The Future of Drop-In Fuels

ARB Contract 13-308

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August 23, 2016

Prepared for the California Air Resources Board

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Acknowledgment We thank Thomas McKone and Eric Munsing for their valuable input. This Report was submitted in fulfillment of 13-308 by UC Berkeley under the sponsorship of the California Air Resources Board. Work was completed as of August 23, 2016.

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Abstract

Biofuels that can serve as a one-to-one replacement for gasoline or diesel, or achieve higher-level blends without modifications to existing fueling infrastructure and engines, offer an opportunity to accelerate the deployment of low-carbon liquid fuels. In this report, we reviewed the completed and ongoing research related to drop-in fuel production from feedstocks that can be produced in California, assessed potential pathways for conversion of biomass to hydrocarbon fuels from "well to pump" (excluding tailpipe combustion emissions) on the basis of expected cost, energy use, GHG emissions, criteria air pollutant emissions, water use, and technical potential in California, and modeled potential pathways to scaling up drop-in fuel production in the state. Biomass sources considered included crop residues, forest residues, primary mill waste, secondary mill waste, and urban wood waste. Our findings suggest that thermochemical pathways are the most promising routes in the near- and mid-term, although further research may improve yields for biological and hybrid biological/catalytic routes. Uncertainties associated with the results are significant due to lack of data, data quality, and scale-up scenarios for California conditions. Bio-based hydrocarbon fuels have the potential to have lower life-cycle greenhouse gas (GHG) emissions relative to comparable first generation fuels, such as ethanol or biodiesel, because truck and rail transportation can be partially eliminated in favor of energy-efficient pipelines. The criteria air pollutant emissions may also not be higher than for conventional fuels. We find that pyrolysis, Fischer-Tropsch, and methanol-to-gasoline routes can be scaled up using waste biomass in California to reach as high as 58% displacement of in-state diesel use and 8% of in-state gasoline use.

Executive Summary

Background

The term "drop-in fuel" is not clearly defined in the literature. In an ideal case, a bio-based crude could be produced from biomass, shipped to petroleum refineries, processed alongside conventional crude without requiring equipment retrofits, and the resulting products would be indistinguishable from conventional petroleum fuels and products. Diesel, gasoline, jet fuel, and marine fuel are all made up of a range of molecules, as well as additives, that allow them to meet established fuel specifications that vary by region and season in the United States.

The purpose of this project was to review the completed and ongoing research related to drop-in fuel production from feedstocks that can be produced in California, evaluate potential pathways from well-to-pump (excluding tailpipe combustion emissions) based on their expected costs and environmental performance, and model potential pathways to scaling up drop-in fuel production in the state.

Before ultimately narrowing our analysis to a limited collection of drop-in fuel pathways most relevant for California, we surveyed a wide array of potential production pathways starting with sugars, microalgae, and waste oils/fats. Pathways can be split into the following general categories:

- Biological: Pathways that begin with sugars, sourced from either sugar, starch, or biomass feedstocks, and utilize host microbes to produce final fuels.
- Hybrid biological/chemical: Pathways that begin with sugars, sourced from either sugar, starch, or biomass feedstocks, and utilize host microbes to produce fuel precursors that are converted through catalytic processes to final fuel products.
- Chemical: Pathways that begin with sugars, sourced from either sugar, starch, or biomass feedstocks, or lipids, and utilize purely chemical routes to producing fuels. Furan pathways that convert five-carbon sugars to furfural, and ultimately to fuels are an example, as are renewable diesel pathways.
- Thermochemical: Pathways that use high-temperature processes such as pyrolysis or gasification to produce fuel mixtures.

Methods

To determine which pathways are suitable for scale-up in California, we accounted for two primary factors: 1) the relative maturity and cost-competitiveness of the conversion process and 2) the compatibility of the conversion process with feedstocks widely available in California (including crop residues, forest residues, primary mill waste, secondary mill waste, and urban wood waste). We began by reviewing existing literature and ongoing laboratory research to determine what fuel pathways hold the most promise for feedstocks in California. Based on our findings, we narrowed down the number of pathways under consideration to three options: pyrolysis, Fischer-Tropsch, and methanol-to-gasoline. For each of these options, we conducted a detailed review of previous techno-economic assessments of biomass conversion technologies and an original environmental assessment to determine results for energy, greenhouse gas emissions, criteria air pollutant emissions, and water. We also identified key data gaps that should be addressed in future research. Using these results, we constructed an optimization tool called California Drop-In (CAdi) fuel logistics model, which calculates the environmental impacts associated with large-scale deployment of second-generation transportation fuels in California. In addition to accounting for life-cycle emissions and fuel use, CAdi integrates additional optimization and GIS tools that provide more resolved information on how the well-to-pump emissions footprint varies on an individual feedstock-supplier-to-refinery level. Based on the results of our scenarios in which different objectives and constraints are used to explore possible routes to scale-up of drop-in fuels, we are able to determine the potential fuel production levels and the expected net emissions, fossil energy demand, and water use associated with these strategies. Our results allow us to identify key opportunities for future research and potential barriers to overcome.

Results

There is a clear need to move toward fuels that can be blended at higher levels with conventional petroleum without the need for vehicle or infrastructure retrofits if bio-based fuels are to gain a substantial market share in the near- and mid-term. We found that pyrolysis, Fischer-Tropsch, and methanol-to-gasoline conversion pathways remain the most likely candidates for deployment, despite advances in biological and hybrid biological/catalytic fuel production pathways. In terms of environmental impacts, the results (which have significant uncertainties because of lack of data, data quality, and scale-up scenarios for California) suggest that all three pathways can achieve greenhouse gas (GHG) and criteria air pollutant emissions reductions relative to conventional fuels, and if hydrogen can be derived from renewable sources for the pyrolysis pathway, the GHG footprint could be further reduced. Regarding scale, the drop-in fuel pathways are likely to achieve relatively high market penetration in California's diesel market (as much as 58%), but lower penetration (8%) in the gasoline market.

Conclusions

Our research has shown that there are pathways to hydrocarbon fuels resembling gasoline, diesel, and potentially jet fuel that can be scaled up using California's existing waste biomass. These strategies appear able to reduce net GHG emissions in the state, particularly for the heavy-duty freight transportation sector, as well as lower criteria air pollutant emissions, although significant uncertainties about the emission levels exist. Based on the potential scale of production, any decarbonization strategy for transportation in California must either include large-volume biofuel imports from other states or electrification of the state's passenger transportation fleet. In fact, the higher likelihood that advanced biofuel pathways will produce suitable diesel or jet fuel replacements means that such a strategy would be complementary to an electrification strategy, assuming that heavy-duty freight is less likely to be and air travel will not be electrified.

Introduction

Although ethanol currently dominates the U.S. biofuel market, the so-called blend wall limits its potential market share. The U.S. Environmental Protection Agency (EPA) allows for sale of E15 blends for use in vehicles manufactured after 2001, but most gasoline sold in the U.S. remains at or under the previous limit of E10 and the approval of E15 use required a lengthy regulatory process [Strogen et al. 2012]. Biofuels that can serve as a one-to-one replacement for gasoline or diesel, or achieve higher-level blends without modifications to existing fueling infrastructure and engines, offer an opportunity to accelerate the deployment of low-carbon liquid fuels. Additionally, bio-based hydrocarbon fuels have the potential to achieve more favorable life-cycle greenhouse gas (GHG) emissions relative to comparable first generation fuels, such as ethanol or biodiesel, because truck and rail transportation can be partially eliminated in favor of energy-efficient pipelines [Strogen et al. 2012].

Determining which pathways for converting biomass to drop-in fuels based on claims in the research literature can be challenging. Basic science publications typically highlight the novelty and advantages of the documented approach (high yield or new product) without addressing the practical challenges of applying the approach, which is beyond the scope of basic research. Low yields, challenges associated with separations, or costly inputs can pose problems for otherwise exciting conversion pathways. Novel molecules may be presented as a suitable replacement for gasoline, diesel, or jet fuel based solely on their carbon number and basic structure. Fuel properties and engine testing, which require larger volumes of fuel than what is produced in bench-scale experiments, may validate these claims or reveal that what was thought to be a promising blendstock has undesirable effects on performance.

The purpose of this project was to review the completed and ongoing research related to drop-in fuel production from feedstocks that can be produced in California, evaluate potential pathways from well-to-pump (excluding tailpipe combustion emissions) based on their expected costs and environmental performance, and model potential pathways to scaling up drop-in fuel production in the state.

Background

The term “drop-in fuel” is not clearly defined in the literature. In an ideal case, a bio-based crude could be produced from biomass, shipped to petroleum refineries, processed alongside conventional crude without requiring equipment retrofits, and the resulting products would be indistinguishable from conventional petroleum fuels and products.

Hydrocarbons in gasoline range in size from 4 carbons to 12, with 55% alkanes, 25% aromatic hydrocarbons, 10% cycloparaffins, and 10% alkenes [Gibbs et al. 2009]. Maximizing gasoline’s octane number, and thus preventing knock in spark-ignited (SI) engines, requires a mixture of less reactive compounds such as aromatics and hydrocarbons containing double bonds. Important characteristics of gasoline blends include octane number, stability, energy content, density, sulfur content, and vapor pressure. Diesel fuel is comprised of larger molecules, ranging from 12 carbons to 20. Because diesel is used in compression-ignited (CI) engines, it contains a higher fraction of reactive saturated hydrocarbons (75%) and a smaller fraction of less reactive aromatic hydrocarbons (25%). Important characteristics of diesel blends include cetane number, energy content, density, lubricity, cold-flow properties, sulfur content, and stability.

Because producing appropriate blendstocks or complete replacements will be challenging, it is important to focus on fuels that are responsible for the largest share of GHG emissions and energy demand. Gasoline makes up the largest share of fuel consumption at 51% (by Btu) (Figure 1). Diesel and jet fuel have roughly equal shares of 16-17%. Ethanol currently has a 4% share of consumption. Residual fuel oil, which is used almost entirely in transportation applications, makes up a much smaller fraction at 2%. Based on the relative size of each fuel market, we have chosen to focus on alternative fuels for use in highway vehicles and aviation: gasoline, diesel, and jet fuel. We also address potential alternatives for marine fuel. For the purposes of this project, we refer to bio-based hydrocarbons as drop-in fuel. This includes individual molecules, as well as the ranges of molecules produced through thermochemical pathways such as pyrolysis and gasification with Fischer-Tropsch synthesis. Many of the fuels referred to as drop-in may only be appropriate at limited blends with petroleum fuel in existing engines. Conversely, there may be fuels not considered drop-in because they contain oxygen, such as butanol, but are compatible with engines at higher blends.

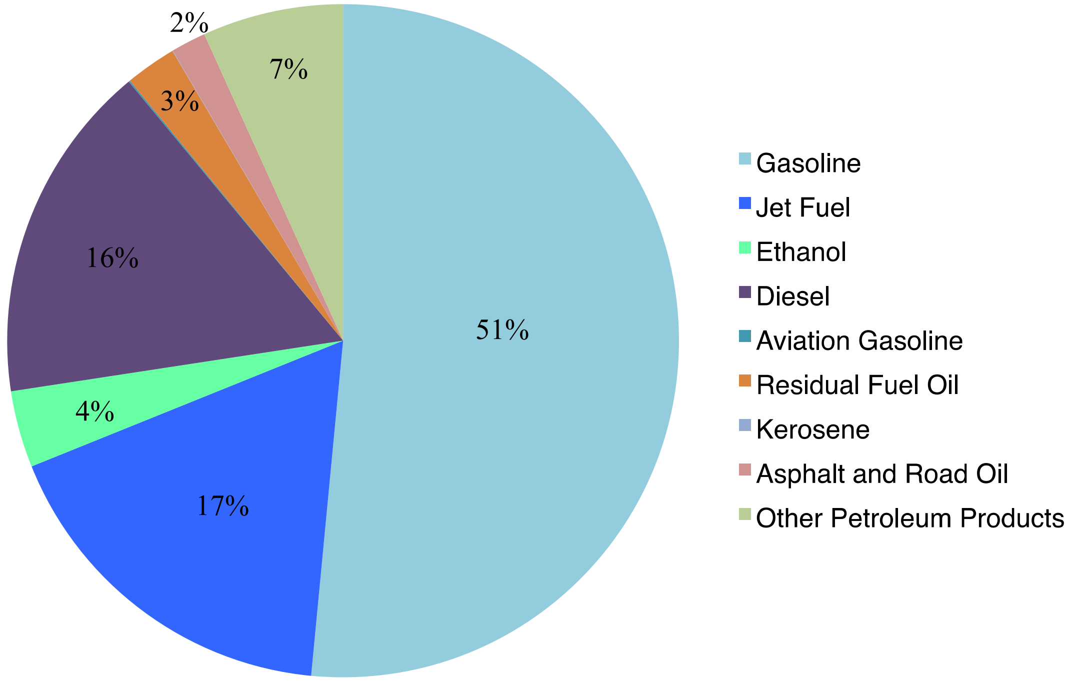

Figure 1: 2014 Fuel Consumption in California on the Basis of Higher Heating Value (Data Source: EIA 2014)

In contrast to ethanol production processes, technologies to convert bio-based feedstocks to liquid hydrocarbon fuels are less mature. Drop-in fuel pathways can begin with sugars/starches, fats/oils, lignocellulosic biomass, or algae, and result in fuels that meet specifications for gasoline, diesel, jet fuel, and marine fuel. Tracking the range of appropriate feedstocks, relative maturity, and economic viability of this rapidly changing array of fuel production technologies is a challenge in itself. We approach this problem by narrowing the solution space based on what feedstocks are readily available in California at a large scale, and then further selecting pathways based on their relative maturity, expected production costs, and ability to displace conventional gasoline, diesel, and marine fuels.

Materials and Methods

To determine which pathways are suitable for scale-up in California, we accounted for two primary factors: 1) the relative maturity and cost-competitiveness of the conversion process and 2) the compatibility of the conversion process with feedstocks widely available in California. The project was split into 6 tasks:

1. Review of Literature and Ongoing Laboratory Research

2. Life-Cycle Cost and Environmental Assessment Data Gap Analysis
3. Scale-Up Scenario Modeling
4. Identification of Research Needs
5. Identification of Potential Barriers
6. Development of a Strategy to Monitor and Track Progress with Drop-In Fuels

Task 1: Review of Literature and Ongoing Laboratory Research

Feedstock Availability and Composition

Because drop-in fuels can be produced from a wide variety of feedstocks, understanding the biomass resources available in California is a critical first step to determining which fuel pathways are most promising for in-state production. Figure 2 shows the solid biomass residue availability in California, including annual crop residues (including orchard trimmings), forest residues, primary mill waste, secondary mill waste, and urban wood waste (including wood found in municipal solid waste (MSW)). Our analysis focuses only on waste biomass because of the potential for indirect land use change (iLUC) issues associated with converting arable land to biomass crop production, although it should be noted that substantial uncertainty remains regarding the environmental impacts of direct and indirect land use change [McManus et al. 2015]. We report availability on an annual basis because multi-month storage of biomass to smooth out seasonal variations in availability is typically not problematic. This is not necessarily the case for wet biomass such as food processing waste. We do not explore dedicated bioenergy feedstock crop production because these crops are typically low value and will not compete effectively with higher-value food crops grown in California. Additionally, high-yielding biomass crops such as switchgrass require irrigation when grown in California, which will increase the cost of production and apply further pressure to already limited fresh water resources in the state. A key takeaway from Figure 2 is that, in terms of dry biomass residue, woody biomass is dominant on a mass basis (74% of the total solid biomass resources in California versus 26% for the crop residues). Given recent tree die-offs resulting from the drought, bark beetle infestation, as well as woody residue from orchards whose trees are cut down as a response to the drought, recent woody biomass supply is likely to be even higher than what is shown in Figure 2.

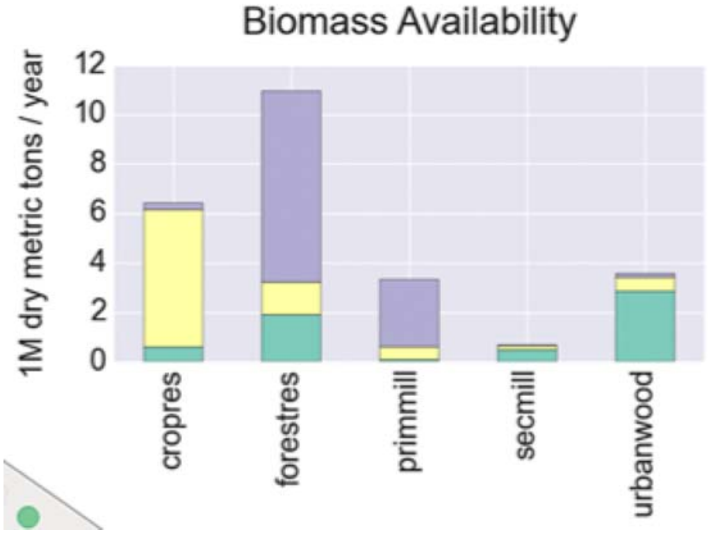

Figure 2: Distribution of Solid Biomass Resources in California by Type and Region

To illustrate regional differences, the total dry biomass availability per resource is partitioned into a north coast and mountain region (purple), a central valley region (yellow), and a central coast and southern region (turquoise) (Data sources: CBC 2015, NREL 2014). cropres = crop residue; forestres = forest residue; primmill = primary mill waste; secmill = secondary mill waste

Biomass type is important for selecting drop-in fuel pathways because the composition varies by crop/source. Biomass is made up of cellulose, hemicelluloses, lignin, and a small fraction of ash (incombustibles) and extractives, as shown in Figure 3. Extractives include compounds that are soluble in either water or the fuel product such as inorganic material, non-structural sugars, nitrogenous material [Sluiter et al. 2005]. For example, chlorophyll and waxes are included in extractives for herbaceous biomass. Cellulose and hemicelluloses can be broken down into their constituent sugars for biological conversion processes. Figure 3 shows the breakdown based on the polysaccharides that make up cellulose and hemicelluloses, as well as uronic acids, lignin, ash and extractives. Cellulose corresponds to the polysaccharide glucan, which can in turn be broken down into glucose monomers (a six-carbon sugar). Galactan, mannan, xylan, and arabinan are made up of five-carbon sugar monomers (galactose, mannose, xylose, and arabinose) and together make up the hemicellulose component of biomass.

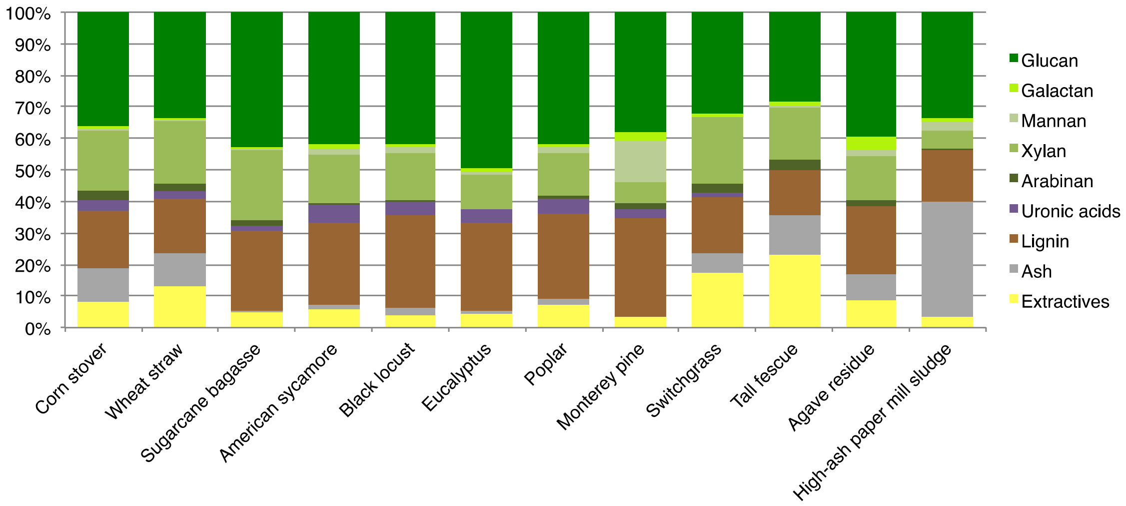

Figure 3: Composition of Common Biomass Feedstocks (Data Source: DOE 2004)

During biological conversion processes, pretreatment and saccharification processes break down cellulose and hemicellulose into five- and six-carbon monomers, and these sugars must subsequently be metabolized by host microbes capable of making desirable fuels (or fuel precursors). With the exception of Monterey Pine and other softwoods, the xylose makes up the majority of five-carbon sugars present in biomass. Because xylose is not naturally-occurring as a sugar monomer, engineering host microbes to metabolize it presents a challenge. Many of the promising biological pathways to advanced fuels reported in the literature focus exclusively on conversion of glucose. However, as Figure 3 shows, the glucose fraction (denoted by the glucan bar) typically makes up less than 40-50% of total biomass. It is widely recognized that commercially viable biological pathways for converting fuels must utilize both five- and six-carbon sugars [Klein-Marcuschamer 2010].

Lignin presents a greater challenge than conversion of five-carbon sugars. A polyaromatic compound that varies in composition from feedstock-to-feedstock, lignin presents an opportunity to produce high-value platform chemicals and fuel additives, but the technical challenges associated with breaking down lignin in a cost-effective manner have so far led most facilities to simply combust it for process heat and electricity [Scown et al. 2014]. Because biological processes aimed at converting sugars do not convert lignin, biological processes are typically applied to lower-lignin feedstocks, while higher-lignin feedstocks are used in harsh thermochemical processes such as pyrolysis or gasification. Figure 3 shows that herbaceous feedstocks such as corn stover, wheat straw, and switchgrass have lower lignin contents while woody feedstocks typically contain more lignin. Thus, most thermochemical conversion studies focus on woody biomass while biological conversion studies often use herbaceous biomass [PNNL 2009, Humbird et al. 2011, Xu et al. 2016, NREL 2012]. The split between herbaceous and woody solid biomass resources in California is 26% and 74%, respectively.

MSW is another feedstock of interest because of the co-benefits associated with diverting solid waste from landfills. In 2014, Californians produced 28 million metric wet tons of municipal solid waste [CalRecycle 2015]. Of that total mass, approximately 18 million tonnes could be converted to bio-based fuels (see breakdown in Figure 4). However, a fraction of this waste is already recovered for other purposes (recycling or composting, for example). In 2013, 63% of disposed paper and paperboard was diverted from landfills and 60% of yard trimmings were diverted, while only 16% of wood waste and 5% of food waste were diverted [EPA 2015]. Figure 4 shows the MSW breakdown before and after waste diversion. Note that wood in MSW is accounted for as urban wood waste in Figure 2. After accounting for waste already diverted for other purposes, the total wet tonnes available for conversion is reduced to 9.5 million wet metric tons. Accounting for moisture content is challenging because the overall moisture content of MSW is fairly high but the moisture contents of individual components, such as paper and paperboard, are lower. If we assume an average moisture content of 50%, total tonnage available for conversion is approximately 5 million dry metric tons.

The advantage of utilizing MSW is that, as a feedstock, it is available everywhere in California and – if not used for biofuel conversion – would need to be disposed of in landfills after tipping fees had been paid. A disadvantage is that the organic waste not already diverted for other purposes is likely to require sorting to remove inorganic contaminants and may have a relatively high moisture content (50% or greater) that makes the material more suitable for anaerobic digestion than biological or thermochemical conversion to fuels. Data on fuel yields from MSW for common conversion pathways is sparse, and often uses idealized simulated data that is unlikely to reflect actual plant operations. However, ongoing research and commercialization may improve data availability and performance. Efforts to convert MSW to liquid fuels include Fulcrum Bioenergy's Sierra BioFuels Plant in Storey County, Nevada, which will use gasification and Fischer-Tropsch synthesis to produce a jet fuel product from both organic and inorganic waste, as well as experimental work at the Joint BioEnergy Institute, Advanced Biofuel Process Demonstration Unit, and Idaho National Laboratory on conversion of mixed paper and corn stover feedstock streams [Biofuels Digest 2015, Sun et al. 2015].

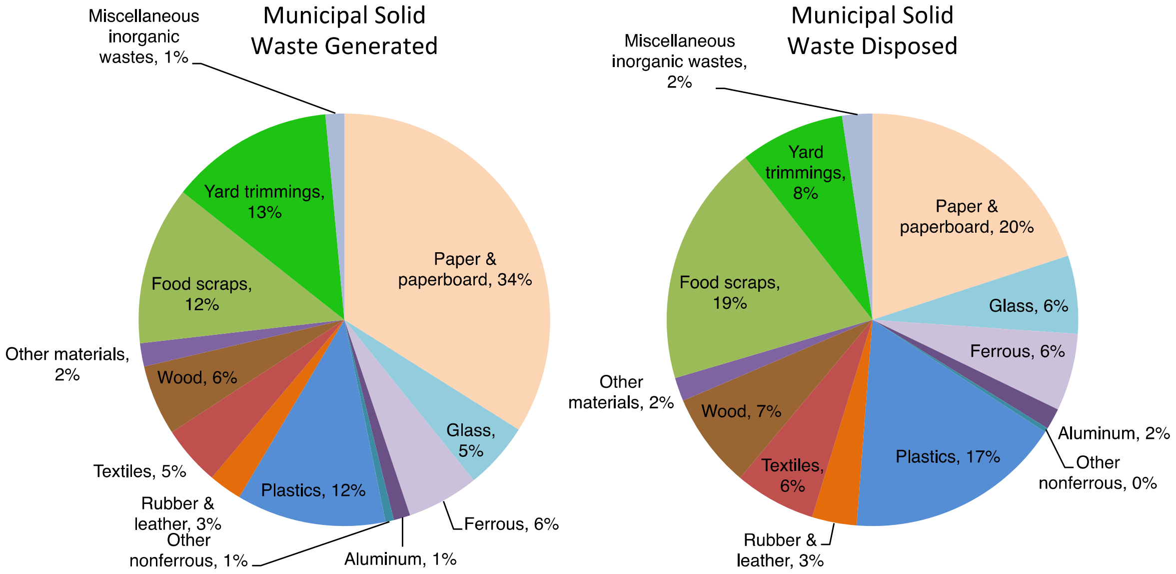

Figure 4: Composition of Municipal Solid Waste

Overview of Drop-In Fuel Pathways

Before ultimately narrowing our analysis to a limited collection of drop-in fuel pathways most relevant for California, we surveyed a wide array of potential production pathways starting with sugars, microalgae, and waste oils/fats. Pathways can be split into the following general categories:

- Biological: Pathways that begin with sugars, sourced from either sugar, starch, or biomass feedstocks, and utilize host microbes to produce final fuels.
- Hybrid biological/chemical: Pathways that begin with sugars, sourced from either sugar, starch, or biomass feedstocks, and utilize host microbes to produce fuel precursors that are converted through catalytic processes to final fuel products.
- Chemical: Pathways that begin with sugars, sourced from either sugar, starch, or biomass feedstocks, or lipids, and utilize purely chemical routes to producing fuels. Furan pathways that convert five-carbon sugars to furfural, and ultimately to fuels are an example, as are renewable diesel pathways.
- Thermochemical: Pathways that use high-temperature processes such as pyrolysis or gasification to produce fuel mixtures.

Each of the above-mentioned pathway categories is capable of producing hydrocarbon fuels, either as a single compound or a complex mixture (as is the case for thermochemical routes). However, the yields, energy needs, and emissions can vary dramatically. Potential pathways are shown in Figure 5. Because woody biomass dominates California's waste biomass feedstock supply (74% of total available biomass resources), and biological routes to drop-in fuels have not yet achieved the necessary yields to make conversion of herbaceous or woody biomass commercially viable, our detailed literature review focuses on thermochemical routes, including pyrolysis, gasification with Fischer-Tropsch synthesis, and methanol-to-gasoline.

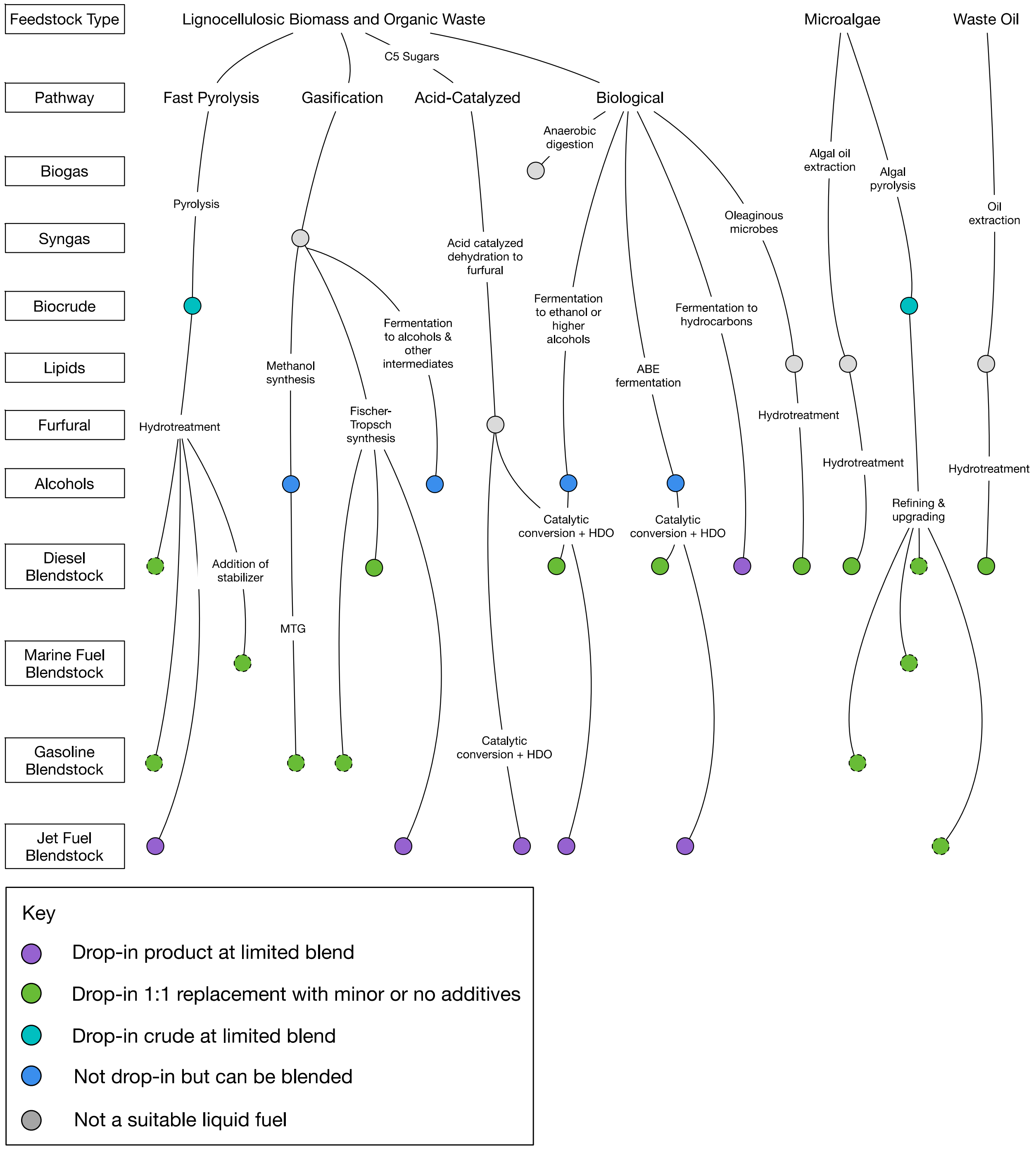

Figure 5: Potential Pathways to Drop-In Fuels

Dashed outlines indicate fuel products that have not been extensively tested and proven to be drop-in.

Pyrolysis Process Overview

The pyrolysis pathway includes the fast pyrolysis of biomass to bio-oil, followed by hydrotreating the bio-oil to drop-in gasoline and diesel. Several LCAs have evaluated this study [PNNL 2013, NREL 2010, NREL 2012, Iribarren 2012], providing information on mass balance and process yields, energy demands, and greenhouse gas emissions. The process of converting biomass to pyrolysis oil has been demonstrated on a commercial scale by the Dutch company BTG, although there are no plants currently in operation that convert the pyrolysis oil to drop-in fuels. Most of the LCA reports on the pyrolysis pathway used process simulation software, such as Aspen, to evaluate the performance of the pyrolysis pathway. Due to the harsh conditions of the pyrolysis process, this pathway is not highly sensitive to the type of biomass feedstock; similar yields have been observed from mill residues and corn stover feedstocks.

The process of biomass fast pyrolysis involves the rapid heating of biomass in the absence of oxygen to temperatures of 400 - 600°C to thermally decompose the biomass. The products of pyrolysis are light gaseous hydrocarbons, solid char, and a mixture of oxygenated hydrocarbons referred to as pyrolysis oil, or bio-oil.

Figure 6 shows the process flow diagram (PFD) of the pyrolysis pathway. This flow diagram is based on the process as described in [PNNL 2013]. The numbers in parentheses labeling each mass flow correspond to the stream number in the pyrolysis stream table; Table A1 in Appendix A.

Biomass enters the process and is first dried and ground before entering the pyrolyzer. Fast pyrolysis is most effective when the input biomass is dried to a moisture content of <10 wt%, and ground to a particle size of 2-6mm. The dried and ground biomass enters the pyrolyzer, where it is rapidly heated to a temperature of 500°C. Within the pyrolysis unit, hot sand is used as a heat carrier, and a fluidizing gas is used to maintain fluidized conditions within the reactor. Residence time within the reactor is 2 seconds. The pyrolysis reactor produces char and a mixture of vapors. The sand is heated by combustion of char and off-gases from the pyrolyzer. For simplicity, this sand heating process is not depicted in the PFD. Most of the noncondensable gases produced in the pyrolyzer are recycled back into the unit as the fluidizing agent. Excess off-gas is sent to the gas combustion unit to provide process energy. Process off-gas does not meet all of the thermal energy loads for the pyrolysis pathway, so natural gas is purchased from an off-site source.

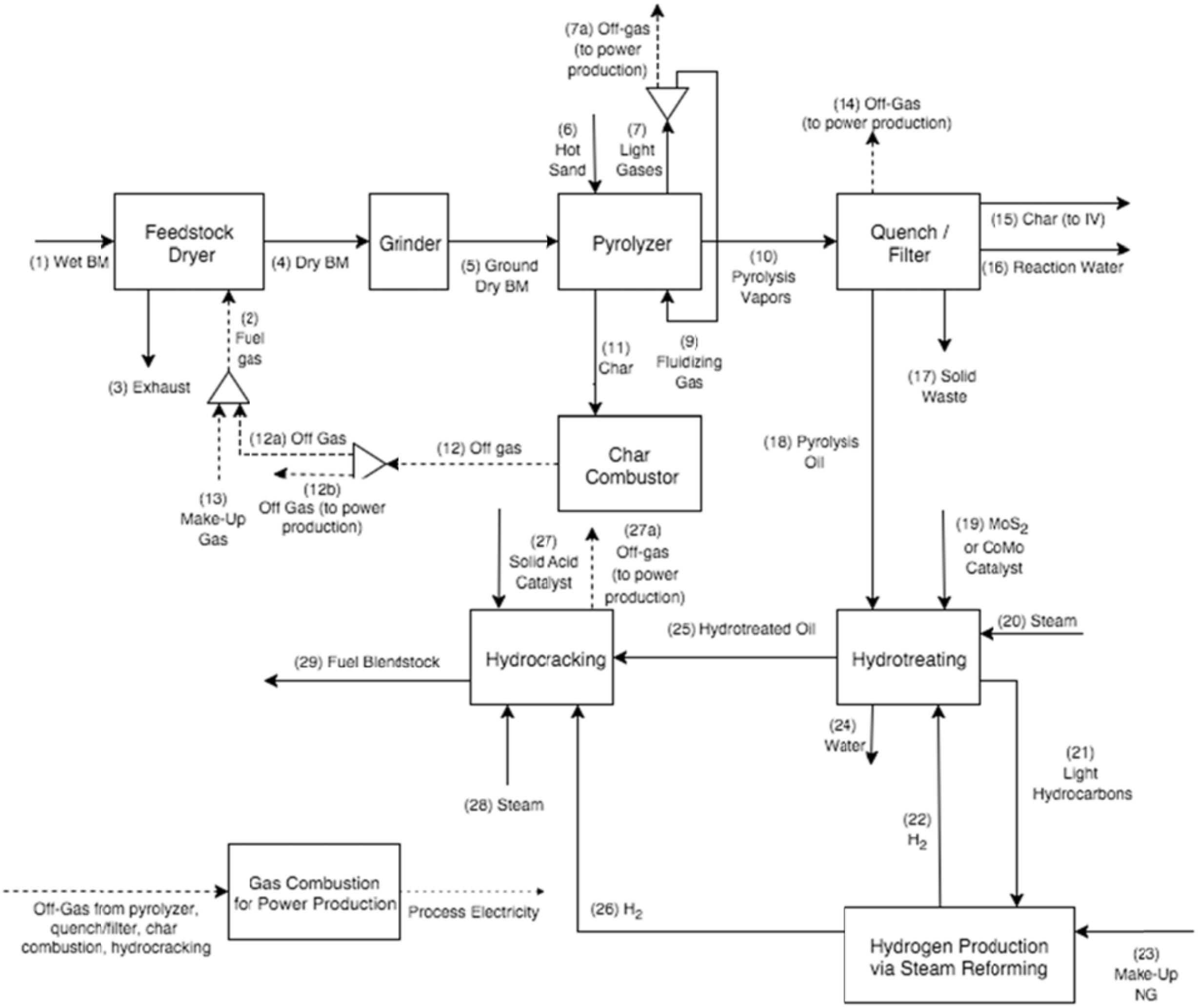

Figure 6: Pyrolysis Process Flow Diagram (Primary Data Source: PNNL 2013)

The pyrolysis vapors are sent to the quench / filter step, where a filter removes solid waste and the quenching process liquefies the remaining pyrolysis vapors into pyrolysis oil. The light hydrocarbons are removed as off-gas and sent to the gas combustion unit. The pyrolysis oil is sent to the hydrotreating process, which involves contacting the pyrolysis oil with hydrogen in the presence of a catalyst to first hydrogenate, and then deoxygenate the hydrocarbons. Hydrogenation reactions are commonly used in petroleum processes and have been demonstrated at large scale. However, deoxygenation has not typically been used at a scale that would be observed in a drop-in fuels plant, thus is a less mature technology.

Several catalysts have been proven effective for these hydrotreating reactions, including molybdenum-based sulfides, noble metals, base metals and metal phosphides. The products from the hydrotreating reactions include light hydrocarbon off-gases, an aqueous liquid phase and the hydrocarbon liquid phase. The off-gases are sent to the steam reforming reaction for hydrogen production, the aqueous phase is easily separated off, and the hydrocarbon liquid phase is sent to the hydrocracking reactor. The hydrocracking reactor catalytically cracks the hydrocarbons to the range of hydrocarbon chain lengths appropriate for drop-in fuels, producing both diesel and gasoline.

Both the hydrotreating and hydrocracking reactions require high volumes of hydrogen for operation. Hydrogen for these unit processes is produced on-site in a steam reforming unit. The steam reforming unit takes off-gas from the hydrotreating unit with natural gas sourced off-site to convert methane to hydrogen and carbon dioxide.

Gasification / Fischer-Tropsch Process Overview

The Fischer Tropsch (FT) diesel process is a well-known and mature technology to convert syngas (a combination of hydrogen and carbon monoxide) to diesel fuel. Gasification is a thermal treatment process that thermally decomposes biomass. Gasification reactions occur at much higher temperatures than pyrolysis (around 800°C), and take place in the presence of oxygen. As a result, the product from gasification is a crude syngas mixture, comprised mainly of hydrogen and carbon monoxide, with other light hydrocarbons and noncondensable gases.

Figure 7 shows the PFD for combining gasification and Fischer-Tropsch to produce diesel fuel from a biomass feedstock. This process flow diagram was based on the life cycle assessment from the high-temperature gasification scenario in [Swanson et al. 2010]. The numbers in parentheses labeling each mass flow correspond to the stream number in the FT stream table; Table A2 in the Appendix.

As in the pyrolysis pathway, the biomass is first dried and ground before entering the gasification unit. Gasification is most effective when the biomass moisture content is <10wt% and the particle size is reduced to 12-mm. Before entering the gasifier, the dried and ground biomass is pressurized in a lockhopper. In the gasification process, biomass, steam and oxygen enter the gasifier at a temperature of 870°C. The oxygen feed stream is at 95% purity, and is derived from an air separations unit.

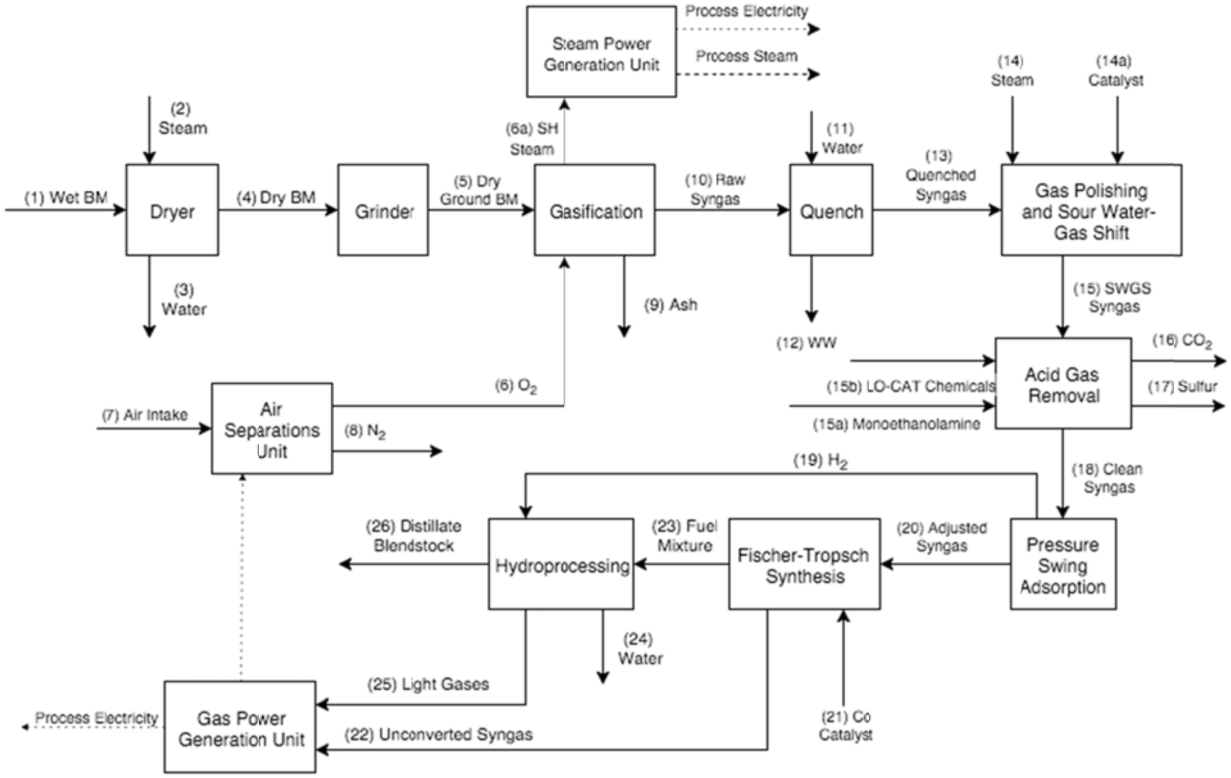

Figure 7: Gasification/Fischer-Tropsch Process Flow Diagram (Primary Data Source: Swanson 2010)

The products of value from the gasifier are hydrogen and carbon monoxide, the chemical constituents of syngas. The gaseous product stream from the gasifier also contains char, ash, ammonia, hydrogen sulfide and other contaminant gases. The solids (char and ash) are removed with a filter after the gasification unit, and the gaseous stream is sent to a series of syngas cleaning stages. The first stage in syngas cleaning is a quench step, where extra water and solids are removed. Following the quench, the crude syngas enters a sour water gas shift reactor, where the ratio of hydrogen to carbon monoxide is brought to 2.1:1 for the optimal performance of the Fischer-Tropsch reaction. The adjusted syngas is then sent to an acid gas removal system, where a monoethanolamine-based process removes hydrogen sulfide and carbon dioxide to concentrations of 4ppm and 2%, respectively. The hydrogen sulfide is sent to the liquid phase oxidation (LO-CAT) reaction, which turns this side product into a solid sulfur cake. At this point, the clean and adjusted syngas enters the Fischer-Tropsch reaction, where it reacts over a cobalt-based or iron-based catalyst in a fixed bed FT reactor at 200°C. The diesel chain growth is governed by the following equation 1

$$CO + 2.1H_2 \rightarrow \text{--}(CH_2)\text{--} + H_2O \quad (1)$$

Some of the unconverted syngas is sent back through the FT reactor, and the off-gas is sent to the gas-fired power generation unit. The hydrocarbon product from the FT reaction is then sent to the hydroprocessing stage, where impurities are removed and long chains are cracked to the desired diesel range.

Two generators produce on-site process power: a steam generator and a gas generator. Waste heat is collected through a steam system, which runs through the steam generator, providing 9.6 MW of power. Off-gas is collected from unit processes and combusted in the gas turbine, producing 26.3 MW of power. This is sufficient to meet process demands.

Gasification / Methanol-to-Gasoline Process Overview

The Methanol-to-Gasoline (MTG) process is a mature technology to upgrade methanol to gasoline, and has been developed and implemented by ExxonMobil. The technology has been successfully demonstrated on a commercial scale in New Zealand, and there are proposals to construct several new plants in North America.

Figure 8 shows the process flow diagram for the gasification / MTG pathway. The numbers in parentheses labeling each mass flow correspond to the stream number in the MTG stream table; Table A3 in Appendix A. The biomass enters the plant and is fed to a dryer, where its moisture content is reduced to <12%. The dried biomass is then pressurized in the presence of CO_2 in a lockhopper, and is then sent to the directly heated gasification chamber, where it is gasified in the presence of 99.5% pure oxygen and steam. In the gasification step, the biomass thermally decomposes into a mixture of gases (primarily CO, H_2 and ammonia) and solid products such as char, ash, and tar. Following gasification, the crude gaseous product is sent to the tar reforming and scrubbing stage. The mixture passes through a catalytic tar cracker, where some of the tar, methane, and other light hydrocarbons are converted to CO and H_2, and some of the ammonia is converted to H_2 and N_2. The gaseous mixture is then sent to a wet scrubber, where the remaining impurities (tar, ammonia and particulates) are removed. The scrubbed syngas is then sent to the gas purification where sulfur is removed in a liquid phase oxidation process followed by a ZnO catalyst bed. The LO-CAT process consolidates the removed sulfur into a solid sulfur cake. The next stage is the steam reformation, which takes place at 800 - 900°C, and adjusts the hydrogen to carbon monoxide ratio to 2:1, the optimum for the methanol synthesis reaction. The adjusted syngas is compressed and sent to the methanol synthesis reactor, where syngas is converted to methanol in a shell-and-tube reactor over a ZnO/CuO catalyst. The methanol is then sent to the Methanol-to-Gasoline conversion process, where methanol is partially dehydrated to dimethyl ether (DME) over a methanol dehydration catalyst. DME is then converted to olefins, and then aromatics and paraffins over a zeolite (ZSM-5) catalyst. The crude gasoline mixture is then sent to the gas fractionation stage, where fuel-grade gasoline is produced. The steam cycle and turbine generate sufficient steam and electricity to meet the process demands.

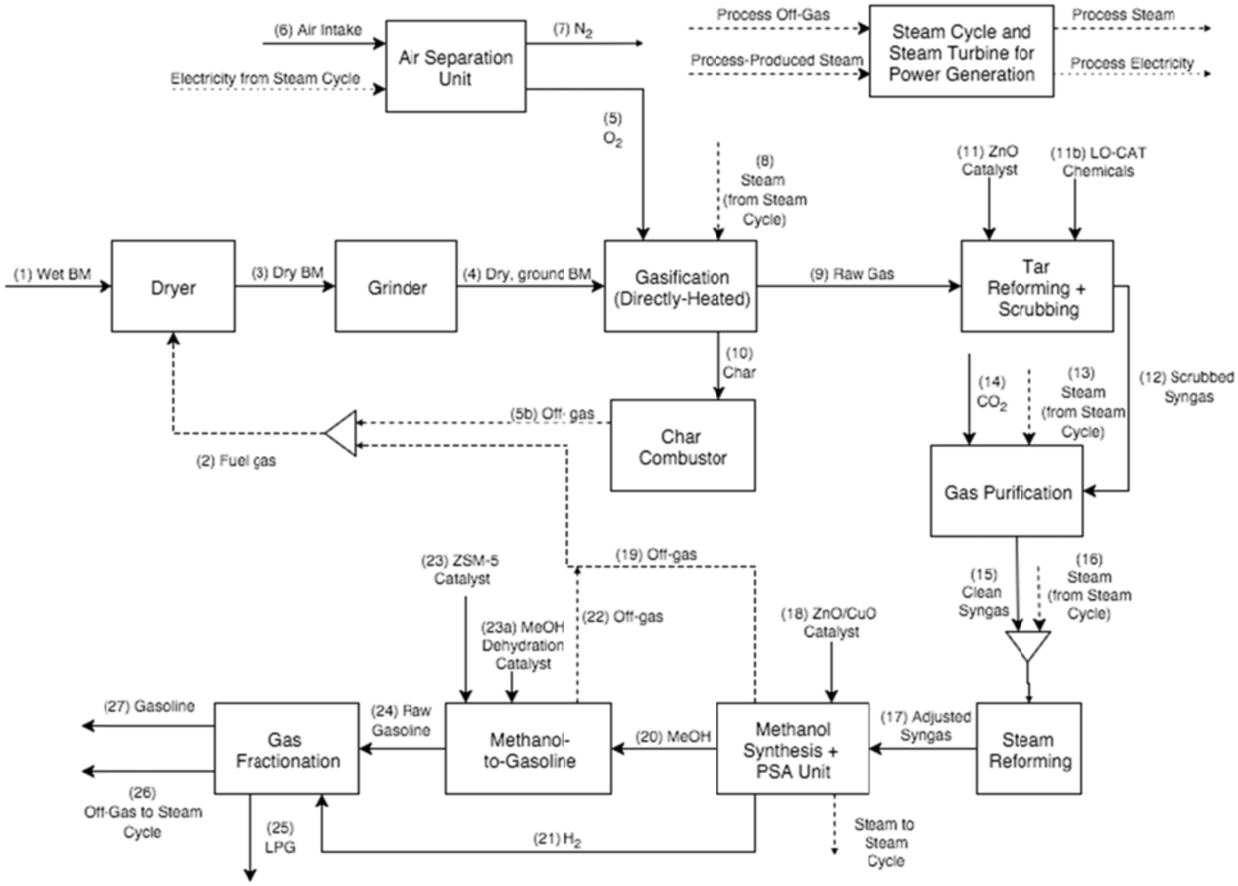

Figure 8: Methanol-to-Gasoline Process Flow Diagram (Primary Data Source: PNNL 2009)

Task 3: Scale-Up Scenario Methods

This section details our review of available techno-economic assessments of biomass conversion technologies for each of the individual drop-in fuel production pathways. Our approach for understanding the well-to-pump environmental burdens of each fuel pathway involves both the curation of California-specific data as well as the formulation of an optimal facility placement model. In addition to environmental considerations, this section also aims to provide insights into what fraction of California's available feedstocks can be utilized and the volume of fuel that can ultimately be produced.

Given the limited knowledge of how the supply chains for these pathways may develop in the future, we rely on a scenario-analysis approach to understand the potential of drop-in fuels both in California. Table 1 outlines the major objectives and constraints of the six scenarios we explored. Each scenario provides estimates for greenhouse gas (GHG), particulate (PM_{10}, $PM_{2.5}$), nitrogen oxide (NO_x), sulfur dioxide (SO_2), and carbon monoxide (CO) emissions; energy consumption; and water withdrawals. The scenarios are equally divided into three groups, where each explores a possible scale-up trajectory.

Table 1: Scenario Objectives and Constraints for Scaling Drop-In Fuel Production in California

GROUP	**PRIORITIZED**			**CENTRALIZED**		**DISTRIBUTED**	
Scenario No.	1a	1b	2	3	4	5	6
Minimize	-	-	-	GHG emissions	GHG emissions	GHG emissions	GHG emissions
Maximize	Gasoline Production	Diesel Production	Net Fuel Production	-	-	-	-
Constraints	-	-	-	New Refinery Only	Co-location at Refinery	-	Equal Fuel Blend
Sourcing*	California feedstocks	California feedstocks	California feedstocks	California feedstocks	California feedstocks	California feedstocks	California feedstocks
Fuels	Gasoline	Diesel	Gasoline & Diesel	Gasoline & Diesel	Gasoline & Diesel	Gasoline & Diesel	Gasoline & Diesel

* Drop-in fuel feedstocks considered are: (i) agricultural residues, (ii) forest residues, (iii) urban wood, (iv) primary mill, and (v) secondary mill.

The first scenario group *prioritizes* the displacement of an individual fuel type, which in our analysis includes only gasoline (S1a), only diesel (S1b), and total fuel output (S2). Accordingly, feedstocks are collected and facilities are sited in a manner that maximizes the total production of a respective fuel type. The second group *centralizes* growth about a limited subset of potential facility siting locations, which consider aspects such as proximity to highway, rail, and pipeline infrastructure, and proximity to other industrial facilities or power plants. The objective of this group is to minimize the output of GHGs, and the only optimization criterion for this group is that refineries can only be sited at either previously undeveloped locations (S3) or current petroleum, ethanol, or biodiesel refineries (S4). The third group *distributes* the growth of the drop-in fuel logistics networks about the state. Again, the objective of this group is to minimize the output of GHGs. However, unlike the centralized scenarios, facilities can be sited with a lesser set of siting constraints. The major differentiating factor between scenarios in this group is the assignment of products to regional bulk fuel terminals (e.g., relative market penetration). Scenario S5 allows both gasoline and diesel to be sold up to the point in which local fuel demand allows. In contrast, Scenario S6 prioritizes the even distribution of drop-in fuels across the state. The centralized and distributed group scenarios falls under a common branch of operations research called location analysis, where the goals are to minimize the total costs of sourcing materials, siting facilities, and distributing products [Eranki and Dale 2011, Eranki et al. 2011, Eranki et al. 2013].

Model Scope and Data

In this study, we developed an optimization tool called the California Drop-In (CAdi) fuel logistics model, which calculates the environmental impacts associated with large-scale deployment of second-generation transportation fuels in California. CAdi is similar to the California Air Resources Board's California-modified Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (CA-GREET) model [CARB 2015] in that both models track emissions across the same technical processes, capturing the effects from material extraction, feedstock treatment, material transport and storage, fuel production, and fuel distribution and storage. This cradle-to-gate perspective is commonly referred to a fuel's well-to-pump life cycle. Figure 9 provides an outline of the model's major components and their

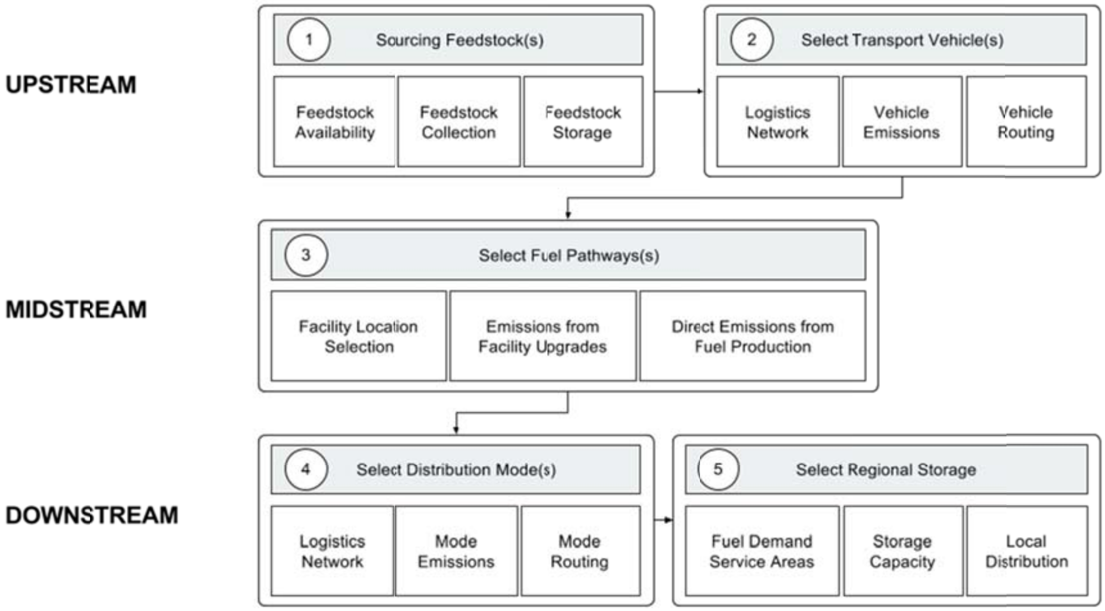

Figure 9: Major Components of the California Drop-In (CAdi) Fuel Logistics Model.

Each component includes the relevant model subprocesses.

associated subprocesses. Whenever possible, the CAdi model mirrored the assumptions used in CA-GREET in order to preserve some level of comparability between the two decision analysis tools. These aspects are discussed in greater detail in the following sections. While equally comprehensive in scope, CAdi integrates additional optimization and GIS tools that provide more resolved information on how the well-to-pump emissions footprint varies on an individual feedstock-supplier-to-refinery level.

The following subsections discuss each of the individual model components (1-5) outlined in Figure 9, detailing the processes involved, available data sources, and all relevant modeling assumptions for the six scenarios explored.

Sourcing Feedstocks

Understanding drop-in fuel production pathways at a process level is a crucial first step for determining the feasibility of potential feedstock-to-fuel schemes. The methanol-to-gasoline (M2G), Fischer-Tropsch (FT), pyrolysis-to gasoline (PG), and pyrolysis-to-diesel (PG) pathways require herbaceous and/or woody solid biomass as process inputs. Therefore, each of the scale-up scenarios first estimates the availability of these feedstock types across California.

Based on our review of prior studies that assessed biomass availability in California [DOE 2011, NREL 2014, CBC 2015], we consider five categories of solid biomass resources in this study: crop residues, forest residues, primary mill waste, secondary mill waste, and urban wood wastes. The first category, crop residues, represents a composite of many herbaceous residues, such as corn, wheat, soybeans, cotton, apples, almonds, and other orchard and field crops. The California Biomass Collaborative (CBC), the data generators, formulated these statistics for the state on a county level using land use, cropland productivity, and technical recovery data [CBC 2015]. Forest residues include recoverable woody materials from primary wood harvesting activities [CBC 2015], including forest thinnings, slash, and shrubs. These data were derived from the California Department of Forestry and Fire Protection [Rosenberg et al. 2005], which was later compiled by the CBC. We consider primary and secondary mill wastes as separate categories, as was done by studies conducted by the NREL [2014] and DOE [2011]. These categories include a variety of course and fine woody residues, byproducts, or scraps from milling operations [CBC 2015]. The key distinction between the categories is secondary mills use products from primary mills as material inputs. The last category, urban wood, represents the wood material found in municipal solid waste streams, which includes tree trimmings, debris from construction sites, etc. [CBC 2015].

Figure 10 visualizes the spatial distribution and magnitude of each of these five solid biomass resource categories. In total, California produces 24.9 million dry tons of biomass annually, with 11.0 million dry tons produced in the state's north coast and mountain region (NCM), 8.0 million dry tons produced in the central valley region (CV), and 5.9 million dry tons produced in the central coast and southern region (CCS). The largest solid biomass feedstock is forest residues, which amounts to 44% of the California's total yield. The general trend is that forest residues and primary mill wastes are concentrated in the NCM region, crop residues in the CV region, and urban wood and secondary mill wastes in the CCS region. Overall, the split between herbaceous and woody solid biomass resources is 26% and 74%, respectively.

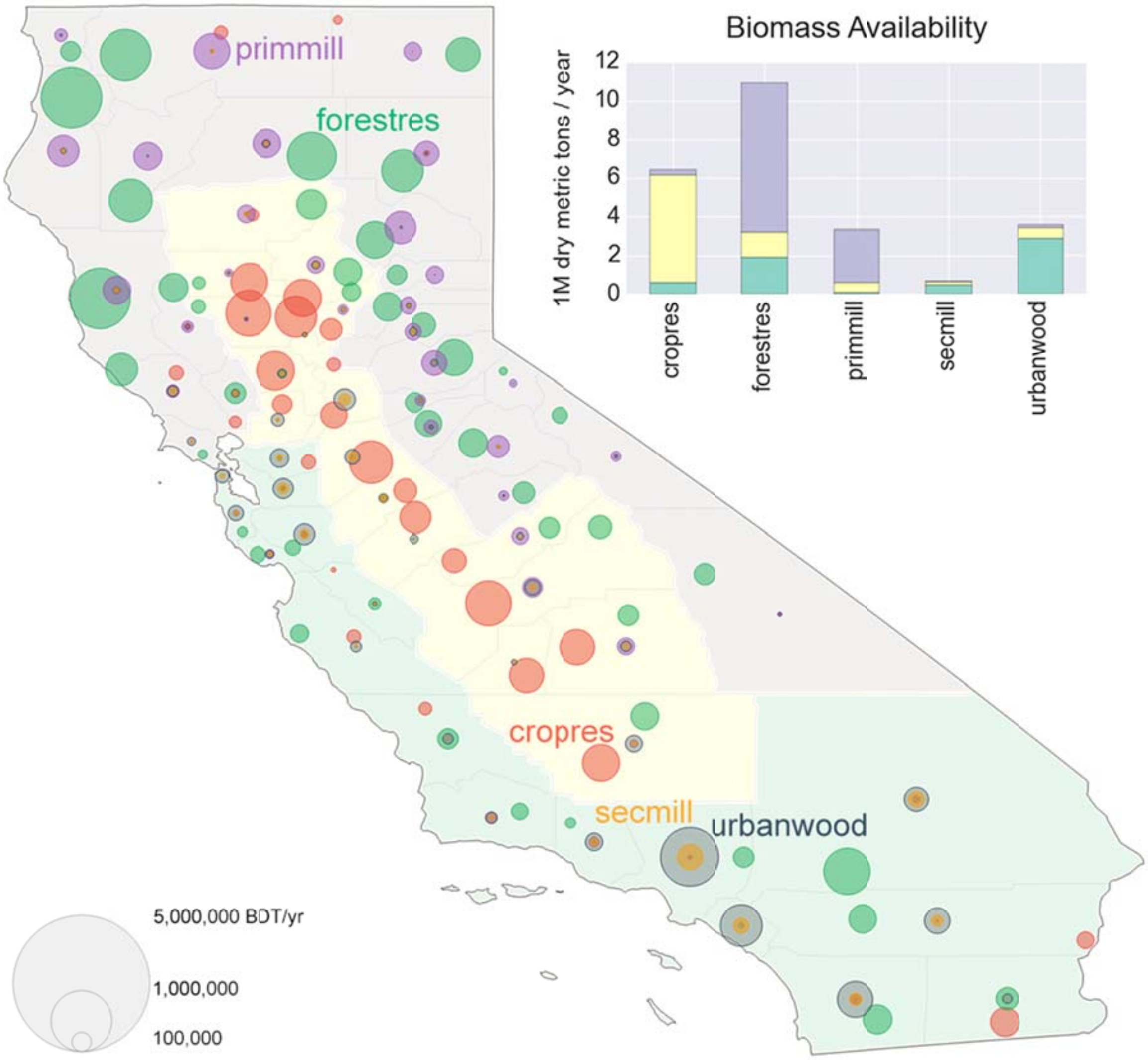

Figure 10: Map of the Distribution of Solid Biomass Resources

(Herbaceous: cropres, woody: forestres, primmill, secmill, and urbanwood) in California. To illustrate regional differences, the total dry biomass availability per resource is partitioned into a north coast and mountain region (purple), a central valley region (yellow), and a central coast and southern region (green) [CBC 2015, NREL 2014].

Once the annual yields were determined for each feedstock, emission factors were developed for the handling of these resources prior to their shipment to refineries. Table 2 summarizes our results, which were subsequently used as inputs to CAdi model for this model component. For crop and forest residues, we rely on emission factors developed in the CA-GREET model [CARB 2015]. Here, in absence of specific information, we assume that handling of corn stover is a proxy for all crop residues. For the other wood wastes, we assume that the biomass is ground into course material using a hammermill grinder, which requires a direct electricity input of 77 kWh per dry ton [Adams et al. 2015]. We use this direct energy demand data and the emissions intensity of the California electricity grid to estimate the emission factors for urban wood, primary mill residues, and secondary mill residues (Table 2).

Table 2: Emission Factors for Feedstock Handling

			(kg / dry metric ton)			
Feedstock	**GHG**	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**CO**
Crop Residues	24.5	0.19	0.020	0.020	0.0090	0.11
Forest Residues	14.5	0.11	0.011	0.011	0.0060	0.068
Urban Wood	33.0	0.040	0.0060	0.0040	0.041	0.029
Primary Mill Residues	33.0	0.040	0.0060	0.0040	0.041	0.029
Secondary Mill Residues	33.0	0.040	0.0060	0.0040	0.041	0.029

Due to data quality, numbers are shown to two significant digits for the criteria air pollutants and to three for GHG emissions.

Feedstock Transport

The upstream transportation component of the CAdi model analyzes the emissions generated by shipping solid biomass feedstocks between resource suppliers and refineries. This component of the model requires the development of two major inputs: freight emission factors, and an integrated, multimodal freight network.

For each of the scenarios in this study, we assume that solid biomass resources are transported to refineries either by truck or a combination of truck and rail. Table 3 lists the greenhouse gas and criteria air emission factors originally developed for this study. For the heavy-duty truck emission factors, our representative vehicle is a California In-State Class-8 truck (model year: 2012) and base the emission rates on data taken from the California Air Resources Board’s EMission FACtors (EMFAC) model [CARB 2014a] in emission rates caused by differential speeds were ignored as most of the freight turnover for this model occurs along highways where speeds are relatively constant [Caltrans 2015a]. On average, it is assumed that class-8 freight trucks require 20.5 MJ/km to operate; this information was used to calculate the well-to-pump emissions associated with this mode using CA-GREET [CARB 2015]. The normalization of emissions to the total metric ton-kilometers (tkm) or the functional unit for freight assessments is based on methods described in [Facanha and Horvath 2007]. We assume that trucks operate with an average of 24.1 metric tons of payload [Taptich and Horvath 2014] and that 50% of the kilometers driven are empty.

Table 3: Well-to-Wheel Emission Factors for Truck and Rail Freight Modes

Transport Mode	(kg / metric ton-km) GHG	NO_X	PM_{10}	$PM_{2.5}$	SO_2	CO
Class 8 Truck	0.130	1.85E-04	8.01E-06	6.63E-06	5.33E-05	6.41E-05
Diesel-Electric Rail	0.0200	1.52E-04	4.52E-06	4.41E-06	4.44E-06	3.12E-05

For the rail emission factors, our representative vehicle is a diesel-electric, line-hail locomotive. We assume each locomotive achieves the fleet-average fuel economy of 1,132 gross metric ton-kilometers per gallon [CARB 2014b], averages fuel efficiency of 20.8 bhp-hr/gallon fuel efficiency [EPA 2009], and hauls an average of 3,500 metric tons per train [Taptich et al. 2015]. Pump-to-wheel emission rates were based on a fleet composite of line-haul emission factors [AAR 2012], assuming emission rates reflect the tiered emission standards for this class of diesel-electric locomotives [EPA 2009, CARB 2014b]. Well-to-pump emissions for diesel fuel were estimated using the CA-GREET model. For both rail and truck modes, emissions associated with vehicle manufacturing and maintenance were ignored, since these vehicle components represent only a small fraction (1-5%) of the total emissions footprint the vehicles [Taptich et al. 2015].[1]

Once the well-to-pump emission factors were developed, we had to develop a bottom-up vehicle routing model that incorporates the locations of feedstock supplies and refineries within the national highway and freight rail networks [Taptich and Horvath 2015]. The first step in this process was to assign to the county-level data to locations along the multi-modal network. For forest and crop residues, we assumed the representative locations would be located in forested and cultivated lands, respectively. Using land cover data from the USDA Forest Service [USFS 2015] and the USDA National Agricultural Statistics Service [NASS 2015], we performed a spatial clustering analysis to select these locations. For the other biomass resources, county-centroids were assumed as representative locations, since the spatial distribution of these feedstocks was less certain. Next, we joined the highway and rail networks at road-to-rail freight terminals. It is important to note that not all goods can move between the two networks at each terminals, since each terminal is equipped to handle only unique set of commodity types [Taptich and Horvath 2015]. Accordingly, the topology of the truck-rail networks for herbaceous and woody feedstocks varied in this study. Lastly, we modeled the flow of feedstocks through the truck-rail networks by solving for the shortest GHG emission paths using an open-sourced routing model that implements the Dijkstra algorithm [pgRouting Community 2015]. The final outputs of this multistep process were a set of travel cost matrices that reflected the total emissions per metric ton transported for every feedstock supplier-refinery combination explored in the study.

Fuel Production

As it is the case for similar facility location models [Tittmanns et al. 2010], the CAdi model requires a finite set of potential refinery locations to be determined prior to solving for an optimal set of siting policies. In this study, we assumed that refineries can either be co-located with existing refineries or sited at a new location. Existing refineries include all petroleum (18 in total), ethanol (12 in total), and biodiesel facilities (8 in total) in California [EIA 2015, Ethanol Producers Magazine 2015]. Following Tittmann et al. [2010], our siting approach used population as a surrogate for availability of essential services, including trucking companies, skilled labor, and materials. We first identified cities and towns in California as potential candidates using Caltrans' GIS database of cities in California [Caltrans 2015b].

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[1] A copy of our emission factor calculations is provided in an Excel document in the CAdi model. See: https://github.com/mtaptich/California-Drop-In-CAdi-Fuel-Model/tree/master/docs

Next, we produced a preliminary set of potential new facility locations by performing a cluster analysis on the city boundary GIS data. In order to improve the model optimization, we limited the number of clusters to an arbitrarily picked 100 potential locations. From this refined set of candidates, we selected the top 50 most isolated locations relative to the candidate set in order to avoid bunching of locations. Finally, we screened our set such that our potential locations are a minimum of 25 km from any existing biodiesel, ethanol, or petroleum refineries. In total, 37 new locations were identified. As a matter of convention, we assumed that the emissions associated with constructing a new facility are negligible given the magnitude of the lifetime fuel output, in which case emissions would be normalized. Figure 11 maps the complete set of potential siting locations in California assumed in this study by refinery type and provides statistics on the regional distribution of these sites.

Fuel Distribution

The downstream distribution of fuel between refineries and bulk fuel terminals follows a similar methodological approach as the movement of feedstocks during upstream transport. The major distinction between these two freight operations is the incorporation of pipelines as a freight model. Table 4 provides a summary of the GHG and criteria air emissions factors originally estimated in this study. We assumed the average pipeline diameter across the distribution network was 8” [CDC 2000], the unit energy demand was 71 kJ/tkm [Strogen and Horvath 2013], and the primary energy source was electricity [EPA 2015]. We acquired GIS data for the petroleum product pipeline network data from the U.S. Energy Information Administration [EIA 2015]. Local connections to a pipeline were assumed using engineering judgment for petroleum facilities. In addition, the directionality of pipelines was not considered, which may be an issue since pipelines do not frequently reverse flows. Data were not available to confidently determine directionality.

Table 4: Emission Factors for Petroleum Product Pipelines

Transport Mode	(kg / metric ton-km)					
	GHG	**NO_X**	**PM_{10}**	**$PM_{2.5}$**	**SO_2**	**CO**
Pipeline (8")	0.00900	1.04E-05	1.51E-06	1.02E-06	1.05E-05	7.53E-06

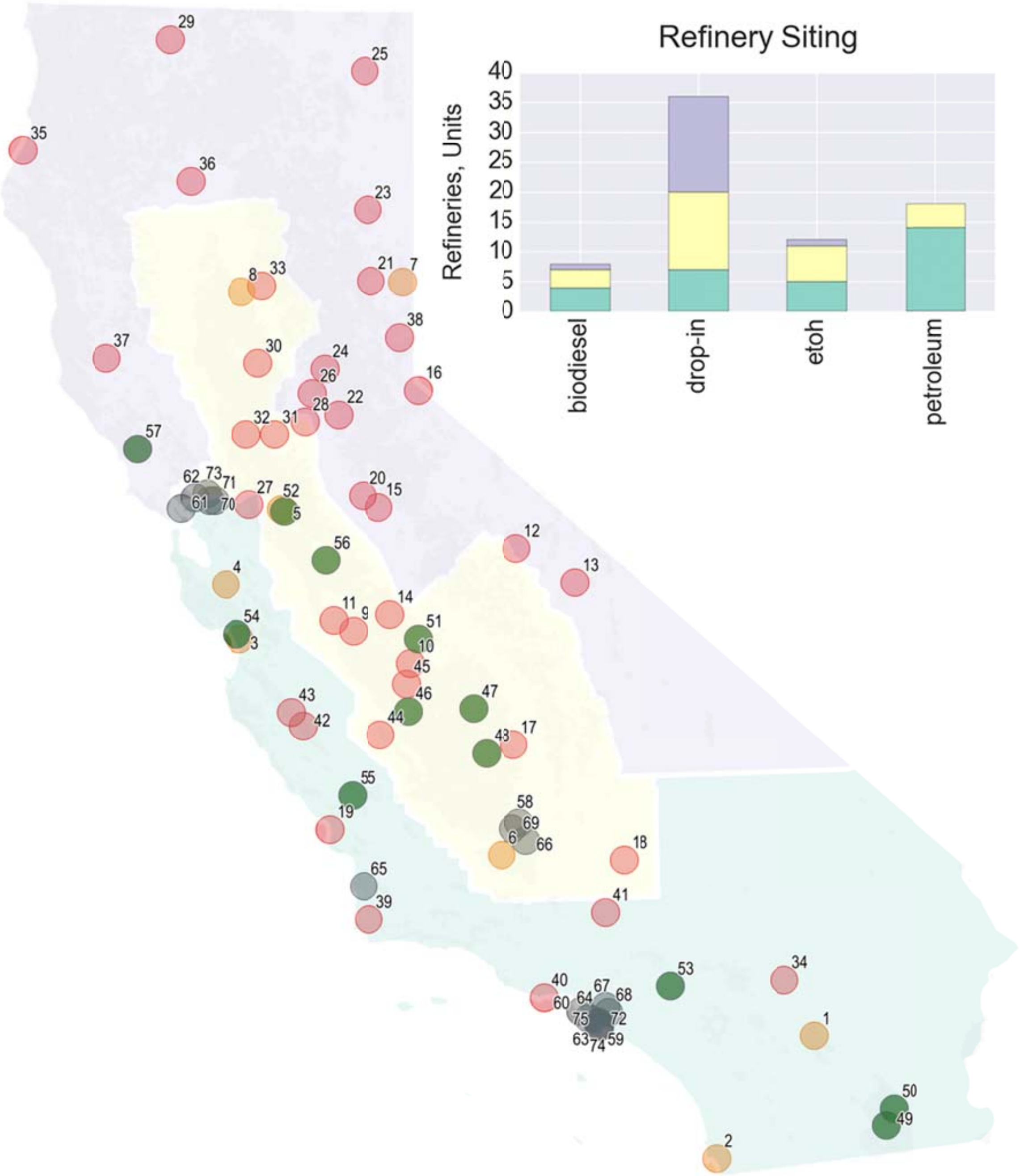

Figure 11: Map of Potential Biorefinery Locations in California by Refinery ID

Red: new development for drop-in fuels; black: petroleum refinery; orange: biodiesel refinery; green: ethanol refinery, which were assigned internally. Also shown are the outlines of three major agricultural divisions.

Regional Storage and Local Distribution

The final component of the CAdi model calculates the environmental impacts of regional fuel storage and distribution. Figure 12 maps the spatial distribution of regional bulk fuel terminals, i.e., a storage facility used primarily for petroleum products which has a total bulk storage capacity of 50,000 barrels or more in California [EIA 2015]. Data on total storage capacity at bulk terminals were not available. Instead, we based the storage of fuel on county-level retail fuel sales [CEC 2012a, CEC 2012b], which were allocated to a tract level based on population and then reallocated to terminals based on minimum travel distances by truck. In order to reduce the required memory and CPU power needed to model the scenarios in this study, we reduced the dimensionality of the CAdi model by assuming that the distances traveled from local distribution were equal to the value assumed in the CA-GREET model (45 km).

Summary of Model Assumptions:

(i) Drop-in fuels are perfect substitutes for conventional gasoline, diesel, and marine fuels. (e.g., there is no “blend wall.”)
(ii) Drop-in fuels displace only fuels sold for use in California.
(iii) Demand for fuel is fixed, estimated at an annual level, and proportional to population density.
(iv) Intermodal terminal exchanges and fuel storage activities have negligible impacts on optimizing transport and shipment of fuels.
(v) The locations of bulk fuel terminals (total bulk storage capacity of 50,000 barrels or more) are fixed and no additional pipelines are constructed to move drop-in fuel around the state. Therefore, isolated biorefineries would need trucks and/or trains to move fuel to regional bulk terminals or send their fuels to refineries to ship to terminals via pipelines. The directionality of pipelines is not considered.
(vi) Information regarding the local connections between petroleum product pipelines and bulk terminals is limited in availability. We assume that pipeline-terminal transfers are carried out using 8” pipelines and are situated such that the transport distances are minimized.
(vii) Biorefinery capacity can be designed across a continuum, such that the optimization could be solved as the relaxation of a mixed integer facility location problem.
(viii) Emissions from feedstock collection, transport, and fuel production scale linearly with biomass quantities.
(ix) As a means of reducing the dimensionality of our optimization model, which is discussed in a later section, we combine the mill and urban wood wastes into a single category deemed *scrapwood*.
(x) Facilities are assumed to support more than one biomass-to-biofuel pathway (e.g., by building two different biorefineries next to each other in close proximity).
(xi) Emissions associated with storage are ignored (e.g., initial biomass handling, evaporative emissions from refined products, etc.).

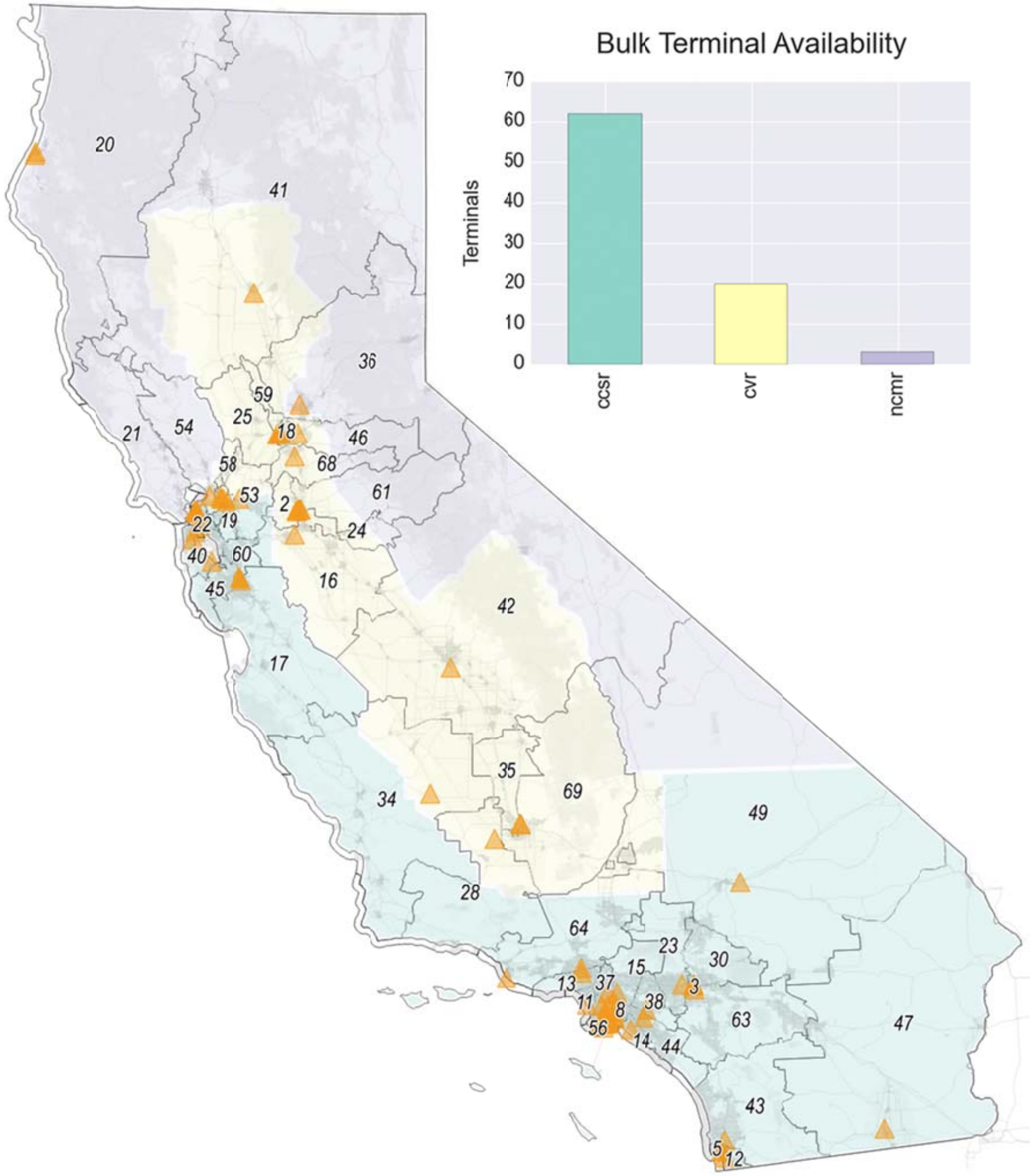

Figure 12: Map of Fuel Demand Service Areas Labeled by Bulk Fuel Terminal ID

Bulk fuel terminal ID was assigned internally. Bulk terminals are shown in yellow, though not all are distinguishable due to clustering at this map resolution. Also shown are overlays of the three major agricultural divisions.

Model Formulation

The scenarios previously outlined are motivated by two separate and distinct objectives. Accordingly, we provide a mixed-integer program specific to each situation. Table 5 outlines our model's decision variables, i.e., the set of quantities that need to be determined in order to solve the problem, and exogenous variables, i.e., quantities based on conditions external to our problem.

Table 5: Decision (Bolded) and Exogenous Variables and their Descriptions

Variable	Description
$\boldsymbol{y_j}$	Select production at a location (j)
$\boldsymbol{x_{m,n,i,j}}$	Transport tons of feedstock (m) for fuel pathway (n) from a location (i) to a refinery (j)
$\boldsymbol{w_{j,k}}$	Transport tons of fuel from refinery (j) to demand service area (k)
F_j	Emissions from capital improvements at a refinery (j)
h_m	Emissions from sourcing, collection, and handling of feedstock (m)
$c_{i,j}$	Emissions transporting tons of feedstock from a location (i) to a refinery (j)
p_n	Direct emissions from producing fuel under a drop-in pathway (n)
$s_{j,k}$	Emissions transporting tons of fuel from a refinery (j) to a fuel terminal (k)
ls	Emissions transporting tons of fuel from a fuel terminal (k) to a fueling station
$e_{\boldsymbol{c} \mid \boldsymbol{n}}$	Well-to-pump emission factor for conventional fuel given the drop-in pathway (n)
b_i	Tonnage of feedstock available at location (i)
A_j	Maximum tonnage of feedstock a refinery will accept per process unit
d_k	Demand for fuel at demand service area (k)
$\boldsymbol{\gamma_{m,n}}$	Feedstock to fuel conversion efficiency for feedstocks (m) and pathway (n)
M	The maximum process units at location j
V_j	Binary variable. If V_j takes that value of one, then $\boldsymbol{y_j}$ is forced to be greater than or equal to one. If V_j is zero, then $\boldsymbol{y_j}$ is forced to be zero.

To summarize these background data, we assumed that the scenarios have X number of feedstock providers, Y number of refinery siting options, 3 feedstock types (crop residues, forest residues, and scrap wood), 4 drop-in fuel pathways (methanol to gasoline, Fisher-Tropsch, pyrolysis to gasoline (pg), and pyrolysis to diesel (pd)), and W bulk fuel terminals. The "last-mile" component of the fuel supply chain was treated as a constant to reduce the dimensionality of the model. We assume this component was 40 km long.

Under Scenarios S3-S6, the objective of our model was to minimize total well-to-tank emissions (E_a: drop-in fuel emissions; E_c: conventional fuel emissions) for each fuel demand service area, k, given a fixed demand for fuel, d_k, and a derived value of drop-in fuel supply, w_k:

$$\boldsymbol{Z = \min E_a + E_c} \tag{1.A1}$$

$$\boldsymbol{Z = \min \sum\nolimits_{k}^{K} [w_k\, e_{ak} + (d_k - w_k)\, e_{ck}]}$$

(1.A2)

Furthermore, the model optimally decides if and where to place a refinery, y_j, the amount of biomass that could be processed from each location, $x_{m,n,i,j}$, and the amount of fuel to sell to each service area, $w_{j,k}$. The model objective, *Z*, under Scenarios S3-S6, reduces to the following form:

$$\boldsymbol{Z = \min \sum_{j}^{J} F_j\, y_j + \sum_{j}^{I} \sum_{i}^{I} \sum_{n}^{N} \sum_{m}^{M} (h_m + c_{i,j} + p_n)\, x_{m,n,i,j} + \sum_{j}^{J} \sum_{k}^{K} (s_{j,k} + ls - e_{c\,|\,n})\, w_{j,k} + \sum_{k}^{K} d_k\, e_{ck}}$$

(1.A3)

The objective of our model under Scenarios S1-S2 was to maximize the total production of specific types of drop-in fuels by optimally selecting the amount of fuel to sell to each service area, $w_{j,k}$ for each respective refinery *j*. The formalized objective is:

$$\boldsymbol{Z = max \sum_{j}^{J} \sum_{k}^{K} w_{j,k}}$$

(1.B1)

The optimal policies for meeting this objective are likely to be unrealistic in practice since transport costs are not considered. For instance, optimal policies could involve sourcing feedstocks from extended distances rather than locally, which is a more sensible decision. The same is possible for distributing fuels to local markets (e.g., bulk terminals). With these issues in mind, we chose to implement a more practical objective for our model under Scenarios S1-S2.

To preserve realistic freight logistics, we configured an alternative objective that strongly incentivizes the production of a particulate type of fuel while also considering transport costs. Our heuristic for Equation 1.B1 assigns an arbitrarily large value to the well-to-pump emission factor for the conventional fuel being displaced, thereby creating a significant but artificial demand to offset this fuel. For instance, if we wished to maximize gasoline production, we would set the conventional emission factor ($e_{c\,|\,n,SCENARIO=GAS}$) to 10^9; thus, setting the model to produce as much of this fuel as possible. The alternative objective is as follows:

$$\boldsymbol{Z = \min \sum_{j}^{I} \sum_{i}^{I} \sum_{n}^{N} \sum_{m}^{M} c_{i,j}\, x_{m,n,i,j} + \sum_{j}^{J} \sum_{k}^{K} (s_{j,k} - e_{c\,|\,n,SCENARIO})\, w_{j,k}}$$

(1.B2)

Under all scenarios, technical operations are constrained by numerous factors, which take into account the amount of feedstock available in each location,

$$\sum_{j}^{J} x_{i,j} \leq b_i, \forall\, i \in I \tag{2}$$

the amount of feedstock that a refinery is willing to accept in total,

$$\sum_{i}^{I} x_{m,n,i,j} \leq A_j y_j, \forall\, j \in J \tag{3}$$

the amount of fuel it could produce based on the amount of total feed collected, and

$$\sum_{k}^{K} w_{j,k} = \sum_{i}^{I} \sum_{n}^{N} \sum_{m}^{M} \gamma_{m,n}\, x_{m,n,i,j}\ , \forall\, j \in J \tag{4}$$

the amount of fuel it could feasibly sell to a particular demand service area:

$$\sum_{j}^{J} w_{j,k} \leq d_k, \forall\, k \in K \tag{5}$$

Each facility is constrained to being at between 1 and M process units or otherwise the production activities are forced to zero.

$$y_j \leq M_j V_j, \forall\, j \in J \tag{6}$$

$$V_j \leq y_j, \forall\, j \in J \tag{7}$$

$$V_j \in \{0, 1\}, \forall\, j \in J \tag{8}$$

The model maintains that all shipments must be positive.

$$x_{m,n,i,j} \geq 0, \forall\, m \in M, \forall\, n \in N, \forall\, i \in I, \forall\, j \in J \tag{9}$$

$$w_{j,i} \geq 0, \forall\, j \in J, \forall\, i \in I \tag{10}$$

In addition, the pyrolysis pathway produces two fuels (gasoline and diesel). Since the allocation of emissions and other impacts is unique to each fuel due to differences in energy densities (MJ/kg), we treat each pathway as an individual though this is not actually the case. To maintain the coupled relationship, we assign a constraint that states that our decisions to source a feedstock between a supplier and a refinery must be equal for each pyrolysis pathway (pg, pd):

$$\boldsymbol{x_{m,\{pg\},i,j}} = \boldsymbol{x_{m,\{pd\},i,j}}, \forall \boldsymbol{m} \in \boldsymbol{M}, \forall \boldsymbol{i} \in \boldsymbol{I}, \forall \boldsymbol{j} \in \boldsymbol{J} \tag{11}$$

The full source code for the CAdi model can be found at this web address:
https://github.com/mtaptich/California-Drop-In-CAdi-Fuel-Model

Results

Task 2: Life-Cycle Cost and Environmental Assessment Data Gap Analysis

Mass Balance

A complete stream table detailing the mass flow of each stream in the process flow diagrams can be found in Appendix A (Tables A1-A3) for each pathway.

Table 6 compares the process yields of each pathway. The weight percentage (wt%) values are calculated by dividing the total mass of fuel products by the dry weight of the biomass feedstock. The gallon of gasoline equivalent (GGE) yield does not necessarily scale linearly with the percent weight yields because the pathways yield different fuel products. One gallon of diesel has the same energetic value as approximately 1.14 gallons of gasoline. The pyrolysis pathway yields a mixture of gasoline and diesel, FT produces diesel and MTG produces gasoline. As can be observed, the pyrolysis pathway generally has higher yields, ranging from 19 - 26 wt%, and the gasification pathways show similar yields, ranging from 14 - 18 wt%. The harsh thermochemical conditions of both pyrolysis and gasification processes make these pathways highly insensitive to the type of biomass feedstock.

Table 6: Pathway Yields

Study	Pathway	Yield		Feedstock
		wt %	*GGE / dry MT biomass*	
PNNL 2013	Pyrolysis	26%	99	Wood chips
NREL 2010	Pyrolysis	23%	87	Corn stover
Iribarren 2012	Pyrolysis	19%	79	Wood chips
Swanson 2010	FT	17%	62	Corn stover
PNNL 2009	MTG	14%	50	Wood chips
Phillips 2011	MTG	17%	61	Poplar wood
Zhu 2012	MTG	18%	65	Woody biomass

Values rounded to two significant figures, MT = metric ton, GGE = gallon of gasoline equivalent

Other material inputs for these pathways include hydrogen, natural gas, catalysts, and other chemicals. The pyrolysis and FT pathways include hydrogen production capabilities within the plant design itself to avoid purchasing and transporting hydrogen from off-site. The pyrolysis pathway uses steam reforming of natural gas to produce hydrogen, using both process off-gas and make-up natural gas purchased from off-site as the feedstock. The FT pathway includes a pressure-swing adsorption unit and separates hydrogen from the syngas produced upstream. The MTG pathway does not require hydrogen.

All three pathways require fuel gas for thermal energy purposes, which can be supplied either as natural gas or noncondensable process off-gases. Since the gasification reaction produces a gaseous product, FT and MTG do not require natural gas to be purchased from off-site, as excess syngas can be combusted when necessary. Process off-gas does not meet all of the thermal energy loads for the pyrolysis pathway, so natural gas is purchased from an off-site source.

Catalysts are required for many of the chemical conversion unit processes, including acid gas removal, FT synthesis, hydrotreating, tar reforming, methanol synthesis, MTG, and hydrocracking. The specifics of catalyst loading and deactivation are outside the scope of this study, but the literature sources can be consulted for assumptions about the catalyst loading. The environmental assessment herein was not able to include the production of the catalysts due to data unavailability.

Additional process chemicals include monoethanolamine for FT acid gas removal and LO-CAT chemicals. The LO-CAT process is used to convert hydrogen sulfide gas (removed from syngas cleaning steps in FT and MTG pathways) to solid sulfur cakes (which currently do not have a market value).

Energy Demand

Each pathway uses a variety of energy sources to meet the energy loads of each unit process. The electrical energy loads can be met from purchased electricity from the grid (off-site), or from an on-site electrical generating unit (EGU). On-site EGUs can either be gas or steam-powered. The thermal energy loads are met by light hydrocarbon gas combustion, char combustion, or steam. Many of the unit processes produce noncondensable light gases, which can be captured and combusted for on-site process energy. Char is produced in the pyrolysis reaction, and is combusted to provide heat to the pyrolyzer unit. Most of the pathways have a steam system to optimize heat recovery. Table 7 compares the energy loads of each pathway found in various literature sources, and the energy sources that are used to meet the thermal energy demand.

Table 7: Pathway Energy Demands

Study	Pathway	Electricity Demand	Thermal Demand	Thermal Energy Sources
		kWh / GGE	*MJ / GGE*	
PNNL 2013	Pyrolysis (on-site H_2)	1.2	21	char, off-gases, steam, off-site NG
PNNL 2013	Pyrolysis (off-site H_2)	1.4	17	char, off-gases, steam, off-site NG
Iribarren 2012	Pyrolysis	2.0	0.0040	char, off-gases, off-site NG
NREL 2012	Pyrolysis	2.2	34	char, off-gases, off-site NG
Swanson 2010	Gasification / FT	2.2	7.3	off-gases, steam
PNNL 2009	Gasification / MTG	2.1	14	char, steam, off-gases
Philipps 2011	Gasification / MTG	0	26	steam, off-gases

Values rounded to 2 significant digits, GGE = gallon of gasoline equivalent, NG = natural gas, off-gases = noncondensable light hydrocarbons emitted from unit processes

Pyrolysis Energy Balance

Sand is used as a heat carrier to maintain the reaction temperature within the pyrolysis unit, and char combustion provides the heat to the sand and pyrolysis reaction. Other heating loads are met with process steam. The steam system is integrated with the hydrogen plant, and is powered primarily from off-gas combustion. Excess steam could theoretically be used to generate power on-site, although simulations of this process have not shown there to be an excess of steam, and have assumed that electrical energy is purchased from the grid.

All of the studies reviewed in the literature described similar energy systems within the pyrolysis process, but reported very different values for the energy consumption. Table A4 in the Appendix A compares the energy consumption information given by the PNNL, NREL and Iribarren pyrolysis studies. The electricity consumption values range from 106 to 194 kWh per ton of feedstock, however, the thermal energy demand ranges from 0.37 to 6,300 MJ per ton of feedstock.

The PNNL [2013] study reported energy information from a total utility balance of the plant, giving an electrical energy load of 121 kWh and a thermal energy load of 2,180 MJ per dry ton of biomass. With this approach, there is no disaggregation among unit processes, and the reported energy consumption does not include the combustion of any on-site produced char or off-gases. The PNNL [2013] study does state that the char produced during pyrolysis is combusted to provide process heat, and the pyrolyzer produces 120 kg of char per dry ton of biomass. This value is not considered in the total energy requirement for the process.

The NREL [2012] study provides input-output tables for the pyrolysis unit processes, which includes electricity and thermal energy demand for each segment of the pyrolysis pathway. The total electrical energy load is 192 kWh and the thermal energy load is 6,300 MJ per dry ton of biomass. Char combustion is used to meet the thermal energy demand for the pyrolysis unit, and natural gas combustion is used for the hydrotreating, hydrocracking, and distillation processes. The inclusion of the char combustion is the reason for the large difference in thermal energy demand between this study and the PNNL [2013] study. It is not clear if this natural gas is sourced off-site, or whether it is off-gas from the process itself.

The Iribarren [2012] study provides detailed information of the electricity consumption of each unit process, but incomplete information regarding the thermal energy demand. The study only mentions the natural gas required to start up the pyrolysis process, referred to as “start-up” energy. Once the pyrolysis process is underway, the char combustion sustains the high reaction temperature, but this value is not reported in the process energy balance, nor is the combustion of any onsite off-gases.

Gasification / Fischer-Tropsch Energy Balance

Most of the energy required for the FT pathway is provided by the process steam system. The gasification process is highly exothermic, and the reaction is cooled by way of a steam cycle. The steam cycle serves three purposes. First, steam is piped throughout the process to meet heating loads. Second, steam is used as a feedstock for the gasification and water-gas shift unit processes. Third, remaining steam is fed through a steam generator to produce electric power for the process. Along with the steam cycle, power is also produced in a gas combustion turbine. Some of the unconverted syngas from the fuel synthesis (FT) process, and noncondensable gases from hydroprocessing are combusted in the gas turbine. As a result of the steam cycle and the gas combustion turbine, the FT pathway results in net energy production. The literature provides total electrical and thermal energy loads, both of which are met with on-site power production. However, there is no information on how much energy is met with the steam cycle, and how much is met with the gas combustion turbine. Table A5 in the Appendix provides detailed energy demand by each unit process in the FT pathway.

Gasification / Methanol-to-Gasoline Energy Balance

The electrical and thermal energy loads for the MTG pathway can be met entirely with the on-site steam system and combustion of process off-gases. The gasification process is highly exothermic, and a steam cooling system produces super saturated steam, which is used as a heat carrier and is also run through a steam electricity generating unit. The Methanol-to-Gasoline unit process contains a purge stream that sends process off-gases to a gas combustion turbine to generate additional thermal energy. This purge stream decreases the overall yield of the MTG pathway slightly, but allows the process to be powered entirely from on-site sources [PNNL 2009]. Table 7 shows the energy requirement for the MTG pathway from the different literature sources. A detailed overview of the energy demand for each unit process in the MTG pathway can be found in Table A6 in Appendix A.

Cost Analysis from Literature Review

Although the pyrolysis, Fischer-Tropsch, and Methanol-to-Gasoline pathways to drop-in biofuels have not been implemented at commercial scale, many of the literature sources include projections of expected capital and operating costs for the production of drop-in gasoline and diesel from these pathways. (Pollution control costs cannot be established.)

It is important to note that the economic analyses for these pathways were performed using the *N*th plant method. The *N*th plant analysis determines costs assuming that the process technology has reached maturity, to avoid cost overestimation associated with “first of a kind” plant construction. As a result, assumptions about the *N*th plant are often quite optimistic, and result in generously low cost estimates.

Pyrolysis Cost Analysis

The [PNNL 2013] pyrolysis LCA includes a techno-economic analysis, with capital and operating cost information. The capital and operating costs were based on an existing commercial biorefinery and Aspen Capital Cost Estimator software, using *N*th plant assumptions about the operating conditions and lifetime of the plant. Table 8 shows the *N*th plant assumptions that guided the economic analysis.

Table 8: Pyrolysis *N*th Plant Assumptions (Data Source: PNNL 2013)

Assumption Description	Assumed Value
Internal rate of return	10%
Plant financing debt / equity	60% / 40% of total capital investment
Plant life	30 years
Income tax rate	35%
Interest rate for debt financing	8.0% annually
Term for debt financing	10 years
Working capital cost	5.0% of fixed capital investment (excluding land)
Depreciation schedule	7-year MACRS* schedule
Construction period	3 years (8% 1st year, 60% 2nd year, 32% 3rd year)
Plant salvage value	No value
Startup time	6 months
Revenue and costs during startup	Revenue = 50% of normal Variable costs = 75% of normal Fixed costs = 100% of normal
On-stream factor	90% (7,884 operating hours per year)

*MACRS = Modified Accelerated Cost Recovery System

The internal rate of return (IRR) is a metric used to measure the potential profitability of an investment, and is calculated as the discount rate that sets all net present value cash flows equal to zero. Some other cost estimates use a return on investment (ROI) rather than a rate of return to predict how an estimate will perform over time. The ROI is much simpler to calculate, and is equivalent to the percentage difference in value of an investment over a set period of time. Another important economic term to define is the 7-year Modified Accelerated Cost Recovery System (MACRS). MACRS is one system to deal with capital depreciation. The concept behind capital depreciation is that capital equipment loses value over time; therefore the project loses money over time from investing in the capital to build the plant. Under a MACRS model, the capital cost of a system is recovered over a specified lifetime (typically 7 years for capital equipment). Under a 7-year MACRS depreciation schedule, the total cost is recovered over 7 years through tax deductions on the depreciating value of the capital equipment.

The details of the capital investment can be found in Table 9. (Numbers reflect two significant digits.) Roughly 90% of the capital cost is for the pyrolyzer, hydrotreating and hydrogen generation equipment.

Table 9: Pyrolysis Capital Costs Based on 2,000 Metric Tons of Biomass per Day (Data Source: PNNL 2013)

Unit Processes	Capital Investment ($ million)
Fast pyrolysis	290
Heat recovery and filtration	23
Hydrotreating	210
Product Finishing	33
Hydrogen generation	120
Balance of plant	17
Total Capital Cost	**690**

Year of source data: 2011. All values adjusted to 2014 dollars using the Producer Price Index – Industry Data.

Table 10 shows the breakdown of the operating costs, to determine the estimated selling price per gallon of gasoline equivalent.

Table 10: Pyrolysis Operating Costs Based on 2,000 Metric Tons of Biomass per Day (PNNL 2013)

Item	Cost ($ / GGE)
Feedstock and handling	0.95
Natural gas	0.10
Catalysts and chemicals	0.33
Waste disposal	0.01
Electricity and utilities	0.09
Fixed costs[2]	0.55
Capital depreciation	0.35
Average income tax	0.1
Average ROI (10%)	0.96
Minimum Selling Price	**3.5**

GGE = gallon of gasoline equivalent. Year of source data: 2011. All values adjusted to 2014 dollars using the Producer Price Index – Industry Data.

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[2] Fixed costs include labor, benefits and general overhead, maintenance, insurance, and taxes.

The anticipated selling price of gasoline from biomass pyrolysis was calculated based on the capital cost, operating expenses, and financing schedule. The capital cost includes the cost of all reactors, processing equipment and other materials, the cost of installation, and indirect costs associated with plant construction. Operating expenses include the feedstock and handling, energy purchased off-site (both natural gas and electricity), catalysts and chemicals, waste disposal, income tax, and other fixed costs to operate the plant. With the capital cost, financing assumptions, and operating expenses, under *N*th plant assumptions, a selling price of $3.5 was calculated per gallon of gasoline from the biomass pyrolysis pathway.

Fischer-Tropsch Cost Analysis

Data for the economic evaluation of the FT pathway were taken from the [Swanson 2010] study. Like the technoeconomic analyses from the PNNL studies, [Swanson 2010] made *N*th plant assumptions to inform the operating cost calculations, which are detailed in Table 11.

Table 11: Fischer-Tropsch *N*th Plant Assumptions

Assumption Description	Assumed Value
Internal Rate of Return	10%
Plant life	20 years
Income tax	39%
Depreciation schedule	7-year MACRS* 20-year MACRS* (for steam/power generation plant only)
Construction period	3 years (8% 1st year, 60% 2nd year, 32% 3rd year)

*MACRS = Modified Accelerated Cost Recovery System

To finance the plant, a 10% internal rate of return and 39% income tax rates were assumed. A 7-year MACRS method was applied to most of the plant, with a 20-year MACRS for the steam / power generation plant. The plant lifetime was assumed to be 20 years. Extra electricity generated on-site is assumed to be sold back to the grid at the retail price of $0.054 per kWh. All financial values are reported in 2014 dollars for FT pathway economic evaluation.

A breakdown of the capital cost can be found in

Table 12. The total capital investment includes the cost of all reaction equipment along with installation and indirect costs. The capital cost for all pumps, compressors and heat exchangers includes the cost of equipment spares necessary for the continuous operation of the plant. Prices for capital equipment were determined by using values from the literature, as well as the Aspen Icarus Process Evaluator software. Installation costs for compressors were set at 20% of the compressor selling price. Other equipment installation costs were calculated using a methodology for solid-liquid chemical plants [Peters et al. 2003]. The balance of plant cost (including facilities for wastewater treatment and cooling towers) was assumed to be 11% of the total purchased equipment cost. Indirect costs associated with construction and operation of the plant included engineering and supervision, construction expenses, and legal and contractor's fees.

Table 12: Fischer-Tropsch Capital Costs Based on 2,000 Metric Tons of Biomass per Day (Swanson 2010)

Unit	Capital Cost ($ million)
Pre-processing	27
Gasification	81
Syngas cleaning	40
Fuel synthesis	59
Hydroprocessing	40
Power generation	55
Air separation unit	29
Balance of plant	40
Indirect Cost	160
Contingency	110
Working capital	95
Total capital investment	**730**

Year of source data: 2007. All values adjusted to 2014 dollars using the Producer Price Index – Industry Data.

Table 13 shows the breakdown of operating costs for materials and resources associated with the FT plant. The fixed operating costs include employee salaries and benefits, overhead, maintenance, and insurance. The estimated selling price of diesel from the FT pathway was calculated as $4.27 per GGE.

Table 13: Fischer-Tropsch Material and Disposal Operating Costs Based on 2,000 Metric Tons of Biomass per Day (Swanson 2010)

Material	Cost	Unit
Feedstock (corn stover)	99	$ / dry ton
LO-CAT chemicals	210	$ / ton
Amine make-up	2.9	$ / kg
Process steam	11	$ / ton
Cooling water	0.41	$ / ton
Hydroprocessing	30	$ / m3
Natural gas	0.28	$ / m3
Solids disposal	31	$ / ton
Wastewater disposal	1.4	$ / m3
Electricity	0.06	$ / kWh
Sulfur	53	$ / ton
Fischer-Tropsch cobalt catalyst	40	$ / kg
Water gas shift copper-zinc catalyst	21	$ / kg
Steam methane nickel-aluminum catalyst	40	$ / kg
Pressure swing adsorption packing	5.3	$ / kg

Year of source data: 2007. All values adjusted to 2014 dollars using the Producer Price Index – Industry Data.

Methanol-to-Gasoline Cost Analysis

The [PNNL 2009] study includes a technoeconomic analysis of the MTG pathway, and also incorporates *N*th plant assumptions. Many of the *N*th plant assumptions were the same as observed in the PNNL [2013] pyrolysis study and are detailed in Table 14. All economic values are scaled to 2014 dollars for the MTG cost analysis.

Table 14: Methanol-to-Gasoline *N*th Plant Assumptions (Data Source: PNNL 2009)

Assumption Description	Assumed Value
Internal Rate of Return	10%
Plant life	20 years
Working capital	5% of total capital investment
Depreciation schedule	7-year MACRS*
Construction Period	2.5 years (8% in 1st 6 months, 60% in next 12 months, 32% in last 12 months)
Start-up time	6 months
Revenue and costs during start-up period	Revenue = 50% of normal Variable costs = 75% of normal Fixed costs = 100% of normal
Land	6% of total purchased equipment cost (taken as 1st year construction expense)

*MACRS = Modified Accelerated Cost Recovery System

The breakdown of capital costs for the MTG drop-in plant is shown in Table 15. Most of the capital equipment costs were derived from the Aspen Icarus capital cost software, and the cost of the gasification units was based on literature values. The installation cost (TIC) was assumed to be 247% of the total purchased equipment cost (TPEC) [PNNL 2009]. Indirect costs included engineering, construction, legal and contractors fees, and project contingency. Altogether, the total indirect costs were assumed to be 126% of the total purchased equipment cost.

Table 15: Methanol-to-Gasoline Capital Costs Based on 2,000 Metric Tons of Biomass per Day (Data Source: PNNL 2009)

Unit	Capital Cost ($ million)
Air separation unit	11
Feed prep and drying	13
Gasification with tar reforming, heat recovery and scrubbing	46
Syngas cleanup and compression	30
Methanol synthesis	8.9
MTG, gas fractionation	27
Steam system and power generation	12
Remainder off-site battery limits	2.2
Installation Cost	220
Indirect Costs	300
Total Capital Cost	**680**

Year of source data: 2008. All values adjusted to 2014 dollars using the Producer Price Index – Industry Data.

Table 16 provides a detailed breakdown of the operating costs, including prices for feedstock, chemicals and catalysts, utilities and wastewater treatment. Using an *N*th plant analysis, the selling price of gasoline from the MTG pathway was calculated to be $4.1 per gallon.

Table 16: Methanol-to-Gasoline Operating Costs Based on 2,000 Metric Tons of Biomass per Day (Data Source: PNNL 2009)

Item	Cost ($ / GGE)
Biomass	1.2
Natural gas	0
Catalysts & chemicals	0.42
Waste disposal	0.06
Electricity and utilities	-0.42
Fixed costs	0.68
Capital depreciation	0.69
Average income tax	0.43
Average ROI (10%)	0.91
Estimated selling price	4.1

Year of source data: 2008. All values adjusted to 2014 dollars using the Producer Price Index – Industry Data.

Pathways Cost Comparison

Table 17 compares the capital cost and the anticipated selling price of drop-in fuels from the pyrolysis, FT, and MTG pathways, with all prices adjusted to 2014 dollars. Since all costs reported are estimations subject to study-specific assumptions about the *N*th plant, these cost values should be viewed as approximations. However, the literature sources generally used similar methodology and assumptions to estimate capital cost and fuel selling price, so it is reasonable to compare the capital investment and selling price of the fuels from the various pathways.

For all three pathways, costs were evaluated using a 10% IRR and a 7-year MACRS depreciation schedule. The main differences in financial assumptions for the pathways are plant life and construction period. Both the pyrolysis and the FT pathways assumed a 3-year construction period, however, MTG assumes a 2.5-year construction period. A more significant difference in assumptions is the anticipated plant life: MTG and FT assume a 20-year plant life while the pyrolysis pathway costs were calculated assuming a 30-year plant life. Each literature source used Aspen Capital Cost Estimation Software and industry knowledge to estimate the total capital investment. Operating costs were all based on market prices for various materials, resources, and commodities.

Table 17: Pathways Cost Comparison (Data Sources: PNNL 2013, Swanson 2010, PNNL 2009)

Pathway	Total Capital Cost	Minimum Selling Price
	$ million	*$ / GGE*
Pyrolysis	690	3.5
FT	730	4.9
MTG	680	4.1

Values rounded to two significant digits. GGE = gallon of gasoline equivalent
All values are in 2014 dollars.

Greenhouse Gas Emissions

This study sought to calculate the GHG emissions for each pathway using the energy demand provided in the literature and consistent emissions factors. The purpose of these calculations is to determine the GHG emissions associated with the fuel production stages; it does not consider the upstream biomass cultivation or energy associated with manufacturing upstream materials. Additionally, these calculations only consider the GHG emissions from the on-site and off-site energy production and combustion; fugitive carbon dioxide and methane emissions from unit processes were not included.

The main source of GHG emissions for the pathways is the combustion of fuels for energy. Table 18 gives the emissions factors for each energy source. The off-site electricity was taken as the emissions factor for the average California electric grid [eGRID 2015]. It was assumed that steam cycles produce zero GHG emissions since the steam is produced from the excess heat in gasification reactions, not from fossil fuel combustion. Therefore, both process heat and electricity generated from the process steam cycles have zero associated GHG emissions. The emissions factor for natural gas combustion was taken from Argonne National Laboratory's GREET model [GREET 2015]. Biogenic carbon emissions were not considered, so char combustion and process off-gas combustion both have a zero GHG emissions factor.

Table 18: Greenhouse Gas Emission Factors

Energy Type	Value	Unit	Source
Off-site electricity, CAMX	300	*g CO2e / kWh*	eGRID for CAMX
Off-site electricity, WECC	400	*g CO2e / kWh*	eGRID for WECC
On-site steam-generated electricity	0	*g CO2e / kWh*	Assumption
On-site gas-generated electricity	420	*g CO2e / kWh*	CEC natural gas electricity generating unit efficiency
Natural gas	57.0	*g CO2e / MJ*	GREET for NG combustion
Steam	0	*g CO2e / MJ*	Assumption: produced from biomass
Char	0	*g CO2e / MJ*	Biogenic carbon emissions
Process off-gas	0	*g CO2e / MJ*	Biogenic carbon emissions

Values rounded to two significant digits. All of the sources use the same characterization factors for converting GHG emissions of various molecules into CO_2e.

The emissions factor for the on-site gas-generated electricity was calculated by multiplying the efficiency of a natural gas electricity-generating unit by the emission factor for natural gas combustion. It was assumed that a combined cycle natural gas combustion unit would be used on-site to generate electricity. These units have a typical heat rate of 7,855 Btu/kWh in California [Nyberg 2014].

The GHG emissions were calculated for each pathway using the emissions factors in Table 18 and the energy demand rates found in the literature (as given in Table 7). Table 19 compares the energy demand and corresponding GHG emissions of each pathway, expressed per gallon of gasoline equivalent.

Table 19: Greenhouse Gas Emissions Pathway Comparison

	Units	Pyrolysis	FT	MTG
Energy Demand				
Electricity	kWh / GGE	1.8	2.2	1.8
Steam	MJ / GGE	0	7.3	12
Char	MJ / GGE	19	0	0.1
Natural Gas	MJ / GGE	29	0	0
Energy Generated				
Gas Turbine	MJ / GGE	n/a	6.7	n/a
Steam Turbine	MJ / GGE	n/a	18	41
Excess Energy				
Total Excess Energy	kWh / GGE	n/a	2.7	4.1
Total Excess Energy	MJ / GGE	n/a	9.6	15
GHG Emissions				
Base Case	kg CO_2e / GGE	2.15	-0.79	-1.9
CAMX Offset	kg CO_2e / GGE	n/a	-0.79	-1.9
WECC Offset	kg CO_2e / GGE	n/a	-1.1	-2.6
Natural Gas Offset	kg CO_2e / GGE	n/a	-0.54	-1.3

Values rounded to two significant digits, GGE = gallon of gasoline equivalent

Figure 13 compares the average yield and GHG emissions for each pathway. The error bars represent the range of yields found in the literature (as given in Table 6). Since GHG emissions are calculated per metric ton of dry biomass processed, the GHG footprint per GGE varies with the change in yield. The GHG emissions in Figure 13 are depicted assuming no external allocation of excess energy.

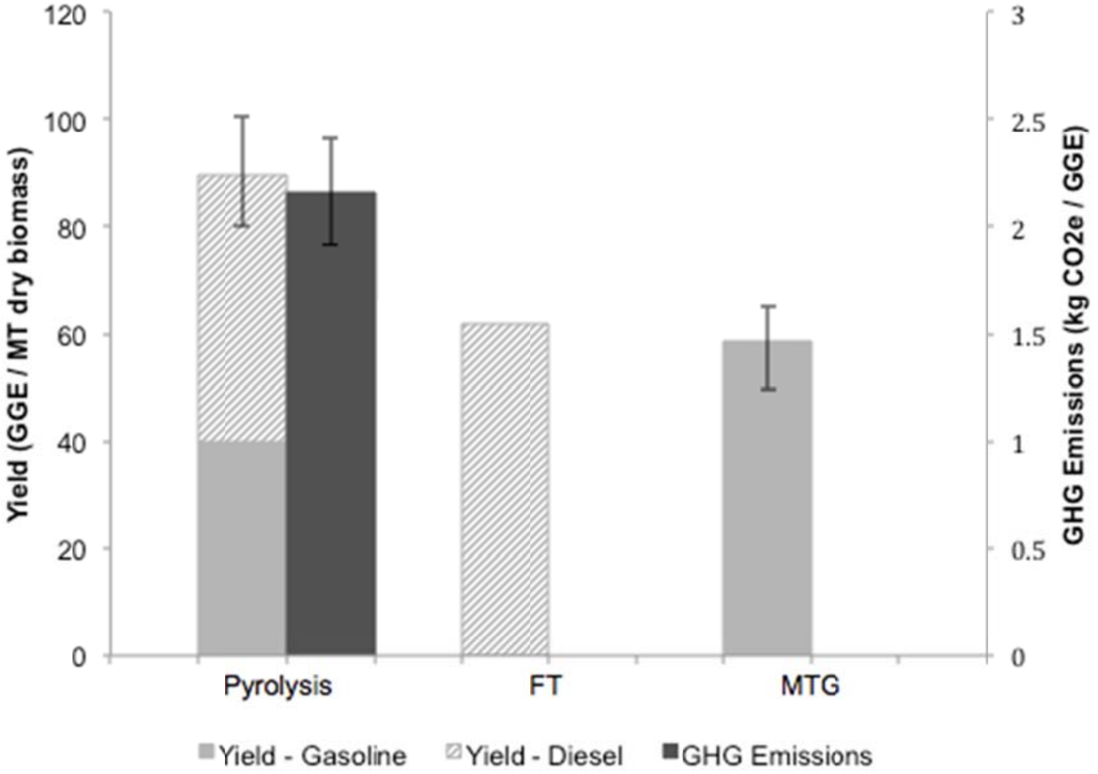


Figure 13: Yield and Greenhouse Gas Emissions for Each Pathway without excess electricity credits

FT and MTG Pathways have 0 GHG emissions due to steam cycles and combustion of biogenic carbon.
Error bars represent the range in yields found in the literature.
GGE = Gallon of gasoline equivalent, MT = metric ton

Pyrolysis Greenhouse Gas Emissions

For the pyrolysis pathway, the energy demand was taken as the average value between the PNNL [2013] and NREL [2012] studies. This is an electrical demand of 160 kWh, and a natural gas demand of 2,500 MJ per metric ton of dry biomass processed (or 1.8 kWh electricity and 29 MJ natural gas per GGE). Additional heat energy for the pyrolyzer unit is provided through char combustion, however this is not factored into the GHG calculation because char is a source of biogenic carbon. For the pyrolysis pathway, all of the electricity and natural gas are purchased from off-site.

Fischer-Tropsch Greenhouse Gas Emissions

The FT process is a net power producing process, and produces energy with two generators: a steam generator and a gas generator. The total energy production from the FT pathway is 410 MJ from the steam turbine and 1,140 MJ from the gas turbine per metric ton of dry biomass processed. The gas turbine is powered entirely from process off-gases, which are biogenic sources of hydrocarbon fuel. As a result, the GHG emissions from the gas turbine are set to zero because biogenic carbon dioxide is assumed to be re-sequestered continuously as new biomass is grown. As a result, the total GHG emissions associated with the FT pathway at the refinery is equal to 0 kg CO_2e per GGE. This pathway does not rely on any off-site electricity or fossil fuels, and all of the energy provided is from carbon-neutral sources (steam or biogenic fuel gas).

The FT pathway generates a total of 1,550 MJ, however, the total energy demand is only 950 MJ per metric ton of dry biomass processed. The net 600 MJ of thermal energy is sold back to the grid. A system expansion allocation method was also chosen to allocate the GHG credits from the production of this excess energy. System expansion allocation involves calculating the GHG credit based on the GHG emissions associated with the energy to be offset. In this analysis, three different system expansion offset values were evaluated. First, the average California grid mix for the CAMX region, with a GHG emissions factor of 0.29 kg CO_2e / kWh. Second, the average Western grid mix for the WECC NERC region, with a GHG emissions factor of 0.40 kg CO_2e / kWh. Third, the thermal energy is sold back to the grid just as natural gas, with a GHG emissions factor of 0.06 kg CO_2e / MJ. Figure 14 compares the GHG emissions of each pathway when the system expansion method was used to allocate the excess energy.

Methanol-to-Gasoline Greenhouse Gas Emissions

Energy for the MTG pathway is supplied from the system-wide steam cycle, char combustion, and process off-gas combustion. Char and off-gases produced in the gasifier are combusted to provide heat for the dryer unit process. Since these are both biogenic sources of carbon, this combustion does not contribute to the net GHG impact. The rest of the thermal energy demands in the process are met by the steam cycle. Saturated high pressure steam is generated by cooling streams in the gasification, steam reforming, and MTG synthesis unit processes. Some of the high pressure steam is superheated using thermal energy from biogenic fuel gases purged from the methanol synthesis and MTG process steps.

Like the FT pathway, the MTG pathway is also a net producer of energy. The total thermal energy demand from the system is 680 MJ, the electrical demand is 370 MJ, and the steam system generates 1,750 MJ per metric ton dry biomass processed. The net 700 MJ of energy produced is sold back to the grid. The same system expansion allocation technique from the FT pathway was used to evaluate the GHG footprint of the MTG pathway. Figure 14 compares the GHG emissions of each pathway with the system expansion method used to allocate the excess energy.

Figure 14 compares the GHG emissions of each pathway assuming system expansion allocation of excess energy produced. The “base case” assumes that the excess energy is sold back to the CAMX electric grid, at a carbon credit of 0.29 kg CO_2e / kWh. The error bars represent the different systems that the excess energy could be allocated to. The lower bound on the error bar assumes that the excess electricity is sold to the WECC grid (at a carbon credit of 0.40 kg CO_2e / kWh). The upper bound on the error bar assumes that the excess energy is sold back simply as natural gas (at a carbon credit of 0.06 kg CO_2e / MJ). The pyrolysis pathway does not produce excess energy, so the system expansion allocation is not applicable.

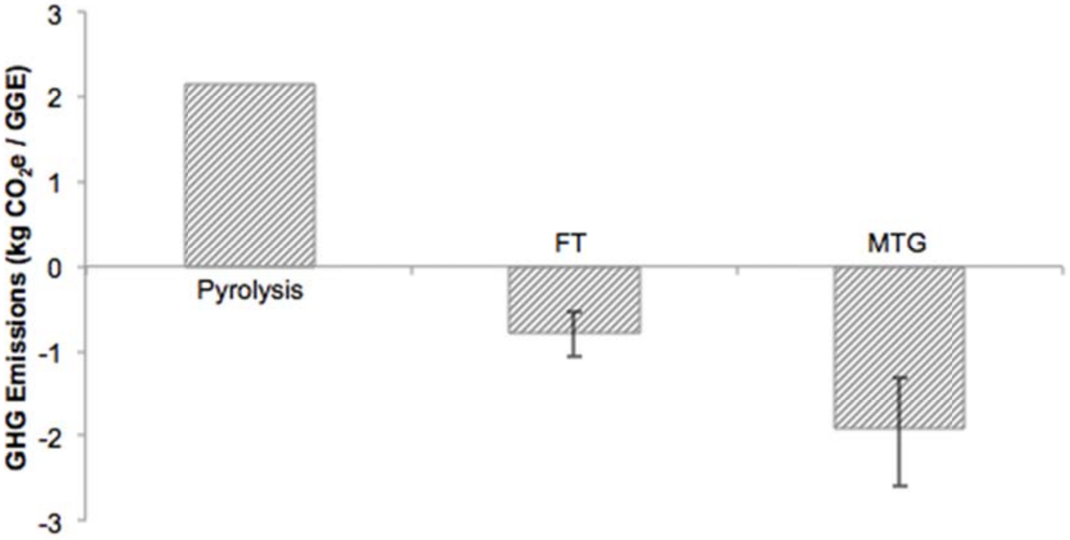


Figure 14: Greenhouse Gas Emissions with System Expansion Allocation

Negative values for FT and MTG pathways are due to offset credits for net electricity exports, using system expansion. Base case assumes system expansion to CAMX grid, lower bound of error bars assumes system expansion to WECC grid, and upper bound assumes system expansion to offset straight natural gas.

Criteria Air Pollutant Emissions

The existing literature on production pathways to drop-in biofuels has limited information concerning air emissions other than greenhouse gases. This is in part because conventional chemical process modeling software is not designed to quantify combustion-related and fugitive emissions, and required control technology will vary depending on the size of the facility, the state, and the local air quality management district. For this reason, even sparsely-available literature values vary greatly and often confuse process/fugitive emissions with combustion emissions, resulting in inadvertent double-counting. However, it is critical to understand the potential air quality impacts of new fuel production technologies, particularly in California. Of the six criteria air pollutants identified by the EPA, this study focused on quantifying emissions of NO_x, SO_x, particulate matter (PM) and carbon monoxide (CO) because they are most relevant for the processes in question. The focus is exclusively on well-to-pump emissions because sufficient combustion and emissions testing data are not yet available to accurately characterize tailpipe differences between conventional gasoline/diesel and bio-based alternatives. The two criteria air pollutants that were omitted from this analysis are ozone (O_3) and lead (Pb). Ozone is not a primary air pollutant, meaning that it is formed in the atmosphere as a result of chemical reactions rather than being emitted directly from sources of air emissions. Lead is a heavy metal that is generally not found in biomass feedstocks, and is not expected to be present in significant quantities in any of the unit processes for drop-in biofuel production. Particulate matter emissions were divided into three categories: $PM_{2.5}$, PM_{10} and PM (unspecified). Several data sources did not specify the size of particulate emissions, and these data sources comprise the PM (unspecified) category.

No comprehensive studies on the air pollutant emissions from each pathway to drop-in biofuels exist, so a literature review was conducted to quantify air emissions from individual unit processes where possible. Table 20 shows the unit processes involved in all three pathways to drop-in fuels and their sources for air pollutant emissions. Data were taken from recent best available control technology (BACT)-based permits issued in California for identical or similar processes, with a few exceptions. In cases where permits were only granted for furnaces associated with unit processes, we assumed that no significant non-combustion emissions are associated with those processes.

Table 20: Unit Process Air Pollutant Emissions

Unit Process	Air Emissions Information/Assumptions
Pyrolysis	No non-combustion emissions
Gasification	No non-combustion emissions
Grinding	NETL 2011: LCI data (.0072 g PM_{10}/kg dry biomass)
Char combustion	Based on permits issued for gas boilers in California based on BACT • Base case using selective catalytic reduction and oxidation catalyst: 5 ppm CO, 2 ppm NO_x in flue gas, 4.97 g PM_{10} and $PM_{2.5}$/kg dry biomass, 0.0067 g SO_x/kg dry biomass • High end using low-NO_x burner and flue gas recirculation: 50 ppm CO and 20 ppm NO_x. Same PM and SO_x emissions as base case.
Steam Reforming	No non-combustion emissions
Methanol Synthesis (fugitive CO only)	Grillo-Reno 2011: LCA of MeOH production from sugarcane
Hydrocracking and Hydrotreating	No data
Gas Combustion Electric Generating Unit	GREET 2015
Drying	No non-combustion emissions
Air Separations Unit	No non-combustion emissions
Quench / Filter	No non-combustion emissions
MTG	No non-combustion emissions
Tar Reforming and Scrubbing	No data
Gas purification	No data
Acid Gas Removal	No data
Fischer-Tropsch Synthesis	No data
Pressure Swing Adsorption	No data

The air pollutant emissions from each unit process were scaled according to the mass balance for each pathway to approximate the air emissions for pyrolysis, FT and MTG. Figure 15, Figure 16, and Figure 17 show the air emissions of CO, NO_x, PM (unspecified), PM_{10}, $PM_{2.5}$ and SO_x per gallon of gasoline equivalent for the pyrolysis, FT and MTG pathways, respectively. The total air emissions values in Figure 15, Figure 16, and Figure 17, are broken down by the contribution from each unit process. The error bars represent the range in fuel yields found in the literature for each pathway, as well as variations in permitted emission factors for CO and NO_x. Figure 16 does not have any error bars because only one literature source was used to determine the yield for the Fischer Tropsch pathway, and the unit-relevant processes could be associated with single permitted values rather than ranges. The results shown in Figure 15, Figure 16, and Figure 17 assume allocation of all air emissions to the production of fuel (i.e., no system expansion to account for offsets). Since these values were calculated with incomplete data, these values should be treated as a lower bound of air pollution to be expected from these pathways.

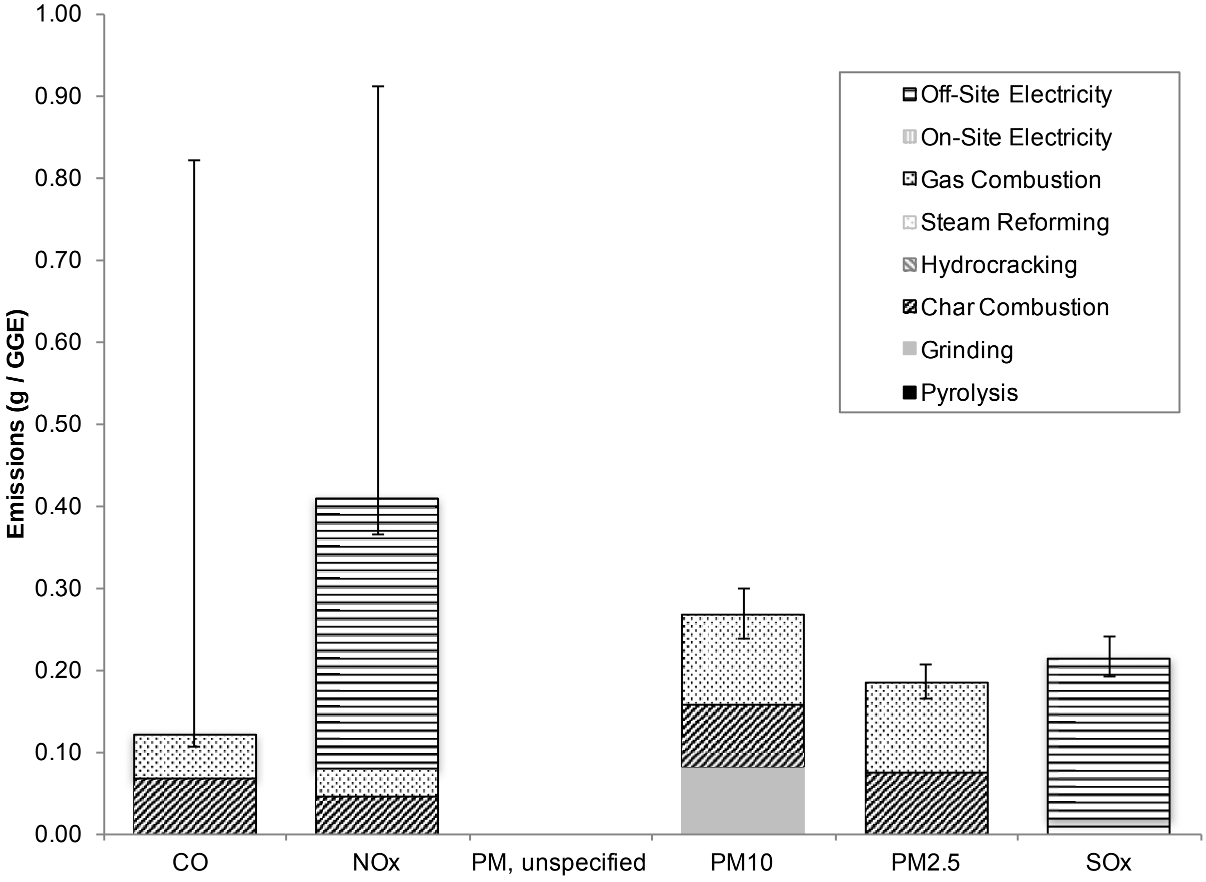


Figure 15: Pyrolysis Air Pollutant Emissions

Error bars represent range in fuel yields and differences in permitted emissions
GGE = gallon of gasoline equivalent

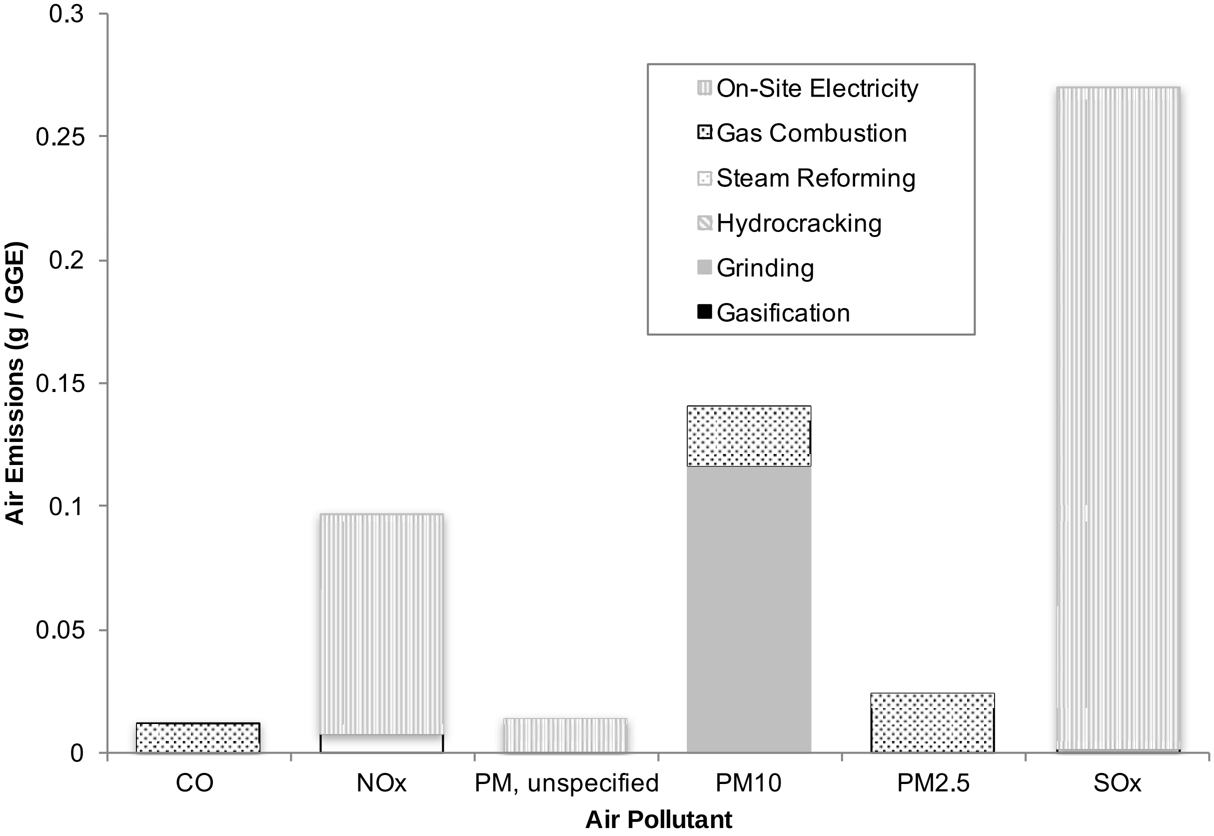


Figure 16: Fischer-Tropsch Air Pollutant Emissions

GGE = gallon of gasoline equivalent

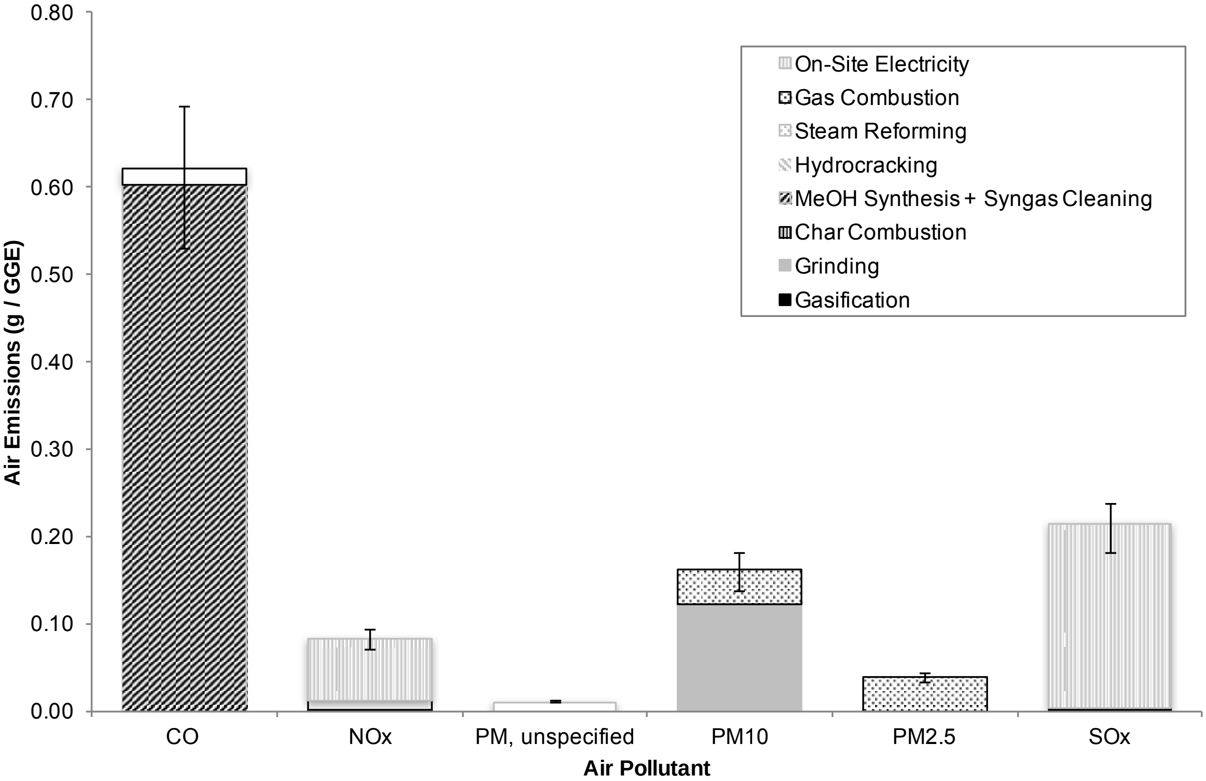


Figure 17: Methanol-to-Gasoline Pollutant Emissions

Error bars represent range in fuel yield and permitted emissions.
GGE = gallon of gasoline equivalent

Figure 18 compares the three criteria air pollutants from all three pathways when offset credits from the excess electricity are considered. The error bars in Figure 18 represent the range in values that would yield from system expansion allocation if the excess energy produced in the FT and MTG pathways was sold back to the grid. The upper bound on the error bars assumes that the excess energy was sold back as natural gas and the lower bound on the error bars assumes that the excess energy was sold back as electricity to the WECC grid. The baseline value shown assumes the excess energy is sold to the CAMX grid.

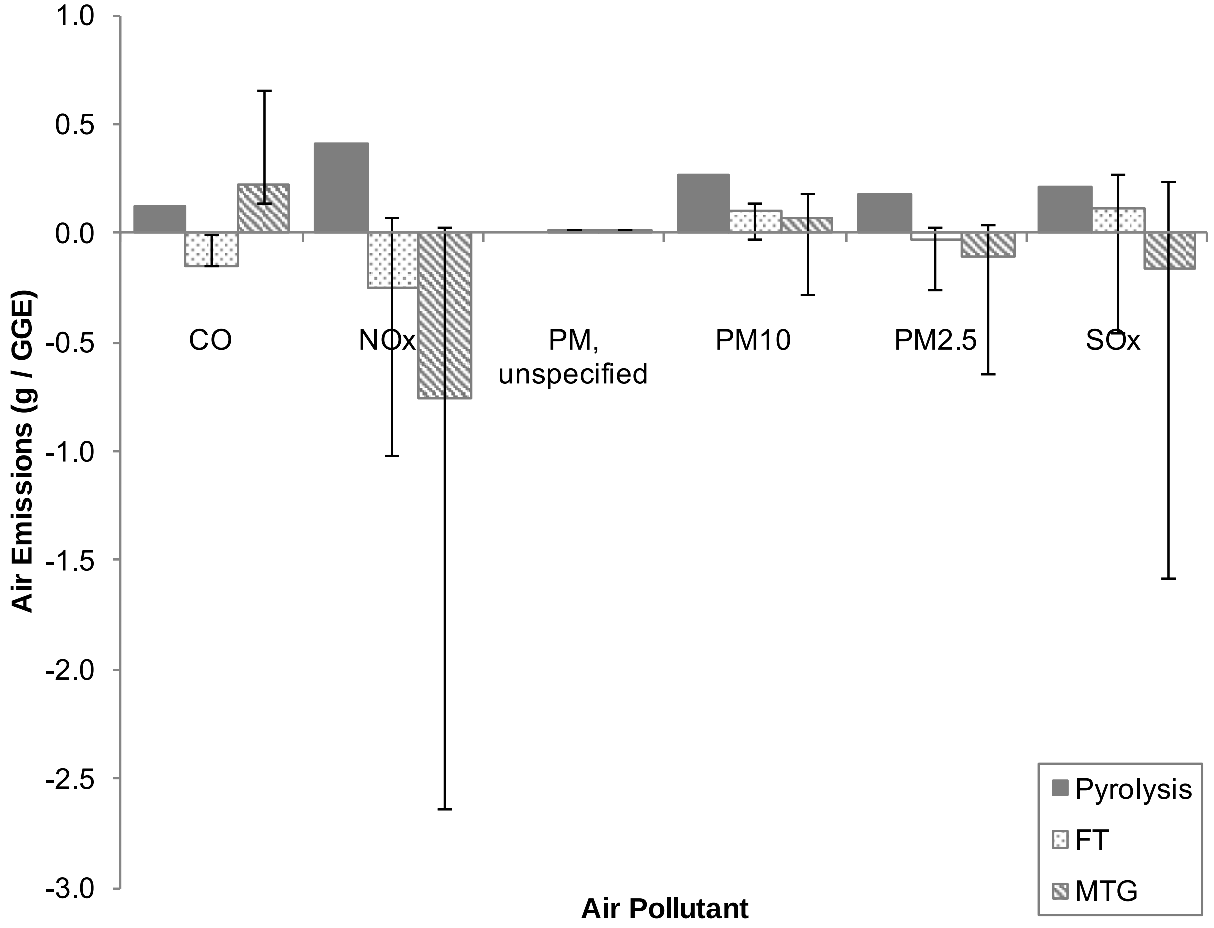


Figure 18: Comparison of Air Pollutant Emissions with System Expansion Allocation

Error bars represent different energy offset for system expansion allocation, in addition to variations in yield and emission factors discussed above: lower bound = WECC, upper bound = natural gas, baseline value = CAMX

Water Consumption

Gasification and pyrolysis pathways are generally considered to be more water-efficient than biological routes to fuels because, while process water is required for pretreatment and dilution of the sugar stream prior to fermentation, very little water is needed for thermochemical routes aside from what is required for process steam and cooling.

We conducted a life-cycle water use inventory based on the mass and energy balances for each pathway (see results in Figure 19). We focus on evaporative losses rather than total withdrawals, although none of these facilities are assumed to use once-through cooling, so direct water consumption and withdrawals will not differ substantially. The primary driver of on-site water demand is steam electricity generation, which requires cooling water. In terms of indirect water use, water embedded in natural gas extraction and processing is an important contributor, as is cooling water required at offsite power generation facilities. Direct water use at the biorefinery for pyrolysis is fairly low, but because the facility does not export electricity, and instead requires electricity and natural gas imports, total water use is positive. MTG benefits from large water use offsets but its net water consumption is positive because of substantial steam electricity generation on-site. The FT pathway proves most water efficient because of its relatively low steam electricity generation on site, net electricity exports, and no demand for imported natural gas. The results indicate that none of these biorefineries are likely to pose a local water demand issue, particularly given that nearly half of the pyrolysis pathway's water demand occurs remotely at off-site power generation facilities or natural gas processing facilities.

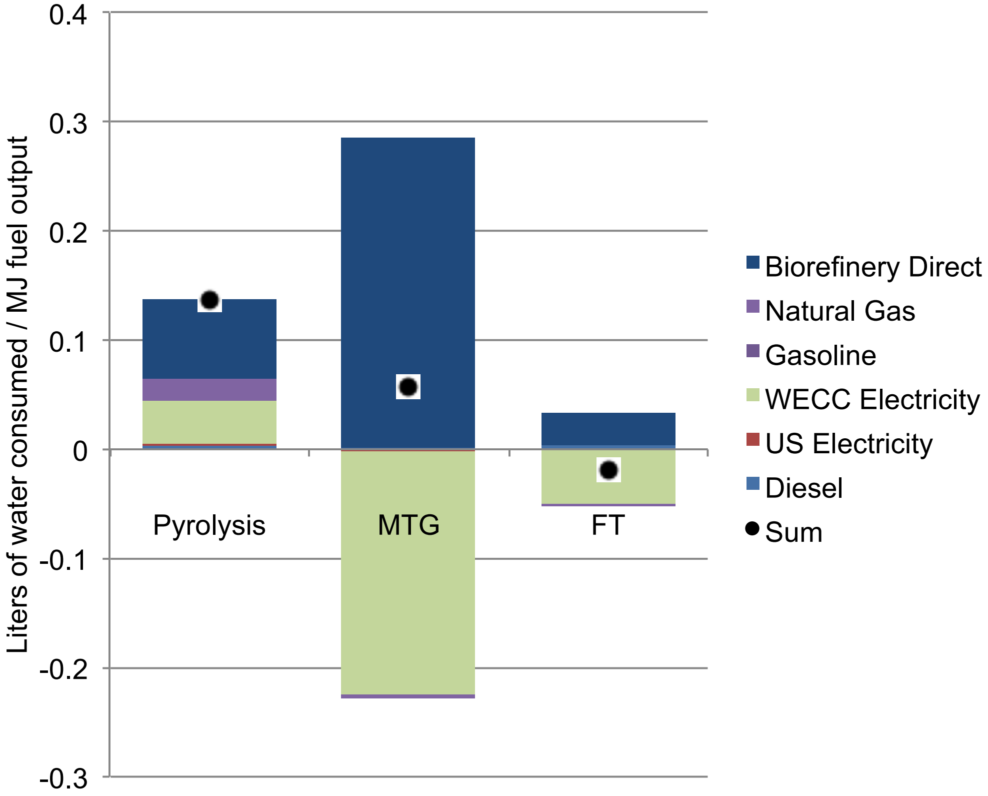


Figure 19: Life-Cycle Water Use for Thermochemical Pathways

Marine Fuels

Typically, the global shipping industry relies on heavy or low-grade petroleum-based fuels with high sulfur content to power marine freight fleets [Adom 2013]. Recent reports on the significant GHG emissions from the global shipping industry have raised concern about the use of these dirtier fuels, and consequently increased interest in developing pathways to bio-based marine fuels [IMO 2015]. Previous attempts to switch to alternative fuels in marine engines have resulted in several problems, such as filter plugging and decreased energy density. Significant advancements must be made in the state of bio-based marine fuels before we see the existence of a true drop-in marine fuel. To date, there have been no successful demonstrations of bio-based marine fuels that can be used as a one-to-one replacement for petroleum fuels, however, there are several types of bio-based fuels that can be blended with conventional marine fuels. The types of biofuels investigated as replacements for marine fuels include biodiesel, bio-oil, straight vegetable oil (SVO) and dimethyl ether (DME).

Biodiesel

A 2010 report prepared for the US Maritime Administration has provided an overview of using biodiesel in marine engines [Nayyar 2010]. Diesel blends incorporating 20% biodiesel (referred to as B20) generally perform well with no adverse side effects in terrestrial diesel engines, however, they have caused significant complications to marine engines. In tests performed by the Washington State Ferry

System, B20 caused significant filter clogging in marine engines, requiring filters to be replaced up to 4 times per day, as opposed to twice per year with petroleum diesel. The U.S. Coast Guard has reported similar filter clogging issues with the use of B20 in their marine fleet. Filter clogging is partially due to higher cloud point temperatures and increased levels of microbial growth in biodiesel. The cloud point temperature is the point at which wax crystals begin to form in a diesel fuel. Biodiesel has a higher cloud point temperature than petroleum diesel, so biodiesel begins to solidify at more moderate temperatures, which creates problems for the operation of marine engines. Implementing a heating system within fuel lines can be implemented to mitigate this issue and decrease the level of filter clogging. Additionally, the Washington State Ferry System experiment found high levels of bacteria in the diesel sludge, due to the humid environment in marine engines. Adding biocide into biodiesel blends has been demonstrated to decrease levels of bacterial growth and decrease the amount of sludge formed, further alleviating the filter clogging issue [Nayyar 2010].

Despite complications to the performance marine engines, B20 has demonstrated the same power output as petroleum diesel in marine engines [Nayyar 2010, Roskilly 2008]. With engine modifications in place, the use of biodiesel blends is suggested as a replacement for petroleum marine diesel.

Bio-Oil

Bio-oil (also referred to as pyrolysis oil) can be combusted directly in slow and medium-speed diesel engines, and therefore holds promise as a replacement for heavy fuel oil (HFO) and light fuel oil (LFO). However, several differences between bio-oil and petroleum fuel oils require attention and modifications to the marine engine fuel system. Pyrolysis oil is acidic and corrosive, which requires more expensive metals to be used within the marine engine. Additionally, pyrolysis oil has a much lower energetic value than petroleum equivalents; petroleum fuel oil contains approximately 40 GJ/ton, whereas bio-oil contains 17-23 GJ/ton [Florentinus 2012]. Lastly, experiments have demonstrated difficulty with auto-ignition of bio-oil without additives [Czernik 2004]. As a result of these insufficiencies, the simplest use of bio-oil in transportation fuels is as a blend with diesel fuels. A Canadian company CANMET has produced stable blends of 5-30% bio-oil in diesel, and the Italian University of Florence has produced emulsions of 10-90% bio-oil in diesel. These emulsions have demonstrated promising ignition characteristics; however they do require high levels of costly surfactants to achieve stabilization [Czernik 2004].

Straight Vegetable Oil (SVO)

Like pyrolysis oil, SVO can be used directly in many diesel engines, with some modifications to the marine engine. SVO has a higher viscosity than HFO or LFO, so an engine heating system may be necessary to lower the viscosity before combustion [Florentinus 2012].

Di-methyl Ether (DME)

Di-methyl ether (DME) has demonstrated successful combustion directly in terrestrial diesel engines, but its use in marine engines is still under development. DME can be produced from methanol or syngas, both of which can be produced from biomass sources [Florentinus 2012].

Summary of Data Gaps

As with any emerging technology, there are several gaps present in the literature of pathways to drop-in biofuels. Most of the gaps have been mentioned previously in this report, but this section will serve as a summary.

Criteria Air Pollutant Emissions

Of the six LCA reports closely analyzed in this literature review, none had information regarding air emissions other than greenhouse gases. Although there is information regarding the air emissions for most individual unit processes for each pathway, these emissions factors may not be representative of the actual air emissions to be observed in the pathway. Air emissions depend greatly on the feedstock to the particular unit process. While most of the unit process emissions data were gathered from a biorefinery-specific literature source, the feedstock composition will vary depending upon its level of treatment upstream.

Specific Thermal Energy Sources

There is some uncertainty with the exact energy demands for different pathways. Literature on most pathways included information about the different sources of on-site energy, but did not quantify the amount of char or off-gas that was combusted to meet a certain thermal energy load. Without data from a commercial plant, it is difficult to know exactly how the energy loads will balance, but this lack of data does present a significant gap in the analysis.

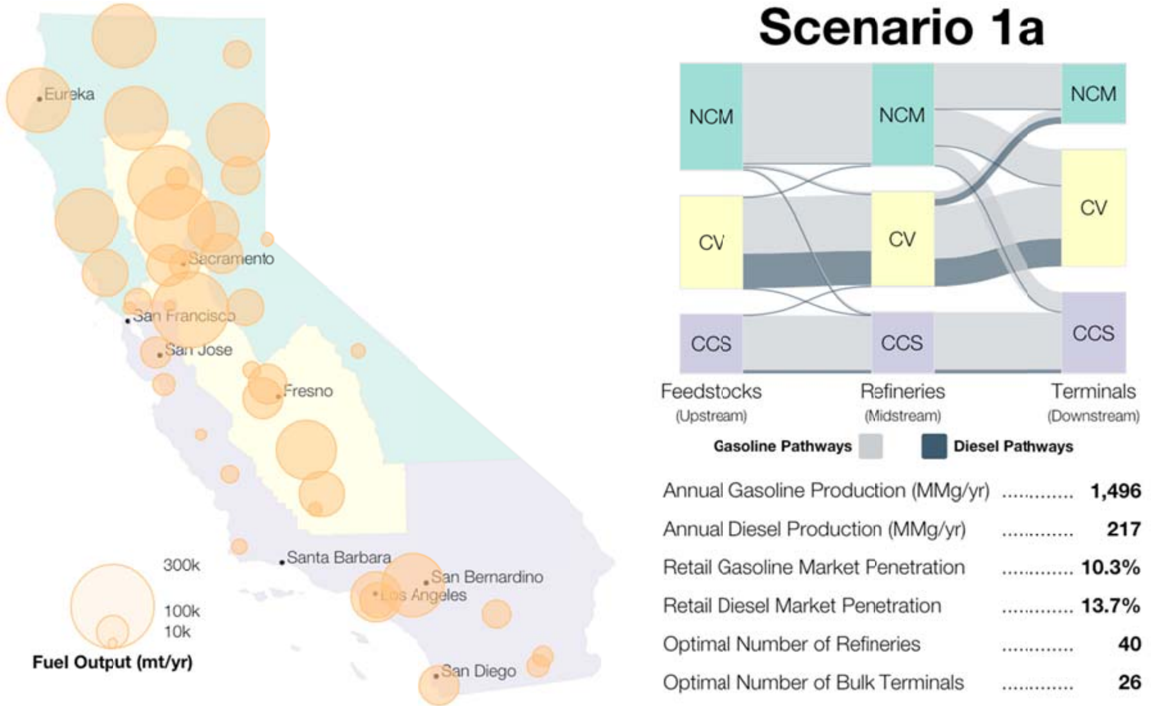
Drop-In Fuel Performance Testing

The final gap that extends beyond this study and into the broader world of drop-in fuels is the lack of performance testing for "drop-in" products in the public domain. All of the pathways evaluated in this study assume that the final product will perform as a gasoline or diesel replacement, as long as the hydrocarbons are of a similar size and structure to petroleum-based incumbents. However, there are no publicly-available results of performance testing to confirm this assumption. If there is interest to use drop-in fuels as a one-to-one replacement for petroleum-based gasoline and diesel fuels, the performance of these fuels must be verified.

Task 3: Scale-Up Scenario Modeling Results

The following sections document our results for each scale-up scenario. Numerical results corresponding to the figures can be found in Appendix B.

Scenario 1a – Maximize Gasoline



Annual Gasoline Production (MMg/yr)	**1,496**
Annual Diesel Production (MMg/yr)	**217**
Retail Gasoline Market Penetration	**10.3%**
Retail Diesel Market Penetration	**13.7%**
Optimal Number of Refineries	**40**
Optimal Number of Bulk Terminals	**26**

Figure 20: Summary of Results for the Facility Selection Optimization Under Scenario 1a

The infographic shows the scale of total fuel production at each refinery (LEFT), the flow of materials between up-, mid-, and downstream processes (RIGHT), and a summary of key statistics. *Regional Codes*: NCM – North Coast and Mountain region; CV – Central Valley region; CCS – Central Coast and Southern region.

The objective in Scenario S1a is to maximize the production of gasoline from biomass feedstocks sourced in the California. Figure 20 summarizes the optimal network logistics resulting from this policy pathway. Our results show that California could produce approximately 1,500 million gallons per year (10.3% of annual retail gasoline sales) of drop-in gasoline. Under this scenario, all of the state's woody feedstocks (e.g., forest residues, primary and secondary mill wastes, and urban wood) would be converted to gasoline through a methanol to gasoline pathway. This fuel pathway would represent 85% of total gasoline production. Herbaceous feedstocks would be converted to gasoline through the pyrolysis pathway. Pyrolysis also produces diesel as a co-product of the process. Thus, while the objective of this scenario is to maximize gasoline production, scenario S1a would yield 217 million gallons of diesel per year, or 13.7% of the retail diesel market.[3]

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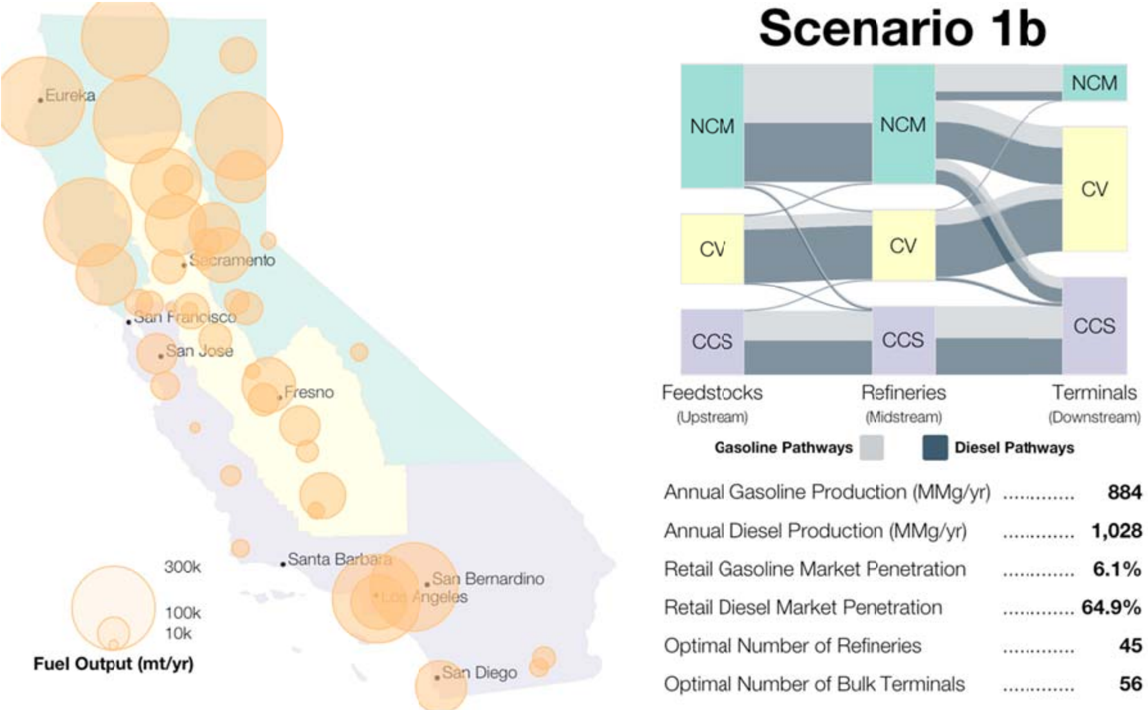
[3] Due to data availability, we were only able to benchmark the production of drop-in fuel against total retail sales of gasoline and diesel. Retail sales include all taxable sales occurring to individual drivers at pump stations. These sales do not include commercial sales for which county-level data are not available. For example, the California Energy Commission states that retail sales only amount to 42% of the total.

In total, 40 refineries would be needed to process the 24.9 million metric tons per year of biomass feedstocks, 48% of these refineries could be co-located at current refinery locations. Our scenario results find that refineries would need to store an average of 620,000 metric tons of solid biomass feedstock on-site at the refineries per year (about 1,700 metric tons per day). Over 65% of this biomass would be sourced from in-county feedstock providers. The largest production region for gasoline is the North Coast and Mountain (NCM) region, representing 46% of the state's total. 87% of the diesel that is also produced under this scenario occurs at refineries in the Central Valley (CV) region. Once produced, the fuels are then distributed to 26 total bulk fuel terminals, the majority of which are located in the CV region.

Scenario 1b – Maximize Diesel

Figure 21 summarizes the optimal network logistics resulting from a policy objective to maximize the production of diesel from biomass feedstocks sourced in the California (S1b). Our results show that optimizing for diesel production would produce approximately 1,028 million gallons per year (64.9% of annual retail diesel sales) of drop-in diesel. Under this scenario, all of the state's herbaceous biomass would be converted to diesel through a Fisher-Tropsch pathway, amounting for 54% of all drop-in diesel fuel sales. The remaining woody feedstocks would be converted to diesel through the pyrolysis pathway; a process which nets approximately 710 million gallons of diesel per year. Again, pyrolysis also produces gasoline as a co-product of the process. Following Scenario S1b would also net 883 million gallons of gasoline per year.



Annual Gasoline Production (MMg/yr)	884
Annual Diesel Production (MMg/yr)	1,028
Retail Gasoline Market Penetration	6.1%
Retail Diesel Market Penetration	64.9%
Optimal Number of Refineries	45
Optimal Number of Bulk Terminals	56

Figure 21: Summary of Results for the Facility Selection Optimization Under Scenario 1b

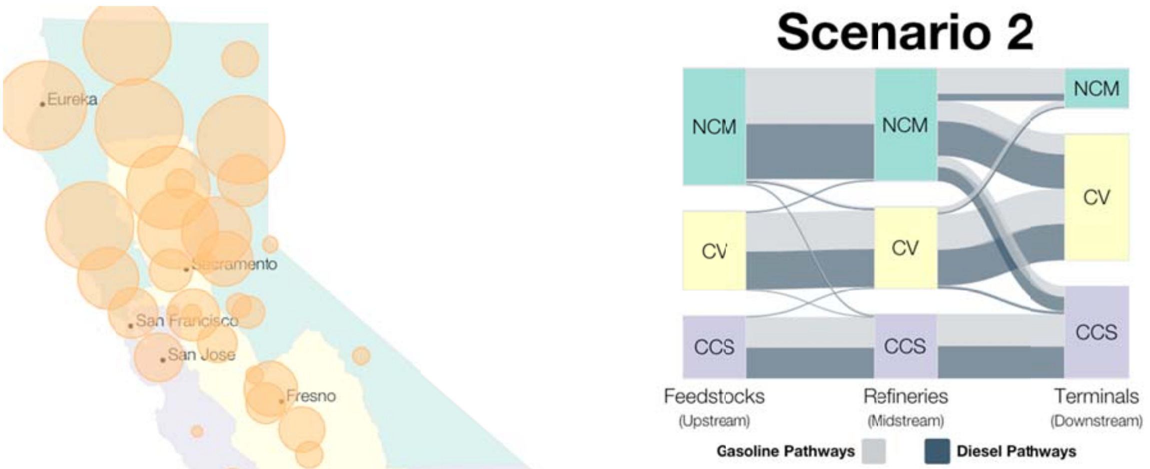
The infographic shows the scale of total fuel production at each refinery (LEFT), the flow of materials between up-, mid-, and downstream processes (RIGHT), and a summary of key statistics. *Regional Codes*: NCM – North Coast and Mountain region; CV – Central Valley region; CCS – Central Coast and Southern region.

In total, 45 refineries would be needed to process the 24.9 million metric tons per year of biomass feedstocks. The optimal distribution of refineries across the three regions is in fact uniform, with 15 refineries sited in each region. Since there are more refineries in S1b compared to S1a, scenario results find that refineries are on average smaller than in S1a. Refineries would require an average of 560,000 tons of solid biomass feedstock onsite at the refineries per year. Just as with scenario S1a, a significant fraction (65%) of biomass feedstocks used at refineries is sourced within the county. Once produced, the fuels are then distributed to 56 total bulk fuel terminals, the majority of which are located in the CV region.

Scenario 2 – Maximize Fuel Output

The last of the three prioritization scenarios assesses a policy pathway that aims to maximize the total production of gasoline and diesel in the state. This scenario is distinctive because it is the only scenario of the six categories considered where a single fuel pathway (pyrolysis) is optimal.

Figure 22 summarizes the optimal network logistics resulting from scaling the production of fuels using the pyrolysis fuel pathway in California. Results show that optimizing for total fuel production would produce approximately 2,080 million gallons per year of drop-in fuels (8% of retail gasoline sales and 58.4% of annual retail diesel sales).



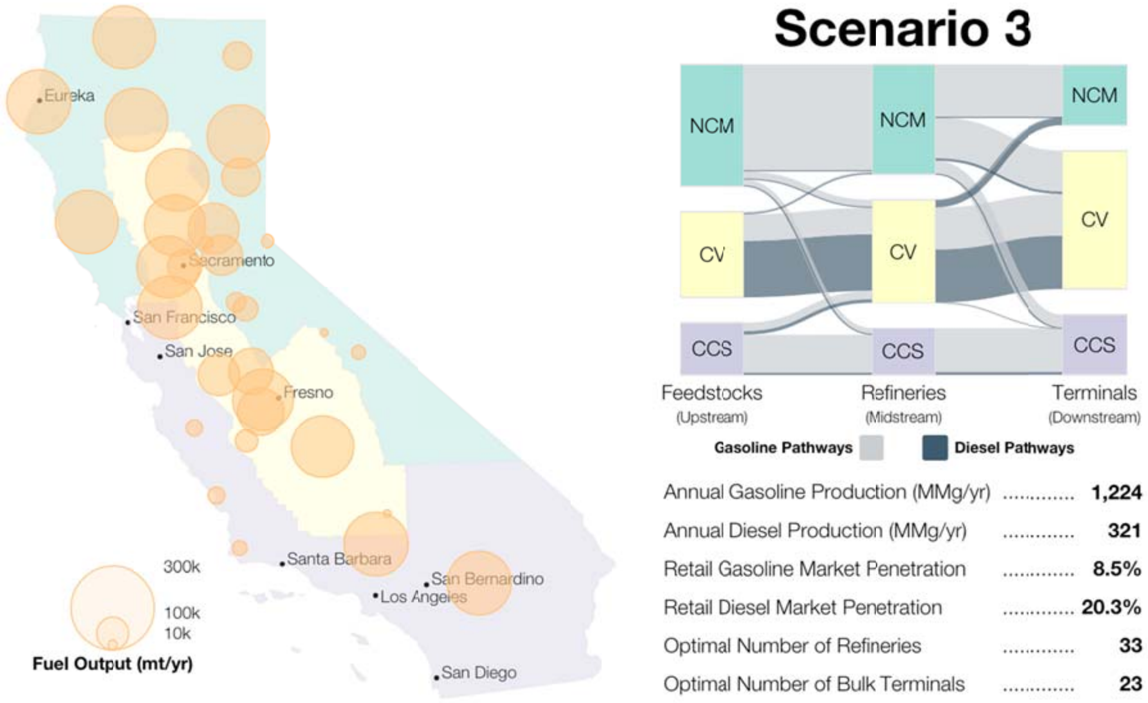
Annual Gasoline Production (MMg/yr)	**1,156**
Annual Diesel Production (MMg/yr)	**924**
Retail Gasoline Market Penetration	**8.0%**
Retail Diesel Market Penetration	**58.4%**
Optimal Number of Refineries	**42**
Optimal Number of Bulk Terminals	**54**

Figure 22: Summary of Results for the Facility Selection Optimization Under Scenario 2

The infographic shows the scale of total fuel production at each refinery (LEFT), the flow of materials between up-, mid-, and downstream processes (RIGHT), and a summary of key statistics. *Regional Codes*: NCM – North Coast and Mountain region; CV – Central Valley region; CCS – Central Coast and Southern region.

A total of 42 refineries would be needed in order to scale drop-in fuel production optimally, 22 of which would require the expansion of refineries at new locations. The average gasoline output per year at a refinery under this scenario is 2.1 MMg/year, where the average diesel output is 1.7 MMg/year. Refineries would require an average of 600,000 tons of solid biomass feedstock onsite at the refineries per year, slightly less than what would be needed under Scenario S1a. Approximately 58% of this biomass would be sourced from in-county feedstock providers. As Figure 22 shows, across the state a total of 43% of all biomass is sourced from the NCM region, 31% is sourced from the CV region, and 25% is sourced from the CCS region. The majority of the fuel produced at the refineries is then shipped to bulk fuel terminals in the Central Valley. In total, our results show that 54 bulk fuel terminals would receive this fuel.

Scenario 3 – Incentivize Only New Growth



Annual Gasoline Production (MMg/yr)	1,224
Annual Diesel Production (MMg/yr)	321
Retail Gasoline Market Penetration	8.5%
Retail Diesel Market Penetration	20.3%
Optimal Number of Refineries	33
Optimal Number of Bulk Terminals	23

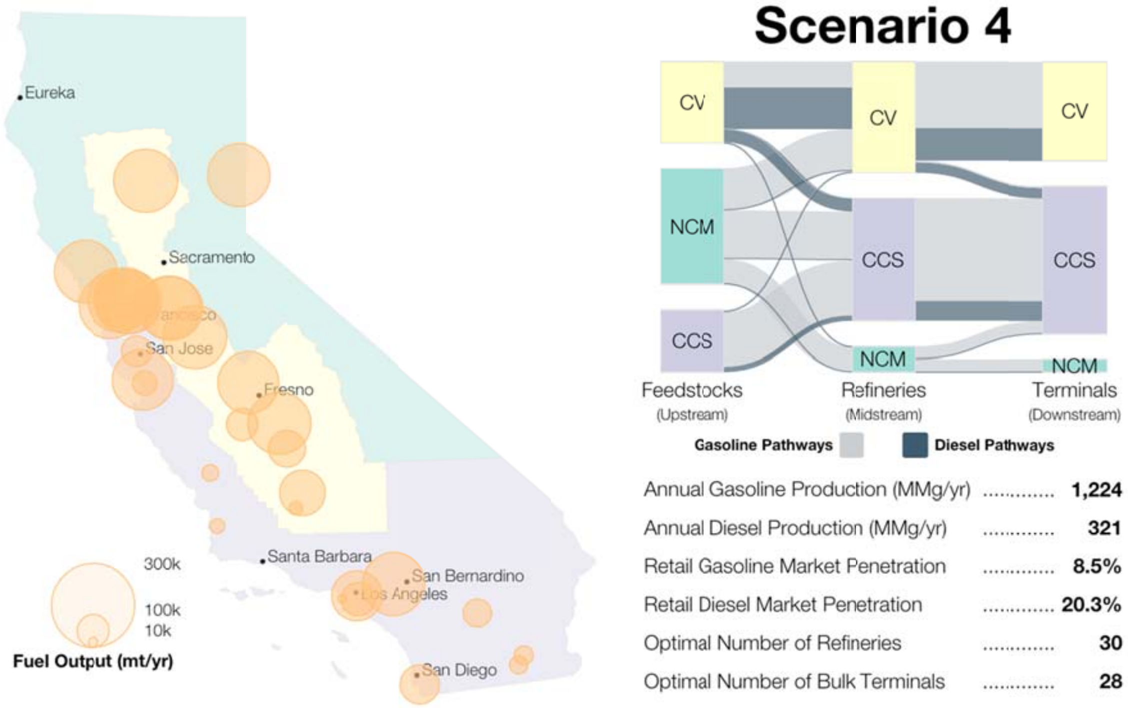
Figure 23: Summary of Results for the Facility Selection Optimization Under Scenario 3

The infographic shows the scale of total fuel production at each refinery (LEFT), the flow of materials between up-, mid-, and downstream processes (RIGHT), and a summary of key statistics. *Regional Codes*: NCM – North Coast and Mountain region; CV – Central Valley region; CCS – Central Coast and Southern region.

The objective of Scenario S3 is to minimize the total greenhouse gas footprint of fuels produced in the state under the constraint that the growth in the drop-in fuel market must occur at new locations (e.g., no co-location with current refineries occurs). The results of this scenario indicate that the optimum policies for meeting this target require a combination of methanol-to-gasoline and Fisher-Tropsch fuel pathways. As Figure 23 illustrates, Scenario S3 would produce a total of 1,545 million gallons of total fuel output per year (8.5% of the retail gasoline market and 20.3% of the retail diesel market), requiring all of the state’s herbaceous and woody biomass resources as inputs. Crop residues would be converted to diesel via Fisher-Tropsch fuel pathways and woody biomass would be converted to gasoline via methanol to gasoline fuel pathways.

The results from the scenario optimization suggest that a total of 33 new refineries would be needed in order to achieve the greatest greenhouse gas reductions. On average, refineries would need to store 620,000 tons of solid biomass feedstock on-site per year and average productions levels would be 40 MMg/refinery-year for gasoline and 12 MMg/refinery-year for diesel. Similar to the prioritization scenario group, a little over half (55%) of the biomass feedstocks would be sourced from in-county feedstock providers. Once produced, the fuels are then distributed to 23 total bulk fuel terminals, the majority of which are located in the CV region. The average annual supply of drop-in fuels at the bulk terminals would be 53 MMg/year for gasoline and 14 MMg/year for diesel.

Scenario 4 – Incentivize Only Co-Location



Annual Gasoline Production (MMg/yr)	1,224
Annual Diesel Production (MMg/yr)	321
Retail Gasoline Market Penetration	8.5%
Retail Diesel Market Penetration	20.3%
Optimal Number of Refineries	30
Optimal Number of Bulk Terminals	28

Figure 24: Summary of Results for the Facility Selection Optimization Under Scenario 4

The infographic shows the scale of total fuel production at each refinery (LEFT), the flow of materials between up-, mid-, and downstream processes (RIGHT), and a summary of key statistics. *Regional Codes*: NCM – North Coast and Mountain region; CV – Central Valley region; CCS – Central Coast and Southern region.

Scenario S4 is the second of the two centralization scenarios. Under this scenario, the objective is to again minimize the total greenhouse gas emissions associated with the scale up, however the growth of the drop-in fuel processes could only occur at current petroleum, ethanol, and/or biodiesel refineries (e.g., colocation only). Figure 24 provides an overview of the optimal network logistics resulting in this scenario. The model's total output for this scenario is exactly the same in terms of total fuel output, fuel pathway utilization, and relative market penetration as scenario S3. The key distinction for this scenario is where the facilities are located and how fuels are distributed to bulk fuel terminals. In total, 30 out of the total 38 existing refinery facilities would be needed to scale the drop-in fuel production to the optimal levels of fuel output. Scenario S4 had the lowest fraction of biomass feedstocks sourced by refineries within a county (31%), since very few current refineries occur in regions with significant biomass availability (i.e., NCM and CV regions). Once produced, the fuels are then distributed to 28 total bulk fuel terminals, the majority of which are located in the CV region. The average annual supply of drop-in fuels at the bulk terminals would be 44 MMg/year for gasoline and 12 MMg/year for diesel.

Scenario 5 – Incentivize Distributed Growth

The last category of scenarios considers an objective of greenhouse gas mitigation while allowing distributed growth. Scenario S5 is the least constrained of the four scenarios with regards to emission mitigation. Figure 25 summarizes the optimal network logistics resulting from this policy pathway. Our results show that California could produce approximately 1,224 million gallons per year (8.5% of annual retail gasoline sales) of drop-in gasoline and 321 million gallons per year (20.3% of annual retail gasoline sales) of drop-in diesel. These are the same values reported for Scenarios S3 and S4. Again, under this scenario, all of the state's woody feedstocks (e.g., forest residues, primary and secondary mill wastes, and urban wood) would be converted to gasoline through a methanol-to-gasoline pathway and herbaceous feedstocks would be converted to gasoline through the Fisher-Tropsch pathway.

In total, 52 refineries would be needed to process the 24.9 million metric tons per year of biomass feedstocks, 26 of these refineries could be co-located at current refinery locations. Our scenario results find that refineries would need to store an average of 490,000 tons of solid biomass feedstock on-site per year and average productions levels would be 30 MMg/refinery-year for gasoline and 8 MMg/refinery-year for diesel. Roughly 60% of this biomass would be sourced from in-county feedstock providers. Once produced, the fuels are then distributed to 31 total bulk fuel terminals, two-thirds of which are located in the Central Valley Region. The average annual supply of drop-in fuels at the bulk terminals would be 39 MMg/year for gasoline and 10 MMg/year for diesel.

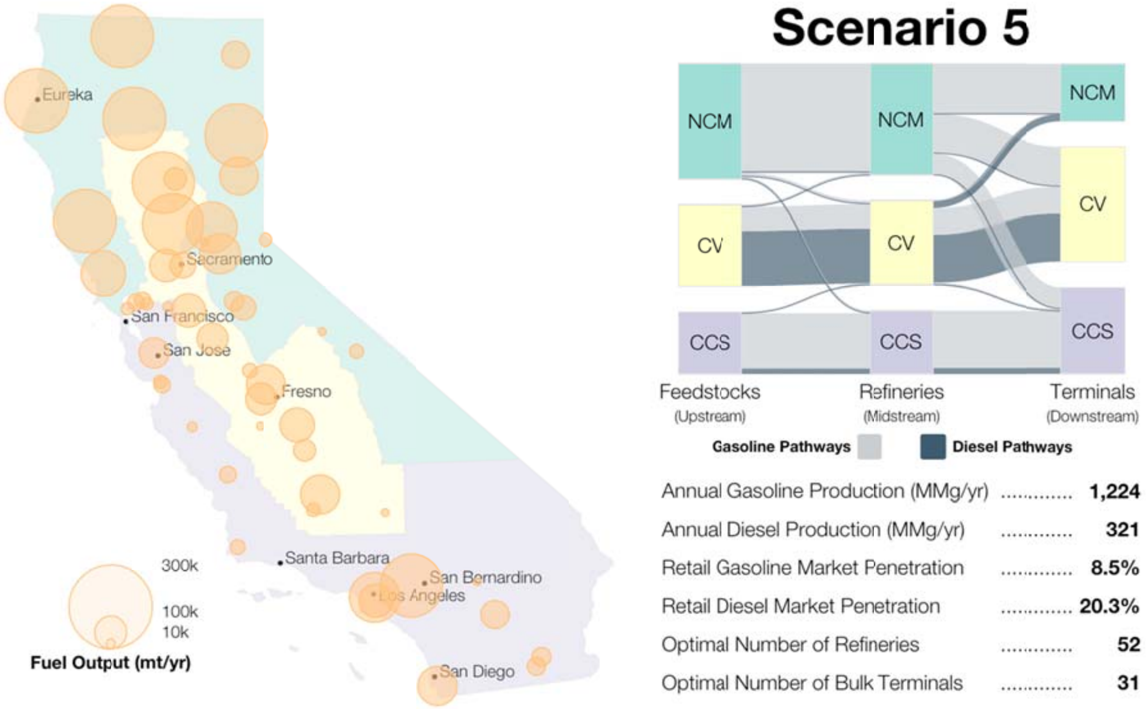


Figure 25: Summary of Results for the Facility Selection Optimization under Scenario 5

The infographic shows the scale of total fuel production at each refinery (LEFT), the flow of materials between up-, mid-, and downstream processes (RIGHT), and a summary of key statistics. *Regional Codes*: NCM – North Coast and Mountain region; CV – Central Valley region; CCS – Central Coast and Southern region.

Scenario 6 – Require Equal Blending

The last scenario assesses a policy that aims to minimize greenhouse gas emissions while guaranteeing an equal blending of drop-in fuels across the state (e.g., blend equals relative market penetration). Figure 26 provides an overview of the optimal network logistics for this scenario. The model's total output for this scenario is exactly the same in terms of feedstock transport, total fuel output, fuel pathway utilization, and relative market penetration as Scenario S5. The key distinction for this scenario is how fuels are distributed to bulk fuel terminals. The fuels produced under this scenario are then distributed to 68 total bulk fuel terminals, the majority of which are located in the CCS region. The average annual supply of drop-in fuels at the bulk terminals would be 18 MMg/year for gasoline and 10 MMg/year for diesel.

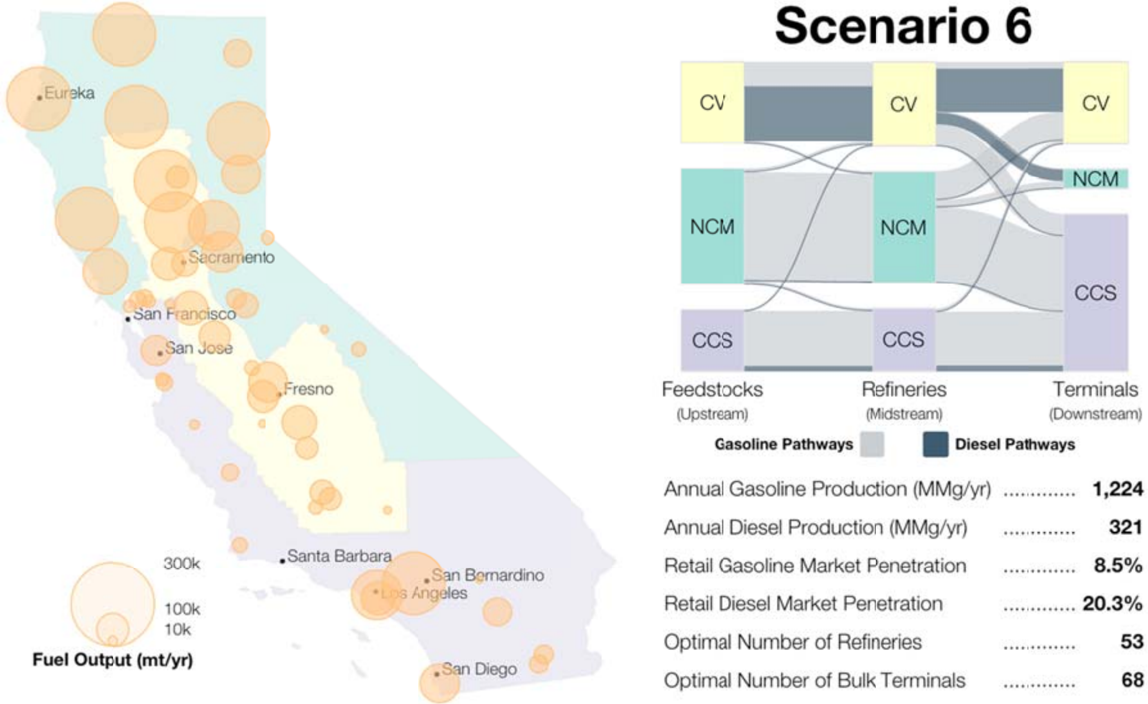


Figure 26: Summary of Results for Facility Selection Optimization Under Scenario 6

The infographic shows the scale of total fuel production at each refinery (LEFT), the flow of materials between up-, mid-, and downstream processes (RIGHT), and a summary of key statistics. *Regional Codes*: NCM – North Coast and Mountain region; CV – Central Valley region; CCS – Central Coast and Southern Region.

Freight Impacts

Figure 27 summarizes the total freight turnover corresponding to each modeled scenario. Upstream freight operations require the largest share of goods movement in each of the scenario pathways. The percentage split in total ton-kilometers for each scenario are 79% (S1a), 66% (S1b), 69% (S2), 84% (S3), 95% (S4), 79% (S5), and 53% (S6). This allocation of freight activities between supply-chain segments is caused by multiple factors. The major driver in this process-level split is due to the differences in mass between biomass feedstocks and produced fuels. In our scenarios, preprocessed feedstocks are 5-6 times greater by mass than the resulting produced fuels. Holding transport distances equal, these differences in mass are directly proportional to the differences in freight turnover.

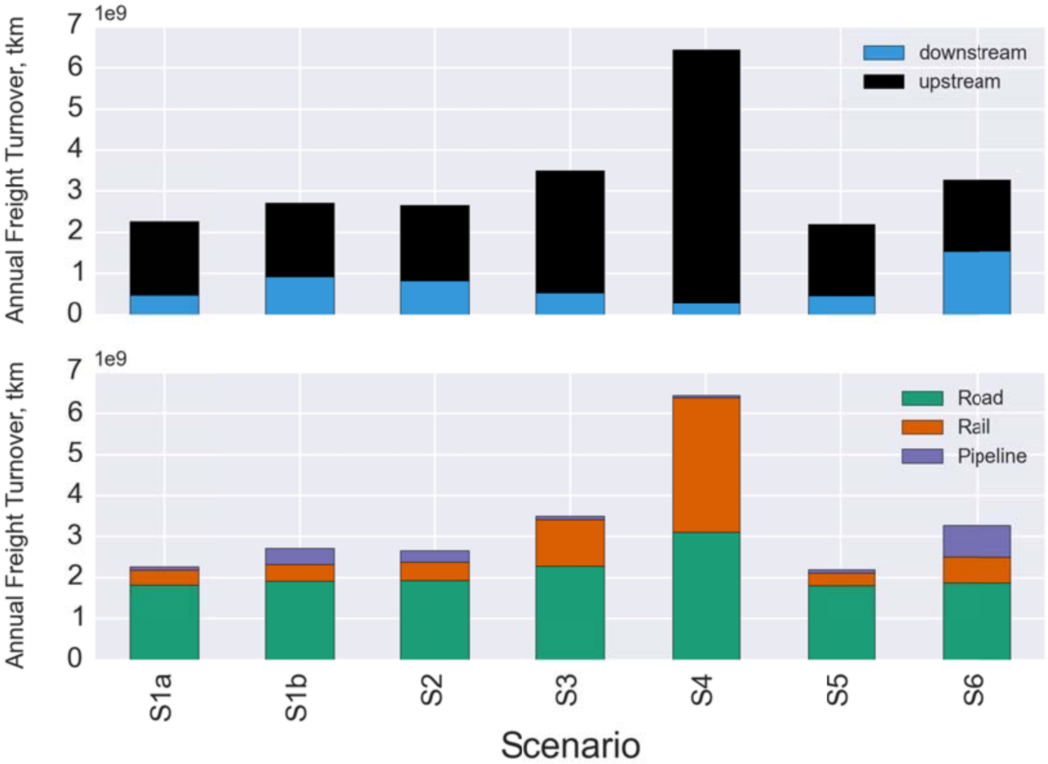


Figure 27: Split of Total Annual Metric ton-km by Supply-Chain Segment and Transport Mode for Each Scenario

The second important driver of these results is how or, more importantly, where refineries are sited across the state. Naturally, drop-in fuel refineries with more localized supply-chains (i.e., high accessibility to both feedstock providers and fuel purchasers) will require less freight services. For instance, let us compare and contrast the scenarios with the largest (S4) and smallest (S6) upstream freight demand in terms of total metric ton-kilometers required. Scenario S4 has the largest shares of upstream freight turnover because production sites were constrained to current refinery locations. These locations are often in urban areas away from the major feedstock generating regions of the states, causing the demand for freight services to significantly increase. In contrast, Scenario S6 has the lowest shares of upstream transport (or conversely the largest shares of downstream transport) because of the imposed uniform blending constraint. Under such conditions, the demand for drop-in fuels within local markets is quickly met causing refineries to ship fuels over larger distances to more isolated markets. The cumulative result is greater downstream of freight turnover.

Table 21: Summary of Mode Shares by Supply-Chain Segment for Each Scenario

Scenario	Supply-Chain Segment	Road	Rail	Pipeline
S1a	upstream	88%	12%	-
	downstream	52%	31%	17%
S1b	upstream	88%	12%	-
	downstream	36%	21%	42%
S2	upstream	86%	14%	-
	downstream	42%	23%	35%
S3	upstream	66%	34%	-
	downstream	60%	24%	16%
S4	upstream	50%	50%	-
	downstream	8.0%	73%	19%
S5	upstream	90%	10%	-
	downstream	51%	31%	18%
S6	upstream	90%	10%	-
	downstream	20%	30%	50%

A lesser, but still important driver in the split in freight turnover between supply chain segments is the topology of the network or the arrangement of its various mode-specific elements. In each of the scenarios explored, goods were routed between feedstock supplies, refineries, and fuel purchasers along pathways with the lowest GHG emissions. Pipelines (8.9 g $CO_{2,e}$ /tkm) and rail (20 g $CO_{2,e}$ /tkm) are the lower impact alternative to heavy-duty trucks (130 g $CO_{2,e}$ /tkm), which is the most prevalent mode in terms of total network distances. These lower-impact modes can subsequently move a ton of goods 6-15 times further at the same level of GHG emissions as the heavy-duty truck, which is often the case given the dispersed nature of the exchange nodes within rail and pipeline networks. In essence, our objective for the freight vehicle routing can create distortions in freight demand inventory, impacting the split in freight demand between the supply-chain segments.

For 85% of our scenarios, heavy-duty trucks represent the dominant transportation mode in terms of total mode share (Figure 27, bottom, Table 21). The percentage split in total ton-kilometers by heavy-duty truck for each scenario is 80% (S1a), 71% (S1b), 72% (S2), 65% (S3), 48% (S4), 82% (S5), and 57% (S6). Rail and pipeline modes tend to be utilized more frequently in downstream supply-chain segments. Our rational for these findings is that current fuel distribution infrastructure is already optimized to move fuels between current refineries and bulk terminals using these low-cost modes. For instance, observe the differences between the downstream mode-split of Scenarios S3 (i.e., production sites can only occur as new development) and S4 (i.e., sites must be co-located with current refineries). The scenario that incentivizes co-location about refineries utilizes rail or pipeline for 92% of its downstream freight turnover, while the contrasting scenario only utilizes rail or pipeline for 40% of its downstream freight turnover.

Environmental Impacts

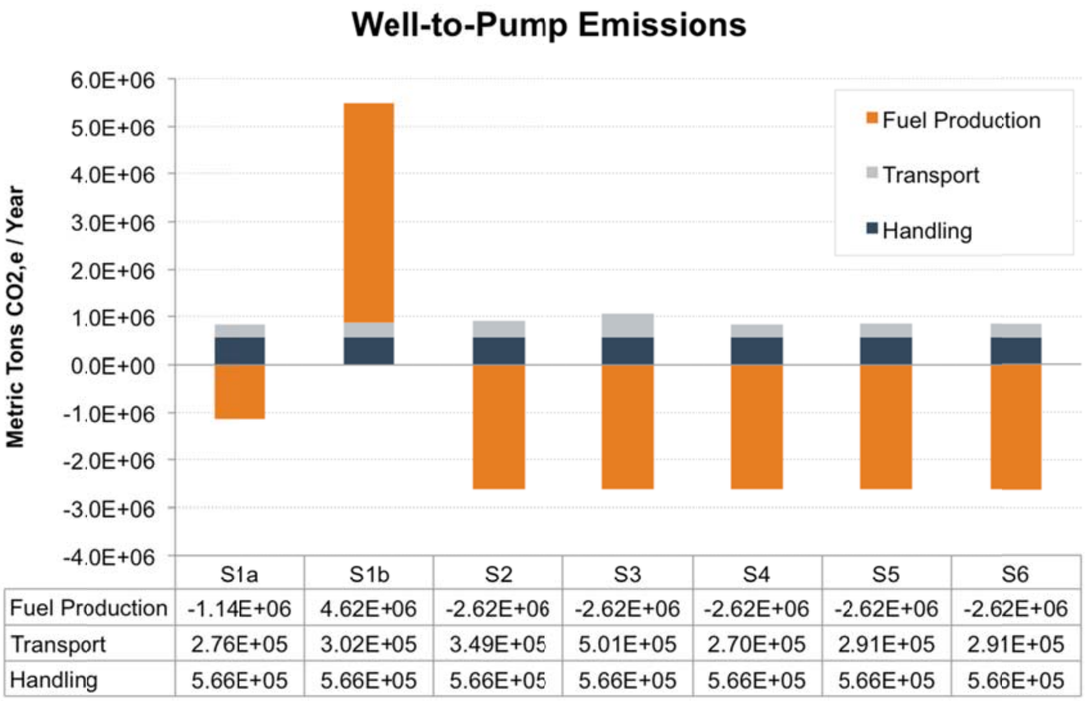
Table 22 summarizes the absolute and relative change in emissions from the 2015 baseline for each of the scenarios assessed. These estimates reflect the emissions modeled within the scope of this study, which encompasses all processes from biomass harvesting through fuel dispensing (i.e., well to pump). Our scenario analysis finds that it is possible to reduce the emissions of GHGs and criteria air pollutants using drop-in fuels. However, the uncertainties associated with the numbers and stemming from the assumptions upon which the analysis is based are significant, thus the interpretation of results must be done carefully.

Table 22: Absolute and Relative Change in Emissions from 2015 Baseline

	PRIORITIZED			CENTRALIZED		DISTRIBUTED	
Pollutant	S1a	S1b	S2	S3	S4	S5	S6
$CO_{2,e}$ (mt /yr)	-6,100,000 (-11.3%)	-2,890,000 (-5.4%)	-1,910,000 (-3.5%)	-7,010,000 (-13.0%)	-6,860,000 (-12.7%)	-7,090,000 (-13.1%)	-7,070,000 (-13.1%)
NO_x (mt /yr)	-5,200 (-6.4%)	-6,600 (-8.2%)	-7,100 (-8.8%)	-4,500 (-5.5%)	-4,000 (-5.0%)	-4,700 (-5.8%)	-4,600 (-5.7%)
PM_{10} (mt /yr)	-275 (-3.3%)	-290 (-3.3%)	-270 (-3.3%)	-290 (-3.4%)	-270 (-3.2%)	-290 (-3.5%)	-290 (-3.4%)
$PM_{2.5}$ (mt /yr)	-320 (-4.6%)	-300 (-4.3%)	-270 (-3.9%)	-350 (-5.0%)	-330 (-4.8%)	-350 (-5.0%)	-350 (-5.0%)
SO_x (mt /yr)	-5,300 (-9.2%)	-6,400 (-11.1%)	-6,900 (-12.0%)	-4,700 (-8.3%)	-4,700 (-8.2%)	-4,800 (-8.3%)	-4,700 (-8.3%)
CO (mt /yr)	-1,200 (-3.3%)	-2,400 (-7.0%)	-2,700 (-7.8%)	-900 (-2.5%)	-700 (-2.2%)	-900 (-2.6%)	-900 (-2.6%)

By adopting Scenarios S3, S4, S5, and S6, it appears that the state could reduce the well-to-pump emissions from its retail fleet by about 7 million metric tons (mt) of $CO_{2,e}$ per year, which would be a 13% reduction from the baseline. These scenarios produce the largest GHG reductions out of the scenarios considered, however, the other scenarios in the prioritized category also have mitigation potentials of 2-6 million metric tons of $CO_{2,e}$ per year scales.

A closer look at the breakdown of emissions by major modeling component (Figure 28) shows that the GHG emissions associated with fuel production dominate the total GHG footprint of each scenario. For scenarios in the centralized and distributed categories, the GHG emissions credits allocated to fuel production are achieved by offsetting electricity during fuel production. Handling GHG emissions are equal across each scenario since the optimal scale-up under each scenario utilizes all of the state's available biomass resources considered. Transportation GHG emissions amount to only a small fraction of total emissions, thereby minimizing the effects of decisions governing how or where these processes are implemented across the state. Moreover, these results suggest that selecting the best feedstock and fuel pathway combination is the most impactful decision regarding GHG mitigation. A summary of the fuel pathway emission factors for each scenario is provided in Table 23.



	S1a	S1b	S2	S3	S4	S5	S6
Fuel Production	-1.14E+06	4.62E+06	-2.62E+06	-2.62E+06	-2.62E+06	-2.62E+06	-2.62E+06
Transport	2.76E+05	3.02E+05	3.49E+05	5.01E+05	2.70E+05	2.91E+05	2.91E+05
Handling	5.66E+05	5.66E+05	5.66E+05	5.66E+05	5.66E+05	5.66E+05	5.66E+05

Figure 28: Breakdown of Well-to-Pump Greenhouse Gas Emissions by Model Component for Each Scenario

Table 23: Well-to-Pump Emission Factors

Scenario	Pathway	$CO_{2,e}$ (g/MJ)	NO_x (g/MJ)	PM_{10} (g/MJ)	$PM_{2.5}$ (g/MJ)	SO_x (g/MJ)	CO (g/MJ)
S1a	PG	21.7	0.023	0.0041	0.0034	0.0030	0.023
	PD	22.8	0.026	0.0047	0.0038	0.0034	0.026
	M2G	-11.4	0.013	0.0024	0.0014	0.0046	0.013
S1b	PG	19.5	0.012	0.0029	0.0021	0.0038	0.012
	FT	-2.30	0.030	0.0042	0.0030	0.0042	0.030
	PD	20.6	0.014	0.0032	0.0024	0.0043	0.014
S2	PG	20.0	0.014	0.0032	0.0024	0.0036	0.014
	PD	21.1	0.016	0.0036	0.0028	0.0041	0.016
S3	FT	-1.80	0.032	0.0042	0.0030	0.0044	0.032
	MT	-11.0	0.014	0.0024	0.0014	0.0047	0.014
S4	M2G	-10.2	0.017	0.0025	0.0015	0.0050	0.017
	FT	-1.20	0.033	0.0043	0.0031	0.0046	0.033
S5	M2G	-11.4	0.013	0.0024	0.0014	0.0046	0.013
	FT	-2.30	0.030	0.0042	0.0030	0.0042	0.030
S6	M2G	-11.3	0.013	0.0024	0.0014	0.0047	0.013
	FT	-2.30	0.030	0.0042	0.0030	0.0042	0.030

Due to data quality, numbers are shown to two significant digits for the criteria air pollutants and to three for GHG emissions.

The results favor drop-in fuels over their conventional counterparts (i.e., CA gasoline and low-sulfur diesel) from both GHG and criteria air emissions perspectives. Table 22 shows the extent to which particulate matter, nitrogen oxide, oxides of sulfur, and carbon monoxide emissions decrease under each scenario. However, it is important to note that because this is a well-to-tank study, these results do not capture any changes in vehicle tailpipe emissions associated with using different fuel blends. Combustion and emissions testing would be required to determine the full lifecycle emissions from the use of fuels and fuel blends.

Major Limitations and Uncertainties Associated with Scaling

Scenario analysis reveals that incentivizing the production of drop-in fuels could lead to a net reduction in GHG and criteria air pollutant emissions. These results are based on a set of input data modeling assumptions that introduce varying levels of uncertainty to the assessment. Differences exist between California biomass resources estimates across individual studies and assessment years [DOE 2011, NREL 2014, CBC 2015], which has implications on the total fuel potential as well as the optimal facility citing policies for each scenario considered. Given the state of knowledge regarding feedstock handling and transport emission factors [CARB 2015], the transportation network [Taptich and Horvath 2014, Taptich and Horvath 2015], and other energy infrastructure [EIA 2015], we believe that our emissions results for the logistics component of each scenario are robust.

That said, we were not able to assess potentially important factors governing the operation of these system in practice, such as network capacities, feedstock losses during transport, and local land use considerations (e.g., onsite storage, permitting). In addition, our facility-siting criteria were not influenced by local air quality conditions, such as whether a region is within attainment of federal or state pollutant concentration standards. Given the results of the analysis, future scenarios should consider these aspects in greater detail. Lastly, accounting for time in scale-up assessments is challenging. Our scenarios offer results for policy targets (e.g., that it is thought optimal to operate *n* number of refineries) rather than detailing the short-term means by which these targets could be hit (e.g., through construction scheduling). In light of these results, future research could explore the optimal penetration of drop-in fuel technologies on more discrete time scales, considering infrastructure lead times, the seasonality of biomass resources, and other temporal considerations that were not included in this study.

Discussion and Recommendations

Tasks 4 and 5: Identification of Research Needs and Identification of Potential Barriers

Through a critical review of existing literature and ongoing laboratory experiments, we have identified a few key challenges that are not always addressed in journal papers or reports, but should be considered as new pathways are evaluated for commercial viability.

Fuel Yield and Hydrogen Requirements

Fuel yield per unit mass of feedstock input is a clear starting point for evaluating the viability of a drop-in fuel pathway. It is critical to measure fuel yield on the basis of heating value (higher heating value or lower heating value) because volumetric and mass-based energy content can vary substantially. Oxygenated compounds such as ethanol (35% oxygen by mass), butanol (21.5% oxygen), and biodiesel (11% oxygen) have a lower energy density than pure hydrocarbons. However, maximizing yield presents a particular challenge when producing highly reduced compounds (containing little or no oxygen) from biomass. If oxygen is removed biologically, it leaves as CO_2, in which case carbon from the feedstock must be “sacrificed” along with the oxygen. If oxygen is removed by hydrodeoxygenation, it is released as H_2O and hydrogen atoms are required; this hydrogen can come from renewable or fossil sources, but if it is produced via steam reforming of methane, one fossil carbon atom is released to the atmosphere for every four atoms of hydrogen produced [Karatzos et al. 2014]. Although scientists may argue that one strategy is broadly preferable to the other, only a life-cycle GHG assessment can elucidate which option is preferable, and this is likely to vary on a case-by-case basis [Balakrishnan et al. 2015, Sreekumar et al. 2015].

For feedstocks that contain a larger-than-average lignin fraction, such as woody biomass, making use of lignin is key to achieving desirable yields. Until biological routes to lignin conversion become viable, thermochemical conversion remains the preferable option for achieving this goal. However, it should be noted that thermochemical routes are subject to the same fundamental dilemma regarding yield maximization. Our analysis showed that, although the pyrolysis pathway maximizes yield, its GHG footprint per unit of fuel output is likely to be higher than competing pathways because of the fossil energy and hydrocarbon demands. Even in this high-yield case, much of the carbon in the feedstock is lost to exhaust, either during the pyrolysis process, or through combustion of solid and gaseous waste products for on-site heat and electricity (Figure 29). Conversely, the MTG and FT pathways resulted in net electricity exports and thus net negative GHG emissions. Whether net power-producing pathways are economically favorable will depend on the price that bio-based power producers are able to command from utilities.

Figure 29: Carbon Flows for Pyrolysis Pathway

Sugar Utilization

For biological routes, utilization of both five- and six-carbon sugars is essential to achieving higher fuel yields and reducing costs. Many of the publications documenting promising pathways to hydrocarbon fuels or useful precursors focus exclusively on glucose conversion, and although this is a natural starting point, further research is required to engineer organisms to utilize all sugars available in biomass [Beller et al. 2015, Goh et al. 2012, Goh et al. 2014]. Converting five- and six-carbon sugars is necessary for achieving commercially viable fuels [Klein-Marcuschamer 2010].

Clean Sugar Stream Requirements

In addition to challenges associated with moving from glucose conversion to pathways to those that utilize glucose, xylose, arabinose, mannose, and galactose, microbial hosts must also achieve high yields, rates, and titers in hydrolysates in comparison to clean sugar streams. For the purposes of conducting reproducible experiments, much of the bench-scale research on biological pathways to drop-in fuels is based on clean, dilute glucose streams (from corn grain or sugarcane, not biomass). At cellulosic biorefineries, however, the hydrolysate delivered to the bioreactor will contain a multitude of contaminants and unconverted biomass. The hydrolysate composition will vary depending on the feedstock and pretreatment process employed. Additional research devoted to conducting further experiments with hydrolysates from a variety of pretreatment processes (ammonia fiber expansion, dilute acid pretreatment, ionic liquid pretreatment) will provide insight into how performance in clean sugar streams translates to performance in real-world biorefinery operations. For catalytic routes, extrapolating from results generated using clean sugar streams can be even more problematic. Contaminants in sugar streams can poison catalysts, rendering them ineffective.

Co-Products

Co-products can serve to either help or hinder drop-in fuel pathways, depending on their market value and potential profit margins. Distiller's dried grains with solubles (DDGS) have previously been a financially and environmentally beneficial co-product for the corn ethanol industry, although the recent price drop has made selling DDGS for animal feed less attractive. For cellulosic fuels, finding opportunities to produce high-value chemicals is likely to be vital to scaling up production, provided oil prices remain low. Specifically, identifying opportunities for utilizing lignin has been flagged as a research priority [Ragauskas et al. 2014]. Further experimental research in this area is critical. However, from an environmental perspective, it is worth noting that removing what has previously been used as a renewable fuel for generating process heat and electricity will result in higher GHG emissions for biorefineries. High electricity offset credits, particularly in the Midwest where coal-fired power plants still make up a substantial fraction of grid electricity, will be reduced if lignin is instead converted to bio-based chemicals.

Biocrude Compatibility with Petroleum Refineries

Although some companies claim to produce biocrude that is compatible with existing petroleum refineries, in practice, these oils are still blended at very low fractions. Further research to understand practical blend walls for biocrude/crude mixtures, and a deeper understanding of what retrofits must be made to enable higher blends to be processed is necessary.

Engine and System Compatibility

As discussed earlier in this report, the term “drop-in fuel” is generally confusing within the scientific community because even hydrocarbons that can be blended with gasoline, diesel, or jet fuel without issue may not be appropriate as a 100% replacement for any of those fuels. In terms of policy-making, it is important to articulate more specifically the goals of moving away from first-generation fuels such as ethanol and biodiesel, and which of these goals are of highest priority. For example, goals might include achieving higher blend walls without requiring vehicle modifications, compatibility with existing fueling infrastructure, compatibility with existing petroleum product pipelines and storage tanks, certain viscosity of blended fuels in pipelines, and higher volumetric energy content. An establishment of goals and priorities is critical because producing hydrocarbon fuels from biomass inherently comes at a cost – whether that cost is translated into lower yields or increased hydrogen requirements for hydrodeoxygenation. Conversely, there are benefits associated with blending non-drop-in fuels such as ethanol, including increased octane number and improved efficiency. Rather than simply categorizing fuels as drop-in or non-drop-in, our analysis indicates that specifying desirable characteristics of advanced fuels will likely lead to more informed decision-making.

Well-to-Wheel Criteria Air Pollutant Emissions

A crucial takeaway from our analysis is that, although thermochemical routes to drop-in fuels are likely to be the most promising in the short- and mid-term for California, these biorefineries are likely to result in varying levels of criteria air emissions reductions based on current best available technologies. Our results are conservative, and unit processes for which no emissions data exist are assumed to have zero criteria air pollutant emissions. Additionally, we do not attempt to quantify the tank-to-wheel changes in emissions resulting from a switch to bio-based fuels because sufficient engine and emissions testing data are not yet available. For these reasons, our results carry a high degree of uncertainty and further research is required to refine emissions estimates and develop complete well-to-wheel emissions factors.

Potential Production Scale

California is generally considered to be unsuitable for large-scale cultivation of dedicated bioenergy crops, in part because its arable land is too valuable to justify production of low-value agricultural products, and in part because its climate necessitates irrigation to maintain high biomass yields. For this reason, our study focused on production of fuels solely from biomass residue. As previous studies have shown, some fraction of dedicated biomass crops will be required nation-wide to achieve substantial market penetration for bio-based fuels [Scown et al. 2012]. The results indicate that it is unlikely California will ever produce enough liquid fuel to satisfy all in-state demand of gasoline, diesel, and jet fuel. In Scenario 2 of our analysis, where total fuel output is maximized, 8% of in-state gasoline demand can be displaced by bio-based hydrocarbons, and 58% of diesel can be displaced. However, if the passenger vehicle fleet is electrified, total gasoline demand should be dramatically reduced, thus allowing for a smaller total volume of biofuel to displace a larger fraction of remaining liquid fuel demand [Scown et al. 2013]. Assuming California moves toward electrifying passenger transportation, pathways that favor diesel production are particularly beneficial, since heavy-duty freight is likely to remain dependent on liquid fuels.

Task 6: Developing a Strategy to Monitor and Track Progress with Drop-In Fuels

Critically evaluating new fuel pathways under development is challenging, in part because scientific literature may contain yields achieved under idealized conditions, and companies conducting experiments under more real-world conditions typically do not make their results public. However, we have provided a set of guidelines in this report that should allow decision-makers to quickly determine whether a fuel pathway is ready for commercialization or needs further basic research before it can be scaled up.

We have documented our scenarios analyses, including three thermochemical pathways, in a wiki, freely available through github, where anyone can access the model and alter parameters to generate new results. This platform provides an opportunity for feedback and suggested changes. As these pathways develop, yields, emission factors, and other inputs can be changed to generate up-to-date results. The URL is: https://github.com/mtaptich/California-Drop-In-CAdi-Fuel-Model/tree/master/docs

Summary and Conclusions

There is a clear need to move toward fuels that can be blended at higher levels with conventional petroleum-based fuels without the need for vehicle or infrastructure retrofits if bio-based fuels are to gain a substantial market share in the near- and mid-term. Developing a firmer understanding of what blending levels are appropriate for different advanced fuels, from both thermochemical and biological routes, will be important in deciding how to prioritize research, development, deployment efforts, and funding. This requires more early-stage research and engine and emissions testing of new fuels, which can be challenging for pathways where researchers are not yet making sufficient quantities to facilitate such testing.

In terms of pathways that are most promising in the near- and mid-term in California, we found that thermochemical pathways, including pyrolysis, Fischer-Tropsch, and methanol-to-gasoline remain the most likely candidates for deployment, despite advances in biological and hybrid biological/catalytic fuel production pathways. The reasons for this are twofold: 1) California's waste biomass supply is dominated by woody biomass, although herbaceous crop residues make up a non-negligible fraction, and the relatively high lignin content in woody biomass makes biological pathways less attractive; 2) Biological or hybrid biological/catalytic pathways to hydrocarbon fuels frequently suffer from low yields, and may only utilize glucose, meaning five-carbon sugars derived from hemicelluloses are not converted. Although further research may make biological or biological/catalytic pathways more attractive than the more-mature thermochemical pathways, more research is required to further develop them.

In terms of environmental impacts, all three pathways appear able to achieve GHG and criteria air emission reductions relative to conventional petroleum-based fuels, and if hydrogen can be derived from renewable sources for the pyrolysis pathway, its GHG footprint can be further reduced. Water use for all pathways is relatively minimal, although pyrolysis does use an amount of water close to typical cellulosic ethanol facilities – nearly 5 liters of water per liter of fuel produced. The MTG pathway uses approximately half that, and the FT facility has net-negative water use because of its electricity exports. However, it is important to keep in mind that the results are uncertain because of missing data from certain unit processes, potential variations in energy systems configurations at biorefineries (e.g., exporting char for other uses and using natural gas for heat and power, or obtaining hydrogen from renewable sources rather than natural gas reforming). Further engine and emissions testing is needed to determine whether fuels derived from these three pathways alter engine efficiency or emissions in any way.

Regarding scale, the drop-in fuel pathways are likely to achieve relatively high market penetration in California's diesel market (as much as 58%), but lower penetration in the gasoline market (8%). This means that any decarbonization strategy for transportation must either include large-volume biofuel imports from other states or electrification of the state's passenger transportation fleet. In fact, the higher likelihood that advanced biofuel pathways will produce suitable diesel or jet fuel replacements means that such a strategy would be complementary to an electrification strategy, assuming that heavy-duty freight and air travel are less likely to be electrified without major improvements in battery technologies.

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APPENDIX A

Tables A1 – A3 detail the mass flows of each stream in the process flow diagrams (PFD) (Figures 6-8) found in the main text. In each of the tables, the steam number listed in each row corresponds to the process number indicated in its respective PFD. Each process was modeled by U.S. Department of Energy-funded studies and assumes a plant capacity capable of handling a feedstock input rate of 2,000 metric tons of biomass per day.

Table A1: Pyrolysis Stream Table (primary data source: PNNL 2013)

Stream number corresponds to mass flow in Figure 6

Stream Number	Stream Name	Mass Flow
		kg/h
1	Wet BM	1200
2	Flue Gas	
3	Exhaust	
4	Dry BM	1000
5	Ground Dry BM	1000
6	Hot Sand	
7	Light Gases	
8	Off-Gas (to IX)	
9	Fluidizing Gas	3000
10	Pyrolysis Vapors	
11	Char	120
12	Flue Gas	
13	Make-Up Gas	
14	Off-Gas (to IX)	120
15	Char (to IV)	
16	Rxn Water	120
17	Solid Waste	20
18	Pyrolysis Oil	620
19	MoS2 or CoMo Catalyst	
20	Steam	
21	Off-Gas	
22	H2	174
23	Make-Up NG	
24	Water	
25	Hydrotreated Oil	422
26	H2	57
27	Solid Acid Catalyst	
28	Steam	
29	Fuel Blendstock	260

Table A2: FT Stream Table (primary data source: Swanson 2010)

Stream number corresponds to mass flow in Figure 7

Stream Number	Name on PFD	Mass Flow	Temp	Pressure
		Metric ton	*°C*	*bar*
1	Wet BM (corn stover)	1.2	25	1.01
2	Steam	1.8	200	1.98
3	Water	0.20	120	1.98
4	Dry BM	1.0	90	1.01
5	Dry Ground BM			
6	O2	0.33	149	28
7	Air Intake			
8	N2			
9	Ash	0.05	50	26.62
10	Raw Syngas	1.7	1300	26.62
11	Water	1.8	203	26.62
12	WW	0.68	40	24.82
13	Quenched Syngas	1.7	203	25.93
14	Steam	0.25	190	10
15	SWGS Syngas	1.3		
15a	Monoethanolamine			
15b	LO-CAT Chemicals			
16	CO2	0.11	180	28
17	Sulfur	0.0014	50	3.45
18	Clean Syngas	1.6	76	26
19	H2	0.002	30	25
20	Adjusted Syngas	1.6		
21	Co Catalyst			
22	Unconverted Syngas	0.07	45	23.6
23	Fuel Mixture	0.48	42	23.6
24	Water	0.29	35	22.2
25	Light Gases	0.023	35	22.2
26	Distillate Blendstock	0.17	37	1.03

Table A3: MTG Stream Table (primary data source: PNNL 2009)

Stream number corresponds to mass flow in Figure 8

Stream Number	Stream Name	Mass Flow	Temp	Pressure
		kg	°C	bar
1	Wet BM	1710	15	1.7
2	Flue gas	30	15	6.2
3	Dry BM	1000	110	23
4	Dry, ground BM			
5	O2	0		
6	Air Intake			
7	N2			
8	Steam	0		
9	Raw Gas	1410	870	23
10	Char			
11	Catalyst			
12	Scrubbed Syngas	1350	750	23
13	Steam	84	380	31
14	CO2	654	49	29
15	Clean Syngas	630	49	29
16	Steam			
17	Adjusted Syngas			
18	Zno/CuO Catalyst			
19	Off-Gas			
20	MeOH	446	44	29
21	H2	0.28	43	57
22	Off-Gas			
23	ZSM-5 Catalyst			
24	Raw Gasoline	140	370	21
25	LPG	35	48	7.6
26	Fuel Gas			
27	Gasoline	140	71	1.7

Table A4: Pyrolysis Energy Demands Study Comparison

	Iribarren 2012		NREL 2012		PNNL 2013	
Type of Energy	Electricity	Thermal Energy	Electricity	Thermal Energy	Electricity	Thermal Energy
Unit / ton dry biomass	kWh	MJ	kWh	MJ	kWh	MJ
Total Energy Demand	194	0.4	192	6,300	121	2,180
Disaggregated by Unit Process						
Pre-treatment	90					
Pyrolysis	73	0.4	94	3,390		
Hydrotreating	8					
Hydrocracking and Distillation	11		9	2,910		
Steam Reforming	12					

Table A5: FT Energy Demands (primary data source: Swanson 2010)

Unit Process	Energy, MJ / ton dry Biomass
Power Usage	
Pre-processing	-150
Gasification	-8.6
Syngas Cleaning	-180
Fuel Synthesis (FT)	-22
Hydroprocessing	-95
Air Separation Unit	-500
Total Power Consumption	955
Power Generation	
Gas Turbine	1,100
Steam Turbine	410
Net Power Generation	600

Table A6: MTG Energy Demands (primary data source: PNNL 2009)

Unit Process	Energy, MJ / ton dry Biomass
Power Consumption	
Air separations unit	-370
Lock hopper gas compressor	-8.6
Dryer air blower	-4.3
Char burner air compressor	-22
Syngas compressor	-82
Reformer air compressor	-78
Reformer flue gas blower	-26
Clean syngas compressor	-200
Methanol synthesis recycle compressor	-104
MTG recycle and H2 compressor	-160
Total Power Consumption	-1,000
Power Generation	
Steam turbines	2,400
Net power	1,400

APPENDIX B

Table B1: Biomass Inventory.

		Metric tons per year (2013)				
County	Fips	cropres	forestres	primmill	secmill	urbanwood
Alameda	6001	3750	8100	300	30867	113880
Alpine	6003	0	17900	14700	0	161
Amador	6005	4100	112600	30500	1594	2881
Butte	6007	392050	214600	79900	7686.7	17547
Calaveras	6009	1300	194400	55900	0	4958
Colusa	6011	596390	52800	5500	114.31	1702
Contra Costa	6013	56880	5000	100	10162	95039
Del Norte	6015	0	111400	46000	0	1702
El Dorado	6017	3000	370200	175100	654.1	13969
Fresno	6019	574620	149900	109200	14117	68501
Glenn	6021	403900	43700	16700	285.77	2225
Humboldt	6023	0	1037700	275800	4442.6	8355
Imperial	6025	239960	142400	0	228.62	25949
Inyo	6027	230	129500	5800	114.31	2365
Kern	6029	384900	215100	16900	6372.2	80186
Kings	6031	327740	1000	0	1736.4	8542
Lake	6033	13020	227600	37500	457.23	3799
Lassen	6035	9810	513300	173100	57.154	1782
Los Angeles	6037	990	119300	5900	179120	971118
Madera	6039	162510	118200	75300	1306.4	12335
Marin	6041	160	23900	2000	2993.8	18586
Mariposa	6043	100	133700	27800	57.154	1548
Mendocino	6045	17090	1021700	220500	5460.4	5568
Merced	6047	291370	2500	0	596.94	23122
Modoc	6049	21400	324600	101100	57.154	542
Mono	6051	190	76000	26000	0	3216
Monterey	6053	54670	93200	2400	3359.4	33520
Napa	6055	39870	123100	8200	8258.3	16657
Nevada	6057	390	226700	82300	2250.8	6814
Orange	6059	40	9900	200	64826	486440
Placer	6061	51050	167200	85100	8251.9	24087
Plumas	6063	0	375100	291700	114.31	1628
Riverside	6065	80980	225900	2800	35416	182166
Sacramento	6067	193810	700	0	34059	127260
San Benito	6069	6350	40900	1600	2363.3	5347
San Bernardino	6071	2370	622500	17000	67535	164908
San Diego	6073	26080	244900	5600	41599	367374
San Francisco	6075	0	0	0	6510.2	54089
San Joaquin	6077	510650	2300	100	24186	60903
San Luis Obispo	6079	47370	118600	3800	1676.5	30104
San Mateo	6081	980	28300	9000	5214.6	65914
Santa Barbara	6083	31920	78900	4000	3838.4	38867
Santa Clara	6085	9020	67900	4400	20636	120406
Santa Cruz	6087	2960	75700	23200	6088.3	15946
Shasta	6089	17850	663200	234600	3303.1	16174
Sierra	6091	0	108000	85200	0	235
Siskiyou	6093	51190	732700	358300	4899.8	2714
Solano	6095	106030	3000	100	3381.1	46263
Sonoma	6097	57750	293200	45200	14425	32327
Stanislaus	6099	163510	11600	400	13603	22371
Sutter	6101	478170	0	0	2109.2	6352
Tehama	6103	39410	246100	89400	7407.3	4482
Trinity	6105	110	516300	223000	114.31	844
Tulare	6107	361460	117800	82200	8827.1	32361
Tuolumne	6109	190	228000	135200	2788.7	3638
Ventura	6111	28010	30000	4200	11128	84152
Yolo	6113	424090	22300	200	5091.3	18372
Yuba	6115	133490	95800	27800	3698.7	6352

Table B2: Details on the refinery locations considered in this study.

Refinery id	County	Facility Type	FIPS	Long	Lat
1	Riverside	biodiesel	6065	-116.1581	33.6577
2	San Diego	biodiesel	6073	-117.1398	32.6952
3	Santa Cruz	biodiesel	6087	-121.7701	36.9048
4	Santa Clara	biodiesel	6085	-121.9187	37.3449
5	San Joaquin	biodiesel	6077	-121.366	37.9561
6	Kern	biodiesel	6029	-119.1616	35.1782
7	Plumas	biodiesel	6063	-120.1435	39.7981
8	Butte	biodiesel	6007	-121.8191	39.7045
9	Merced	drop-in	6047	-120.634717	36.98481016
10	Fresno	drop-in	6019	-120.0590433	36.72290972
11	Merced	drop-in	6047	-120.8343318	37.06573296
12	Mono	drop-in	6051	-118.98177	37.64877
13	Inyo	drop-in	6027	-118.3946638	37.36639252
14	Madera	drop-in	6039	-120.2655373	37.11758506
15	Tuolumne	drop-in	6109	-120.3820715	37.98515469
16	El Dorado	drop-in	6017	-119.9803249	38.92893943
17	Tulare	drop-in	6107	-119.0320865	36.06610842
18	Kern	drop-in	6029	-117.9587072	35.12614135
19	San Luis Obispo	drop-in	6079	-120.8565612	35.38594723
20	Calaveras	drop-in	6009	-120.5468661	38.07639709
21	Plumas	drop-in	6063	-120.4716784	39.80955451
22	El Dorado	drop-in	6017	-120.7971454	38.73026553
23	Lassen	drop-in	6035	-120.5084	40.37714
24	Placer	drop-in	6061	-120.94991	39.09604
25	Modoc	drop-in	6049	-120.549604	41.49434509
26	Placer	drop-in	6061	-121.0732964	38.89832898
27	Contra Costa	drop-in	6013	-121.6957634	37.99045528
28	Sacramento	drop-in	6067	-121.1441971	38.66747402
29	Siskiyou	drop-in	6093	-122.6364841	41.72662537
30	Sutter	drop-in	6101	-121.6335133	39.13244901
31	Sacramento	drop-in	6067	-121.4498449	38.56334196
32	Yolo	drop-in	6113	-121.7418472	38.55562036
33	Butte	drop-in	6007	-121.6050966	39.7604676
34	San Bernardino	drop-in	6071	-116.4312739	34.12059336
35	Humboldt	drop-in	6023	-124.1598704	40.78879861
36	Shasta	drop-in	6089	-122.3759755	40.58655007
37	Mendocino	drop-in	6045	-123.2051047	39.14379378
38	Nevada	drop-in	6057	-120.1718922	39.35395137
39	Santa Barbara	drop-in	6083	-120.4620747	34.66074741
41	Los Angeles	drop-in	6037	-118.1567169	34.70402337
42	Monterey	drop-in	6053	-121.1270797	36.2118052
43	Monterey	drop-in	6053	-121.2449627	36.32417692
44	Fresno	drop-in	6019	-120.3534548	36.15124828
45	Fresno	drop-in	6019	-120.0965	36.55936
46	Fresno	etoh	6019	-120.078744	36.342619
47	Tulare	etoh	6107	-119.4268	36.35782
48	Tulare	etoh	6107	-119.302643	36.001466
49	Imperial	etoh	6025	-115.519294	32.913497
50	Imperial	etoh	6025	-115.430622	33.041511
51	Madera	etoh	6039	-119.974893	36.922085
52	San Joaquin	etoh	6077	-121.339606	37.94182
53	San Bernardino	etoh	6071	-117.537425	34.098353
54	Santa Cruz	etoh	6087	-121.803	36.948056
55	San Luis Obispo	etoh	6079	-120.631467	35.662383
56	Stanislaus	etoh	6099	-120.91539	37.55245
57	Sonoma	etoh	6097	-122.851065	38.423286
58	Kern	petroleum	6029	-118.9869709	35.4394919
59	Los Angeles	petroleum	6037	-118.2366773	33.81857758
60	Los Angeles	petroleum	6037	-118.410994	33.91142239
61	Contra Costa	petroleum	6013	-122.3986654	37.94977952
62	Contra Costa	petroleum	6013	-122.2556323	38.04347369
63	Los Angeles	petroleum	6037	-118.2434726	33.81085594
64	Los Angeles	petroleum	6037	-118.3323174	33.85320784
65	Santa Barbara	petroleum	6083	-120.5110799	34.93019131
66	Kern	petroleum	6029	-118.9179525	35.29471943
67	Los Angeles	petroleum	6037	-118.1666469	33.9463723
68	Los Angeles	petroleum	6037	-118.1466266	33.89955124
69	Kern	petroleum	6029	-119.0479216	35.38733029
70	Contra Costa	petroleum	6013	-122.1110171	38.01995188
71	Contra Costa	petroleum	6013	-122.0639052	38.02302629
72	Los Angeles	petroleum	6037	-118.2312293	33.80108934
73	Solano	petroleum	6095	-122.1383191	38.07200664
74	Los Angeles	petroleum	6037	-118.2368612	33.79830058
75	Los Angeles	petroleum	6037	-118.2336629	33.77905473

Table B3: Final terminals considered with accompanying fuel storage capacities.

Term. id	County	FIPS	Diesel Capacity (10^6 gal / year)	Gasoline Cap. (10^6 gal / year)	Long	Lat
1	Los Angeles	6037	0.002515596	0.035579186	-118.238694	33.791408
2	San Joaquin	6077	14.19423807	47.13351809	-121.334348	37.941952
3	San Bernardino	6071	1.572154416	7.342295622	-117.370231	34.058107
4	Los Angeles	6037	8.410993461	118.9604034	-118.164018	33.953004
5	San Diego	6073	4.145772266	71.54258356	-117.141032	32.693753
6	Los Angeles	6037	2.111818075	29.86837777	-118.158469	33.80163
7	Los Angeles	6037	0.125582492	1.776168772	-118.215598	33.779647
8	Los Angeles	6037	10.90363403	160.9245513	-118.159912	33.8619
9	Los Angeles	6037	0.364539438	5.15584262	-118.215598	33.779647
10	Los Angeles	6037	2.825408772	39.96100685	-118.262119	33.83161
11	Los Angeles	6037	19.72424468	278.9687229	-118.418697	33.916346
12	San Diego	6073	15.55288288	268.3923168	-117.140205	32.693189
13	Los Angeles	6037	24.31974509	343.9649193	-118.46804	34.179382
14	Orange	6059	12.47121622	367.3586517	-117.999913	33.703025
15	Los Angeles	6037	39.82269658	563.2300242	-118.122139	34.006183
16	San Joaquin	6077	98.31776079	352.6208567	-121.348869	37.751423
17	Santa Clara	6085	53.68346908	689.7267973	-121.884916	37.364626
18	Sacramento	6067	6.470314038	113.2304957	-121.512485	38.568612
19	Contra Costa	6013	7.658436428	153.8852403	-122.05744	38.008487
20	Humboldt	6023	25.80188521	82.44985916	-124.194044	40.776818
21	Contra Costa	6013	16.65822549	256.7894082	-122.387766	37.928277
22	Contra Costa	6013	8.346960261	132.0895238	-122.368592	37.913015
23	San Bernardino	6071	90.00228523	504.2797134	-117.47941	34.06293
24	San Joaquin	6077	13.92878401	49.26584206	-121.291294	37.950372
25	Yolo	6113	32.5441106	97.27074336	-121.522145	38.569586
27	Los Angeles	6037	0.982266201	13.89262566	-118.225974	33.805531
28	Kern	6029	21.02116568	119.8840154	-119.323665	35.277551
29	Los Angeles	6037	13.24944618	187.3927818	-118.2784	33.908921
30	San Bernardino	6071	75.5427463	352.8006981	-117.366543	34.063189
31	Sacramento	6067	1.807814483	29.33053978	-121.514597	38.567564
33	Los Angeles	6037	3.79943763	53.73712811	-118.288897	33.777221
34	Kern	6029	25.00485844	236.6316831	-119.9566	35.6448
35	Kern	6029	51.52985752	134.8477195	-119.05425	35.398611
36	Placer	6061	37.10038219	419.2915179	-121.31576	38.81067
37	Los Angeles	6037	44.58908487	630.6431635	-118.222434	34.008941
38	Orange	6059	33.10427649	441.6882365	-117.837087	33.86608
39	Contra Costa	6013	1.488467753	31.18339942	-122.368832	37.925251
40	San Mateo	6081	21.8482941	558.2344461	-122.398775	37.692517
41	Butte	6007	94.22476588	261.4305384	-121.811684	39.707342
42	Fresno	6019	114.2629733	566.9226101	-119.74571	36.674827
43	San Diego	6073	53.60881193	920.523647	-117.117762	32.786951
44	Orange	6059	26.81553124	776.9092012	-117.867108	33.80958
45	Santa Clara	6085	12.47573867	280.4676928	-121.911811	37.391616
46	Sacramento	6067	13.88573357	224.6415583	-121.33638	38.572158
47	Imperial	6025	17.4148275	130.1318745	-115.564909	32.825592
48	San Bernardino	6071	2.11515595	9.878228318	-117.370231	34.058719
49	San Bernardino	6071	21.68807294	84.61279582	-116.887039	34.88147
52	San Joaquin	6077	3.625480938	10.840188	-121.333544	37.941219
53	Contra Costa	6013	13.37482039	234.5695717	-121.919984	38.029594
54	Contra Costa	6013	20.93440247	222.5076298	-122.241231	38.053037
55	Los Angeles	6037	0.025871177	0.36590751	-118.264432	33.761004
56	Los Angeles	6037	3.582997734	50.67592286	-118.293468	33.764288
57	Contra Costa	6013	3.090642207	58.3718764	-122.364834	37.92121
58	Contra Costa	6013	3.7551529	51.53861972	-122.095967	38.027444
59	Yolo	6113	4.273699816	50.24403503	-121.521163	38.570612
60	Santa Clara	6085	15.60174568	256.0326852	-121.908975	37.39443
61	San Joaquin	6077	42.45899074	144.0089204	-121.290754	37.95368
62	Los Angeles	6037	0.39438131	5.577909433	-118.239367	33.791409
63	San Bernardino	6071	90.82434196	711.3348012	-117.363011	34.024029
64	Los Angeles	6037	72.84043479	874.5431861	-118.474914	34.218438
65	Los Angeles	6037	5.268412182	94.54754137	-118.15139	33.800611
66	Contra Costa	6013	2.480389683	42.11989376	-122.11763	38.025233
67	Los Angeles	6037	0.941745378	13.31952171	-118.236689	33.839512
68	Sacramento	6067	9.152175198	123.5878036	-121.358782	38.381111
69	Kern	6029	86.16224307	195.0205154	-119.0464	35.395118
70	Los Angeles	6037	6.22225241	88.00406995	-118.22289	33.90761
71	Los Angeles	6037	0.357658543	5.058523082	-118.259123	33.765992
73	Los Angeles	6037	1.585935223	22.43058384	-118.210779	33.77398

Glossary of Terms, Abbreviations, and Symbols

Acronyms

CO	Carbon monoxide
DDGS	Distiller's dried grains with solubles
EGU	Electricity-Generating Unit
FT	Fischer-Tropsch
GHG	Greenhouse gases
GGE	Gallons of gasoline equivalent
IRR	Internal rate of return
MT	Metric ton
MTG	Methanol-to-Gasoline
NO_x	Nitrogen oxides
O_3	Ozone
Pb	Lead
PFD	Process flow diagram
PM	Particulate matter
ROI	Return on investment
SO_x	Sulfur oxides