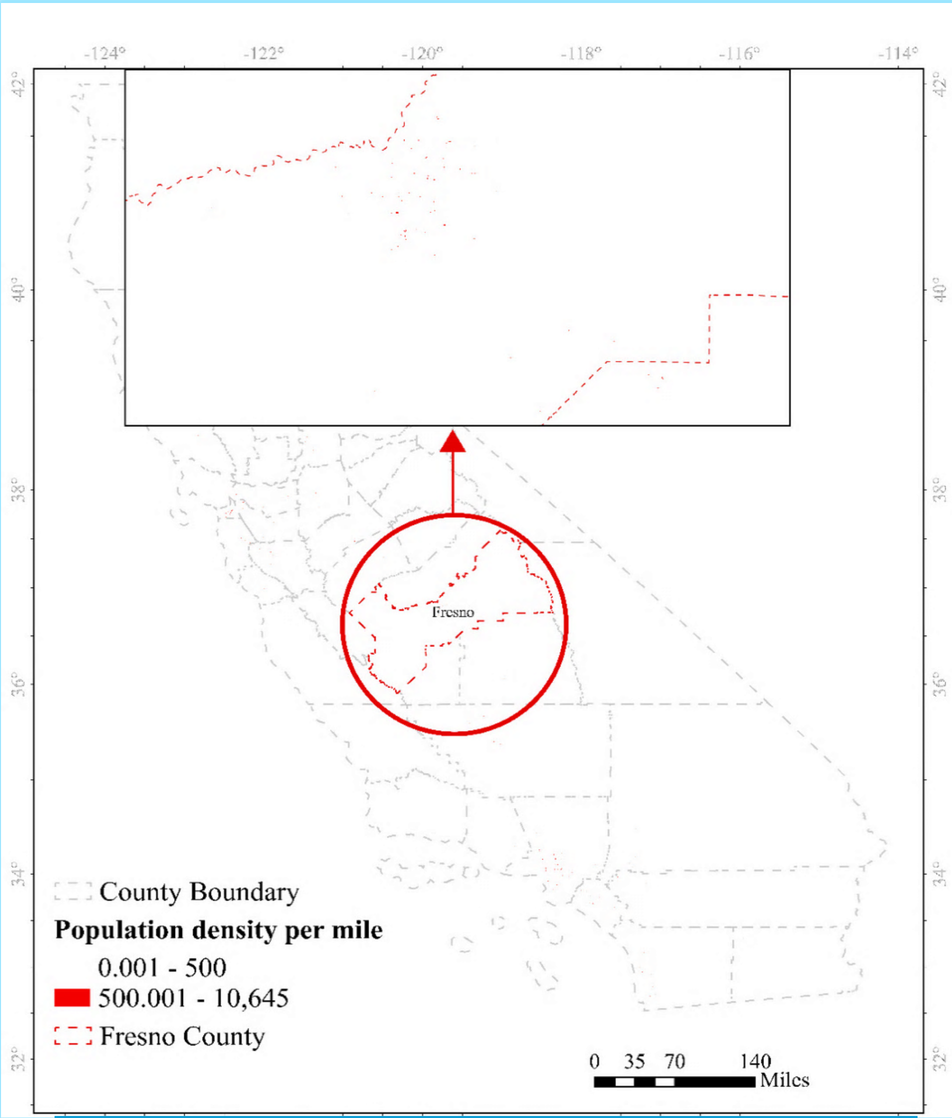

Figure 27. Population density per square miles.

4.3.10 Economic and Workforce Readiness

4.3.10.1 Unemployment Rate (Workforce Availability and Equity Screen)

Workforce readiness was included as a siting criterion because the biomass innovation campus model depends on local labor availability and the ability to deliver measurable employment benefits. County-level labor force and unemployment data were obtained from the California Labor Market Information Division (LMID), which publishes official labor statistics for the state [100]. The most recent reporting month (December 2025, including the survey week of December 12) was used as the baseline workforce snapshot.

Under the December 2025 dataset, Imperial County had the highest unemployment rate (18.60%), while San Mateo County had the lowest (3.50%). For labor market scale context, Los Angeles County had the largest labor force (5,148,900) and Alpine County the smallest (490). The unemployment rate (%) was incorporated as a siting indicator to prioritize locations where new industrial development could address local employment needs. Values were normalized to a 0–1 suitability score using min–max scaling, with higher unemployment rates assigned higher priority (**Figure 28**). This approach ensures that areas with relatively higher unemployment are favored in siting, supporting workforce development and public-benefit objectives.

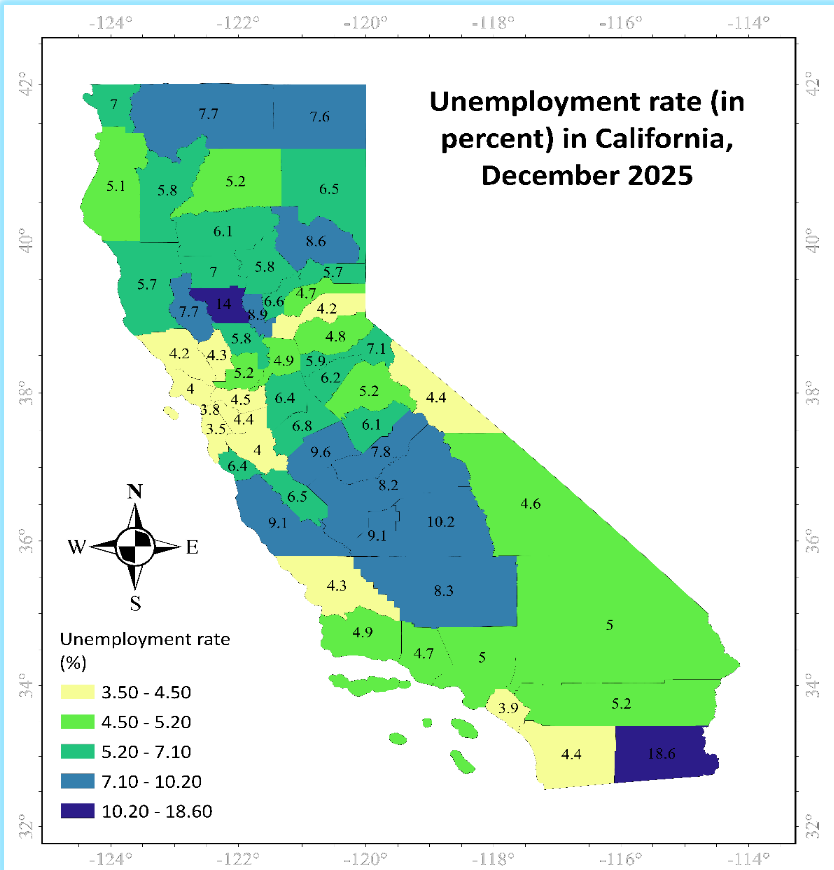

Figure 28. County-level unemployment rates in California, December 2025, used to assess workforce availability and

4.3.10.2 Economic Diversity and Future Resource Stability

Economic resilience was included as a workforce and economic-readiness criterion because long-run project viability depends not only on current labor availability but also on the stability of the surrounding socio-economic system, particularly under increasing climate and disturbance pressures [101].

The Economic Diversity & Value indicator from the Regional Resource Kit (RRK) dataset (PlanScape) provides a standardized, percentile-style index (0–91) ranking each landscape unit relative to all others in California; the index is not a measure of dollars or GDP [102]. This indicator combines multiple normalized socioeconomic variables, including sectoral diversity, employment, income, business diversity, and overall economic output, into a single composite score. Higher values indicate a more diversified and shock-resilient local economy, while lower values i indicate a more diversified, resilient local economy, while lower values indicate greater specialization and higher vulnerability to economic disruption. For siting purposes, the indicator is expressed as a 0–1 suitability score, with higher RRK values assigned higher priority (1 = most suitable, 0 = not suitable) (**Figure 29**).

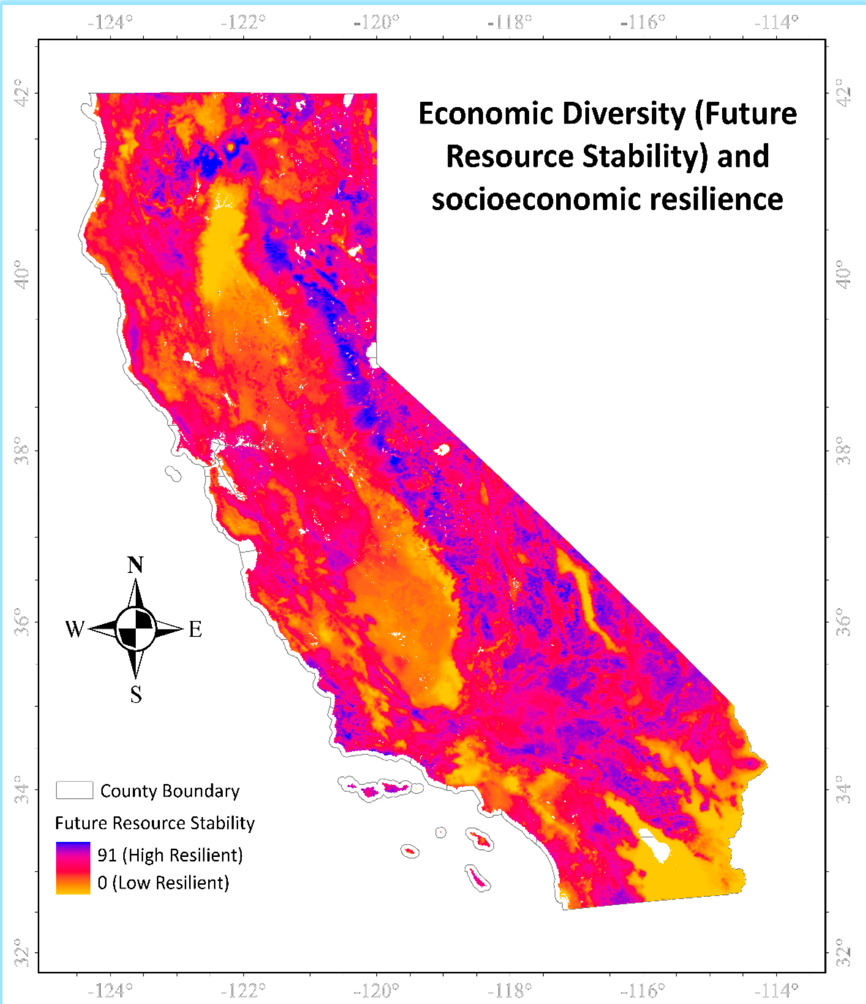

Figure 29. Economic diversity and socio-economic resilience scores.

4.3.11 Composite Suitability Mapping and Candidate Biofacility Site Selection

A statewide suitability analysis was conducted to identify locations most suitable for biofuel facilities by harmonizing 23 siting criteria to a standardized 0–1 scale, where higher values indicate greater suitability. Each criterion was reclassified using literature-based thresholds and data-driven breaks. The standardized layers were combined through an equal-weight additive overlay, generating a composite suitability surface:

$$\boldsymbol{S} = \sum_{i=1}^{n} \boldsymbol{R_i}$$

where R_i is the reclassified score for criterion i and $n = 23$. The resulting composite raster ranged from 2.17 to 14.50, representing cumulative suitability across all factors.

Candidate facility sites were extracted from this surface using a structured GIS workflow designed to identify high-suitability developable land parcels while maintaining geographic distribution. First, the top 10% of suitability values were selected using quantile classification, producing a binary mask of high-suitability cells. Contiguous cells were grouped into discrete patches using an 8-neighbor connectivity approach and converted to polygons. Each polygon was evaluated for area and mean suitability, with patches smaller than 10 hectares excluded to ensure practical site footprints. Centroids of the remaining polygons were ranked by descending mean suitability. A minimum spacing rule of 50 miles was applied sequentially, retaining only centroids at least 50 miles from previously selected sites.

The analysis reveals significant spatial variability in suitability. The highest cumulative values (>14.0) occur in portions of Nevada, Butte, and Santa Clara counties, while the highest county-level mean scores (>10) are found in Yuba and Plumas. Areas with lower mean suitability (<7) include San Benito, Lake, and Inyo counties. Across the state, roughly 19.62 million ha met the “suitable land” criteria. San Bernardino (2.23 Mha), Kern (1.96 Mha) and Fresno (1.55 Mha) offer the largest suitable areas, while Alpine, Colusa, and Tehama counties contain minimal suitable land. Applying the high-suitability criteria (top 10%, ≥10 ha, ≥50 miles spacing) reduces the candidate subset to approximately 2.0 million hectares statewide. The largest high-suitability patches are in Butte (166,506 ha), Placer (155,996 ha), Los Angeles (148,789 ha), and Fresno (146,537 ha). The smallest patches are in Alpine (0.09 ha), San Benito (0.27 ha), and Tehama (2.97 ha). Following the spacing rule, 77 candidate biofacility locations were identified statewide. The highest counts occur in Butte (16), Santa Clara (15), and Fresno (10) counties, with the remaining sites distributed across other regions (**Figure 30**).

This approach balances site quality, developable scale, and geographic distribution. It provides a transparent, replicable framework to support a statewide strategy for Innovation Campuses while minimizing environmental, social, and operational risks.

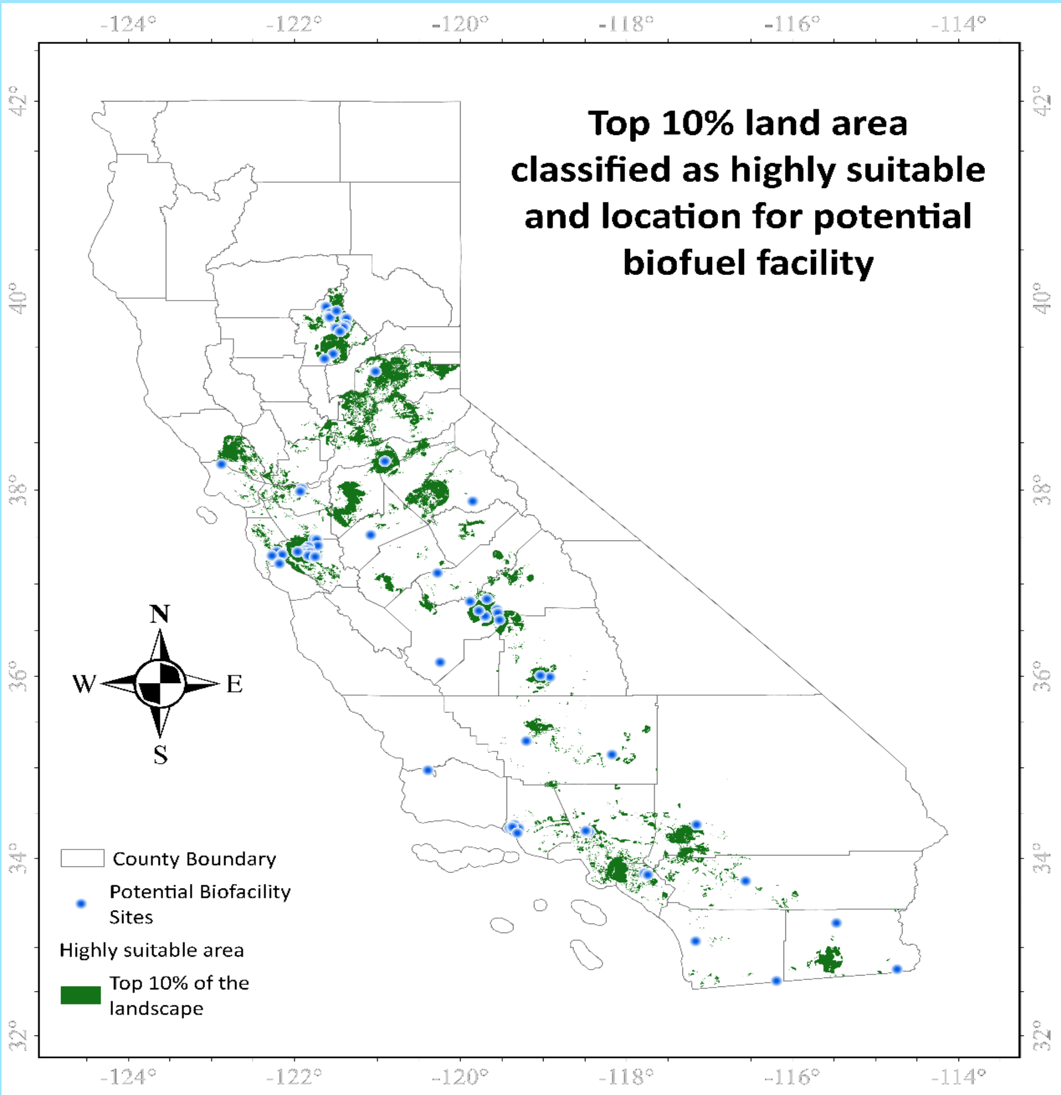

Figure 30. High-suitability land (top 10%) and proposed candidate locations for renewable diesel facilities across California.

4.4 Existing Bioenergy Infrastructure and Proposed Biorefinery Site

California's bioenergy sector comprises a mix of operational, proposed, and legacy facilities, which influence the feasibility, risk profile, and commercialization pathways for new biomass-to-liquids projects. These facilities shape permitting familiarity, workforce availability, contractor capacity, and potential opportunities for site repurposing. As of 2025, the Woody Biomass Utilization Group at the University of California identified 89 bioenergy projects statewide, including 22 operational facilities, 18 projects in active development or proposed stages, and 49 facilities classified as closed, idle, or cancelled [88]. For siting and deployment context, these facilities were grouped into three functional categories—Operational, Active Development/Proposed, and Closed/Idle—and mapped as existing bioenergy infrastructure (**Figure 31**).

Building on the statewide suitability analysis, nine high-suitability site patches were identified in Fresno County that meet the minimum area and spacing criteria (top 10%, ≥10 ha, ≥50 miles spacing). For subsequent techno-economic modeling and infrastructure discussion, a representative Fresno candidate location was selected at 36.710608, −119.778176 (**Figure 31**). This site is located near the Rio Bravo Fresno Biomass Power facility (36.688823, −119.723405), a biomass-fired power plant located near Malaga, CA. Rio Bravo Fresno historically utilized agricultural pruning and urban wood as primary fuel streams and employed circulating fluidized bed (CFB) boiler technology with emissions controls, e.g., Selective Non-Catalytic Reduction (SNCR) and Electrostatic Precipitator (ESP). Its presence demonstrates local precedent for industrial biomass handling and operations. Proximity to an existing facility is relevant to deployment because it suggests established industrial land use, local familiarity with biomass logistics, and potential opportunities for infrastructure reuse or workforce redeployment, even though the pathway evaluated here differs from power-only combustion.

All techno-economic analysis (TEA) results and scenario comparisons presented in the subsequent portion of this report are parameterized to the selected Fresno biorefinery location (**Figure 31**). The siting analysis contextualizes the feasibility of developable land, infrastructure access, and proximity to relevant industrial assets within the Fresno supply shed.

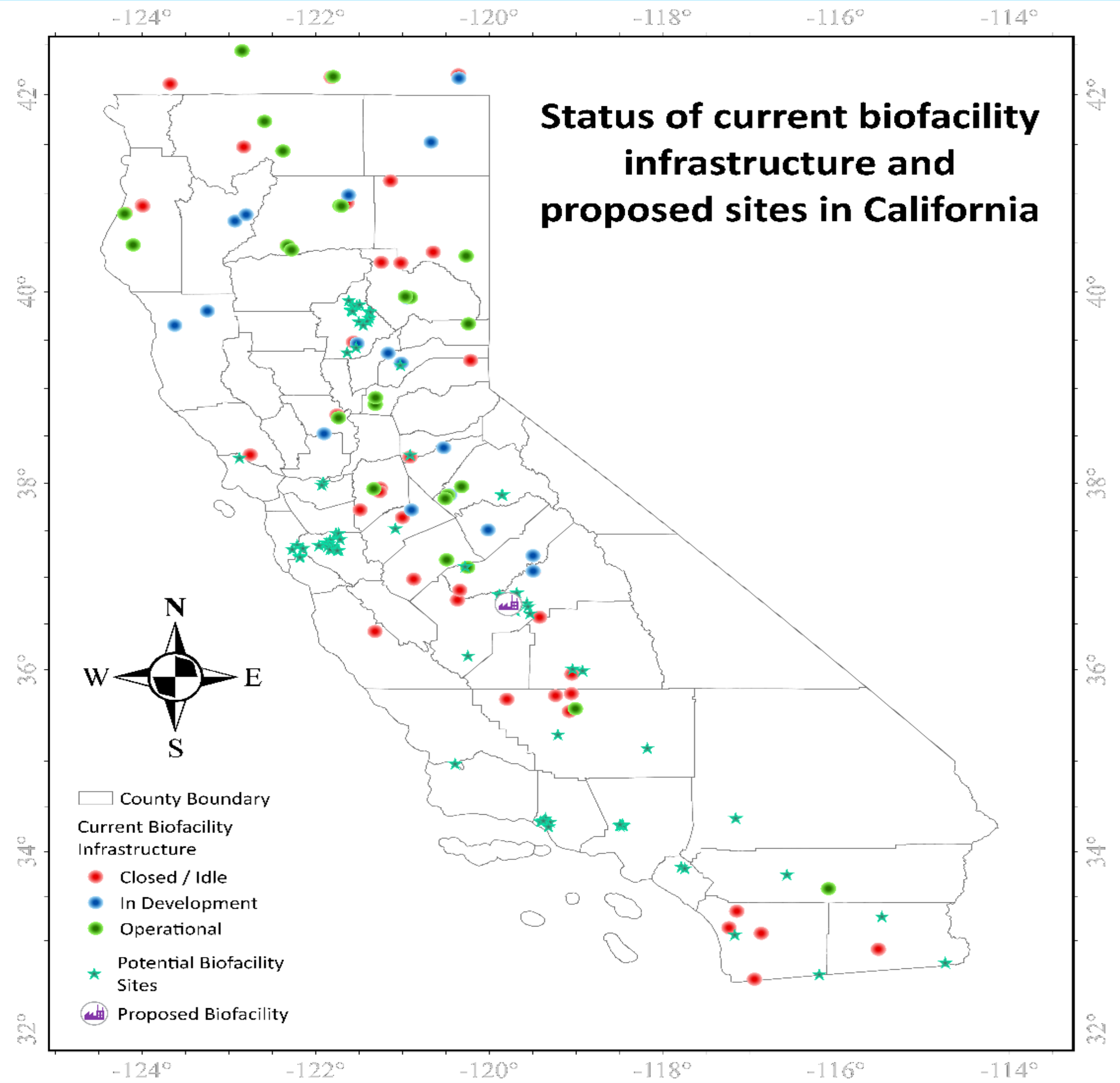

Figure 31. Existing bioenergy facilities in California, categorized by operational status, and locations of potential new biofacility sites.

5. TECHNO-ECONOMIC AND FINANCIAL FEASIBILITY ANALYSIS

This chapter presents a techno-economic and financial feasibility analysis of a commercial-scale integrated biorefinery designed to process 1,000 bone-dry tons (BDT) of feedstock per day, operating 330 days per year (330,000 BDT annually. The analysis evaluates four capital investment scenarios and corresponding annual operating cost structures, estimates product yields and projected revenue streams, and quantifies the value of applicable policy incentives and environmental credits. Overall financial performance is assessed using standard investment metrics, including net present value (NPV), internal rate of return (IRR), payback period, and debt service coverage ratio (DSCR).

To reflect uncertainty in real-world feedstock procurement and market conditions, the techno-economic assessment (TEA) compares multiple feedstock composition scenarios representing plausible supply portfolio. In addition, a ±40% sensitivity analysis on total installed capital cost is applied to characterize cost variability, capital exposure and investment risk.

5.1 Strategic Rationale and Analytical Objectives

Fresno County is strategically positioned for advanced biofuel production and carbon management infrastructure due to its access to three major underutilized residue streams: (i) wildfire-mitigation forest residues generated through fuels reduction and forest management activities, (ii) abundant agricultural residues produced by intensive Central Valley cropping systems, and (iii) a significant municipal solid waste (MSW) stream shaped by landfill diversion mandates and methane-reduction objectives. These materials are often managed through low value uses or disposal pathways that create environmental and economic burdens,

including elevated wildfire risks from excess forest fuels, residue accumulation and uncontrolled decomposition, and methane emissions from landfilling.

The integrated biorefinery concept evaluated in this chapter addresses these challenges by converting mixed residue feedstock into drop-in renewable diesel (RD) and durable biochar. This approach integrates transportation decarbonization, waste diversion, and carbon management within a single facility footprint, improving overall system efficiency and environmental performance. To reflect realistic supply-chain conditions and procurement uncertainty, the techno-economic assessment evaluates four feedstock composition scenarios: (1) 100% forest residues (2) 50% forest residues and 50% agricultural residues, (3) 50% forest residues, 25% agricultural residues, and 25% MSW, and (4) 50% MSW, 25% forest residues, and 25% agricultural residues.

The objectives of this chapter are to:

(i) define a technically feasible and policy-defensible facility configuration capable of processing these feedstock portfolios while maintaining renewable diesel quality and preserving biochar market eligibility.

(ii) quantify capital expenditures (CAPEX), operating expenditures (OPEX), levelized RD production costs, and key financial performance indicators (NPV, IRR, payback period, and DSCR) across scenarios.

(iii) evaluate how feedstock composition influences carbon intensity (CI), Low Carbon Fuel Standard (LCFS) credit generation, and overall project economics.

(iv) assess project robustness under a ±40% variation in total installed CAPEX to characterize investment risk and identify commercial viability thresholds; and

(v) provide a data-driven recommendation identifying the most economically competitive and environmentally resilient configuration for deployment in Fresno County.

5.2 Techno-Economic Assessment Framework and Scenario Design

The techno-economic assessment (TEA) is structured as a harmonized scenario framework in which facility scale and core conversion design are held constant across all cases, and variation is introduced solely through feedstock composition. Each scenario assumes nominal plant throughput of 1,000 bone-dry ton equivalents (BDT-eq) per day and evaluates alternative supply portfolios of forest residues, agricultural residues, and MSW-derived refuse-derived fuel (RDF). Adjustments in feedstock composition influence key technical and economic parameters, including conversion yields and product distribution, front-end handling and preprocessing requirements, life-cycle carbon intensity (CI), and the magnitude of policy-driven credit revenues, while preserving a consistent analytical baseline for cross-scenario comparison. This approach isolates the economic and environmental implications of feedstock variability without confounding results with changes in facility scale or core process configuration.

The analytical methodology follows established TEA practices and cost-estimation conventions widely applied in U.S. Department of Energy (DOE)aligned bioenergy studies. Standardized methods are used for equipment scaling, total installed cost development, operating cost estimation, and discounted cash-flow analysis of commercial thermochemical conversion systems [1-4]. These methods are supplemented by peer-reviewed literature and published engineering design studies specific to oxygen-blown gasification–Fischer–Tropsch (FT) liquid fuel pathways and slow-pyrolysis biochar production [5-11].

Together, these sources provide a consistent, transparent and defensible basis for estimating capital expenditures (CAPEX), operating expenditures (OPEX), and key financial performance indicators, including levelized fuel cost, NPV, IRR, payback period, and DSCR, under alternative feedstock configurations.

5.3 Feedstock Supply, Properties, and Logistics

5.3.1 System Boundary Definition

The proposed Fresno biorefinery is modeled as an integrated, dual-train thermochemical conversion facility with shared balance-of-plant systems. The facility is designed to process forest residues, agricultural residues, and MSW-derived refuse-derived fuel (RDF) under a technically feasible configuration that remains consistent with applicable regulatory and policy frameworks.

The TEA adopts a gate-to-gate system boundary, beginning at feedstock delivery to the plant gate and concluding with finished product storage and outbound loading. Upstream activities (e.g. forest management operations, agricultural production, or municipal waste collection) and downstream product distribution and end use are excluded from direct cost modeling but are addressed separately where relevant for life-cycle carbon intensity (CI) evaluation.

Within the defined boundary, the modeled unit operations include:

(i) ***Feedstock logistics and preparation***, including inbound transport to the facility, material reception, storage, size reduction, drying, and internal material handling.

(ii) Renewable diesel production train, consisting of:

- Oxygen-blown gasification.
- Syngas cleanup and conditioning, (including particulate removal, tar reforming, and acid gas management as required);
- Fischer–Tropsch (FT) synthesis, and
- Product upgrading and hydro processing to meet drop-in renewable diesel specifications

(iii) Biochar production train, based on slow pyrolysis of eligible biomass fractions, followed by biochar stabilization, cooling, storage, and loadout for transport to end users or carbon management markets.

Shared balance-of-plant infrastructure, including the air separation unit (ASU), steam and power generation systems, cooling systems, water supply and wastewater treatment, emissions control systems and general utilities, is modeled as integrated support systems serving both conversion trains. This integrated configuration reflects commercial-scale design practice and enables consistent allocation of capital and operating costs across scenarios.

5.3.2 Scenario

Definitions and Feedstock Supply Assumptions

Four feedstock supply scenarios were developed to represent plausible resource portfolios in Fresno County while maintaining a constant biorefinery throughput of 1,000 bone-dry tons per day (BDT), equivalent to 330,000 BDT annually, assuming 330 operating days per year (see **Table 3**). Across all scenarios, facility scale, core conversion technologies, and baseline operating conditions are held constant. As a result, differences in techno-economic performance, carbon intensity (CI), and financial outcomes are attributable solely to variations in feedstock composition.

In scenarios incorporating municipal solid waste (MSW), the material is not modeled as unprocessed waste. Instead, MSW is assumed to undergo off-site preprocessing to produce refuse-derived fuel (RDF) meeting defined quality and contamination thresholds. RDF is routed exclusively to the renewable diesel (RD) production train via gasification and Fischer Tropsch synthesis. This assumption reflects operational feasibility, syngas quality control requirements, and regulatory considerations related to emissions management and fuel certification.

To preserve biochar product quality and maintain eligibility for carbon-removal crediting and soil-amendment markets, biochar production is restricted to clean biomass feedstocks, specifically forest residues and agricultural residues. MSW-derived materials are excluded from the biochar production train to avoid contamination risks and to ensure alignment with prevailing carbon accounting protocols and market acceptance standards.

Table 3. Evaluated Feedstock supply scenarios (total throughput fixed at 1,000 BDT per day).

Scenario	Name	Forest Residue	Agricultural Residue	MSW (as RDF to RD train)	Primary purpose
1	Biomass only	100% (330,000 BDT per year)	0%	0%	Baseline without Ag and MSW integration
2	Biomass-only	50% (165,000 BDT per year)	50% (165,000 BDT per year)	0%	Without MSW integration
3	Moderate MSW integration (Base Case)	50% (165,000 BDT per year)	30% (99,000 BDT per year)	20% (66,000 BDT per year)	Balanced economics and policy value
4	High MSW utilization	25% (82,500 BDT per year)	25% (82,500 BDT per year)	50% (165,000 BDT per year)	Tests higher MSW dependence and CI benefits

Collectively, these scenarios provide a structured framework for evaluating key tradeoffs among (i) feedstock procurement costs and preprocessing requirements, (ii) RD yield and total fuel output, (iii) carbon intensity (CI) and associated LCFS credit generation, and (iv) biochar production volumes and related carbon credit revenues under progressively higher levels of MSW/RDF integration.

5.3.3. Plant Scale and Operating Profile

The Fresno County biorefinery is modeled as a greenfield, commercial-scale thermochemical conversion facility with an assumed 20-year operating life following construction. The facility is designed for continuous 24-hour, seven-day-per-week operation. Annual performance is represented using g a 90% capacity factor, consistent with commercial-scale thermochemical facilities that require scheduled outages for inspection, turnaround, and routine maintenance (see **Table 4**). All capital expenditures are assumed to occur in Year 0, with steady-state operations commencing in Year 1. For analytical clarity and consistency with standard techno-economic assessment practice, startup inefficiencies and ramp-up effects are not explicitly modeled.

The system boundary is held constant across all scenarios and excludes upstream feedstock production and downstream product distribution and end-use combustion. These stages are incorporated only to the extent that they affect delivered feedstock cost assumptions and lifecycle carbon intensity (CI) calculations relevant to credit generation.

Table 4. Operating profile and production basis (constant across scenarios).

Parameter	Value	Notes	Basis
Nominal feedstock capacity (F_{day})	1,000 BDT per day	Bone-dry ton basis	Facility design capacity
Operating days (D)	330 days per year	90% capacity factor	[113, 114]
Annual feedstock throughput (F_{yr})	330,000 BDT per year	$F_{yr} = F_{day} \times D$	Throughput × operating days
Operating mode	24/7	Scheduled maintenance included in D	[113]
Project operating life (n)	20 years	Post-construction operating horizon	[113]
Construction timing	Year 0	All CAPEX incurred at Year 0	Facility design
Startup/ramp-up	Excluded	Steady state assumed from Year 1	Facility design

To ensure conservative and replicable results, several potential incentives are intentionally excluded from the baseline financial model. Renewable Fuel Standard (RFS) credits are not included, the federal 45V hydrogen production tax credit is not applicable to this renewable diesel pathway, and federal Investment

Tax Credits (ITC) are excluded from the base-case evaluation.

5.3.4 Feedstock Characterization

Feedstock properties were parameterized using representative ultimate and proximate analyses, moisture contents, and heating values (HHV/LHV) consistent with published thermochemical conversion literature and specification-controlled RDF practices. These parameters establish the facility's mass and energy balances, inform lifecycle carbon accounting, and directly influence gasification performance, syngas composition, and downstream fuel yields. The total annual chemical energy input of the facility is calculated as:

$$\mathbf{E_{feed}} = \sum_{\mathbf{k}} \mathbf{m_k} \cdot \mathbf{LHV_k}$$

where E_{feed} is the annual feedstock energy input ($MJ.\,yr^{-1}$), m_k is the annual dry mass of feedstock k delivered to the facility ($kg.\,yr^{-1}$), and LHV_k is the lower heating value of feedstock k on a dry-mass basis ($MJ.\,kg^{-1}$).

Forest residues (clean biomass) are represented as woody fuel-reduction material typical of California forest management operations. A dry-basis ultimate analysis is assumed as follows: C 50.84%, H 5.72%, N 0.66%, S 0.25%, O 41.46%, ash 5%. Moisture content is assumed at 15% moisture (wet basis) with a representative lower heating value (LHV) of 18 MJ kg^{-1} [14-16]]. These parameters are consistent with reported values for western U.S. Forest residues and thermochemical conversion studies.

Agricultural residues (clean biomass) are modeled as a blended crop-residue stream characterized by lower energy density and relatively higher inorganic content compared to woody biomass. The assumed dry-basis composition is C 34.07%, H 4.03%, N 0.43%, O 13.68%, and ash 3.61%, with moisture content ranging from 10–15%. The higher heating value (HHV) is estimated using the Channiwala–Parikh correlation, yielding HHV ≈ 14.4 $MJ.kg^{-1}$ (dry basis) and LHV ≈ 10.3 $MJ.\,kg^{-1}$ (dry basis) [17-21]. These assumptions reflect typical properties of Central Valley crop residues reported in the literature.

MSW is modeled only after preprocessing into a specification-controlled RDF stream consistent with standard RDF/SRF quality practice. The assumed dry-basis composition is C 53.12%, H 7.69%, N 0.84%, S 0.26%, O 27.57%, and ash 7.76%, with 20% moisture. Chlorine content is controlled within a range of ≤0.5–1.5% to support stable gasification performance and manage corrosion and emissions risks. Energy content is represented using HHV ≈ 18.1 $MJ.\,kg^{-1}$ (dry basis) and LHV ≈ 12.6 $MJ.\,kg^{-1}$ (dry basis) [22-28]. Consistent with the system boundary and product quality constraints, RDF is routed exclusively to the renewable diesel production train and is excluded from biochar production to preserve biochar market eligibility and carbon-credit integrity.

5.3.5 Feedstock Reception and Preprocessing

Forest and agricultural residues are delivered to the Fresno facility as chipped or baled biomass and managed through a standardized reception and preprocessing system. Upon arrival, each load is weighed, sampled for moisture and quality assurance, and stored in covered feedstock yards to minimize wetting and dry matter losses. Preprocessing includes primary size reduction to achieve uniform particle size, secondary milling when needed to meet handling and conversion specifications, and indirect drying using recovered process heat. Biomass routed to the renewable diesel (RD) train is dried to ≤20 wt% moisture (typically 15–20%) to ensure stable oxygen-blown gasification performance [130, 131], while biomass allocated to the biochar train is dried further to ≤15 wt% (10–15% typical) to enhance biochar yield and fixed-carbon content [132, 133].

MSW is not processed directly; it is first converted into refuse-derived fuel (RDF) via an on-site or contracted materials recovery facility (MRF). MRF operations include removal of ferrous and non-ferrous metals, separation of glass and inert fractions, selective elimination of chlorine-rich materials (e.g., PVC), shredding and homogenization, and moisture control. The resulting specification-controlled RDF stream has reduced ash and chlorine content (≤0.5 wt% Cl), making it suitable for oxygen-blown gasification and downstream syngas cleanup [134].

5.3.6 Feedstock routing constraints

A key design feature of the Fresno facility is strict feedstock segregation and routing control to ensure operational stability, protect catalysts and upgrading units, and maintain defensible product-quality and carbon-accounting claims. Clear routing protocols are applied across all feedstock scenarios to prevent cross-contamination between conversion trains and to preserve eligibility for applicable fuel and carbon credit programs.

Across all scenarios, MSW is routed exclusively to the RD train and is never used in biochar production. Biochar is produced solely from clean biomass, with 10% of incoming forest and 10% of agricultural residues diverted to the biochar train in each scenario, while the remaining clean biomass along with all MSW when present, is directed to the RD train.

Accordingly, feedstock routing is defined as follows:

- ***Renewable diesel train:*** forest residues, agricultural residues, and RDF,

- ***Biochar train:*** clean forest and agricultural residues only, reflecting the 10% diversion of incoming clean biomass.

This segregation strategy supports predictable feedstock handling and stable conversion performance, ensures consistent renewable diesel specifications, and preserves biochar market eligibility under clean-biomass requirements. It also strengthens the integrity of carbon intensity accounting and credit generation under California regulatory frameworks.

5.3.7 Feedstock Cost Framework

Delivered feedstock cost is defined as the total cost of supplying material to the plant gate. This includes both the at-source price and transportation cost. The at-source price reflects the cost incurred at the point of collection or generation, such as roadside or landing costs for forest residues, farmgate costs for agricultural residues, and a net tipping-fee-based value for MSW prior to processing into RDF. Transportation cost is calculated separately based on haul distance, trucking cost assumptions, and payload capacity. Unless otherwise specified, haul distance is expressed as a one-way distance. However, transportation costs are computed on a two-way, or round-trip, mileage basis to account for return travel. Feedstock cost assumptions are intended to reflect representative California market conditions and the distinct economic structure associated with waste-derived materials. Base-case delivered price assumptions are $30 per BDT for forest residues, $25 per BDT for agricultural residues, and $15 per BDT-eq for MSW processed as RDF. The RDF value represents a net delivered cost shaped by tipping-fee dynamics and preprocessing requirements (**Table 5**).

Transportation costs are modeled using a constant two-way haul distance of 70 miles and an all-inclusive trucking cost of $0.4955 per mile. This corresponds to a distance-normalized transportation factor of $0.16093 per BDT-mile (**Table 6**) [119, 135]. Under this standardized framework, variation in total delivered feedstock cost across scenarios results solely from differences in feedstock composition, as defined in Section 5.3.2 and **Table 3**. Unit cost and logistics parameters are held constant to preserve comparability across scenarios.

Annual transportation cost is calculated as:

$$C_{\text{trans}} = F_{\text{yr}} \times d \times c_{\text{trans}}$$

where F_{yr} is the annual feedstock throughput (BDT yr^{-1}), $d$is the hauling distance (mile, two-way basis), and $c_{\text{trans}}$is the transportation cost factor ($ per BDT-mile).

Annual total feedstock cost is calculated as:

$$C_{\text{feed}} = \sum_k (F_{\text{yr}} \cdot s_k \cdot P_k)$$

where s_k is the mass fraction of feedstock k in the scenario (forest residues, agricultural residues, or MSW) and P_k is the delivered feedstock price ($ per BDT) assigned to feedstock k.

Table 5. Base-case delivered feedstock price assumptions.

Feedstock	Price	Units	Interpretation
Forest residues	30	$ per BDT	Representative market-based source cost
Agricultural residues	25	$ per BDT	Representative market-based source cost
MSW as RDF	15	$ per BDT	Net source cost reflecting tipping-fee dynamics and preprocessing requirements

Table 6. Transportation cost assumptions.

Parameter	Value	Units	Description
Average two-way haul distance	70	miles	Applied uniformly across all scenarios
Trucking cost factor	0.4955	$ per mile	All-inclusive trucking cost assumption
Transportation cost factor	0.16093	$ per BDT-mile	Distance-normalized cost applied to ton-miles

5.4 Process Configuration and Conversion Modeling

The Fresno County biorefinery is modeled as an integrated thermochemical conversion facility consisting of two physically segregated process trains supported by shared utility systems and coordinated heat integration. This configuration reflects commercial-scale design practice and enables operational flexibility while maintaining clear separation between product streams for regulatory and market purposes.

Train 1 produces renewable diesel (RD) through a sequence of feedstock preprocessing, oxygen and steam-assisted gasification, syngas cleanup and conditioning, Fischer–Tropsch (FT) synthesis, and downstream upgrading with final product separation and storage. This train is designed to process forest residues, agricultural residues, and municipal solid waste (MSW)–derived refuse-derived fuel (RDF), consistent with the routing framework defined in Section 4.3.

Train 2 produces biochar through dedicated slow pyrolysis of clean biomass only, limited to forest and agricultural residues. The pyrolysis system is physically and operationally segregated from the RD train to ensure feedstock purity and maintain eligibility for biochar markets and carbon removal credit programs. Shared balance-of-plant systems, including the air separation unit, steam and power generation, water and wastewater treatment, and emissions control systems, support both trains. Heat integration between process units is incorporated where it is technically feasible to improve overall energy efficiency and reduce operating costs. In accordance with the feedstock routing constraints described in Section 4.3, RDF is routed exclusively to the RD train. No MSW-derived material enters the pyrolysis system.

5.4.1 Renewable Diesel Production Train

Oxygen-Blown Gasification with Steam Injection)

Blended forest residues, agricultural residues, and MSW-derived RDF, in scenario-dependent proportions as defined in Section 5.3.2, are converted to synthesis gas (syngas) in an oxygen-blown gasifier supplied by an on-site cryogenic air separation unit (ASU). The RD production train is designed to reflect commercially relevant thermochemical configurations that utilize oxygen and controlled steam injection to stabilize reactor temperature, enhance carbon conversion, and reduce tar formation. Representative operating conditions include gasification temperatures in the range of 850–1,000 °C [136], operating pressures of 10–30 bar [137], and cold gas efficiencies (CGE) between 65 and 75 per cent [138]. Gasification performance is modeled using a CGE-based framework [38]. Cold gas efficiency is defined as the ratio of the chemical energy contained in the produced syngas to the chemical energy contained in the feedstock on a lower heating value basis (**Figure 32**).

$$\mathbf{CGE} = \frac{E_{\mathbf{syngas}}}{E_{\mathbf{feed}}}$$

where E_{syngas} is the annual chemical energy content of raw syngas expressed in MJ per year, and E_{feed} represents the annual chemical energy content of the feedstock input on a lower heating value basis. The assumed CGE range is consistent with commercial oxygen-blown gasification systems processing heterogeneous mixtures of biomass and RDF [138]. The raw syngas stream is modeled as a multicomponent mixture of carbon monoxide (CO), hydrogen (H_2), carbon dioxide (CO_2), water vapor(H_2O), methane (CH_4), light hydrocarbons, and trace contaminants such as particulates, sulfur, and nitrogen-containing compounds. Key gasification reactions incorporated into the modeling framework include partial oxidation, steam gasification of char, the Boudouard reaction, and water–gas shift equilibrium [139].

$$\mathbf{C + \frac{1}{2}O_2 \rightarrow CO}$$

$$\mathbf{C + H_2O \rightarrow CO + H_2}$$

$$\mathbf{CO + H_2O \rightleftharpoons CO_2 + H_2}$$

Syngas Cooling, Cleanup, and Conditioning

Raw syngas exiting the gasifier is first cooled using heat-recovery systems that generate steam for internal process use, improving overall energy efficiency [34, 140]. The cooled syngas then undergoes multi-stage cleanup to remove particulates, tars, and trace contaminants that can adversely affect downstream equipment and catalyst performance [141]. Contaminant removal targets include sulfur species reduced to below 0.1 parts per million by volume (ppmv) [140], chlorine and other acid gases reduced to below 1 ppmv [140], and the removal of alkali metals and additional trace compounds to trace levels [141].

Following cleanup, the syngas is conditioned to achieve a target hydrogen-to-carbon monoxide (H_2/CO) ratio of ~2.0–2.2, consistent with requirements for the Fischer- Tropsch process [22, 142]. Conditioning is modeled using water–gas shift reactors, controlled steam addition, and ratio management systems to ensure stable and optimized performance in downstream synthesis and upgrading units.

Fischer–Tropsch Synthesis

Conditioned syngas is converted into long-chain hydrocarbons through low-temperature Fischer–Tropsch process. In this configuration, synthesis is assumed to operate at temperatures of approximately 200–240 °C [143] and pressures of 20–30 bar [85], using cobalt-based catalysts optimized for paraffinic fuel production [143, 144].

The overall reaction is represented as [145]:

$$\boldsymbol{n}\mathbf{CO + (2}\boldsymbol{n}\mathbf{ + 1)H_2 \rightarrow C_{\boldsymbol{n}}H_{2\boldsymbol{n}+2} + }\boldsymbol{n}\mathbf{H_2O}$$

The synthesis process produces a spectrum of hydrocarbons, with a

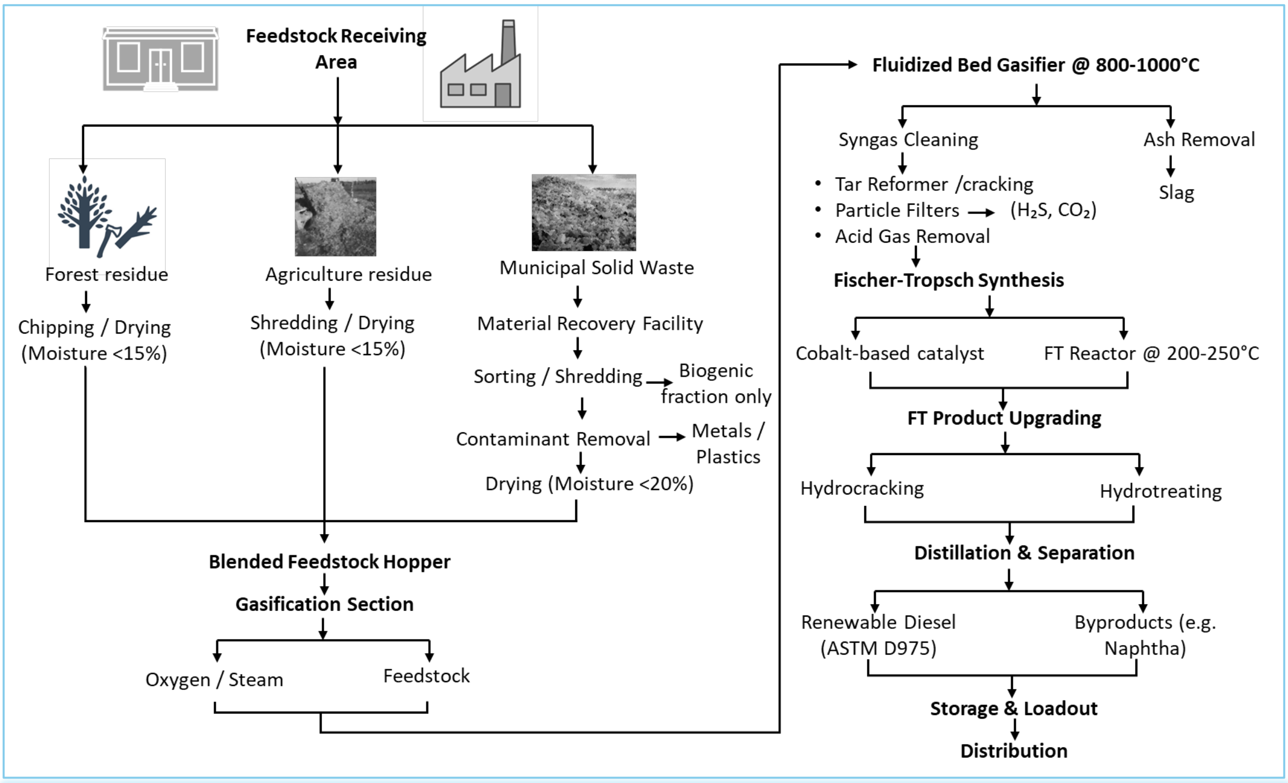

Figure 32. Process flow diagram of renewable diesel production from blended feedstocks.

product slate dominated by long-chain paraffinic waxes, along with lighter fractions in the naphtha range, tail gas, and processing water. These intermediate products are subsequently upgraded through hydrocracking and refining to yield finished renewable diesel and co-products.

Because the synthesis reaction is strongly exothermic, heat recovery from Fischer–Tropsch reactors represents a significant opportunity for internet energy integration. Recovered heat is typically utilized to generate steam or support upstream and downstream process requirements, contributing to overall system efficiency and reduced external energy demand.

Fuel Upgrading and Renewable Diesel Production

Fischer–Tropsch waxes are upgraded through hydrocracking and isomerization to produce ASTM-compliant renewable diesel. Representative operating conditions include temperatures of approximately 330–380 °C [146], moderate hydrogen pressures [147], and hydrogen consumption in the range of 2–4 wt% of liquid product [147]. These upgrading steps convert long-chain paraffin waxes into shorter, branched hydrocarbons with properties suitable for use as drop-in diesel fuel.

Light hydrocarbons and tail gas generated during synthesis and upgrading are either recycled within the process or utilized as internal fuel to support plant energy requirements, improving overall system efficiency. Downstream distillation and separation units yield a primary RD product stream, along with lighter fractions such as naphtha and liquefied petroleum gas (LPG)/light ends. Depending on project economics and market conditions, these co-products may be used for internal energy or treated as secondary co-products. At the facility level, conversion efficiency to liquid fuels is assumed to be 46.7% on a LHV basis, consistent with reported gasification–FT process biorefinery systems [148–150]. Finished products are stored on-site and prepared for distribution via truck and/or rail, enabling integration with existing fuel logistics infrastructure.

5.4.2 Biochar Production Train

Slow Pyrolysis of Clean Biomass

The biochar production train is modeled as a dedicated slow-pyrolysis system designed to process clean biomass streams only, specifically forest residues and agricultural residues. MSW is explicitly excluded to preserve biochar quality, ensure consistent product specification, and maintain defensible carbon accounting and credit eligibility.

Biochar production is based on thermochemical conversion under oxygen-limited conditions, whereby biomass is decomposed into three primary product fractions: (i) a carbon-rich solid (biochar), (ii) condensable vapors (bio-oil/tars), and (iii) non-condensable gases (pyrolysis gas). The distribution of these products is governed by feedstock characteristics and operating conditions, including temperature, heating rate, and residence time [151–153]. Consistent with slow pyrolysis regimes, the system is parameterized to favor solid carbon production through moderate temperatures and extended residence times [154, 155]. Feedstock preparation includes size reduction and drying prior to reactor entry. Moisture specifications are more stringent than for gasification feedstocks, as lower moisture content improves thermal efficiency, increases char yield, and enhances fixed carbon retention. In this analysis, biomass is conditioned to ≤10–15 wt% moisture, with ≤10 wt% preferred for stable operation and high-quality biochar output [156, 157].

The pyrolysis reactor is modeled to operate at temperatures of approximately 450–550 °C with a residence time of 30–60 minutes. These conditions are consistent with typical slow-pyrolysis operating windows that maximize biochar yield while maintaining practical throughput [158, 159]. Under these conditions, feedstock-specific biochar yields are

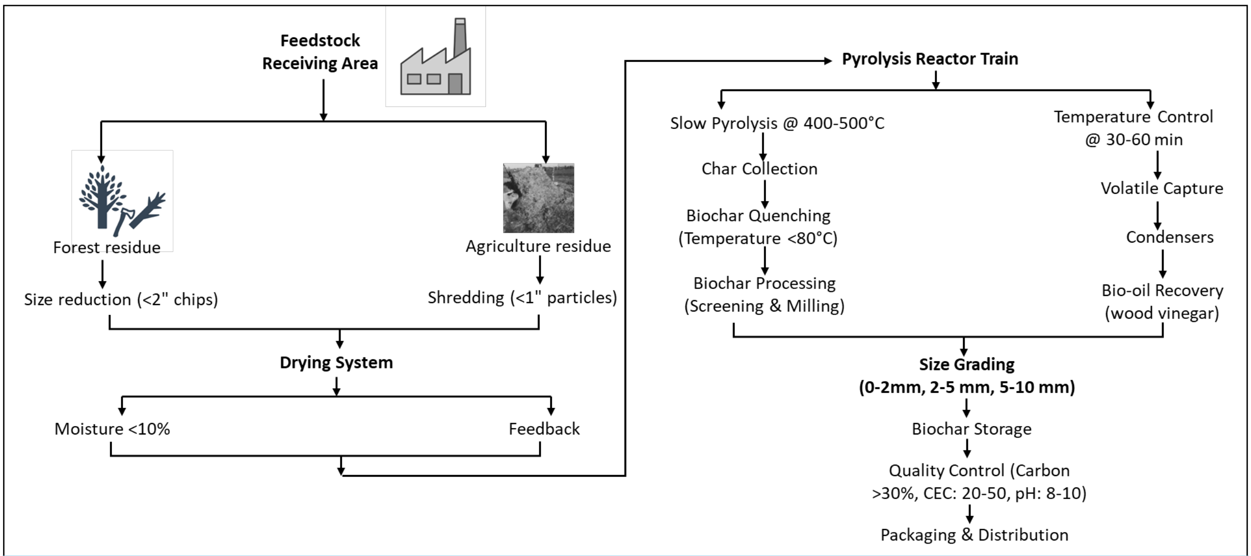

Figure 33. Process flow diagram of biochar production train.

applied based on literature-reported performance ranges. For forest residues, a base-case biochar yield of 0.29 tonnes per tonne of dry feedstock (29 wt%), is assumed (**Figure 33**). For agricultural residues, a more conservative yield of 0.17 tonnes per tonne (17 wt%) is applied, reflecting differences in ash content, volatility, and lignocellulosic composition relative to woody feedstock [161, 162].

In the modeled system, condensable vapors and non-condensable gases are assumed to be combusted to provide process heat for the pyrolysis reactor and biomass drying, contributing to internal energy integration. Under representative conditions, product distributions for woody biomass are approximately 29% biochar, 41% condensable vapors, and 30% gas on a mass basis. [153, 160].

Annual biochar production is computed as a function of the dry biomass flow routed to the pyrolysis system:

$$\boldsymbol{Q}_{\mathrm{BC},i} = \boldsymbol{m}_{\mathrm{py},i} \cdot \boldsymbol{Y}_{\mathrm{BC},i}$$

where $m_{\mathrm{py},i}$ is the annual dry biomass mass flow of feedstock $i$routed to the pyrolysis train (ton per year), and $Y_{\mathrm{BC},i}$ is the corresponding biochar yield (ton biochar per ton dry feed). As described in Section 4.3.6, the fraction of clean biomass allocated to the biochar train is held constant across scenarios to ensure consistent product stream segregation and comparability of results.

Thermal Integration and Off-Gas Utilization

Pyrolysis vapors and non-condensable gases are recovered downstream of the reactor and utilized internally for thermal integration, consistent with commercial and pilot-scale pyrolysis systems. In the base-case configuration, these streams are routed to a combustor or thermal oxidizer to supply process heat for: (i) biomass drying, (ii) maintaining reactor operating temperature, and (iii) steam generation and auxiliary site heating. This approach reduces reliance from external fuels and improves overall system energy efficiency [151, 153]. Condensable vapors may be recovered as bio-oil or tar fractions; however, unless otherwise specified, these streams are not monetized in the base-case techno-economic analysis (TEA). Instead, they are treated as internal energy carriers or managed process streams to support conservative modeling assumptions and avoid overstating co-product revenues.

Biochar Handling, Storage, and Quality Control

Once produced, biochar is discharged from the reactor and undergoes controlled cooling or quenching. This step reduces the risk of oxidation and fire during subsequent handling. Biochar is then screened and conditioned (e.g., sizing/grading) prior to storage and distribution. Quality control protocols are applied to ensure biochar meets standards relevant to both agronomic and carbon market applications. Key parameters include moisture content, ash content, fixed carbon content, and potential contaminants (e.g., heavy metals). These measures reflect best practices for producing consistent, credit-eligible biochar and support robust chain-of-custody documentation required by carbon removal programs [154, 155]. For carbon accounting purposes, biochar is conservatively assumed to maintain storage permanence of at least 100 years. This aligns with durable carbon removal conventions used across multiple frameworks and reflects the medium-to-high durability range commonly cited in the literature, where 70–90% of carbon remains stable over a century depending on storage conditions) [163, 164].

5.4.3 Utilities and Heat Integration

Both conversion pathways share key utility systems, including a cryogenic air separation unit (ASU) for oxygen production, with nitrogen used for inerting, as well as steam and power generation systems, water and wastewater treatment, and air pollution control equipment. Heat integration is a critical performance and cost driver: recoverable heat from syngas cooling and FT synthesis is used for steam production and feedstock drying, while pyrolysis off gas provides heat, reducing reliance on external energy sources. This integrated energy approach enhances operational efficiency, lowers variable costs, and supports improved carbon intensity outcomes.

The facility is configured to produce renewable diesel as the primary product, biochar as a co-product, and internal heat and power through energy recovery. Carbon flows are allocated among renewable diesel, biochar (for durable sequestration), and process emissions. This configuration establishes the technical foundation for mass, energy, and carbon accounting, as well as the techno-economic performance results presented in the following sections.

5.5 Integrated Mass, Energy, and Carbon Accounting

This section describes the integrated framework for mass, energy, and carbon accounting used to evaluate facility-level performance at the Fresno County biorefinery. The framework connects feedstock composition and conversion efficiency to key outputs, including renewable diesel production, biochar generation, and associated carbon intensity (CI). It also supports calculation of policy-relevant carbon mitigation metrics, such as fossil fuel displacement and carbon sequestration. All balances are evaluated on a gate-to-gate basis, consistent with the defined system boundary, and are applied uniformly across the four feedstock scenarios to ensure a transparent and comparable evaluation of system performance under different feedstock supply portfolios.

5.5.1 Operating Basis and Accounting Boundary

The Fresno County biorefinery is modeled at a commercial scale of 1,000 bone-dry tons (BDT) per day, equivalent to 330,000 BDT per year, assuming 330 operating days annually. The facility-level accounting boundary includes:

(i) Feedstock receipt and routing to the renewable diesel and biochar conversion trains.

(ii) Intermediate thermochemical conversion, syngas cleanup, Fischer–Tropsch synthesis and upgrading.

(iii) Slow pyrolysis and biochar handling for clean biomass; and

(iv) Product storage and loadout for renewable diesel and biochar.

Facility-level emissions and carbon capture (where applicable) are included in the gate-to-gate carbon accounting framework.

Upstream processes such as feedstock harvesting, collection, and preprocessing prior to delivery, and downstream processes, including fuel distribution and combustion, are excluded from the facility mass and energy balances. These processes are, however, incorporated separately in the life-cycle carbon intensity framework used to support LCFS and RFS credit valuation.

Total facility mass is conserved by allocating all incoming material across renewable diesel, biochar, aqueous and gas-phase process streams, and solid residues (e.g., ash and inert fractions), such that:

$$\sum \boldsymbol{m}_{\mathbf{in}} = \sum \boldsymbol{m}_{\mathbf{out}}$$

where m_{in} represents the mass flow of all feedstock inputs and m_{out} represents the combined mass flow of all products and residual output streams.

5.5.2 Feedstock energy input (renewable diesel train)

The total annual chemical energy input delivered to the renewable diesel (RD) train is calculated as:

$$\boldsymbol{E}_{\mathbf{feed}} = \sum_{k} \boldsymbol{m}_{k,\mathbf{RD}} \cdot \boldsymbol{LHV}_{k}$$

where $m_{k,\text{RD}}$ is the annual dry mass of feedstock $k$routed to the RD train (kg.yr^{-1}), and LHV_k is the corresponding lower heating value (MJ.kg^{-1}). Feedstock-specific LHV values are assumed to be 18.0 MJ.kg^{-1} for forest residues, 10.3 MJ.kg^{-1} for agricultural residues, and 12.6 MJ.kg^{-1} for MSW-derived RDF. Because a fixed fraction of clean biomass is diverted to the biochar train (Section 4.3.6), the biomass mass entering the RD train reflect this routing constraint (i.e., $m_{k,\text{RD}} = m_k(1 - s_{\text{py}})$ for forest and agricultural residues, while RDF is routed entirely to the RD train).

5.5.3 Renewable Diesel Production and Energy Output

Within the RD train, Fischer–Tropsch (FT) waxes are upgraded through hydrocracking and isomerization to produce ASTM-compliant renewable diesel. Hydrogen demand for upgrading is estimated at approximately 2–4 wt% of the liquid hydrocarbon product and is supplied internally via syngas processing and conditioning systems [34, 140]. The annual energy output in renewable diesel is calculated as:

$$\boldsymbol{E}_{\mathbf{RD}} = \boldsymbol{Q}_{\mathbf{RD}} \cdot \boldsymbol{LHV}_{\mathbf{RD}}$$

where Q_{RD} is annual renewable diesel production (kg.yr^{-1} or gal yr^{-1}), and LHV_{RD} is the energy content of renewable diesel. Renewable diesel is assigned to 43 MJ.kg^{-1} or 130.48 MJ.gal^{-1} on a lower heating value basis [165].

5.5.4 Plant-level fuel conversion efficiency

Plant-level conversion efficiency to liquid fuel is defined on an energy basis as:

$$\boldsymbol{\eta}_{\mathbf{fuel}} = \frac{\boldsymbol{E}_{\mathbf{RD}}}{\boldsymbol{E}_{\mathbf{feed}}}$$

where E_{feed} represents the chemical energy input to the RD train and E_{RD} represents the energy content of the produced renewable diesel. Under the fixed technology configuration applied in this study, the modeled system achieves an average conversion efficiency of approximately 46–47%, consistent with reported performance ranges for commercial-scale oxygen-blown gasification–FT systems [22, 166, 167].

5.5.5 Carbon Intensity of Renewable Diesel (LCFS Basis)

The fuel-cycle carbon intensity (CI) of renewable diesel is calculated as:

$$CI_{RD} = \frac{E_{LC}}{E_{RD}}$$

where E_{LC} is the total lifecycle greenhouse gas emissions allocated to renewable diesel (gCO_2e per year) and $E_{RD}$is the annual renewable diesel energy output (MJ per year). This methodology follows the California Low Carbon Fuel Standard (LCFS), which applies a GREET-based lifecycle accounting framework to quantify emissions across feedstock supply, conversion, and fuel delivery pathways [165, 168]. For blended-feedstock scenarios, the pathway CI is computed as an energy-weighted average of the feedstock-specific lifecycle CI values (**Table 7**), consistent with LCFS multi-feedstock reporting conventions [169]. Allocation of emissions and carbon benefits between renewable diesel and biochar is performed using established co-product accounting approaches for thermochemical biorefineries with integrated carbon management co-products [50].

Table 7. Carbon intensity calculation and durable removal are used for carbon benefit calculation.

Descriptions	Mass/Values	Basis
LCFS Credit Value ($ per MT CO_2e)	55	[170]
RFS Credit Value (Biochar) $/ton	50	[171]
LCFS CI Benchmark (gCO_2e/MJ)	80.17	[168, 169]
CI for Biomass to Fischer-Tropsch Diesel (gCO_2e per MJ)	6.02	[168, 169]
Biochar Yields (Fast Pyrolysis) from Forest residues (%)	20	[161, 162]
Biochar Yields (Fast Pyrolysis) from Agriculture residues (%)	17	[161, 162]
Carbon contains in Forest residue derived biochar (%)	75	[172, 173]
Carbon contains in Agriculture residue derived biochar (%)	65	[172, 173]

5.5.6 Carbon Flow Accounting and Co-Product Allocation (No CCS)

Carbon capture and storage (CCS) is not included in the process design or economic model. Consequently, the climate-performance results presented here reflect only: (i) avoided emissions associated with displacement of conventional California diesel by renewable diesel, and (ii) durable carbon sequestration associated with biochar storage or soil application, treated as carbon removal with ≥100-year permanence.

No credit is taken for point-source CO_2 capture, transport, or geologic storage, and process CO_2 is assumed to be released within the facility boundary.

Facility-level carbon accounting tracks the fate of feedstock carbon through three principal pools: (1) carbon stored in renewable diesel, (2) carbon retained in biochar as durable sequestration, and (3) carbon released as gaseous process emissions.

The annual incoming carbon from feedstock k is calculated as:

$$\boldsymbol{C}_{\text{in},k} = \boldsymbol{m}_k \cdot \boldsymbol{f}_{C,k}$$

where m_k is the annual dry feedstock mass entering the facility (kg per year) and $f_{C,k}$ is the dry-basis carbon fraction of feedstock k. Carbon fractions are assigned as 50.84% for forest residues [115], 34.07% for agricultural residues [119], and 53.12% for RDF [3]. These values are consistent with published characterization datasets and RDF specification standards. This mass-balance framework follows standard carbon accounting practices for thermochemical conversion systems and ensures conservation of carbon across the facility boundary [174, 175].

5.5.7 Avoided Emissions from Renewable Diesel Displacement and LCFS Credit Revenue

Annual avoided emissions from displacing of conventional California diesel with renewable diesel (RD) are calculated using the Low Carbon Fuel Standard (LCFS) crediting framework.

Avoided emissions represent the reduction in greenhouse gas emissions per unit energy when the modeled RD carbon intensity is lower than the petroleum diesel reference value for

LCFS compliance. Annual avoided emissions are calculated as:

$$E_{\text{avoided}} = (CI_{\text{ref}} - CI_{\text{RD}}) \cdot E_{\text{RD}} \cdot 10^{-6}$$

$$N_{\text{LCFS}} = \max(0, E_{\text{avoided}})$$

where $CI_{\text{ref}} = 80.17$ gCO_2e/MJ is the California diesel reference carbon intensity under the LCFS [168, 169], CI_{RD} is the modeled carbon intensity of renewable diesel (gCO_2e per MJ), E_{RD} is the annual renewable diesel energy output ($MJ.yr^{-1}$), and 10^{-6} converts gCO_2e to metric tons CO_2e. This estimate provides the regulatory basis for LCFS credit generation, where each metric ton of CO_2e reduction relative to the diesel baseline corresponds to one LCFS credit under standard accounting conventions [169, 176]. N_{LCFS} represents the annual LCFS credit quantity (tCO_2e credits per year). LCFS credit revenue is calculated in Section 4.8.3 using an assumed LCFS market price [170].

5.5.8 Biochar sequestration and carbon removal credit calculation (durable CDR)

Durable carbon removal associated with biochar production is quantified by converting the carbon retained in biochar into CO_2-equivalent sequestration. Biochar production is restricted to clean forest and agricultural biomass, explicitly exclusion of MSW, to maintain product quality and ensure defensible carbon accounting and eligibility for carbon removal crediting.

The annual carbon stored in biochar is calculated as:

$$C_{\text{BC}} = \sum_i \left(Q_{\text{BC},i} \cdot f_{C,\text{BC},i}\right)$$

and the corresponding CO_2-equivalent sequestration is:

$$E_{\text{seq}} = C_{\text{BC}} \cdot \frac{44}{12}$$

where $Q_{\text{BC},i}$ is annual biochar production from biomass type i (t/yr, dry basis), $f_{C,\text{BC},i}$ is the biochar carbon fraction (tC per t biochar), and 44/12 converts carbon mass to CO_2-equivalent mass.

Biochar carbon fractions are assumed to be 0.75 for forest-derived biochar and 0.65 for agricultural-residue biochar, consistent with typical fixed-carbon retention values for slow pyrolysis of woody and herbaceous biomass [172, 173]. Biochar sequestration is treated as durable carbon removal with a conservative permanence threshold of ≥100 years, consistent with established CDR accounting conventions and crediting frameworks [177, 178].

The annual durable carbon removal credit quantity is defined as:

$$N_{\text{CDR}} = E_{\text{seq}}$$

where N_{CDR} is expressed in tCO_2e per year, with one credit per metric ton of CO_2e durably removed).

CDR Credit Intensity Per Ton of Biochar

To express carbon removal performance on a per-unit biochar basis, a biochar-specific carbon removal factor (tCO_2e per ton biochar) is calculated as:

$$\boldsymbol{\phi}_{\mathbf{CDR,BC}} = \frac{\boldsymbol{E}_{\mathbf{seq}}}{\boldsymbol{Q}_{\mathbf{BC,tot}}}$$

where $Q_{\mathrm{BC,tot}} = \sum_i Q_{\mathrm{BC},i}$ is total annual biochar production (ton per year). Under the assumed carbon fractions, the theoretical sequestration factors are:

Forest biochar: $\boldsymbol{\phi}_{\mathbf{CDR,BC,F}} = \mathbf{0.75} \cdot \frac{\mathbf{44}}{\mathbf{12}}$

$$= \mathbf{2.75\ tCO_2e\ per\ ton\ biochar}$$

Agricultural biochar:

$$\boldsymbol{\phi}_{\mathbf{CDR,BC,A}} = \mathbf{0.65} \cdot \frac{\mathbf{44}}{\mathbf{12}}$$
$$= \mathbf{2.38\ tCO_2e\ per\ ton\ biochar}$$

For blended biochar production, the facility-level credit intensity is calculated as a weighted average based on the relative contribution of each feedstock type to total biochar output. This approach is consistent with carbon accounting methodologies that link credit generation directly to measured carbon retention in the solid product.

Published estimates of durable carbon removal from biochar typically range from approximately 1.9 to 2.7 tCO_2 per ton of biochar, depending on feedstock characteristics, process conditions, carbon stability assumptions, and crediting methodologies [179–183].

Monetization in the Financial Model

Biochar carbon removal credit revenue is incorporated into the financial model as:

$$\mathbf{R}_{\mathbf{CDR}} = \mathbf{N}_{\mathbf{CDR}} \cdot \mathbf{P}_{\mathbf{CDR}}$$

where P_{CDR} is the assumed CDR credit price ($100/$tCO_2e$) applied in the TEA. This modular formulation separates physical carbon removal accounting from market assumptions, ensuring transparency and analytical flexibility. Credit revenues can be readily re-evaluated under alternative price scenarios or registry methodologies without modifying the underlying mass, energy, or carbon balances.

5.5.9 RFS (RIN) Credit Accounting for Renewable Diesel

Annual Renewable Identification Number (RIN) revenue is estimated using the U.S. EPA Renewable Fuel Standard (RFS) accounting framework. Under the RFS, qualifying renewable fuel volumes generate RINs based on the fuel's Equivalence Value (EqV), expressed as RINs per physical gallon of fuel. RIN eligibility and D-code classification are applied separately by feedstock stream to maintain policy consistency and avoid overstating credit value [184].

Under the EPA-approved pathways applied in this analysis:

- Renewable diesel derived from forest residues and agricultural residues is classified under Row L with D-code 7 (cellulosic diesel/cellulosic biofuel or biomass-based diesel).
- Renewable diesel derived from MSW is classified under Row P with D-code 5 (advanced biofuel).

The corresponding "RIN – Unverified" market price series is applied for each D-code, using representative values of $2.39 per RIN for D7 and $1.02 per RIN for D5. To avoid overstating potential RFS value and to reflect project-specific eligibility screening, several conservative adjustments are applied: (i) 10% of incoming clean biomass is excluded from RIN generation to account for uncertainty, handling losses, or non-creditable material; (ii) 26% of forest-residue input is excluded due to assumed non-eligibility associated with federal forest land origin (i.e., only 74% of forest residues are credited); and (iii) MSW/RDF-derived contributions are excluded from RIN claims because the mixed waste stream is assumed unable to reliably document and certify the biogenic fraction required for RFS compliance in this base-case assessment.

Although MSW is processed as RDF for conversion, its RFS eligibility is treated as uncertain and conservatively excluded from credit generation. Under these assumptions, the eligible renewable diesel volume for RIN generation is calculated as:

$$\mathbf{V_{RD,elig} = V_{RD,total} \cdot f_{elig}}$$

where $V_{\mathrm{RD,\,total}}$ is total renewable diesel production (gal yr^{-1}), and f_{elig} is the combined eligibility fraction applied to the renewable share of production. Assuming proportional allocation of RD output to the energy share of eligible clean biomass, the eligibility factor is defined as:

$$\boldsymbol{f_{\mathrm{elig}} = (1 - f_{\mathrm{exclude}}) \cdot (0.74\, s_{\mathrm{F}} + 1.00\, s_{\mathrm{A}})}$$

where $f_{\mathrm{exclude}} = 0.10$, and s_{F} and s_{A} are the forest and agricultural residue shares of clean biomass supplied to the RD train (energy or dry-mass basis, consistent with model implementation). The equivalence value (EqV), representing the number of RINs generated per gallon of renewable diesel, follows EPA's methodology [185–187]:

$$\mathbf{EqV} = \left(\frac{\mathbf{R}}{\mathbf{0.972}}\right) \cdot \left(\frac{\mathbf{EC}}{\mathbf{77{,}000}}\right)$$

where R is the renewable content of the fuel (fraction on an energy basis), and EC is the lower heating value of renewable diesel in Btu gal^{-1} . For renewable diesel produced entirely from qualifying renewable biomass, $R \approx 1.0$, resulting in an EqV typically near 1.7 RIN per gallon, consistent with established RFS equivalency conventions [187].

Total annual RIN generation for each eligible fuel stream *j* is computed as:

$$N_{RIN,j} = V_{RD,j} \cdot EqV_j$$

where $V_{RD,j}$ is the eligible renewable diesel volume associated with pathway *j*, and EqV_j is the corresponding equivalence value.

5.5.10 Total Climate Benefit

The total annual climate benefit of the integrated biorefinery is defined as the combined contribution of fossil fuel displacement (avoided emissions) and durable carbon removal:

$$E_{\text{total}} = E_{\text{avoided}} + E_{\text{seq}}$$

where E_{avoided} represents avoided emissions from replacing petroleum diesel with renewable diesel, and E_{seq} represents durable carbon removal through biochar sequestration. Because carbon capture and storage (CCS) is not included in the system design, no additional mitigation credit is assigned to process CO_2 capture or geologic storage. This combined accounting reflects the dual climate function of the facility – producing low-carbon transportation fuels while simultaneously delivering durable carbon removal. As such, it is consistent with emerging evaluation approaches for integrated biorefineries that generate both fuel-based emissions reductions and carbon removal co-products, enabling climate benefits beyond conventional fuel-only pathways [1, 188–190]. The resulting credit quantities are monetized in Section 4.8.3 using assumed market prices for LCFS, RFS (RIN), and carbon removal credits.

5.5.11 Summary of Key Parameters and Yield Assumptions

The mass, energy, and carbon balance calculations described above rely on a consistent set of conversion assumptions that link feedstock inputs to renewable diesel and biochar outputs. **Table 8** summarizes the key parameters applied across all four scenarios, including feedstock routing rules, preprocessing specifications, gasification–FT performance assumptions, and biochar yield and permanence values. Unless otherwise specified, parameters are held constant across scenarios to ensure comparability. Variations are introduced only where they are inherently feedstock-dependent (e.g., lower heating values and biochar yields) or explicitly scenario-driven (e.g., the share of RDF routed to the RD train). Together, these assumptions provide the basis for reproducing the modeled annual product yields, energy outputs, carbon flows, and climate benefit metrics presented in the results section.

Table 8. Key conversion assumptions and yield parameters (used in mass/energy/carbon model).

A) Feedstock routing and preprocessing assumptions

Parameter	Symbol	Value	Units	Applies to	Notes / Implementation
Total plant intake (dry)	F_{day}	1,000	BDT per day	All scenarios	Constant across scenarios
Operating days	D	330	Days per year	All scenarios	Capacity factor = 90%
Annual intake	F_{yr}	330,000	BDT per year	All scenarios	$F_{yr} = F_{day} \cdot D$
Clean biomass diversion to pyrolysis	s_{py}	10%	Fraction of clean biomass	Forest + Ag residues	Applied to forest and Ag; RDF excluded
MSW routed to pyrolysis	—	0	—	MSW	Explicitly excluded from biochar production
Moisture after drying (gasifier feed)	MC_{gas}	≤20	wt% (wet basis)	All gasifier feeds	Achieved using recovered process heat where modeled [130, 131]
Moisture after drying (pyrolysis feed)	MC_{py}	≤15	wt% (wet basis)	Pyrolysis feeds	Improves biochar yield and quality [132, 133]

B) Renewable diesel train (Gasification → FT → Upgrading) assumptions

Parameter	Symbol	Value	Units	Applies to	Notes / Implementation
Gasification mode	—	O_2-blown	—	RD train	Oxygen supplied via ASU (no CCS) [136] [137] [138]
Cold gas efficiency	CGE	0.69	—	RD train	Representative value within reported commercial range [191], [138]
Target syngas H_2/CO ratio to FT	$R_{H2/CO}$	2.0–2.2	mol/mol	RD train	Achieved via WGS and/steam addition [139]
FT operating regime	—	LTFT	—	RD train	Cobalt catalyst under conventional operating conditions [143, 144]
Overall energy efficiency to liquid fuels	η_{liq}	0.467	fraction (LHV basis)	RD train	~46.7%, conversion efficiency. [34, 140]
RD energy content	LHV_{RD}	130.48	MJ per gallon	RD product	Used in LCFS CI and avoided emissions calculations [165, 169]
RD volumetric yield	Y_{RD}	scenario-specific OR constant	Gal per BDT	RD train	Corresponds to ~13.6–14.6 million gal/year (Section 4.10 results)

C) Biochar train (Slow Pyrolysis) assumptions

Parameter	Symbol	Value	Units	Applies to	Notes / Implementation
Pyrolysis temperature	T_{py}	450–550	°C	Biochar train	Representative range for slow pyrolysis conditions [159]
Residence time	τ_{py}	30–60	minutes	Biochar train	Consistent with slow pyrolysis operation [158]
Biochar mass yield (forest)	$Y_{BC,F}$	0.20	ton biochar per ton dry feed	Forest → biochar	Literature-based yield for woody biomass [161, 162]
Biochar mass yield (ag)	$Y_{BC,A}$	0.17	Ton biochar per ton dry feed	Ag → biochar	Lower yield reflects herbaceous biomass characteristics [161, 162]
Biochar carbon fraction (forest char)	$f_{C,BC,F}$	0.75	Ton Carbon per ton biochar	Forest-derived biochar	Used for carbon sequestration calculations
Biochar carbon fraction (ag char)	$f_{C,BC,A}$	0.65	Ton Carbon per ton biochar	Ag-derived biochar	Used for carbon accounting [163, 164]
Permanence for carbon accounting	—	≥100	years	Biochar	Treated as durable carbon removal; no CCS [163, 164]

5.6 Capital Cost Estimation (CAPEX)

5.6.1 Capex Basis and Plant Scope

Capital expenditures for the Fresno County integrated biorefinery are estimated using a hybrid approach that combines literature-calibrated values with engineering bottom-up methods. This approach is consistent with standard chemical engineering cost estimation practices for early commercial thermochemical facilities. The facility is modeled at a fixed throughput of 1,000 BDT equivalent per day (approximately 330,000 BDT-eq per year), assuming continuous operations (24 hours per day, 330 days per year). Capital costs are reported to be using two standard metrics to support transparency and alignment with discounted cash-flow (DCF) analysis:

- ***Total Plant Cost (TPC):*** Represents the fully installed cost of the facility, including direct costs (major process equipment, installation, site development, buildings, utilities, and supporting infrastructure) and indirect costs (engineering, permitting, construction management, and contingency).
- ***Total Capital Investment (TCI):*** Represents the total project-level capital requirements used in financial analysis. TCI is calculated as TPC plus owner and project-related costs, including engineering, procurement, and construction (EPC) fees, land acquisition, working capital, and cost escalation.

This two-tiered cost structure reflects standard techno-economic analysis (TEA) practice, in which process-level installed costs are first developed on a Total Plant Cost basis, and then augmented with indirect and owner costs to derive a finance-ready capital investment estimate.

5.6.2 Systematic Capex Development Approach

(a) Literature calibration and cost-year normalization

Published techno-economic analyses (TEAs) for comparable systems, including gasification–FT/upgrading trains and biomass solids processing, with "nth-plant" analogs where available, were used to establish a reference CAPEX envelope and to verify the integration and balance-of-plant assumptions. When reference studies reported costs in different base years, all costs were normalized to the current study year using a standard cost-index inflator, such as the Chemical Engineering Plant Cost Index (CEPCI) (**Appendix ST6** and **Appendix ST7**):

$$CAPEX_y = CAPEX_{basis} \times \frac{CEPCI_y}{CEPCI_{basis}}$$

where *CAPEXy* is the cost in the target year, *CAPEXbasis* is the cost reported in the reference study, and $CEPCI_y$ and

$CEPCI_{basis}$ are the cost index values for the target and base years, respectively.

(b) Capacity scaling for benchmarking

When literature benchmarks were reported at capacities differing from the Fresno County facility design, costs were scaled for the project throughput using the conventional power-law scaling approach:

$$C_2 = C_1 \left(\frac{Q_2}{Q_1}\right)^n$$

where C_2 is the scaled cost, C_1 is the reference cost, Q_2 is the Fresno County design capacity, Q_1 is the reference capacity, and n is the scaling exponent. A value of $n \approx 0.6$ is applied for major process equipment when civil/site scope is dominant.

This benchmarking and scaling process provides a reasonableness check against published studies. Final CAPEX estimates for the Fresno County facility are anchored on a bottom-up process-island build, integrating literature-informed scaling with engineering-level equipment sizing and installation factors.

(c) Bottom-up installed direct-cost

Installed direct costs were developed for each major facility section to reflect the integrated configuration of the Fresno County biorefinery. The direct cost captures all major equipment and installation expenses associated with plant operations and infrastructure and forms the foundation for TPC and TCI calculations. Key components include:

- ***Site, civil, and buildings*** – Includes site development, grading, foundations, loading facilities, administrative and laboratory buildings, and general construction. Feedstock receiving & preparation – Covers biomass receiving, handling, storage, and preprocessing. For handling municipal solid waste (MSW)/refuse-derived fuel (RDF), this also includes dedicated receiving and processing equipment.
- ***Conversion and upgrading*** – Includes all major thermochemical conversion units and associated systems: oxygen-blown gasification, syngas conditioning and cleanup, FT synthesis, product upgrading, product storage and loadout infrastructure.
- ***Biochar train*** – Encompasses the slow pyrolysis reactor, solids handling systems, biochar conditioning and storage, and off-gas management and tie-ins. All costs are represented on an installed basis.
- ***Utilities and offsites*** – Cover power and steam generation, water treatment, air pollution control, compressed gases, and other supporting infrastructure required to sustain continuous operation.

5.6.3 Scenario Mapping and CAPEX Drivers

The Fresno County biorefinery is modeled at a fixed inbound throughput of 1,000 BDT-eq per day. Under this design, the core conversion and upgrading backbone – including gasification, FT synthesis, upgrading, utilities, core product handling, plant controls, and base infrastructure – is treated as common capacity across all scenarios. Differences in capital expenditures between scenarios are therefore primarily driven by front-end feedstock receiving, preprocessing and cleanup/emissions-control requirements, particularly where RDF/MSW is integrated.

Accordingly, two CAPEX bases are applied:

- ***Biomass-only basis (Scenarios 1–2):*** Includes receiving and preprocessing for clean biomass only. Baseline cleanup and emissions-control systems are sufficient for cleaning feedstocks.
- ***MSW-integrated basis (Scenarios 3–4):*** Adds dedicated RDF/MSW receiving and conditioning infrastructure. Requires a more robust contaminant-control envelope (e.g., enhanced gas cleanup and emissions-control systems). Results in higher installed direct costs and proportionally higher indirect and project-level costs.

5.6.4 Indirect Costs, TPC, And TCI Build-up

Indirect costs were applied as explicit fractions of installed direct costs to account for engineering, procurement, construction (EPC) delivery requirements, and the uncertainties inherent in early commercial-scale facilities. The modeled indirect cost structure is summarized in **Table 9** and includes:

- ***Permitting & licensing:*** 5% of installed direct cost
- ***Engineering services:*** 5% of installed direct cost
- ***Contingency / risk allowance:*** 30% of installed direct cost
- ***Total indirect costs:*** 40% of installed direct cost

These indirect costs, when added to installed direct costs, define the Total Plant Cost (TPC).

To convert TPC to Total Capital Investment (TCI) for financial analysis, additional owner/project adders are applied:

- ***Design-build/EPC fee:*** 5% of TPC
- ***Land & working capital:*** 10% of TPC
- ***Escalation:*** 5% of TP

Table 9. Fresno County Biorefinery Capital Cost Breakdown (1,000 BDT/day, 2024 $M) $.

Description	Scenario 1 & 2 (Biomass only)	Scenario 3 & 4 (MSW-integrated)
Site, Civil, Structural & Construction	30.99	30.99
Feedstock Handling & Preparation (biomass + RDF)	21.75	21.75
Air Separation Unit (ASU)	18.69	18.69
Gasification Island	27.02	27.02
Syngas Cleanup	28.08	28.08
FT Synthesis	56.25	56.25
Fuel Upgrading	37.28	37.28
Biochar Train	12.50	15.50
Utilities & Offsites	21.10	25.50
Total Gross Direct Cost	***253.65***	***261.05***
Permitting & Licensing (5% of direct cost)	12.68	13.05
Engineering Services (5% of direct cost)	12.68	13.05
Contingency/Risk Allowance (30% of direct cost)	76.10	78.32
Total Indirect Cost (40% direct cost)	***101.46***	***104.42***
Total Plant Cost (TPC) = Direct cost + indirect cost	***355.11***	***365.47***
Design-Build Fee (5 % of TPC)	17.76	18.27
Land & Working Capital (10% of TPC)	35.51	36.55
Escalation (5% of TPC)	17.76	18.27
Total Capital Investment (TCI)	***426.14***	***438.57***

5.6.5 Capital Annualization for Levelized-Cost Metrics

For economic evaluation and levelized-cost analysis, the Total Capital Cost Investment (TCI) is converted to an equivalent annual capital charge using the standard capital recovery factor (CRF):

$$CRF = \frac{i(1+i)^n}{(1+i)^n - 1}$$

where i is the discount rate (10% per year) and n is project life (20 years). Under these assumptions, the CRF is 0.11746. The annualized capital charge is then calculated as:

$$C_{\text{cap,ann}} = TCI \times CRF$$

This annualized capital cost is consistently applied in the TEA to compute levelized fuel costs and financial performance metrics including NPV, IRR, payback period, DSCR, enabling direct comparison across feedstock configurations.

5.6.6 Capex Sensitivity Design

To account for capital cost uncertainty associated with early-commercial deployment of integrated thermochemical biorefineries, a one-way sensitivity analysis was performed. In this analysis, the base-case total installed capital (TCI) is varied by ±40%, while all technical, operating, and market assumptions are held constant. This sensitivity range reflects plausible variability in vendor pricing, equipment supply chain variability, site-specific conditions and construction complexity, early commercial learning and engineering risk and inflation and escalation uncertainty. The resulting CAPEX ranges provide bounds for financial and levelized-cost modeling, supporting robust policy and investment evaluation. Estimated high- and low-cost scenarios are summarized in **Table 10**, illustrating the potential impact on TCI and annualized capital charges for each scenario.

Table 10. CAPEX variability ranges for sensitivity analysis (TCI basis, $M).

Scenario	−40%	−20%	Base	+20%	+40%
Scenario 1	255.7	340.9	426.16	511.3	596.6
Scenario 2	255.7	340.9	426.16	511.3	596.6
Scenario 3	263.1	350.1	438.6	526.2	614.0
Scenario 4	263.1	350.1	438.6	526.2	614.0

5.7 Operating Cost Estimation (OPEX)

Operating expenditure (OPEX) represents the annual costs required to operate the Fresno County biorefinery at steady state and serves as a central input to the discounted cash flow (DCF) analysis. To ensure transparency, cross-scenario comparability, and replicability, OPEX is structured into fixed operating costs and variable operating costs. Fixed costs are primarily driven by facility scale and staffing requirements and are therefore held constant across all scenarios, while variable costs scale with feedstock composition, material flows, and processing intensity.

Because the facility throughput is constant at 1,000 BDT per day (330 operating days per year), scenario-level differences in OPEX are intentionally attributed to feedstock strategy and routing rather than to changes in plant size, workforce, or core equipment configuration.

5.7.1 Fixed Operating Costs

Fixed OPEX represents expenditures that do not vary materially with production rate under continuous operation labor and other costs that do not vary materially with production rate under continuous operation. Labor is held constantly across all scenarios because staffing is driven by 24/7 operations of the core thermochemical conversion train. B Routine maintenance and minor repairs are largely independent of throughput but scale modestly with capital intensity (TPC). MSW-integrated scenarios (Scenarios 3–4) have slightly higher TPC, resulting in proportionally higher maintenance costs. Taxes and insurance are also scaled with TPC, reflecting modest increases in facility value in MSW cases (**Table 11**).

Table 11. Fixed operating cost breakdown (2024 $M).

Fixed OPEX Category	Scenarios 1–2	Scenarios 3–4	Notes
Labor	5.23	5.23	24/7 staffing basis
Maintenance	14.91	15.35	Scales with installed cost (TPC-linked)
Taxes & insurance	4.55	5.48	Modeled as a fraction of TPC (higher for MSW-integrated basis)
Other fixed costs	0.18	0.18	Security, IT/admin overhead, general services
Total Fixed OPEX	**24.87**	**26.24**	

5.7.2 Variable Operating Cost and Unit Assumptions

Variable OPEX are directly dependent on feedstock composition, process intensity, and disposal requirements. Key components include:

- ***Feedstock procurement:*** Costs for forest biomass, agricultural residues, and MSW, including delivery and handling fees.
- ***Electricity and utilities:*** Power, steam, and other utility consumption, which scale with processing intensity.

- ***Transport:*** Inbound feedstock logistics and product distribution.
- ***Catalysts and consumables:*** Materials required for gasification, syngas cleanup, Fischer–Tropsch synthesis, and biochar pyrolysis.
- ***Wastewater treatment:*** Treatment of process water streams from conversion and upgrading operations.
- ***Solid waste disposal:*** Management of ash, inert residues, and pyrolysis rejects.
- ***Product logistics:*** Storage, handling, and loading of renewable diesel and biochar for delivery.

Table 12 summarizes the unit assumptions and representative cost drivers applied across the four scenarios, providing the basis for scenario-specific variable OPEX calculations.

Table 12. Assumptions for utilities, consumables, and waste treatment (2024 $).

Parameters	Value/Units	Basis
Electricity Cost ($/kWh)	0.23	[192]
Net specific Electricity Use (kWh/kg RD)	0.9	[193]
Ash/slag disposal fee ($/ton)	43	[194]
Rejected inerts/metals from RDF of incoming MSW	10%	[58, 195]
Water consumption (gal/day)	200	Assumption
Water price ($/kgal)	3.64	[196]
Wastewater flow volume	40%	Assumption
Wastewater flow charge ($/gal)	0.749	[196]
Waste and sludge disposal fee ($/ton)	10	[197]
Renewable diesel transport/loading ($/gal)	0.08	[198]
Biochar packaging/transport ($/ton)	30	[199]

5.7.3 Variable OPEX by Scenario

Variable OPEX is primarily driven by feedstock procurement and disposal costs, with purchased electricity as a secondary contributor (**Table 13**). As the RDF/MSW share increases, net feedstock costs decline relative to clean biomass, but disposal and solid-handling costs increase due to preprocessing rejects and inerts. Other costs, including transportation, catalysts/consumables, water use, and product handling, contribute modestly to total variable OPEX.

Table 13. Variable operating cost breakdown by scenario ($M/yr, 2024$).

Variable OPEX Category	Scenario 1 (100% FR)	Scenario 2 (50FR/50AG)	Scenario 3 (50FR/25AG/25MSW)	Scenario 4 (25FR/25AG/50MSW)
Feedstock procurement (at-source)	9.90	9.08	8.42	7.01
Feedstock insurance	0.20	0.18	0.17	0.14
Electricity (net purchased)	3.58	2.95	3.03	2.81
Feedstock transportation	1.84	1.84	1.84	1.84
Catalysts & consumables	0.10	0.10	0.10	0.10
Water consumption	~0.00	~0.00	~ 0.00024	~ 0.00024
Wastewater treatment	0.02	0.02	0.02	0.02
Solid waste disposal	0.64	0.55	0.72	0.94
Product handling & storage	1.67	1.37	1.36	1.20
Total Variable OPEX	**17.96**	**16.09**	**15.66**	**14.05**

5.7.4 Total Annual Operating Costs Used in The DCF Model

Total annual operating costs for Fresno County biorefinery are calculated as the sum of fixed and variable OPEX (**Table 14**). Because fixed operating costs remain largely invariant across scenarios, total OPEX trends are driven primarily by feedstock composition and MSW integration. While higher MSW utilization reduces net feedstock procurement costs, it increases preprocessing rejects and inert disposal, introducing offsetting cost burdens. These dynamics must be considered alongside renewable diesel yield, biochar production, and policy credit generation when evaluating overall economic performance.

Table 14. Total annual operating costs by scenario (SM/year, 2024$).

Scenario	Fixed OPEX	Variable OPEX	Total OPEX
Scenario 1 (100% forest)	24.87	17.96	42.83
Scenario 2 (50% forest, 50% Ag)	24.87	16.09	40.96
Scenario 3 (50% Forest / 25% Ag / 25% MSW)	26.24	15.66	41.90
Scenario 4 (50% Forest / 25% Ag / 25% MSW)	26.24	14.05	40.29

5.8 Financial Modeling and Economic Assumptions

This section defines the economic, financial, operating, and market assumptions used in the discounted cash flow (DCF)-based techno-economic assessment (TEA) of the Fresno County biorefinery. The primary objectives are to: (i) establish clear boundary conditions for replication of the financial model, (ii) ensure traceability between input assumptions and modeled outputs, and (iii) isolate scenario-driven impacts, including feedstock composition, conversion performance, and carbon-intensity performance, by holding all non-scenario parameters constant unless otherwise specified.

5.8.1 Capital Structure and Financing Assumptions

Project economics are evaluated using a levered (equity) discounted cash flow (DCF) framework consistent with standard project-finance practices for commercial-scale renewable fuels infrastructure. Total project capital is defined on a Total Capital Investment (TCI) basis and is financed through a fixed capital structure comprising senior debt and sponsor equity (**Table 15**). Key assumptions include:

Debt Financing:

- Debt is assumed to be drawn in full at financial close (Year 0).
- Repayment occurs over the 20-year operating period using a level-payment (annuity) amortization schedule.

Equity Evaluation:

- Financial performance is assessed from the equity perspective.
- Key metrics, including net present value (NPV), internal rate of return (IRR), and payback period, are calculated on an after-tax basis using annual net cash flow to equity.

Table 15. Financing and capital structure assumptions (constant across scenarios).

Parameter	Symbol	Value	Units	Notes
Debt fraction	f_d	60%	% of TCI	Leveraged project structure [200, 201]
Equity fraction	f_e	40%	% of TCI	$f_d + f_e = 1$
Debt term	N_d	20	years	Fully amortized [113]
Interest rate (nominal)	i_d	10%	%	Equal annual payment assumption
Discount rate	r	10%	%	Used for equity NPV discounting [200]

The project is modeled using a 60/40 debt–equity capital structure, consistent with typical leverage observed in commercial-scale bioenergy and renewable fuel infrastructure projects. Total capital investment (TCI) is allocated at financial close (Year 0) as:

$$D_0 = f_d \cdot TCI, \qquad E_0 = f_e \cdot TCI$$

where D_0 is initial debt and E_0 is sponsor equity.

Debt is repaid over a 20-year term using a fully amortizing, level-payment (annuity) structure, resulting in a constant annual debt service (ADS) that includes both principal and interest. An amortization schedule is constructed to determine year-specific allocations of interest and principal.

Annual debt service (principal + interest) under an annuity structure is:

$$ADS = D_0 \cdot \frac{i_d(1 + i_d)^{N_d}}{(1 + i_d)^{N_d} - 1}$$

An annual amortization schedule is generated to compute year-specific interest and principal:

$$Interest_t = i_d \cdot Debt_{t-1},$$

$$Principal_t = ADS - Interest_t$$

$$Debt_t = Debt_{t-1} - Principal_t$$

This treatment ensures that annual debt service (ADS) enters the cash flow as a fixed obligation, interest payments are tax-deductible, reducing taxable income, and principal repayments are excluded from tax calculations, consistent with standard project-finance accounting practices. A 60% debt share falls within commonly reported ranges (50%-70%) for infrastructure-scale bioenergy and renewable fuel projects . A 20-year tenor aligns with the assumed project operating life and ensures full debt repayment within the analysis period [113]. The 10% nominal interest rate represents a mid-range financing cost for early-commercial thermochemical systems, and the 10% equity discount rate is applied consistently across scenarios to enable comparable NPV evaluation [200].

5.8.2 Discounting, Depreciation, and Taxes

Financial performance is evaluated over a 20-year operating life. A nominal discount rate of 10% is applied to equity cash flows to compute NPV. Depreciation and taxation are modeled using a transparent, conservative framework, as summarized in **Table 16**.

Table 16. Tax and depreciation assumptions.

Parameter	Value	Units	Notes
Federal corporate income tax rate	21%	%	Applied to taxable income
Depreciation method	Straight-line	—	Conservative accounting
Depreciation period	20	years	Matches project life
State taxes	Not modeled	—	Excluded for simplicity/replicability

Annual depreciation (*Dep*) is calculated using straight-line depreciation over the project life:

$$\boldsymbol{Dep = \frac{B_{dep}}{n}}$$

where $n = 20$ years and B_{dep} is the depreciable basis. In this analysis, $B_{dep} = TCI$ for direct reproducibility.

Taxable income in year t is calculated on a levered basis, with interest treated as deductible expense:

$$\boldsymbol{TI_t = R_t - OPEX_t - Dep - Int_t}$$

Federal income tax (Tax_t) is:

$$\boldsymbol{Tax_t = \tau \cdot \max(0, TI_t), \tau = 0.21}$$

5.8.3 Revenue Streams and Policy Credit Treatment

Facility revenue is composed of (i) physical product sales and (ii) policy-driven environmental attribute revenues (e.g. LCFS, RIN, and carbon removal credits). To ensure comparability across scenarios, product price assumptions are held constant, allowing differences in revenue to reflect only feedstock composition, conversion performance, and carbon intensity.

(a) Product revenues

Annual revenue ($R_{prod,t}$) from physical product sales is calculated as:

$$\boldsymbol{R_{prod,t}} = \left(\boldsymbol{Q_{RD,t}} \cdot \boldsymbol{P_{RD}}\right) + \left(\boldsymbol{Q_{BC,t}} \cdot \boldsymbol{P_{BC}}\right)$$

where $Q_{\mathrm{RD,t}}$ is renewable diesel production (gal/yr), $Q_{\mathrm{BC,t}}$ is biochar production (t/yr), and P denotes constant base-case prices (**Table 17**).

Table 17. Base-case product price assumptions.

Revenue Component	Value	Units	Application
Renewable diesel price	3.50	\$/gal	Representative California market price; held constant across scenarios [203]
Biochar price	600	\$/t	Blended market value reflecting agricultural amendment and carbon-qualified biochar markets [204–206]

(b) LCFS credit revenue

LCFS revenue is calculated using the standard displacement-credit framework, based on the difference between the carbon intensity (CI) of produced renewable diesel and the California diesel reference CI. Annual LCFS revenue ($R_{LCFS,t}$) is defined as:

$$\boldsymbol{R_{LCFS,t}} = \boldsymbol{N_{LCFS,t}} \cdot \boldsymbol{P_{LCFS}}$$

where $N_{LCFS,t}$ is annual renewable diesel energy output (MJ/yr), and $P_{\mathrm{LCFS}} =$ 55 \$/tCO_2e (base case).

(c) Biochar carbon removal credit revenue (durable CDR)

Revenue from biochar is modeled as a durable carbon removal (CDR) credit, reflecting long-term carbon sequestration in biochar. Annual CRD revenue ($R_{CDR,t}$) is calculated as:

$$R_{CDR,t} = N_{CDR,t} \cdot P_{CDR}$$

where $N_{CDR,t}$ is the $P_{CDR,t}$ is the assumed durable carbon removal credit price \$50/tCO_2e.

(d) RFS / RIN credit revenue

RIN revenue ($R_{RIN,t}$) is modeled using a D-code-specific framework consistent with the U.S. Environmental Protection Agency (EPA) Renewable Fuel Standard (RFS). Eligible renewable diesel volumes generate RINs that can be monetized at prevailing market prices. Annual RIN revenue is then calculated as:

$$R_{RIN,t} = N_{D7,t} \cdot P_{D7} + N_{D5,t} \cdot P_{D5}$$

where $P_{D7,t}$ = \$2.39 per RIN and $P_{D5,t}$ = \$1.02 per RIN are the "RIN – Unverified" market price assumptions applied in the base-case TEA. This structure ensures that the reported RFS value reflects (i) feedstock-specific pathway classification, (ii) conservative eligibility screening, and (iii) D-code appropriate market pricing.

5.8.4 Total Revenue Expression

Total annual facility revenue (R_t) is defined as the sum of product sales and policy-driven credit revenues:

$$R_t = R_{prod,t} + R_{LCFS,t} + R_{CDR,t} + R_{RIN,t}$$

This modular formulation prevents double counting and enables sensitivity analysis of each revenue stream (e.g. LCFS price, RIN price, CDR credit value).

5.9 Financial Performance Metrics

5.9.1 Annual Cash Flow Formulation

Equity cash flow is calculated for each year of the project life, distinguishing between the initial investment period (Year 0) and operating years (Year 1-20).

Year 0 (financial close / construction):

$$CF_0 = -E_0 = -f_e \cdot TCI$$

Years $t = 1 \ldots 20$ (operations):

$$CF_t = (R_t - OPEX_t) - ADS_t - Tax_t$$

where $ADS_t = Int_t + Prin_t$ is total annual debt service and Tax_t is computed from taxable income (TI_t):

$$TI_t = R_t - OPEX_t - Dep - Int_t, \qquad Tax_t = \tau \cdot \max(0, TI_t)$$

5.9.2 Net Present Value (NPV)

Net Present Value (NPV) is calculated as the discounted sum of equity cash flows over the project life [207]:

$$NPV = \sum_{t=0}^{n} \frac{CF_t}{(1+r)^t}$$

where NPV is net present value (USD), CF_t is the net equity cash flow in year t(USD/yr), t is the year index with $t = 0$ representing the initial investment (financial close/construction year) and $t = 1, \ldots, n$ representing operating years, r is the equity discount rate (dimensionless; here $r = 0.10$), and n is the project operating life (years; here $n = 20$). A positive NPV indicates that discounted cash inflows exceed the initial equity investment and that the project meets or exceeds the required return under the stated assumptions.

5.9.3 Internal Rate of Return (IRR)

The equity IRR is the discount rate that makes NPV equal to zero [208]:

$$\mathbf{0} = \sum_{t=0}^{n} \frac{CF_t}{(1+IRR)^t}$$

This is fully applicable to your model and is the correct TEA-consistent definition for levered equity IRR. IRR represents the effective annualized return on equity invested in the project and is a primary metric for comparing investment attractiveness across scenarios and sensitivity cases.

5.9.4 Payback Period (Simple and Discounted)

The payback period measures the time required for cumulative equity cash flow to recover the initial investment [209]. Simple payback is the first year T in which cumulative undiscounted cash flow becomes positive. Linear interpolation may be applied if the payback point occurs between discrete years.

$$T = \min \left\{ t : \sum_{i=0}^{t} CF_i \geq 0 \right\}$$

5.9.5 Debt Service Coverage Ratio (DSCR)

The debt service coverage ratio (DSCR) is a lender-focused metric that measures the project's ability to meet scheduled principal and interest payments using cash flow available for debt service (CFADS) [208]. Consistent with project-finance convention, DSCR is calculated as the ratio of cash flow available for debt service (CFADS) to scheduled annual debt service:

$$DSCR_t = \frac{CFADS_t}{ADS_t}$$

For steady-state screening and reproducibility, CFADS is defined here as operating cash flow before debt service:

$$CFADS_t = (R_t - OPEX_t) - Tax_t$$

Thus, DSCR over time becomes:

$$DSCR_t = \frac{(R_t - OPEX_t) - Tax_t}{ADS_t}$$

DSCR values above approximately 1.3 are generally considered financeable, with higher values indicating greater resilience to revenue or cost variability.5.9.6

Levelized cost of renewable diesel (LCORD)

The levelized cost of renewable diesel (LCORD) represents the net cost of producing fuel on a per-unit basis after accounting for policy credit revenues. It is calculated as:

$$\boldsymbol{LCORD} = \frac{\boldsymbol{C}_{\text{cap,ann}} + \boldsymbol{C}_{\text{OPEX}} - (\boldsymbol{R}_{\text{LCFS}} + \boldsymbol{R}_{\text{RIN}} + \boldsymbol{R}_{\text{BC-credit}})}{\boldsymbol{Q}_{\text{RD}}}$$

5.9.7 Netback Levelized Value of Biochar

The netback levelized value of biochar quantifies whether biochar production represents a net cost or net revenue stream after accounting for both market sales and carbon removal credits. It is calculated as:

$$\boldsymbol{LC}_{\text{BC,net}} = \frac{\boldsymbol{C}_{\text{BC,alloc}} - (\boldsymbol{R}_{\text{BC}} + \boldsymbol{R}_{\text{BC-credit}})}{\boldsymbol{Q}_{\text{BC}}}$$

A negative value indicates that biochar sales plus carbon-credit revenues exceed the allocated production cost.

5.10 Results and Sensitivity Analysis

This section presents the techno-economic, financial, and climate performance of the proposed Fresno County integrated renewable diesel (RD) and biochar facility under four feedstock supply scenarios. Results are structured in two layers to support policy and investment evaluation. First, the base-case capital scenario establishes relative performance across key metrics, including production output, carbon outcomes, revenue composition, project value (NPV/IRR), and lender-facing indicators, such as debt service coverage. Second, a capital cost sensitivity analysis (±40%) spanning −40%, −20%, base, +20%, +40% of total capital investment is applied to assess the robustness of results under early-deployment uncertainty. This analysis identifies breakpoints in project viability and bankability, which are critical for public-sector program design and risk mitigation strategies.

The four feedstock scenarios evaluated are:

- ***Scenario 1:*** 100% forest residues
- ***Scenario 2:*** 50% forest residues / 50% agricultural residues
- ***Scenario 3:*** 50% forest / 30% agricultural residues / 20% MSW
- ***Scenario 4:*** 25% forest / 25% agricultural residues / 50% MSW

Across all scenarios, plant throughput (1,000 BDT/day) and operating assumptions are held constant. As a result, differences in performance are driven primarily by:

- Feedstock-specific conversion yields
- Availability of biochar as a co-product
- Carbon credit generation (LCFS, RIN, and CDR)
- Resulting financial performance under a consistent financing structure

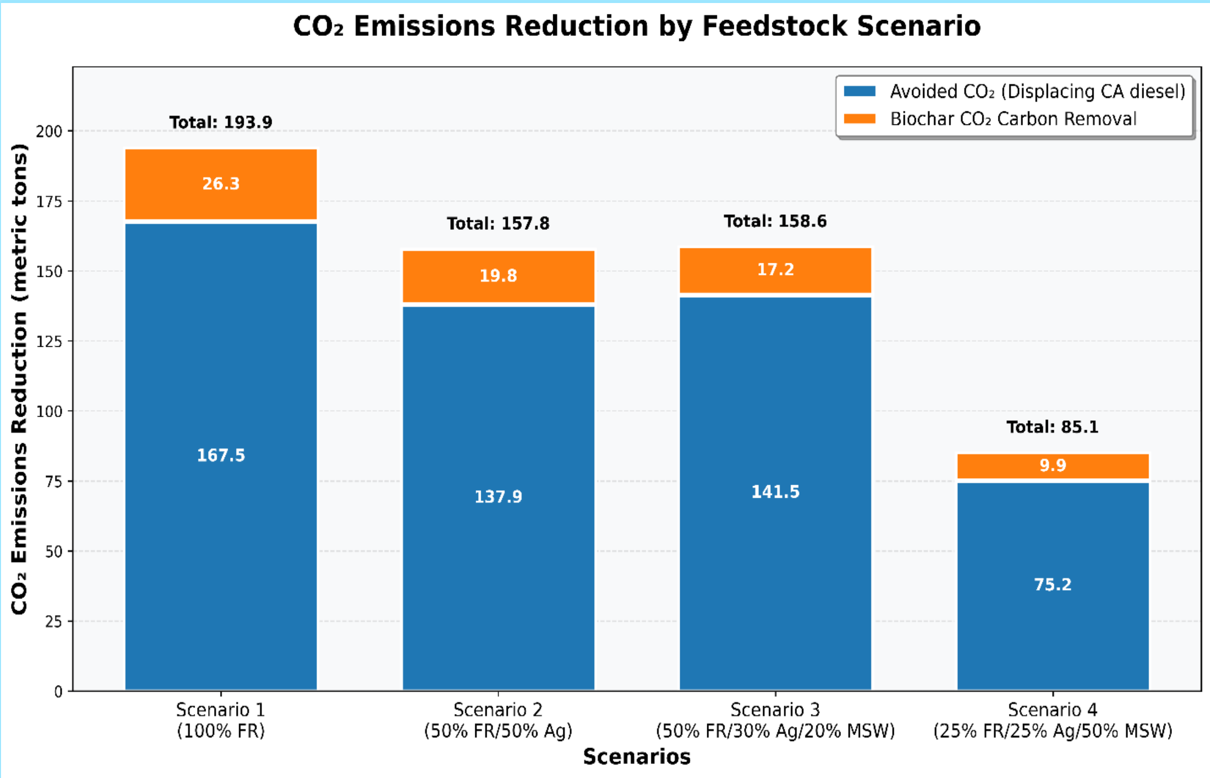

Figure 34. Carbon mitigation outcomes (avoided + removed) by scenario (Base CAPEX).

5.11 Base-Case Production Performance and Carbon Outcomes

5.11.1 Renewable Diesel and Biochar Production

Renewable diesel production varies significantly across scenarios due to differences in feedstock composition and conversion performance. Scenario 1 (100% forest residues) achieves highest output at approximately 17.3 million gallons per year, with a yield of 58.3 gal/BDT. Scenario 2 (50% forest / 50% agricultural residues) reduces output to approximately 14.3 million gallons per year (48.0 gal/BDT), reflecting lower energy density and conversion efficiency of agricultural residues. Scenario 3 (20% MSW integration) maintains comparable output at approximately 14.6 million gallons per year (48.2 gal/BDT), indicating that moderate MSW blending can be accommodated without significant performance loss. Scenario 4 (50% MSW) results in the lowest output at approximately 13.6 million gallons per year (43.2 gal/BDT), consistent with increased heterogeneity and conversion penalties associated with higher MSW content (**Table 18**).

Biochar production declines systematically as MSW share increases, since biochar is produced only from the clean biomass fraction routed to pyrolysis train. Annual biochar output decreases from ~9,570 t per year (Scenario 1) to ~7,590 t per year (Scenario 2), ~6,468 t per year (Scenario 3), and ~3,795 t per year (Scenario 4). This trend directly reduces the facility's durable carbon removal potential, as biochar represents the primary sequestration pathway in the system (**Table 18**).

5.11.2 Climate Performance

The facility's climate benefits are quantified through two complementary pathways: (i) avoided emissions resulting from displacement of petroleum diesel with renewable diesel and (ii) durable carbon removal via long-term biochar sequestration in soils. At base-case capital assumption, modeled outcomes are as follows:

- Avoided emissions from renewable diesel range from approximately 131,153 (Scenario 4, high MSW) to 167,540 tCO_2e per year (Scenario 1, 100% forest residues).
- Biochar-based carbon removal ranges from approximately 9,922 tCO_2e per year (Scenario 4) to ~26,318 tCO_2e per year (Scenario 1) (**Table 18**). Combining avoided emissions and durable removal yields total climate benefit of ~141,075 tCO_2e per year (Scenario 4) to ~193,858 tCO_2e per year (Scenario 1). The total climate benefits of Scenario 2 (~157,793 tCO_2e per year) and Scenario 3 (~158,633 tCO_2e per year) are very close to each other (**Figure 34**).

Overall, Scenario 1 provides the highest overall climate benefit, maximizing both renewable fuel displacement and durable carbon sequestration. Scenarios 2 and 3 deliver similar total climate benefits despite differences in feedstock composition, reflecting a balance between moderate reductions in renewable diesel yield and biochar output. Scenario 4 (50% MSW) exhibits the lowest total climate benefit, driven by lower renewable diesel yield and sharply reduced biochar production.

5.11.3 Revenue Composition at Base CAPEX

At base-case capital assumptions, total annual revenue declines with increasing feedstock complexity. Scenario 1, which uses 100% forest residues, generates the highest total annual revenue at approximately $108.8 million per year, driven by strong renewable diesel (RD) yields and robust biochar production. Scenario 2, with a 50/50 mix of forest and agricultural residues, produces about $79.3 million per year. Scenario 3, which integrates 50% forest residues, 30% agricultural residues, and 20% MSW, achieves roughly $82.5 million per year. Scenario 4, the MSW-rich case with 25%

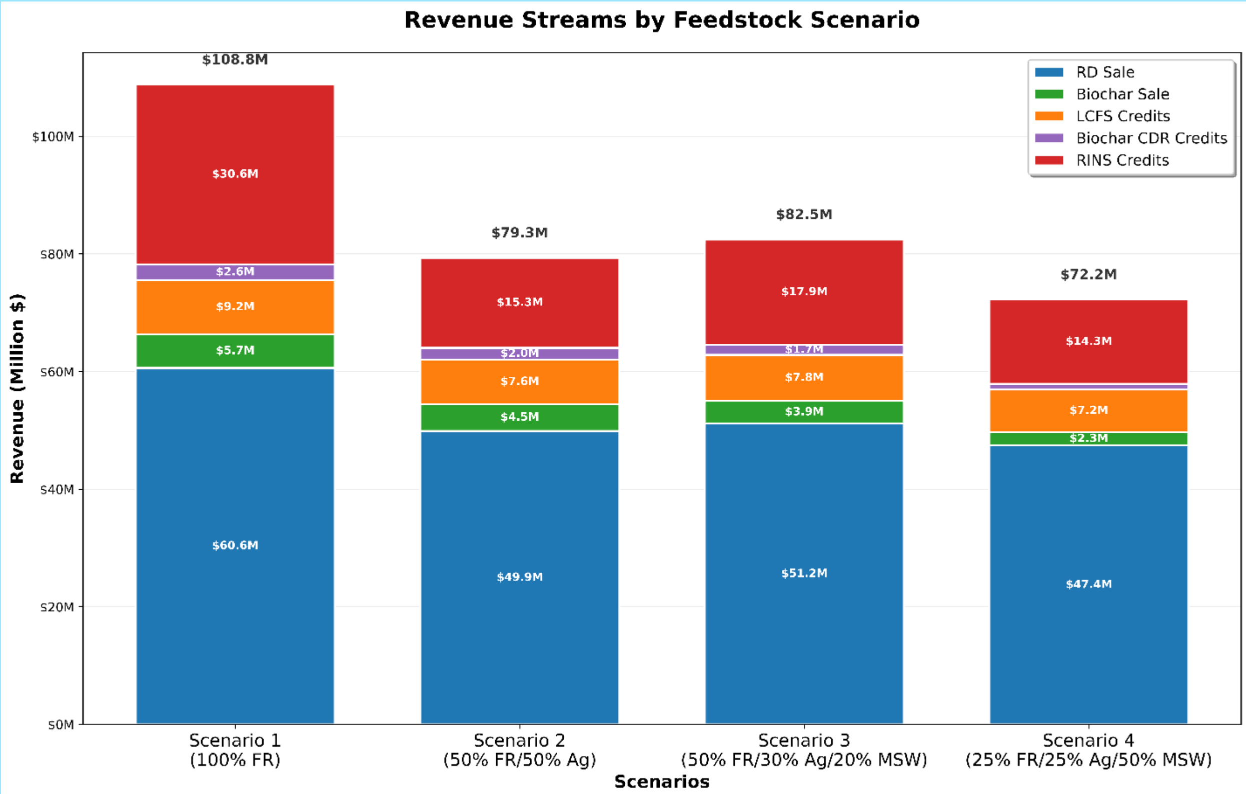

Figure 35. Annual revenue from product sales and credit streams by scenario.

forest residues, 25% agricultural residues, and 50% MSW, generates the lowest revenue at approximately $72.3 million per year, reflecting reduced RD and biochar output (**Table 18**). RD sales remain the dominant source across all scenarios (~$47.44–$60.61M per year). RIN credits are a substantial contributor (~$14.32–$30.62M per year), reflecting feedstock-specific eligibility and pathway classification. LCFS credits provide an additional $7.21–$9.21M per year. Biochar revenues, including sales and durable carbon removal (CDR) credits, are smaller but policy-relevant (~$3–$6M/year combined) and decline sharply as MSW share increases (**Figure 35**).

Table 18. Key Production, Carbon, and Revenue Metrics (Base CAPEX).

Metric	Scenario 1 (100% FR)	Scenario 2 (50% FR/50% Ag)	Scenario 3 (50% FR/30% Ag/20% MSW)	Scenario 4 (25% FR/25% Ag/50% MSW)
RD Yield (gal/BDT)	58.3	48.0	48.2	43.2
RD Production (million gal/yr)	17.3	14.3	14.6	13.6
Biochar Production (t/yr)	9,570	7,590	6,468	3,795
Avoided carbon (CO_2-eq t/yr)	167,540	137,949	141,463	~ 131,153
CO_2 removal with biochar (CO_2-eq t/yr)	26,318	19,844	17,170	9,922
Eligible RD RINs (million credit/yr)	21.78	20.41	20.92	21.00
Revenue from RD sale (million $/yr)	60.61	49.90	51.17	47.44
Revenue from biochar (million $/yr)	5.74	4.55	3.88	2.28
LCFS credits revenue (million $/yr)	9.21	7.59	7.78	7.21
CDR credit revenue from biochar (million $/yr)	2.63	~1.98	1.72	0.99
RIN credit revenue (million $/yr)	30.62	15.31	17.90	14.32
Total annual revenue (million $/yr)	108.82	79.34	82.45	72.25

5.12 Base-Case Financial Performance and Bankability

5.12.1 Levelized Cost of Renewable Diesel (LCORD)

At base-case capital assumptions, the levelized cost of renewable diesel (LCORD), including the effect of stacked policy incentives, increases as feedstock complexity rises and conversion yields decline. Scenario 1 (100% forest residues) achieves the lowest LCORD at approximately $2.58 per gallon, reflecting high fuel yields and strong co-product performance. Scenario 3 (moderate MSW integration) follows at approximately $4.25 per gallon, closely aligned with

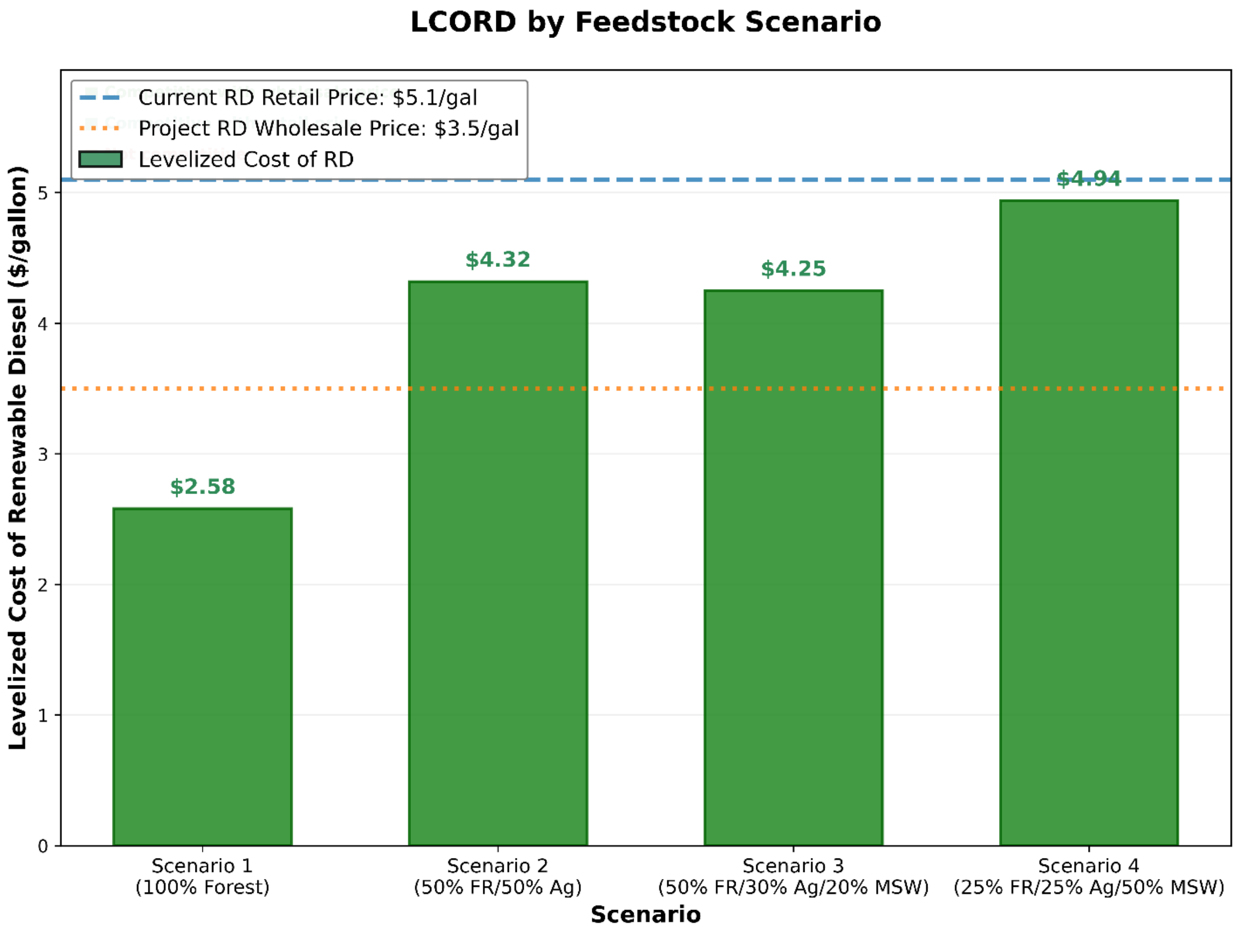

Figure 36. Levelized cost of renewable diesel across four feedstock scenarios, including policy credit impacts (base case CAPEX).

Scenario 2 (50% forest / 50% agricultural residues) at $4.32 per gallon. Scenario 4 (50% MSW) results in the highest LCORD at approximately $4.94 per gallon, driven by reduced renewable diesel output and lower biochar production (**Figure 36**).

5.12.2 Returns and Long-Run Value

Investment performance is evaluated using levered after-tax equity metrics, including IRR and equity NPV (discounted at the assumed project discount rate). Under the credit-inclusive case, Scenario 1 (100% forest residues) consistently represents the strongest investment proposition, while mixed-feedstock and MSW-integrated scenarios exhibit increasing sensitivity to capital costs (**Figure 37**).

At base CAPEX, results fall into three performance tiers:

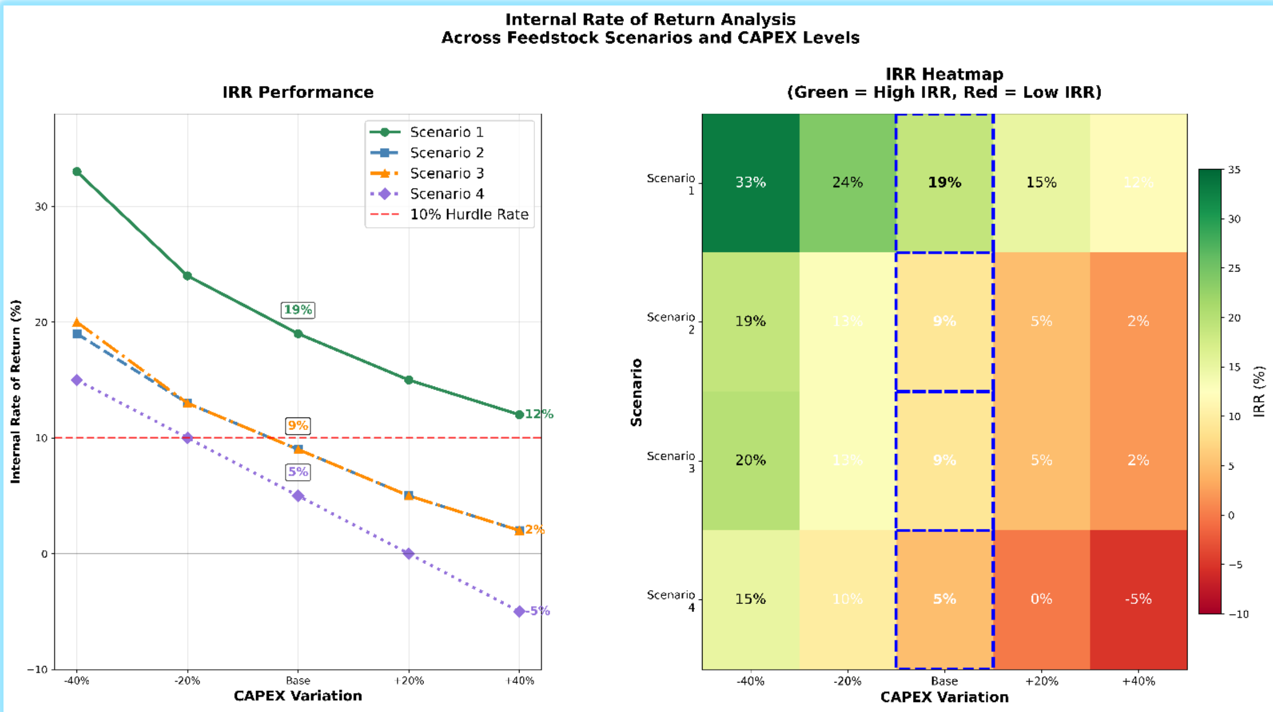

Figure 37. Internal rate of return across feedstock scenarios, illustrating sensitivity to CAPEX and carbon credit contributions.

- ***Scenario 1 (100% forest residues)*** is clearly value-positive and investable, with IRR of 19% and an NPV of approximately \$158.4M. Strong performance is driven by the highest renewable diesel yields, the largest biochar output (and associated carbon removal value), and the highest annual gross profit.
- ***Scenarios 2 and 3 (mixed biomass and moderate MSW integration)*** are near the break-even threshold. Both achieve an IRR of approximately 9%, but NPVs are slightly negative (approximately −\$19.26M for Scenario 2 and −\$12.7M for Scenario 3). These results indicate that modest improvements in capital cost, conversion performance, or credit values could shift these configurations into value-positive territory.
- ***Scenario 4 (high MSW integration)*** shows the weakest financial performance, with IRR of 5% and a negative NPV of approximately −\$74.72M. Under base-case assumptions, this configuration is not robustly investable and would likely require lower capital costs, additional revenue streams (e.g., tipping fees), or improved process performance to achieve viability.

Sensitivity analysis of capital cost (±40%) reinforces these findings and highlights investment breakpoints (**Figure 38**):

- ***Scenario 1*** remains value-positive across the full CAPEX range, demonstrating strong resilience to capital uncertainty (IRR ranging from ~33% to ~12%).

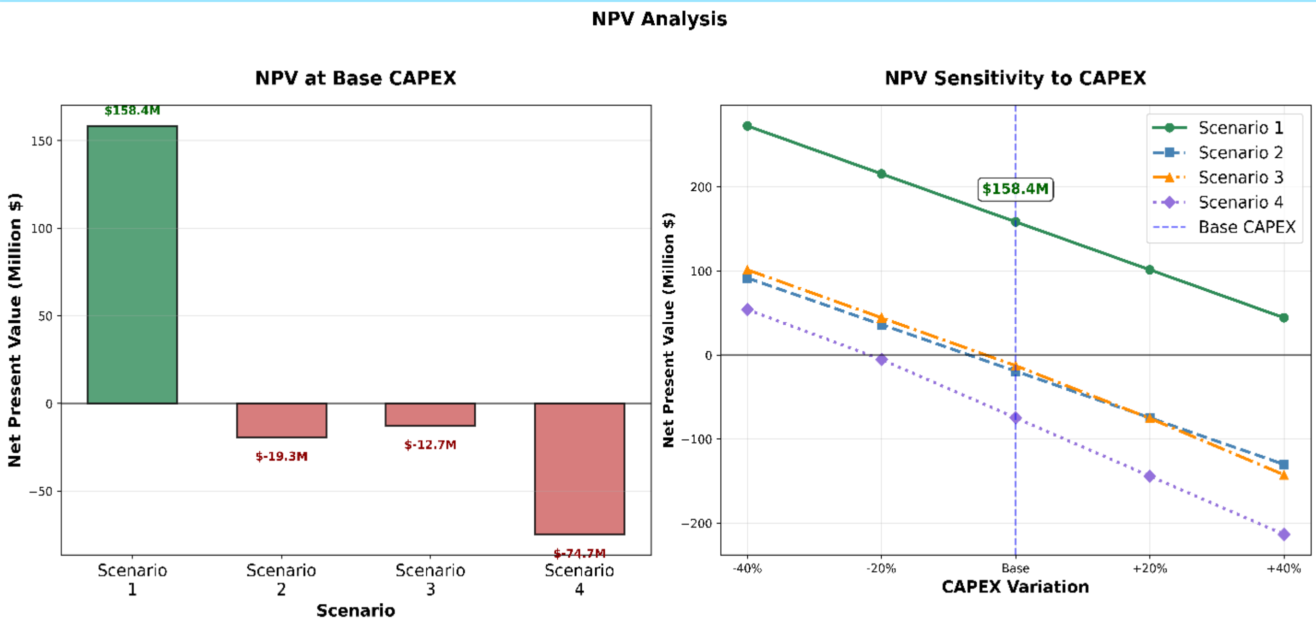

Figure 38. Net present value across feedstock scenarios showing sensitivity to CAPEX and carbon credit contributions.

- ***Scenarios 2 and 3*** transitions from positive to negative NPV between reduced CAPEX (−20%) and base-case levels, indicating a narrow investability window dependent on disciplined project execution.
- ***Scenario 4*** becomes value-positive only under significant CAPEX reduction (approximately −40%), indicating the highest investment risk and narrowest viability envelope. Overall, these results show that clean biomass pathways (Scenario 1) offer the strongest combination of economic return, stability, and resilience to cost uncertainty. Blended and MSW-integrated pathways may be viable but require tighter capital control, performance improvements, or additional policy/market support.

5.12.3 Biochar Netback Economics

Biochar netback, expressed as net levelized cost ($/t), provides a unit-level indicator of whether revenues from biochar sales and associated carbon removal credits are sufficient to offset the costs allocated to biochar production within the integrated facility.

Under base-case capital assumptions, biochar netback increases substantially with higher MSW integration, rising from approximately $2,135/t in Scenario 1 to $4,156.5/t in Scenario 2, $5,063.8/t in Scenario 3, and $9,531.2/t in Scenario 4.

This trend is driven by two reinforcing factors. First, increasing MSW blending reduces the share of clean biomass available for pyrolysis, leading to lower biochar output and a corresponding decline in both market sales and CDR credit generation. Second, Greater process complexity associated with MSW integration increases total system costs, raising the portion of costs attributed to co-products such as biochar. As a result, under the current cost allocation approach and pricing assumptions, biochar does not function as a financial stabilizer in MSW-rich configurations. Instead, its netback becomes increasingly cost-intensive as the system shifts away from clean biomass feedstock.

5.13 Base-Case Risk and Financial Resilience

5.13.1 Debt Service Coverage Ratio (DSCR)

The debt service coverage ratio (DSCR) is used as the primary lender-facing metric to assess whether project cash flow is sufficient to meet scheduled debt obligations (principal and interest). As such, DSCR is a key indicator of project bankability and financing risk. At base-case capital costs, DSCR values vary significantly across feedstock scenarios,

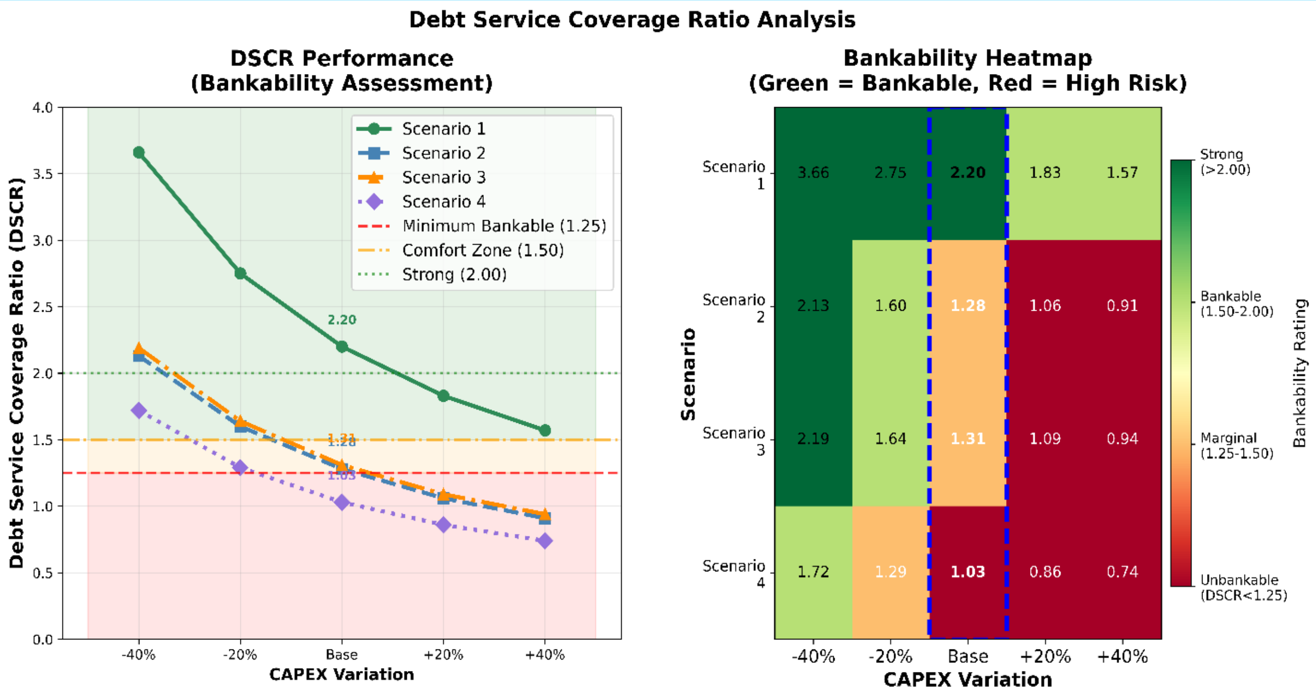

Figure 39. Debt service coverage ratio (DSCR) across feedstock scenarios, showing credit impacts on lender-facing project viability.

reflecting differences in operating margins and conversion performance. The clean-biomass configuration (Scenario 1) achieves a DSCR of 2.20, indicating strong debt coverage and a robust financing profile. The blended feedstock cases show more constrained performance. Scenario 3 achieves a DSCR of 1.31, while Scenario 2 reaches 1.28, placing both cases at or near the commonly cited minimum threshold for project financing (approximately 1.3). The MSW-intensive configuration (Scenario 4) yields a DSCR of 1.03, which is generally considered insufficient to support conventional project financing without additional risk mitigation measures, such as policy support, credit enhancements, or improved revenue certainty (**Figure 39**).

Sensitivity analysis indicates that DSCR declines across all scenarios as capital costs increase. However, the impact is most pronounced in blended and MSW-integrated cases, which begin closer to minimum lender thresholds.

5.13.2 Simple Payback

Simple payback measures the time needed for cumulative equity cash flow to recover the initial equity investment. At base CAPEX, payback periods increase with feedstock heterogeneity and integration complexity. Scenario 1 (100% forest residues) has the shortest payback of 8.2 years, reflecting strong annual

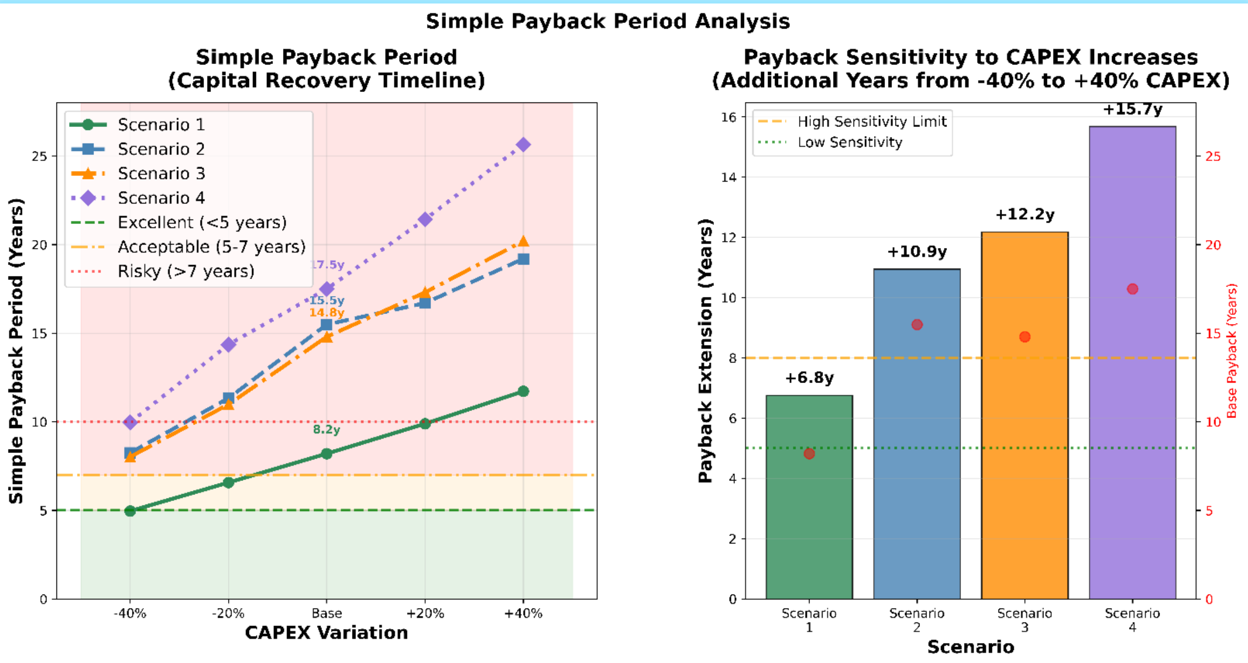

Figure 40. Simple payback periods across feedstock scenarios, illustrating capital recovery risk and sensitivity to CAPEX variation.

growth and robust operating performance. Scenario 2 (50% forest / 50% agricultural) and Scenario 3 (50% forest / 30% agricultural / 20% MSW) have longer paybacks of 15.5 and 14.8 years, respectively, showing that while policy credit revenues support cash flow, capital recovery slows in mixed-feedstock systems. Scenario 4 (25% forest / 25% agricultural / 50% MSW) exhibits the longest payback at 17.5 years, consistent with lower yields, weakest DSCR, and limited resilience to CAPEX escalation (**Figure 40**).

Overall, combined DSCR and payback analysis ranks financial risk: clean biomass (Scenario 1) provides the strongest ability to service debt and recover equity, while high MSW integration (Scenario 4) shows the greatest financial fragility under the base-case assumptions.

5.14 Capex Sensitivity Analysis (±40% Capex)

To assess capital execution risk, each scenario was evaluated across a five-point CAPEX range: −40%, −20%, Base, +20%, +40%. Base CAPEX levels differ slightly across feedstock strategies to reflect integration complexity. Scenarios 1–2 (biomass only) are anchored at $426.16M, with a sensitivity range of $255.7M to $596.6M. Scenarios 3–4 (MSW/RDF-integrated) are anchored at $438.6M, with a range of $263.1M to $614.0M, reflecting additional costs for MSW handling and enhanced syngas cleanup.

5.14.1 Viability Envelope from NPV Breakpoints

NPV sensitivity highlights how each feedstock scenario withstands changes in capital cost. Scenario 1 (100% forest residues) remains value-positive across the entire CAPEX range, with NPV decreasing from $272.6M at −40% CAPEX to $44.3M at +40% CAPEX, demonstrating strong resilience to first-of-a-kind capital uncertainty.

In contrast, Scenarios 2 and 3 (blended biomass and moderate MSW) are close to the viability boundary. They show positive NPV at −20% CAPEX ($36.21M for Scenario 2; $44.3M for Scenario 3) but shift to slightly negative NPV at base CAPEX (−$19.26M and −$12.7M, respectively), indicating that disciplined capital execution and/or performance improvements are needed to maintain value-positive outcomes.

Scenario 4 (50% MSW) has the narrowest viability envelope. Its NPV is near break-even at base CAPEX (−$5.39M) and declines sharply with higher CAPEX −$144.06M at +20% and −$213.39M at +40%), reflecting the structural challenges of high MSW integration under current assumptions (**Figure 41**).

These NPV patterns show that clean biomass pathways are the most robust

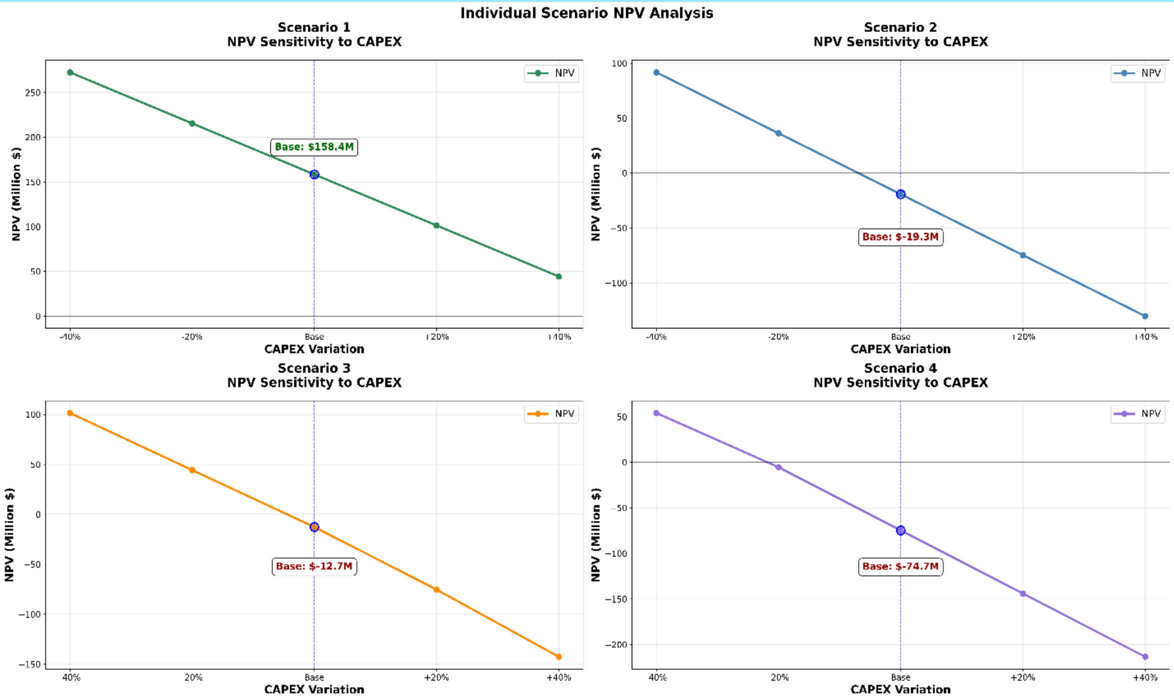

Figure 41. NPV sensitivity by scenario showing the effect of carbon credits across the ±40% CAPEX range.

under capital uncertainty, while blended and MSW-heavy pathways require tighter capital control and performance management to remain financially viable.

5.14.2 IRR Sensitivity to Capital Escalation

Equity IRR declines as CAPEX increases, with the magnitude of impact varying by scenario. Scenario 1 remains robust across the full ±40% CAPEX range, falling from 33% to 40% CAPEX to 12% at +40% CAPEX. Scenarios 2 and 3 show rapid compression, dropping from approximately 19–20% at −40% CAPEX to 2% at +40% CAPEX, highlighting the sensitivity of blended-feedstock investments to capital execution. Scenario 4 is the most vulnerable, with IRR declining from 15% at −40% CAPEX to −5% at +40% CAPEX, confirming that high MSW integration offers the narrowest margin for financial resilience under capital escalation.

5.14.3 DSCR Resilience and Bankability Thresholds

DSCR sensitivity illustrates the lender-facing limits for financeability under CAPEX uncertainty. Scenario 1 remains comfortably financeable across the whole, declining from 3.66 at −40% CAPEX to 1.57 at +40% CAPEX. Scenario 2 moves from financeable at −20% CAPEX

(1.60) to borderline at base (1.28) and becomes non-financeable at +40% (0.91). Scenario 3 remains near the lender threshold at base CAPEX (1.31) but also becomes non-financeable as CAPEX rises. Scenario 4 fails lender thresholds at and above base CAPEX (1.03 at base, 0.86 at +20%, 0.74 at +40%), indicating that conventional debt financing would be difficult without additional revenue streams, credit enhancement, or capital support.

5.14.4 Implications for Deployment and De-Risking

Under the updated credit-inclusive TEA, Scenario 1 (100% forest residue) is the only pathway consistently investable and bankable across substantial CAPEX uncertainty. Scenarios 2 and 3 are conditional: they can be viable under disciplined CAPEX delivery (generally at or below −20%) but become value-negative or fail lender coverage thresholds near or above base CAPEX. Scenario 4 is the most constrained, requiring additional MSW-linked economics (e.g., tipping fees), public cost-share or grants to reduce effective CAPEX, and/or improvements in conversion efficiency and cleanup costs to achieve reliable financeability.

6. SOCIAL AND ENVIRONMENTAL JUSTICE IMPLICATIONS

6.1 Introduction

The deployment of a commercial renewable diesel (RD) biorefinery in Fresno County, California, presents an opportunity to evaluate not only the techno-economic performance of biomass conversion but also its broader social, environmental and public health implications. This section assesses the co-benefits of redirecting forest residues, agricultural residues, and MSW from conventional disposal pathways, such as hazardous fuel accumulation, open burning, decomposition, and landfilling, toward controlled conversion for low-carbon fuels.

Following the California Air Resources Board (CARB) Standardized Regulatory Impact Assessment (SRIA) framework [210], the environmental-justice (EJ) analysis integrates primary three benefit streams:

Avoided wildfire emissions resulting from reduced forest fuel-load through forest-residue procurement.

Life-cycle greenhouse gas (GHG) reductions from RD displacing conventional diesel using a CA-GREET/LCFS-style carbon-intensity (CI) differential

Monetized health and productivity benefits from reduced exposure to wildfire-attributable fine particulate matter ($PM_{2.5}$).

The analysis is particularly relevant to the San Joaquin Valley (SJV) Air Basin, where Fresno County communities experience persistent air-quality challenges and heightened vulnerability to cardiopulmonary outcomes. The SJV is classified as an extreme non-attainment area for $PM_{2.5}$ and ozone under federal Clean Air Act standards, and cumulative pollution burdens disproportionately affect low-income communities and communities of color. By linking Sierra Nevada forest-health interventions with low-carbon fuel production and waste diversion, the modeled biorefinery system supports multiple intersecting California policy priorities: wildfire risk mitigation, transportation decarbonization, and reduction of air-quality inequities in overburdened communities.

Cumulative pollution burdens disproportionately affect low-income communities and communities of color

The analysis evaluates four feedstock scenarios to quantify how sourcing decisions influence the magnitude of climate and EJ co-benefits. Notably, wildfire- and smoke-related benefits in this framework are primarily driven by the scale of forest treatment implied by forest-residue throughput. Consequently, scenarios with the same forest-residue utilization yield identical avoided-wildfire emissions and $PM_{2.5}$-related health outcomes, even if the composition of non-forest feedstocks differs in the techno-economic analysis.

6.2 Methodology

6.2.1 Scenario Definition and Scaling Parameter

The analysis evaluates four feedstock scenarios under a constant nominal facility throughput of 1,000 bone-dry tons (BDT) per day and 330 operating days per year. Environmental-justice co-benefits, specifically wildfire risk reduction and reductions in smoke exposure, are assumed to be primarily driven by the quantity of forest residues procured. Forest-residue utilization serves as a proxy for the scale of hazardous fuel reduction enabled by the project. Accordingly, wildfire- and smoke-related benefits are therefore scaled to forest residue throughput as follows: Scenario 1 utilizing 1,000 BDT/day of forest residues; Scenarios 2 and 3 each utilizing 500 BDT/day each, and Scenario 4 utilizing 250 BDT/day. Because Scenarios 2 and 3 have identical forest-residue throughput, they generate the same wildfire-avoidance and smoke-related health outcomes, despite differences in non-forest feedstock composition in techno-economic analysis.

6.2.2 Translating Forest Residues into Treatment-Equivalent Area

To quantify wildfire-risk reduction, forest-residue utilization is converted into a treatment-equivalent forest area. This approach applies an effective accessible residue density, reflecting conservative recovery assumptions consistent with the biomass-inventory recovery criteria used in this study.

The analysis adopts an effective recoverable forest-residue density of $R_{FR} = 1.865$ BDT per acre. This value is based on 15% recoverable slash applied to 50% technically available residues. Under this convention, the treatment-equivalent area per day is computed as

$$\boldsymbol{A_{day}} = \frac{\boldsymbol{M_{FR,day}}}{\boldsymbol{R_{FR}}} \times \boldsymbol{N_{op}}$$

where $M_{FR,day}$ is the forest residues utilized (BDT per day) and R_{FR} is the accessible residue density (BDT per acre). The corresponding annual treatment-equivalent area $N_{op} = 330$ operating days per year. This formulation maintains dimensional consistency and ensures a

linear relationship between forest-residue throughput and implied scale of forest treatment.

6.2.3 Avoided Wildfire Emissions (Co_2 And $Pm_{2.5}$)

Avoided wildfire emissions are estimated using area-based emission intensities derived from the California Air Resources Board (CARB) statewide wildfire emissions dataset for 2000–2023 [211]. Consistent with Standardized Regulatory Impact Assessment (SRIA) screening methods, annual wildfire emissions are regressed against total burned areas to derive pollutant-specific emission factors on a per-acre basis. The analysis adopts the following emission factor:

EF_{CO_2} = 23.5829 metric tons per acre and $EF_{PM_{2.5}}$ = 0.2215 metric tons per acre. Avoided emissions for pollutant p are computed as:

$$\boldsymbol{E_{p,avoid} = A_{yr} \times EF_p}$$

where $E_{p,avoid}$ is avoided emissions (metric tons/yr), A_{yr} is annual treatment-equivalent area (acres/yr), and EF_p is the pollutant-specific emission factor (metric tons/acre). This approach treats treatment-equivalent areas as a proxy for avoided burned areas. Such results should be interpreted as screening-level (upper-bound) estimates of avoided emissions. More precise estimates would require probabilistic wildfire modeling that links treatments to changes in fire occurrence, severity and behavior.

6.2.4 Renewable Diesel Output and Well-To-Wheel (WTW) Co_2e Abatement

Renewable diesel production attributable to forest residues is calculated using Fischer–Tropsch conversion yields and fuel energy content assumptions consistent with CA-GREET/LCFS carbon-intensity accounting. Key assumptions include:

- RD yield: 58.3 gallons per BDT
- Energy content: 130.48 MJ per gallon.

Lifecycle GHG abatement is calculated relative to:

- California diesel reference carbon intensity, CI_{ref} = 80.170 gCO_2e per MJ
- Biomass-to-RD pathway carbon intensity, CI_{RD} = 6.02 gCO_2e per MJ.

Annual RD production attributable to forest residue is computed as:

$$\boldsymbol{Q_{RD} = M_{FR,day} \times Y_{RD} \times N_{op}}$$

where:

Q_{RD} = annual RD production (gallons per year)
$M_{FR,\,day}$ = forest residues utilized (BDT/day)
Y_{RD} = RD yield (gallons per BDT)
N_{op} =330 operating days per year

The per-gallon fuel-switching emissions factor is calculated as:

$$\Delta EF_{gal} = \frac{(CI_{ref} - CI_{RD}) \times EC_{gal}}{10^6}$$
$$\approx 0.0097056 \text{ tons } CO_2\text{e per gal}$$

Annual well-to-wheel (WTW) CO_2e abatement from RD fuel switching is then estimated as:

$$E_{WTW} = Q_{RD} \times \Delta EF_{gal}$$

To avoid double counting of climate benefits, E_{WTW} is reported as a physical emissions-abatement metric but is not treated as the primary monetized benefit in the base case. This is because the carbon-intensity advantage of RD is typically internalized in techno-economic analysis through LCFS credit revenues. Monetization of E_{WTW} using the Social Cost of Carbon (SCC) is therefore presented as a sensitivity case, rather than a central estimate.

6.2.5 Monetized Climate Benefits Using the Social Cost of Carbon

Monetized climate benefits are estimated using Social Cost of Carbon (SC-CO_2) values for emissions year 2025, consistent with CARB SRIA framework [210] and SC-CO_2 schedules published by the U.S. Environmental Protection Agency (EPA) and the Interagency Working Group (IWG) **(Appendix TS8)** [212, 213]. To avoid double counting of climate benefits, SC-CO_2 monetization in this environmental-justice module is applied only to avoided wildfire-related CO_2 emissions associated with forest-treatment activities enabled by forest-residue procurement. This approach reflects the fact that the carbon intensity advantage of renewable diesel is already internalized in the techno-economic analysis through Low Carbon Fuel Standard (LCFS) credit revenues.

Annual monetized climate benefits are computed as:

$$B_{\text{climate}} = E_{CO_2,\text{avoid}} \times SCC$$

where $B_{climate}$ is annual monetized climate benefits in US$ per year, $E_{CO_2,avoid}$ is avoided wildfire CO_2 emissions (t/yr), and SCC is the Social Cost of Carbon (US$ per ton CO_2).

Under this framework, well-to-wheel (WTW) CO_2e abatement from renewable diesel fuel substitution is reported as a supplementary physical metric. Monetization of WTW emissions reductions using SC-CO_2 is included only as a sensitivity analysis, given its conceptual overlap with LCFS crediting mechanisms.

6.2.6 Health Incidence and Valuation from $PM_{2.5}$ Avoidance

Health co-benefits from reductions wildfire-attributable fine particulate matter ($PM_{2.5}$) are quantified using an incident-based approach consistent with the California Air Resources Board (CARB) Standardized Regulatory Impact Assessment (SRIA) framework [210]. This analysis is further informed by BenMAP-CE–based valuation method [214] calibrated for the San Joaquin Valley (SJV) air basin. Avoided health incidents for endpoint i(including premature mortality, asthma onset, hospital admissions, emergency-department visits, work-loss days) are estimated by scaling basin-specific incidence factors to the project-attributable $PM_{2.5}$ concentrations:

$$\boldsymbol{D_{i,SJV} = r_{i,SJV} \times \Delta PM_{2.5}}$$

Where $D_{i,SJV}$ is avoided health incidents (cases/yr), $r_{i,SJV}$ is the endpoint-specific incidence factor for the SJV (cases per ton $PM_{2.5}$ reduced), and $\Delta PM_{2.5}$ is avoided wildfire-related $PM_{2.5}$ emissions attributable to the project (t/yr). Monetized health benefits are computed as:

$$\boldsymbol{B_{health} = \sum_i D_{i,SJV} \times V_i}$$

Where B_{health} is the total annual health benefits (USD per year) and V_i is the unit economic value per health incident (2022 USD). Key valuation parameters include:

Value of a statistical life (VSL): $13,449,977 per premature mortality case
Asthma onset: $57,703 per case
Work-loss days: $206 per day

Additional cost-of-illness (COI) and willingness-to-pay (WTP) values are applied for morbidity endpoints, including cardiovascular and respiratory hospitalizations, emergency-department visits, lung cancer incidence, asthma symptom days [210]. Because the underlying incidence factors are derived from basin-scale exposure-response modeling developed for regulatory analysis over multi-year horizons, the resulting estimates should be interpreted as screening-level, annualized benefits proportional to avoided $PM_{2.5}$. They do not represent event-specific or season-specific forecasts for any individual wildfire year.

6.3 RESULTS

6.3.1 Physical Co-Benefits Across Scenarios

Because forest-residue procurement serves as the primary scaling parameter for hazardous-fuel reduction, all treatment-related outcomes exhibit a linear relationship with forest residue throughput. Accordingly, Scenario 1 produces the largest co-benefits, Scenarios 2 and 3 produce identical mid-range outcomes, and Scenario 4 produces the smallest outcomes. Under Scenario 1 (1,000 BDT/day forest residues), the modeled system yields an estimated 176,952 acres/yr. This corresponds to approximately 4.173 $MtCO_2$/yr in avoided wildfire emissions and 39,190 $tPM_{2.5}$/yr in avoided particulate emissions. Reducing forest-residue throughput to 500 BDT/day (Scenarios 2 and 3) results in a proportional 50% reductions in outcomes i.e. Under these scenarios, the treatment-equivalent area declines to 88,476 acres per year, with corresponding avoided wildfire emissions of approximately 2.09 million metric tons of CO_2 per year and 19,595 metric tons of $PM_{2.5}$ per year. Under Scenario 4, where forest-residue throughput is reduced to 250 BDT/day, outcomes decline further in proportion to feedstock availability. The treatment-equivalent area is estimated at 44,238 acres per year, with corresponding avoided wildfire emissions of approximately 1.04 million metric tons of CO_2 per year and 9,798 metric tons of $PM_{2.5}$ per year (**Table 19**).

Scenario 1		
Enables hazardous-fuel reduction on **~176,952 acres/year**	Avoids **~4.173 $MtCO_2e$/year** of wildfire emissions	Reduces wildfire smoke emissions by **~39,190 $tPM_{2.5}$/year**

Renewable diesel output attributable to forest residues and the associated WTW CO_2e abatement also scale proportionally with forest-residue throughput. However, in the context of environmental-justice outcomes, avoided wildfire emissions dominates total emissions reductions in mass terms. This reflects large treatment-equivalent areas associated with forest-residue utilization. By comparison, WTW CO_2e reductions from RD fuel substitution are material but approximately an order of magnitude smaller and are treated as partially overlapping with Low Carbon Fuel Standard (LCFS) credit valuation within the techno-economic analysis.

Table 19. Scenario comparison of physical metrics (annualized).

Metric	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Forest residues (BDT/day)	1,000	500	500	250
Forest treatment (acres/yr)	176,952	88,476	88,476	44,238
Avoided wildfire CO_2 (Mt/yr)	4.173	2.087	2.087	1.043
Avoided wildfire $PM_{2.5}$ (t/yr)	39,190	39,190	39,190	39,190
WTW CO_2e abatement (t/yr)	167,540	83,770	83,770	41,885

(Source: Calculations based on CARB wildfire emission factors (23.5829 tCO_2/acre; 0.2215 $tPM_{2.5}$/acre) applied to treatment-equivalent forest area derived from biomass utilization. Scenarios 2 and 3 produce identical results in this EJ module due to identical forest-residue throughput.)

6.3.2 Monetized Climate Benefits Using the Social Cost of Carbon

Monetized climate benefits are estimated by applying SCC values (emissions year 2025) to avoided wildfire CO_2 emissions only. This approach maintains a clear accounting boundary and avoids double counting, as the climate associated with renewable diesel fuel switching is already internalized through LCFS crediting in techno-economic analysis. Using the U.S. EPA SCC at a 2.5% discount rate ($145/t$CO_2$), annual avoided-wildfire climate benefits are estimated at approximately $605.1 million under Scenario 1. Corresponding values decline proportionally to $302.6 million under Scenarios 2 and 3, and $151.3 million in Scenario 4.

Applying the Interagency Working Group (IWG) SCC at a 2.5% discount rate ($100/t$CO_2$) yields the same relative pattern across scenarios, but with lower absolute values. Under this framework, estimated annual benefits are $417.3 million for Scenario 1, $208.7 million for Scenarios 2 and 3, and $104.3 million for Scenario 4.

Across both valuation frameworks, the relative ranking of scenarios remains unchanged, reflecting the direct scaling of avoided wildfire CO_2 emissions with treatment-equivalent area. While absolute benefit magnitudes are sensitive to discount rate and SCC assumptions, the results consistently demonstrate that increased forest-residue utilization—and the associated expansion of treatment area—drives proportionally higher climate benefits (**Figure 42**).

6.3.3 Avoided Health Incidents and Monetized Health Benefits in The San Joaquin Valley Air Basin

Applying SJV air-basin incidence factors and endpoint unit valuations to avoided wildfire $PM_{2.5}$ demonstrates substantial public-health co-benefits that scale

"The results consistently demonstrate that increased forest-residue utilization—and the associated expansion of treatment area—drives proportionally higher climate benefits."

directly with forest-residue throughput and the associated reduction in smoke exposure (**Table 20** and **Table 21**). Under Scenario 1, the model estimates approximately 3,766 avoided cardiopulmonary premature deaths per year and 1,405,130 total avoided health incidents, corresponding to $51.64 billion/yr in monetized health benefits (2022 USD). Scenarios 2 and 3, with half the forest-residue throughput, yield roughly 1,883 avoided premature deaths, 702,565 total avoided incidents, and $25.82 billion/yr. Scenario 4, with one-quarter of the forest residues, results in 941 avoided mortality cases, 351,283 total avoided incidents, and $12.91 billion/yr (**Figure 43**).

Across all scenarios, premature mortality accounts for approximately 98% of total monetized benefits, reflecting the high value of statistical life (VSL), even though morbidity endpoints—such as asthma symptom days and work-loss days—dominate total incident counts.

Consistent with SRIA scaling convention, these estimates should be interpreted as annualized, screening-level indicators proportional to avoided $PM_{2.5}$ rather than as precise, season-specific epidemiological forecasts for Fresno County (**Appendix ST9**).

Table 20. Monetized Health Benefits from Avoided $PM_{2.5}$ (CARB SRIA Valuation at $1.53M per ton).

Scenario	Avoided $PM_{2.5}$ (t/yr)	Health benefits ($B/yr)
Scenario 1	39,190	59.97
Scenario 2	19,595	29.98
Scenario 3	19,595	29.98
Scenario 4	9,798	14.99

Source: Calculations based on CARB SRIA valuation framework applied to avoided wildfire $PM_{2.5}$ emissions.

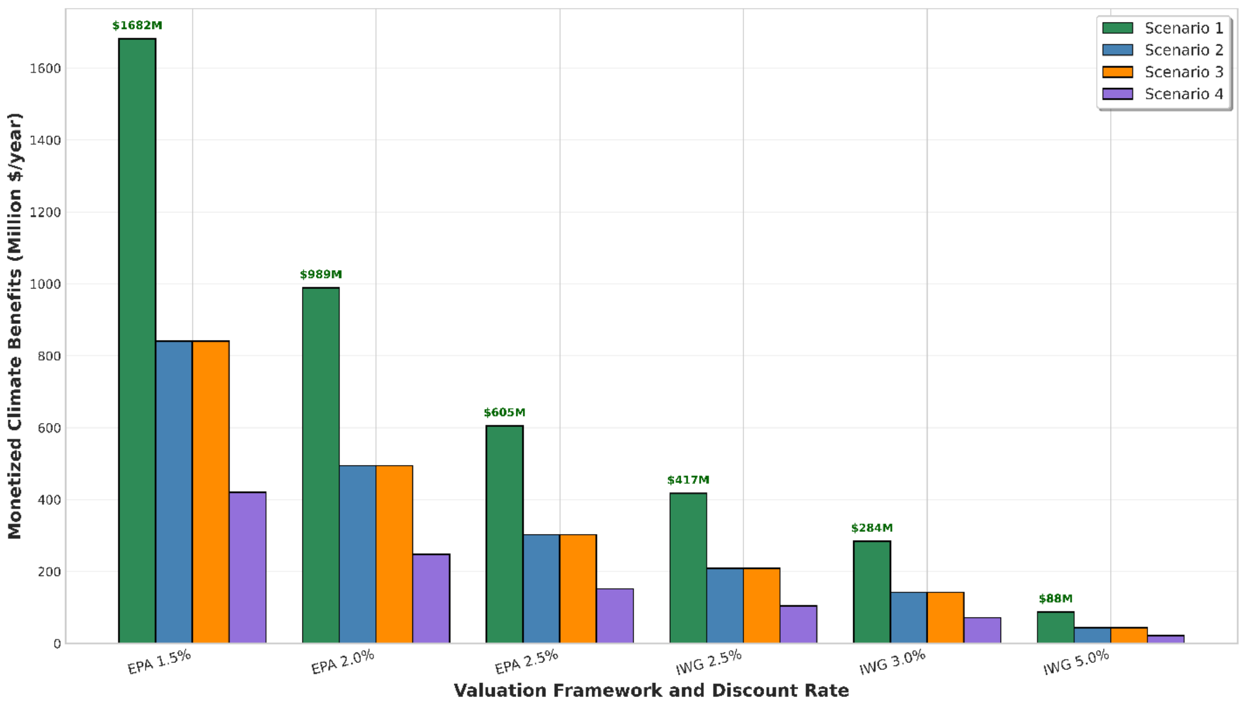

Figure 42. Monetized annual climate benefits (Million $/yr). Values reflect avoided wildfire CO_2 only; LCFS-related benefits are excluded to avoid double counting.

Table 21. Avoided health incidents from wildfire $PM_{2.5}$ (annualized-equivalent, SJV air basin).

Health category	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Cardiopulmonary mortality	3,766	1,883	1,883	941
Hospitalizations (cardiovascular)	582	291	291	145
ED visits (cardiovascular)	970	485	485	242
Acute myocardial infarction	388	194	194	97
Hospitalizations (respiratory)	97	48	48	24
ED visits (respiratory)	2,651	1,325	1,325	663
Lung cancer incidence	226	113	113	57
Asthma onset	9,762	4,881	4,881	2,441
Asthma symptoms	861,397	430,699	430,699	215,349
Work loss days	523,821	261,910	261,910	130,955
Hospitalizations (Alzheimer's)	1,293	647	647	323
Hospitalizations (Parkinson's)	178	89	89	44
Total incidents	1,405,130	702,565	702,565	351,283

Source: Calculations based on San Joaquin Valley–specific incidence factors and unit valuations following CARB SRIA methodology. Scenario results scale directly with avoided wildfire $PM_{2.5}$ attributable to forest-residue procurement.

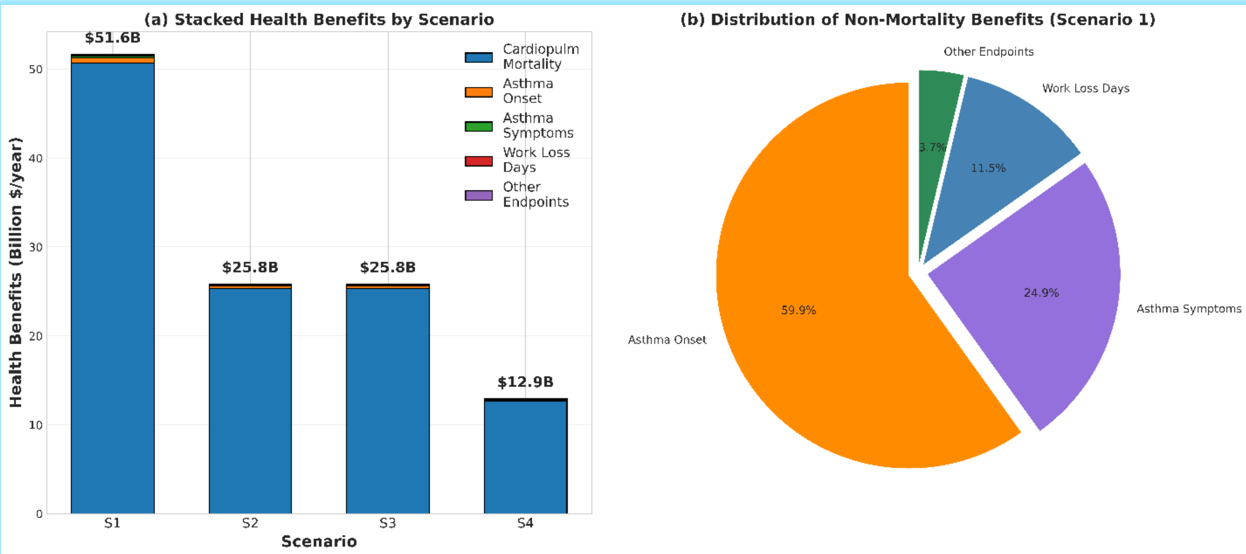

Figure 43. Monetized health benefits by endpoint (SJV air basin, $B/yr, 2022$).

6.4 Discussion

6.4.1 Scenario Comparison and Trade-Offs

The scenario analysis highlights a multi-objective trade-off between optimizing lifecycle carbon intensity across the full TEA/LCA boundary and maximizing smoke-related public-health co-benefits driven by forest fuel reduction in this EJ module.

Mixed-feedstock configurations, particularly those with higher MSW content, can achieve lower net CI when landfill-diversion credits are included in lifecycle accounting. However, this comes at the expense of forest residue share, which directly determines the treatment-equivalent area that drives wildfire and smoke benefits. For example, Scenario 4, with minimal forest residues, represents a 75% reduction in annual treated acreage compared with the forest-dominant Scenario 1 (44,238 vs. 176,952 acres/yr). As a result, Scenario 4 delivers only about one-quarter of Scenario 1's avoided wildfire CO_2 and $PM_{2.5}$ emissions. In contrast, Scenario 1, with the highest forest-residue share, maximizes the treatment-equivalent footprint and associated public-health co-benefits, yielding $51.64 billion per year in monetized health benefits under the incident-based diagnostic.

Scenarios 2 and 3 represent intermediate strategies. They retain substantial forest-treatment co-benefits—roughly half of Scenario 1—while diversifying the feedstock mix beyond the scope of wildfire-treatment benefits. Within the EJ module, Scenarios 2 and 3 are indistinguishable, because they have identical forest-residue throughput. Differences between these scenarios should therefore be evaluated in the broader TEA/LCA system boundary using non-overlapping accounting for other feedstock impacts.

6.4.2 Environmental Justice Implications

The San Joaquin Valley (SJV) is particularly relevant for EJ considerations due to high baseline pollution burdens, persistent non-attainment status for $PM_{2.5}$, and elevated vulnerability to cardiopulmonary outcomes. Reducing wildfire smoke exposure in this region provides disproportionately large marginal benefits to local communities, particularly low income populations and communities of color.

CalEnviroScreen 4.0 identifies many Fresno-area communities highly overburdened, ranking very high statewide on both pollution burden and population vulnerability indicators. These rankings reflect socioeconomic stressors, sensitive populations, and cumulative exposure from freight activity, agricultural operations, and recurring smoke transport from Sierra Nevada wildfires.

Within this context, the incident-based diagnostic shows that monetized health benefits are dominated by avoided premature mortality, because the value of statistical life (VSL) is large relative to morbidity endpoints, even though morbidity outcomes account for most total incident counts. From an environmental-justice perspective, scenarios with higher forest-residue throughput yield proportionally larger reductions in smoke-driven $PM_{2.5}$ exposure, which can reduce acute health events, missed work and school days, and healthcare utilization in already overburdened communities.

Additional EJ-relevant benefits may also arise from agricultural residue or MSW diversion, but these should be quantified within the full TEA/LCA system boundary, with careful attention to LCFS credit treatment and avoiding double counting.

6.4.3 Valuation Framework Sensitivity

The monetized climate benefits based on the Social Cost of Carbon (SCC) are highly sensitive to both the SCC schedule and the discount rate, even though the relative ranking of scenarios remain stable. Under EPA SCC values, Scenario 1 ranges from $605M/yr at a 2.5% discount rate to $1.68B/yr at 1.5%. Using IWG SCC schedules, the same avoided wildfire CO_2 is valued between $87.6M/yr at 5% discount rate and $417.3M/yr at 2.5%. This wide range underscores that SCC-based climate benefits should be reported as a range, rather than a single point estimate.

A similar caution applies to health-benefits monetization. Because $PM_{2.5}$ valuation is dominated by mortality and depends on modeled exposure-response relationships and valuation conventions, the resulting totals are best interpreted as SRIA-consistent screening-level indicators. These estimates are designed for comparability across scenarios and policy options, rather than as precise, county-specific forecasts.

6.5 Conclusion

Using a CARB SRIA-consistent screening framework, this assessment finds that a Fresno County renewable diesel facility could generate substantial environmental-justice and public-health co-benefits by supporting forest fuel reduction and reducing wildfire-attributable emissions. Because the wildfire and smoke module is parameterized on forest-residue throughput, outcomes scale linearly with the forest-residue share of the feedstock mix.

Scenario 1, with 1,000 BDT/day forest residues, maximizes treatment-equivalent area and produces the largest avoided wildfire emissions (4.173

$MtCO_2$/yr and 39,190 $tPM_{2.5}$/yr), which translates to significant SCC-valued climate benefits ($605.1M/yr under EPA SCC at 2.5%) and very large monetized health benefits in the SJV diagnostic ($51.64B/yr, 2022$).

Scenarios 2 and 3, each using 500 BDT/day of forest residues, deliver roughly half of these wildfire- and smoke-related outcomes, while Scenario 4, at 250 BDT/day, yields about one-quarter of Scenario 1's benefits. These findings indicate that, for Fresno-specific environmental-justice planning, increasing the forest-residue share is the most direct lever for maximizing smoke-related public-health co-benefits in the San Joaquin Valley.

Mixed-feedstock configurations may still be preferred under broader lifecycle carbon or waste-management objectives, particularly when MSW diversion credits materially improve net carbon intensity. However, these advantages should be evaluated within the full TEA/LCA boundary using explicit, non-overlapping accounting consistent with LCFS credit treatment, carefully avoiding double counting between monetized damages and compliance-market revenues.

"… Increasing the forest-residue share is the most direct lever for maximizing smoke-related public-health co-benefits in the San Joaquin Valley."

7. COMMUNITY ECONOMIC IMPACTS

Deployment of a 1,000 BDT-eq day^{-1} facility (approximately 330,000 BDT-eq per year) in Fresno County—converting forest and agricultural residues, and in some configuration MSW, into renewable diesel and biochar—is expected to support meaningful long-term employment and associated regional economic activity across the Central Valley. Consistent with standard input–output (IO) economic impact accounting, workforce impacts are categorized as direct, indirect, and induced employment.

Direct jobs include positions associated with facility operations and project-driven activities. Indirect jobs occur arise within supplier and contractor industries that support the project, while induced jobs reflect household spending effects as wages circulate through the regional economy [215–217].

This framework aligns with widely used energy-sector methodologies, including NREL, JEDI-style modeling and U.S. Bureau of Economic Analysis (BEA) IO multiplier approaches [218, 219]. Across all scenarios, consistent multiplier ranges are applied to estimate broader economic impacts, with indirect employment multipliers in the range of 1.7–1.9 and total (direct + indirect + induced) employment multipliers in the range of 2.5–2.7 [220–222].

7.1 Direct Employment Accounting and Scenario Drivers

Direct employment is estimated using a transparent, component-based approach designed to ensure consistency and reproducibility across scenarios. Three primary components are included: (i) conversion facility operations (ii) feedstock supply, and (iii) inbound logistics.

First, conversion and facility operations and on-site support are represented using fixed operation and management (O&M) staffing and continuous 24/7 operations. This includes operators, maintenance personnel, laboratory/QA-QC staff, environmental health and safety (EHS) and compliance staff, supervision, and administrative roles [220, 221, 223, 224]. Total staffing is estimated approximately 59 full-time equivalent (FTE) positions and is held constant across scenarios, as the core conversion platform (gasification, gas cleanup, FT synthesis and upgrading, utilities, product handling, maintenance, QA/QC, and EHS) operates continuously regardless of the feedstock composition (**Appendix ST 10**).

Second, feedstock supply employment for clean biomass (forest and agricultural residues) is estimated using an employment-intensity method applied consistently across biomass streams (0.12–0.16 FTE per 1,000 BDT) [220]. Because total facility throughput is fixed at ~1,000 BDT-eq/day, upstream biomass employment scales with the clean-biomass share of each scenario and declines as the MSW fraction increases.

Third, inbound logistics employment is derived from engineering-based estimates of trucking requirements, including truck trips per day, fleet size, haul distance, payload, and cycle-time, which are then translated into driver and fleet-support FTEs [222]. To maintain consistency with scenario definitions, logistic employment is disaggregated into (i) clean-biomass hauling, which scales with biomass fraction and (ii) MSW transfer –hauling, which is treated as contracted service and counted only as incremental contractor-supported employment. All logistics estimates are based on Fresno-specific assumptions, including an average 35-mile one-way haul distance (70-mile round trip), 14–16 BDT-eq payload per load [225], and 0.7–1.0 hours per trip for loading, unloading and delays. Driver shift assumptions are aligned with hours of service constraints and standard industry practices [218, 226–229].

For consistency, MSW is treated on a BDT-equivalent basis and RDF receiving and preprocessing are modeled as day-shift operations [230]. Because municipal solid waste collection systems are already in place, existing curbside collection employment is excluded. To avoid double counting, MSW-related employment includes only incremental activities, such as transfer/haul from material recovery facilities (MRFs) to the biorefinery, and additional receiving/preprocessing labor attributable to the project [222, 231, 232].

Under this framework, Scenarios 1 and 2 – both biomass-only configurations – yield similar total employment levels, as the facility processes the same quantity of clean biomass. Differences between these scenarios are primarily in workforce composition and training requirements. Scenario 1 concentrates employment in forest operations (e.g., fuels reduction, residue recovery, and forest logistics), while Scenario 2 shifts a larger share of employment to agricultural residue collection and preprocessing (e.g., aggregation, baling, and seasonal logistics).

Across all scenarios, conversion facility employment remains constant (~59 FTE). Variation in total direct employment is driven primarily by:

(i) feedstock-supply jobs, which decrease as MSW share increases; and (ii) MSW receiving and preprocessing jobs, which increase with higher MSW utilization.

With total inbound throughput held constant at approximately 1,000 BDT-eq/day, overall transport and logistics requirements remain broadly similar across scenarios in terms of fleet-sizing [219, 222].

Under these assumptions, the project supports approximately 102–139 direct FTE positions, depending on scenario. When indirect and induced effects are included using standard multipliers, total long-term employment is estimated at 255–375 jobs [215, 219, 222]. During the construction phase (approximately 3–4-year), the project is expected to generate 600–1,000 job-years, derived from biomass engineering, procurement, and construction (EPC) and U.S. Department of Energy BETO benchmarking (**Table 22)** [226–228]

"... Total long-term employment is estimated at 255–375 jobs. During the construction phase (approximately 3–4-year), the project is expected to generate 600–1,000 job-years.."

Table 22. Long-term employment impacts by scenario.

Impact metric	Scenario 1 (100% FR)	Scenario 2 (50% FR / 50% Ag)	Scenario 3 (50% FR / 30% Ag / 20% MSW)	Scenario 4 (25% FR / 25% Ag / 50% MSW)
Feedstock supply (forest + ag residues)	40–53	40–53	32–42	20–26
Transport & logistics (clean biomass inbound)	20–27	20–27	15–22*	7–17*
MSW transfer-haul logistics (contracted; jobs supported)	0	0	~4–5	~10–13
MSW receiving / preprocessing (day shift only)	0	0	4–6	6–9
Conversion facility O&M (24/7 incl. lab, maint., EHS, administration)	~59	~59	~59	~59
Total direct employment	119–139	119–139	114–134	102–124
Total indirect employment ($m_{indirect} = 1.7 - 1.9$)	83–125	83–125	80–121	71–112
Induced employment ($m_{total} - m_{indirect}$; midpoint method)	95–111	95–111	91–107	82–99
Total long-term employment ($m_{total} = 2.5 - 2.7$)	~298–375	~298–375	~285–362	~255–335
Construction-phase jobs (3–4 yr build-out)	600–1,000 job-years	600–1,000 job-years	600–1,000 job-years	600–1,000 job-years

Note: *MSW inbound hauling is modeled as a third-party purchased service reflected in variable OPEX; associated labor is reported as contractor jobs supported by project spending and excludes existing municipal curbside collection employment[219, 222].

7.2 Labor Income and Regional Output

Using an average annual wage range of $80,000–$90,000 per FTE, the direct workforce generates approximately $8.16–$12.51 million per year in direct labor income, depending on the scenario. As the share of MSW increases, upstream clean-biomass handling declines, resulting in lower supply-chain payroll, while employment at the conversion facility remains stable.

When indirect and induced effects are included, total annual labor income increases to approximately $20.4–$33.8 million per year. Applying an output-to-labor-income scaling factor (ϕ = 1.8–2.2), this corresponds to an estimated $36.7–$74.3 million per year in regional economic output.

Modeled project revenues indicate that Scenario 1 generates the largest annual revenue base (approximately $108.8 million per year), followed by Scenario 2 (approximately $79.3 million per year). MSW-integrated Scenarios 3 and 4yield intermediate revenues of approximately $82.5 million and $72.3 million per year, respectively (**Table 23**).

Table 23. Annual Labor Income and Regional Economic Output Impacts by Scenario, Including Project Revenues.

Metric	Scenario 1 (100% FR)	Scenario 2 (50% FR / 50% Ag)	Scenario 3 (50% FR / 30% Ag / 20% MSW)	Scenario 4 (25% FR / 25% Ag / 50% MSW)
Direct annual labor income (W = $80k–$90k)	$9.52–$12.51M/yr	$9.52–$12.51M/yr	$9.12–$12.06M/yr	$8.16–$11.16M/yr
Total annual labor income (direct+indirect+induced)	$23.80–$33.78M/yr	$23.80–$33.78M/yr	$22.80–$32.56M/yr	$20.40–$30.13M/yr
Annual regional economic output (ϕ = 1.8–2.2)	$42.84–$74.31M/yr	$42.84–$74.31M/yr	$41.04–$71.64M/yr	$36.72–$66.29M/yr
Total annual project revenue	$108.82M/yr	$79.34M/yr	$82.45M/yr	$72.25M/yr

Note: Results reflect steady state annual operations. Scenario differences are primarily driven by variations in feedstock composition, which affect upstream labor intensity and overall project revenues.

8. RISKS AND BARRIERS

Deployment of a renewable diesel–oriented Wood Products Innovation Campus (WPIC) in the Fresno Region involves multiple categories of technical, operational, and financial risk. A structured evaluation of these factors is essential to ensure robust project design, realistic performance expectations, and replicability across regions.

8.1 Feedstock Supply Risk

Long-term project viability depends upon the reliable and sustained availability of forest-derived biomass within economically feasible haul distances. Variability in treatment acreage, contractor capacity, permitting timelines, weather conditions, and wildfire activity may affect both the volume and timing of feedstock supply. Although state and federal forest-restoration targets indicate strong long-term demand for treatment, interagency coordination is critical to stabilizing feedstock flows. Additional factors—including moisture content, material heterogeneity, and seasonal access constraints—may influence preprocessing costs and conversion efficiency. These variables are incorporated into the techno-economic analysis through sensitivity modeling of throughput and supply conditions.

8.2 Transportation and Logistics Sensitivity

Transportation distance and fuel costs are key determinants of delivered feedstock price. Haul radius assumptions are particularly sensitive in mountainous or infrastructure-constrained regions. Potential mitigation strategies include strategic siting of aggregation yards, infrastructure improvements, and feedstock densification, which can reduce transportation costs and variability.

8.3 Capital and Operating Cost Variability

Capital intensity for thermochemical conversion and upgrading systems is a primary driver of financial feasibility. Project economics may be affected by construction cost inflation, supply-chain constraints, and financing conditions.

Operating costs are similarly sensitive to feedstock pricing, catalyst replacement cycles, maintenance requirements, and energy integration performance. The techno-economic analysis evaluates these factors under a range of capital and operating cost scenarios to assess project robustness under non-ideal conditions.

8.4 Market and Policy Risk

Project revenues are influenced by renewable diesel market prices and participation in low-carbon fuel policies, such as carbon crediting frameworks. Changes in credit valuation, regulatory structures, or carbon-accounting methodologies may materially affect project economics over time.

While renewable diesel benefits from drop-in fuel compatibility and established end-use markets, policy incentives remain key revenue component. Sensitivity analysis evaluates performance across a range of carbon-intensity values and credit price assumptions.

8.5 Lifecycle and Carbon Accounting Uncertainty

Lifecycle carbon outcomes depend upon regulatory treatment of feedstock baselines, avoided-emission assumptions, and biochar sequestration durability. Evolving accounting standards or verification requirements may affect pathway eligibility and credit valuation.

Maintaining methodological transparency and consistent documentation is therefore essential to ensure credibility and replication across jurisdictions.

8.6 Construction and Permitting Considerations

Project deployment is also influenced by industrial siting, air-quality compliance, and local permitting timelines. Although thermochemical conversion technologies are commercially established, project schedules may be affected by environmental review processes, utility interconnection requirements, and infrastructure integration planning.

In some cases, collaboration with sovereign Tribal governments or development on Tribal lands may introduce distinct governance and permitting pathways, reflecting Tribal authority and jurisdiction. These arrangements can influence timelines and regulatory interfaces depending on site-specific conditions.

8.7 Integrated Sensitivity Framework

The Fresno techno-economic assessment incorporates scenario-based sensitivity framework to evaluate financial and operational performance across a range of feedstock, capital cost, operating costs, and carbon-intensity assumptions. This approach is designed to assess project resilience under realistic, non-optimized conditions, rather than idealized scenarios. From a policy and planning perspective, explicitly identifying and testing key risk variables may enhance the transferability of the WPIC model to other regions. By systematically evaluating feedstock, infrastructure, market, and policy uncertainties, the WPIC framework provides decision-makers with a clear understanding of deployment constraints, trade-offs, and performance boundaries.

> **"From a policy and planning perspective, explicitly identifying and testing key risk variables may enhance the transferability of the WPIC model to other regions."**

9. CONCLUSION

This assessment demonstrates that a renewable diesel-oriented Wood Products Innovation Campus (WPIC) in Fresno County represents a high-impact, multi-benefit infrastructure strategy that can simultaneously advance wildfire risk reduction, transportation decarbonization, and environmental justice outcomes in California's San Joaquin Valley.

At its core, the analysis finds that forest-residue-dominant configuration provides the strongest and most policy-aligned pathway for deployment. By directly linking hazardous-fuel reduction activities in the Sierra Nevada to low-carbon fuel production and biochar co-products, the WPIC model creates a closed-loop system that converts underutilized biomass into economic value while reducing wildfire emissions and associated public health burdens. This integrated approach aligns with state and federal priorities spanning forest resilience, climate policy, and air quality and environmental justice mandates.

From a technical and financial perspective, the results establish a consistent hierarchy across feedstock strategies. The 100% forest-residue scenario delivers the strongest performance across all major bankability metrics—including internal rate of return (IRR), net present value (NPV), debt-service coverage ratio (DSCR), and payback period—while maintaining resilience under capital-cost uncertainty. Blended feedstock scenarios incorporating agricultural residues and limited MSW can remain viable, but they introduce additional operational complexity and financing risk, particularly with respect to syngas cleanup and sustained uptime, which are critical for first-of-a-kind thermochemical systems. High MSW integration is not recommended as an initial deployment strategy under base-case assumptions, unless supported by additional policy incentives, capital subsidies, or demonstrated performance improvements.

From a deployment and planning perspective, the geospatial screening and siting analysis identifies multiple viable locations within Fresno County, indicating that the WPIC model is replicable and adaptable, rather than site constrained. This flexibility enables optimization based on permitting feasibility, infrastructure access, feedstock logistics, and community considerations.

The environmental justice and public health findings further reinforce the importance of a forest-forward approach. Because wildfire and smoke-related benefits scale directly with forest-residue utilization, increasing the forest-residue share provides the most effective lever for reducing $PM_{2.5}$ exposure and associated health impacts in overburdened San Joaquin Valley communities. The analysis indicates that avoided wildfire emissions and smoke exposure can generate substantial climate and health co-benefits, with health impacts—particularly reductions in premature mortality—representing the dominant share of monetized benefits under SRIA-consistent valuation.

The economic and workforce analysis demonstrates that the WPIC model can support meaningful long-term employment (approximately 255–375 total jobs) and regional economic activity, with additional benefits during construction. Importantly, job composition varies by scenario, with forest-residue–dominant pathways supporting rural and forest-based employment, while blended systems diversify into agricultural and waste-management sectors. This provides opportunities for targeted workforce development and regional economic diversification, particularly in disadvantaged communities.

The analysis also highlights key risks and sensitivities, including feedstock supply variability, capital cost uncertainty, policy and market dependence, and evolving carbon-accounting frameworks. These factors underscore the importance of transparent assumptions, scenario-based sensitivity analysis, and careful alignment with regulatory frameworks, particularly to avoid double counting between monetized environmental benefits and compliance-market revenues (e.g., LCFS credits).

In conclusion, the WPIC model offers a practical, scalable pathway for integrating forest management, low-carbon fuel production, and environmental-justice outcomes into a unified infrastructure solution. With appropriate policy alignment, financing structures, and implementation discipline, this approach can serve as a replicable model for biomass-based decarbonization and wildfire mitigation across California and other fire-prone regions.

10. APPENDIX

Appendix TS1: Comparative assessment of BtL technology families: TRL, deployment status, and primary constraints (U.S. vs global).

Technology family	Primary feedstocks	Typical products	Indicative TRL / maturity*	U.S. deployment status (typical)	Global deployment status (typical)	Primary "bankability" constraint
Corn ethanol (biochemical) [25]	Corn grain	Ethanol	TRL 9 (commercial)	Fully commercial	Commercial (U.S., Brazil, EU)	Commodity/ feedstock & policy economics
Sugarcane ethanol (biochemical)[22, 32]	Sugarcane	Ethanol	TRL 9 (commercial)	Limited domestic production	Fully commercial (esp. Brazil)	Land/feedstock economics; policy
Cellulosic ethanol (biochemical) [28, 233]	Ag residues, forest residues, energy crops	Ethanol	TRL ~7–8 (demo–early commercial)	Limited; first-wave plants faced economic headwinds	Demonstrations/early commercials in multiple regions	Delivered feedstock cost + conversion OPEX + sustained yields
Anaerobic digestion + upgrading [234, 235]	Wet organics, manures, MSW organics	RNG/biomethane	TRL 8–9 (commercial)	Commercial; growing in CA	Commercial (EU, U.S.)	Site/feedstock aggregation; pipeline/CNG offtake
Lipid hydrotreating (HVO/HDRD)[236]**	UCO, tallow, veg oils	Renewable diesel (+SAF/naphtha)	TRL 9 (commercial)	Fully commercial	Fully commercial	Lipid availability, price, sustainability constraints
Gasification → FT (BtL-FT)[50, 237–239]	Forest residues, ag residues, MSW/RDF	RD/jet/naphtha (via wax upgrading)	Integrated ~TRL 6–7; FT sub-step	Limited demos; commercialization ongoing; setbacks observed	Pilots/demos historically; limited sustained commercial biomass-FT	Catalyst-grade syngas reliability + FOAK CAPEX

			~TRL 8–9			
Fast pyrolysis → hydro processing [30, 240, 241]	Cleaner lignocellulosic	RD/jet blend stocks	~TRL 6–7 (demo-stage)	Demonstrations: early commercial attempts failed	Demos/pilots in multiple regions	Deep deoxygenation, catalyst life, high H_2 demand
Hydrothermal liquefaction (HTL) → upgrading [242, 243]	Wet organics, sludges, algae	Biocrude → RD/jet blend stocks	~TRL 5–7 (pilot–demo)	Pilots; scale-up ongoing	Pilots/demos	Biocrude variability + upgrading severity + scale-up
Syngas fermentation (gas-to-fuels)[244, 245]	Cleaned syngas from biomass /waste	Alcohol intermediates → fuels	~TRL 5–7 (pathway-dependent)	Demos: biomass syngas adds cleanup burden	Demos/pilots	Gas cleanup + fermentation robustness + carbon efficiency
MTG / mixed-alcohol synthesis (syngas to liquids)[246, 247]	Biomass-derived syngas	Gasoline / alcohols	~TRL 5–6 (pilot–demo)	Pilot-scale	Pilot/demo	Catalyst selectivity + integration + economics

** TRL ranges are indicative planning values synthesized from pathway assessments (not site-specific certification).*

*** Included as a renewable diesel benchmark; it is not the residue-based BtL pathway emphasized for Fresno.*

Appendix TS2: Technology readiness across the biomass-to-FT renewable diesel chain (subsystem view).

Subsystem / technology	Function	TRL range	Why it matters for financeability / operability
Forest residue logistics	Harvest, comminution, transport	7–8	Delivered cost and seasonal variability drive DSCR stress cases [23, 28]
Agricultural residue logistics	Collection and transport (orchard waste, shells/hulls, etc.)	7–8	Mature logistics, but quality/ash/alkali can raise cleanup costs [34, 50, 239]

MSW/RDF preprocessing	Sorting/shredding/drying/ contaminant control	6–7	Enables tipping-fee economics but raises contaminant risk [24]
Indirect/DFB gasification	Produce N_2-free syngas suited for FT	6–7	Key syngas quality lever without oxygen plant [23, 35]
Fluidized-bed / entrained-flow (as alternatives)	Syngas generation with different tar/scale profiles	6–7	Tradeoff: CAPEX, preprocessing demand, tar/ash behavior [29, 30]
Syngas cleanup + conditioning	Tar/acid gas/alkali/Cl/S removal; WGS	5–7	Dominant technical risk + major CAPEX block; governs catalyst life [27, 33, 35]
FT synthesis (fixed/slurry)	Convert syngas to wax/diesel slate	7–9	High maturity step; depends on syngas purity [24, 35]
Wax upgrading (hydrocracking/isomerization)	Convert wax to RD/jet range	7–8	Mature refinery chemistry; CAPEX heavy if greenfield [23, 31]
Refinery co-processing	Upgrade intermediates in existing FCC/hydrocracker	6–8	Key CAPEX-reduction / de-risking strategy [35]
Integrated biomass → FT diesel system	End-to-end chain demonstration	6–7	"Near-commercial," but uptime and cleanup reliability govern bankability [24, 25, 27]

Appendix TS3: Key technical risks and mitigation strategies (for sensitivity design).

Risk	What can go wrong	Mitigation strategies to reflect in design/TEA	Key sources
Lower-than-expected FT yields	Catalyst inhibition or off-spec H_2:CO reduces conversion/selectivity	Strengthen cleanup/guard beds; improve WGS control; specify catalyst and operating window; include yield/uptime sensitivities	[33, 35]
Syngas cleanup reliability	Contaminant breakthrough causes catalyst deactivation or fouling	Redundant cleanup trains; online monitoring; staged polishing; catalyst protection/backup inventory	[24, 27]
Feedstock variability	Changing ash/alkali/Cl/S shifts cleanup loads and operability	Feedstock specs and QC; blending rules; preprocessing upgrades; scenario-specific cleanup design	[34]

Tar fouling	Tar carryover plugs equipment or poisons catalysts	Primary tar reforming; temperature control; guard beds; maintenance protocols	[30, 60]
Catalyst deactivation (trace contaminants)	Gradual loss of activity shortens campaign length	Strong polishing/guard beds; regeneration strategy where applicable; catalyst lifetime modeling	[33]
Fuel specification risk	Product fails ASTM-related properties (e.g., cold flow)	Hydro isomerization severity control; blending strategy; QA/QC and off-spec handling plan	[31, 35]
Co-feeding FT wax challenges	Plugging/handling issues during refinery co-processing	Heated logistics, wax property control, compatible refinery configuration; validated co-feed procedures	[35]
Low biogenic carbon efficiency	Excess carbon exits as CO/CO_2 rather than fuel products	Improve gasification carbon conversion; optimize synthesis conditions; adjust blending strategy; include carbon efficiency sensitivities	[35]

Table ST4: 40-km Radius: Re-treeing Biomass by Crop.

Crop	No. of Parcels	Total Acres	Biomass (BDT)	% of Total
Citrus	215	1,623.1	5,464.7	13.3%
Dates	3	21.9	141.9	0.3%
Apples	1	2.8	69.5	0.2%
Peaches & Nectarines	18	35.8	56.2	0.1%
Pecans	4	44.8	330.2	0.8%
Almonds	77	1,382.1	9,487.1	23.0%
Walnuts	13	807.6	439.3	1.1%
Pistachios	36	1,494.6	24,151.1	58.7%
Pomegranates	13	49.2	306.2	0.7%
Cherries	9	28.3	260.0	0.6%
Plums	12	32.3	452.6	1.1%
Total	401	5,522.5	41,158.7	100%

Note: Biomass yields per acre vary by crop (e.g., 18 BDT/acre for citrus, 25 BDT/acre for pistachios, 23 BDT/acre for almonds, etc.).

Table ST5: 80-km Radius: Re-treeing Biomass by Crop.

Crop	No. of Parcels	Total Acres	Biomass (BDT)	% of Total
Citrus	727	8,126.4	146,275	3.8%
Dates	1	3.1	78	<0.1%
Peaches & Nectarines	140	965.4	8,689	0.2%
Almonds	16	360.0	7,200	0.2%
Walnuts	36	326.3	8,158	0.2%
Pistachios	201	7,865.6	173,043	4.5%
Avocados	1	0.7	12	<0.1%
Apples	5	10.6	127	<0.1%
Pomegranates	13	69.7	1,046	<0.1%
Pecans	16	144.1	3,314	0.1%
Cherries	1	6.4	90	<0.1%
Plums	99	596.5	5,965	0.2%
Apricots	16	62.6	626	<0.1%
Prunes	6	175.6	2,458	0.1%
Pears	8	74.0	888	<0.1%
Total	1,285	18,787	357,969	100%

Table ST6: Capital cost normalization and scaling of literature-reported biomass-to-fuel and biomass-to-hydrogen facilities to a common 2024 USD 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)	Basi s year	CEPCI inflato r	Estimate d CAPEX $2024	Scalin g Factor	Scaling to 1000 BDT per day CAPEX (2024 $ M)	Product & Plant Stage
Tijmensen et al. [248]	1920	387	2000	2.03	785.59	0.52	409.16	FT product, 1st plant, indirect gasifier
Swanson et al. 2010 [22]	2205	498	2007	1.52	758.28	0.45	343.89	FT product, nth plant, indirect gasifier

Swanson et al. 2010 [22]	1920	339	2000	2.03	688.15	0.52	358.41	FT biofuel, Nth plant
Mann and Steward 2020 [104]; Ruth 2011 [249]	500	214	2009	1.53	328.03	2.00	656.06	Adjusted for Hydrogen , 1st plant
Mann and Steward 2020 [104]; Ruth 2011 [249, 250]	2000	344	2009	1.53	527.30	0.50	263.65	Hydrogen , nth plant
Commercia l Project 1 [104, 249–252]	2000	548	2009	1.53	840.01	0.5	420.00	FT product, 1st plant, indirect gasifier
Commercia l Project 2 [104, 249–252]	500	455	2009	1.53	697.45	2.00	1394.9 0	FT product, 1st plant, indirect gasifier
Commercia l Project 3 [104, 249–252]	2000	432	2009	1.53	662.20	0.50	331.10	FT product, 1st plant, indirect gasifier
Tijmensen et al. [248]	2000	542	2009	1.53	830.81	0.50	415.41	hydrogen, 1st plant, indirect gasifier
Spath et al. 2005 [253]	2000	565	2009	1.53	866.07	0.50	433.03	hydrogen, 1st plant, indirect gasifier
Swanson et al. 2009 [254]; Anex et al. 2010 [255]	2000	331	2009	1.53	507.38	0.50	253.69	FT, nth plant, direct gasifier
Swanson et al. 2009	2000	250	2009	1.53	383.22	0.50	191.61	FT, nth plant,

[254]; Anex et al. 2010 [255]								direct gasifier
Tijmensen et al. [248]	2000	638	2009	1.53	977.97	0.50	488.98	hydrogen, 1st plant, direct gasifier
Tijmensen et al. [248]	2000	474	2009	1.53	726.58	0.50	363.29	hydrogen, 1st plant, direct gasifier
Tijmensen et al. [248]	2000	559	2009	1.53	856.87	0.50	428.43	hydrogen, 1st plant, direct gasifier
Phillips et al. [256]	2,000	191	2005	1.70	325.50	0.50	162.75	Ethanol, nth plant
Larson et al. [257]	4,540	541	2003	1.99	1076.62	0.22	237.14	Diesel, gasoline, nth plant
Average CAPEX ($MM 2024)							420.68	

Table ST7: Chemical Engineering Plant Cost Index (CEPCI) values used to inflate literature-reported capital costs to a common 2024 USD 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

Appendix TS8: Values for the SC-CO_2 (in 2022$ per metric ton of CO2).

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

Appendix ST9: Total health benefits from the avoided incidents under four different scenarios.

Health category	Scenario 1	Scenario 2	Scenario 3	Scenario 4
Cardiopulmonary mortality	50.7	25.3	25.3	12.7
Hospitalizations (cardiovascular)	0.0117	0.0058	0.0058	0.0029
ED visits (cardiovascular)	0.0014	0.0007	0.0007	0.0003
Acute myocardial infarction	0.0307	0.0154	0.0154	0.0077
Hospitalizations (respiratory)	0.0012	0.0006	0.0006	0.0003
ED visits (respiratory)	0.0040	0.0020	0.0020	0.0010
Lung cancer incidence	0.0074	0.0037	0.0037	0.0018
Asthma onset	0.5633	0.2817	0.2817	0.1408
Asthma symptoms	0.2343	0.1172	0.1172	0.0586
Work loss days	0.1079	0.0540	0.0540	0.0270
Hospitalizations (Alzheimer's)	0.0202	0.0101	0.0101	0.0050
Hospitalizations (Parkinson's)	0.0030	0.0015	0.0015	0.0007
Total B/yr	51.64	25.82	25.82	12.91

Appendix ST10: Workforce and regional economic benefits.

Facility throughput	$\boldsymbol{M_{\text{in,day}} = 1000}$ BDT-eq day^{-1} Operating days/year: $\boldsymbol{D = 330}$ days yr^{-1} $\boldsymbol{M_{\text{in,yr}} = M_{\text{in,day}} \times D = 330,000}$ BDT-eq yr^{-1}				
Hauling and trucking	One-way distance: $d = 35$miles → round trip $2d = 70$miles Payload: $p = 14$–16BDT-eq/load Delay time: $t_{delay} = 0.7$–1.0 hr/trip [230] Speed: $v = 40$mph → $t_{drive} = 2d/v = 70/40 = 1.75$hr/trip Trip cycle time: $t_{trip} = t_{drive} + t_{delay} \approx 2.45$–2.75hr/trip Shift length: $t_{shift} = 10$ hr/day (conservative planning vs. HOS limits)				
Scenario fractions	Scenario 1: $f_{bio} = 1.0, f_{msw} = 0.0$ Scenario 2: $f_{bio} = 1.0, f_{msw} = 0.0$ Scenario 3: $f_{bio} = 0.8, f_{msw} = 0.2$ Scenario 4: $f_{bio} = 0.5, f_{msw} = 0.5$				
Impact metric	Calculation / formula	Estimated value			
		S-1	S-2	S-3	S-4
1) Feedstock supply (forest + ag residues)	Annual clean biomass handled: $M_{\text{bio,yr}} = f_{\text{bio}} \times M_{\text{in,yr}}$ Employment intensity method: $J_{\text{feedstock}} = \left(\frac{M_{\text{bio,yr}}}{1000}\right) \times EI_{\text{bio}}$ Where $EI_{\text{bio}} =$ 0.12–0.16 FTE per 1000 BDT for Western U.S. forest operations [220].	40–53	40–53	32–42	20–26
2) Transport & logistics (biomass + MSW inbound)	Trips per day [258]: $T_{\text{trips,day}} = \frac{M_{\text{in,day}}}{p}$ So: Low payload (14): $T \approx$ 71.4 trips/day [225] High payload (16): $T \approx$ 62.5 trips/day [225] Round-trip drive time: $t_{\text{drive}} = \frac{2d}{v} = \frac{70}{40} = 1.75$ hr/trip Total trip cycle time:	20–27	20–27	15–22	7–17

	$t_{\text{trip}} = t_{\text{drive}} + t_{\text{delay}} \approx 2.45\text{–}2.75$ hr/trip Trips per truck per day: $N_{\text{trips,truck}} = \frac{t_{\text{shift}}}{t_{\text{trip}}} \approx \frac{10}{2.75} – \frac{10}{2.45} = 3.64\text{–}4.08$ Number of trucks (≈ driver FTEs): $N_{\text{trucks}} = \frac{T_{\text{trips,day}}}{N_{\text{trips,truck}}} \approx 15.4\text{–}19.8$ Fleet support staffing (mechanics/dispatch/supervision/safety) [259, 260]: $J_{\text{support}} = J_{\text{mech}} + J_{\text{dispatch}} + J_{\text{sup}}$ Typical allocation logic: $J_{\text{mech}} \approx \frac{N_{\text{trucks}}}{10\text{–}15}$ $J_{\text{dispatch}} \approx \frac{N_{\text{trucks}}}{15\text{–}20}$ $J_{\text{sup}} \approx 2\text{–}3$ Total transport/logistics: $J_{\text{transport}} = N_{\text{trucks}} + J_{\text{support}}$ MSW share of $J_{\text{transport}}$ is contractor employment supported (variable OPEX purchased service), not plant payroll.				
3) MSW/RDF transfer-haul logistics (contracted; jobs supported)	Daily MSW tonnage: $M_{\text{msw,day}} = f_{\text{msw}} \times 1000$ Trips/day for MSW: $T_{\text{msw}} = \frac{M_{\text{msw,day}}}{p}$ Trucks (≈ drivers) for MSW transfer-haul [232]: $N_{\text{trucks,msw}} = \frac{T_{\text{msw}}}{N_{\text{trips,truck}}}$ Scenario 2 (20% MSW = 200 BDT-eq/day): ~ 3–4drivers + ~ 1support ⇒	0	0	~4–5	~10–13

	Scenario 3 (50% MSW = 500 BDT-eq/day): ~ 8–10drivers + ~ 2–3support				
4) RDF receiving / preprocessing (day shift only)	This term is incremental plant staffing that increases with MSW share based on design assumption. $$J_{\mathrm{RDF}} = \sum_k n_k$$ Where n_k is the number of day-shift positions for each function k (e.g., scale house/receiving, loader, sorting/prep line operators, QA/contamination monitoring, supervisor).	0	0	4–6	6–9
5) Conversion facility O&M (24/7, incl. lab, maint., EHS, admin)	Fixed-OPEX labor plan [220, 226, 228, 261–264]: $$J_{\mathrm{O\&M}} = J_{\mathrm{24/7\ crews}} + J_{\mathrm{day\ shift\ support}}$$ With 24/7 coverage computed using an hours basis: $$\text{FTE per 24/7 position} = \frac{8760}{H_{\mathrm{FTE}}} \approx \frac{8760}{2080} = 4.21$$ Then: $$J_{\mathrm{24/7\ crews}} = \sum_i \left(\text{positions per shift}_i \times 4.21\right)$$ Day-shift support is the count as supervision, engineering, EHS/compliance, lab/QA-QC, maintenance day staff, security/janitorial, etc [220, 221, 223, 224].	~59	~59	~59	~59
6) Total direct employment	$$J_{\mathrm{direct}} = J_{\mathrm{feedstock}} + J_{\mathrm{transport}} + J_{\mathrm{RDF}} + J_{\mathrm{O\&M}}$$	119–139	119–139	114–134	102–124

7) Total indirect employment (given $m_{\text{indirect}} = \mathbf{1.7–1.9}$) [215, 221]	$J_{\text{indirect}} = J_{\text{direct}} \times (m_{\text{indirect}} - 1)$ This is standard IO accounting (indirect = supply-chain effects) [215, 220].	83–125	83–125	80–121	71–112
8) Induced employment	$J_{\text{induced}} = J_{\text{direct}} \times (m_{\text{total}} - m_{\text{indirect}})$ Where $m_{\text{total}} = 2.5–2.7$. Induced reflects household spending of labor income [215, 221].	95–111	95–111	91–107	82–99
9) Total long-term employment	$J_{\text{total}} = J_{\text{direct}} \times m_{\text{total}}$ Total = direct + indirect + induced [221].	~298–375	~298–375	~285–362	~255–335
10) Construction-phase jobs (job-years)	$J_{\text{construct}} = EI_{\text{const}} \times C$ Where $EI_{\text{const}} =$ 0.6–1.0 job-years per (BDT day^{-1}) and $C = 1000$ BDT day^{-1}[226–228]	600–1,000	600–1,000	600–1,000	600–1,000
11) Direct annual labor income	$\text{Income}_{\text{direct}} = J_{\text{direct}} \times W$ with $W =$ \$80,000–\$90,000 per FTE-yr.	\$9.52–\$12.51M /yr	\$9.52–\$12.51M /yr	\$9.12–\$12.06M /yr	\$8.16–\$11.16M /yr
12) Total annual labor income	$\text{Income}_{\text{total}} = J_{\text{total}} \times W$	\$23.80–\$33.78M /yr	\$23.80–\$33.78M /yr	\$22.80–\$32.56M /yr	\$20.40–\$30.13M /yr
13) Annual regional economic output	$\text{Output}_{\text{regional}} = \text{Income}_{\text{total}} \times \phi$ Where $\phi = 1.8–2.2$is your selected output-to-labor-income scaling factor [220, 221, 263].	\$42.84–\$74.31M /yr	\$42.84–\$74.31M /yr	\$41.04–\$71.64M /yr	\$36.72–\$66.29M /yr

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