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Advanced Fuel Production Technology Market Assessment

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PREFACE

Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) created the Clean Transportation Program. The statute authorizes the California Energy Commission (CEC) to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change policies. Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) reauthorizes the Clean Transportation Program through January 1, 2024, and specifies that the CEC allocate up to $20 million per year (or up to 20 percent of each fiscal year's funds) in funding for hydrogen station development until at least 100 stations are operational.

The Clean Transportation Program has an annual budget of about $100 million and provides financial support for projects that:

- Reduce California's use and dependence on petroleum transportation fuels and increase the use of alternative and renewable fuels and advanced vehicle technologies.
- Produce sustainable alternative and renewable low-carbon fuels in California.
- Expand alternative fueling infrastructure and fueling stations.
- Improve the efficiency, performance and market viability of alternative light-, medium-, and heavy-duty vehicle technologies.
- Retrofit medium- and heavy-duty on-road and nonroad vehicle fleets to alternative technologies or fuel use.
- Expand the alternative fueling infrastructure available to existing fleets, public transit, and transportation corridors.
- Establish workforce-training programs and conduct public outreach on the benefits of alternative transportation fuels and vehicle technologies.

To be eligible for funding under the Clean Transportation Program, a project must be consistent with the CEC's annual Clean Transportation Program Investment Plan Update. The CEC issued contract 600-11-002, on September 13, 2012, to provide program support on specific Clean transportation Program topics, including a technical and market assessment of advanced vehicle technologies.

ABSTRACT

This report presents an assessment of the technology status and market potential for advanced fuel production technologies in California. The information is intended to guide the planning, implementation, and evaluation of the Clean Transportation Program. The purpose of this report is to provide a body of knowledge from which the CEC can base its decisions and efforts to further a sustainable and economically stimulating biofuels industry. The report examines the policy-driven efforts and impacts to nurture the biofuels industry; it assesses the feedstock availability and the biofuels production technologies available within the marketplace, including their environmental impacts; and it captures challenges of the biofuels industry. Conventional biofuels are commercial today, providing 14–16 billion gallons of biomass-based fuels. A challenge arises in expanding the fuel production while increasing economic and environmental benefits. Cellulosic, advanced, and drop-in biofuels are active areas of interest for accomplishing these goals. In expanding cellulosic, advanced, and drop-in biofuels, significant growth is occurring in both the biochemical and thermochemical biofuels production processes. Developments and improvements are being made from microbes to catalysts, and fuel quality to compatibility. The potential of biofuels is being approached one advancement at a time through steady efforts, strong research, and policy-driven support.

Keywords: Advanced fuel production; ethanol; biodiesel; gasoline substitute; drop-in biofuel; feedstock; renewable fuel; market assessment; renewable natural gas; renewable hydrogen; biomass.

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EXECUTIVE SUMMARY

California seeks to lead the nation in the effort to reduce fossil fuel consumption and to protect the environment by creating local jobs, diversifying energy markets, and reducing greenhouse gas emissions. Production of biofuels is a promising area in achieving these important goals. According to the Energy Independence and Security Act of 2007, biofuels reduce greenhouse gas emissions by approximately 20–60 percent compared to gasoline. It is estimated that more than 401,000 U.S. jobs were created by the ethanol industry across the economy in 2011. The advanced biofuel facilities now scheduled for construction could create up to 47,000 jobs by 2016, and the potential exists for one to nearly two million jobs to be added across the U.S. economy in the next 12 to 18 years if current production mandates are met.

This report was completed by the National Renewable Energy Laboratory in order to fulfill the Clean Transportation Program goal of helping to attain the state's climate change policy objectives. National Renewable Energy Laboratory's support project for the CEC's Clean Transportation Program includes analysis and reports in the areas of advanced vehicles, fueling infrastructure, advanced fuel production, consumer and investor behavior, plug-in vehicle planning, program benefits, and market impact assessment. This report covers the topic of advanced fuel production.

The purpose of this report is to provide a body of knowledge from which the CEC can base its decisions and efforts to further a sustainable and economically stimulating biofuels industry. The report examines the policy-driven efforts and impacts to nurture the biofuels industry; it assesses the feedstock availability and the biofuels production technologies available within the marketplace, including their environmental impacts; and it captures challenges of the biofuels industry.

Conventional biofuels are commercial today, providing 14–16 billion gallons of biomass-based fuels. A challenge arises in expanding the fuel production while increasing economic and environmental benefits. Cellulosic, advanced, and drop-in biofuels are active areas of interest for accomplishing these goals. Cellulosic biofuels are derived from any cellulose, hemicellulose, or lignin that is derived from renewable sources that have lifecycle greenhouse gas emissions of at least 60 percent less than baseline. Advanced biofuels are renewable fuels, other than ethanol derived from corn starch, that have lifecycle greenhouse gas emissions of at least 50 percent less than baseline. Drop-in biofuels are hydrocarbons substantially similar and intended to be functionally equivalent to gasoline, diesel, and aviation fuel because of their compatibility with current vehicles and infrastructure.

In expanding cellulosic, advanced, and drop-in biofuels, significant growth is occurring in both the biochemical and thermochemical biofuels production processes. Developments and improvements are being made from microbes to catalysts, and fuel quality to compatibility. The potential of biofuels is being approached one advancement at a time through steady efforts, strong research, and policy-driven support.

CHAPTER 1: Introduction

This report presents an assessment of the technology status and market potential for advanced fuel production technologies in California. The information is intended to guide the CEC in the planning, implementation, and evaluation of the Clean Transportation Program.

Organization of this Report

The report is organized into six chapters, including this Introduction. Chapter 2 discusses the role of government regulations and incentives in advanced fuel production. Chapter 3 describes three categories of feedstocks that can be converted to advanced fuels: lignocellulosic biomass; fats, oils, and greases; and biogas. Chapter 4 details the process conversion technologies, current production facilities, and market potential for four advanced fuel types: advanced ethanol and gasoline substitutes; advanced diesel substitutes; renewable natural gas or biomethane; and renewable hydrogen. Chapter 5 discusses several emerging technologies not yet funded by the CEC and includes a review of life-cycle assessment literature for biofuels. Chapter 6 provides a summary of woody biomass conversion technologies and fuel products. Appendix A lists current active biofuel companies.

CHAPTER 2: Role of Government Regulations and Incentives in Advanced Fuel Production

This chapter reviews government regulations and subsidies affecting advanced fuel production in California and includes a gap analysis to identify where funds or resources are being provided to specific fuel production technologies.

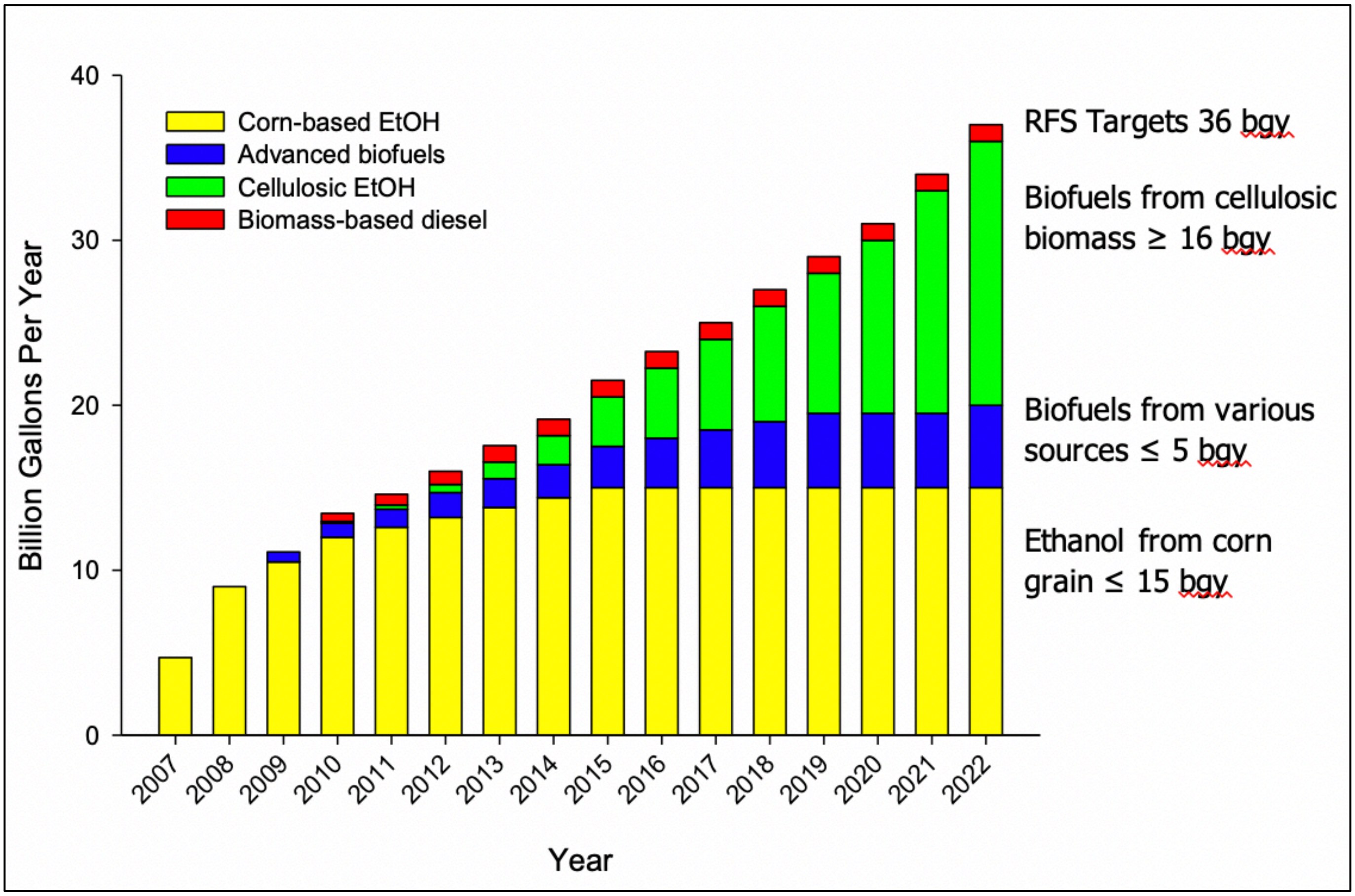
Government Regulations

Federal and state policies have the potential to foster accelerated growth in the renewable fuels markets; policies can also inhibit growth. This section explores the role of government regulations on influencing the future market growth potential of renewable fuels, highlighting the federal Renewable Fuels Standard and California's Low Carbon Fuel Standard and Emissions Trading Program (Assembly Bill 32).

Renewable Fuels Standard: The federal Renewable Fuels Standard (RFS) was first established in 2005 and expanded in the Energy Independence and Security Act of 2007. The expanded program is referred to as RFS2. RFS2 mandated an expansion of renewable fuel production from 9 billion gallons in 2008 to 36 billion gallons in 2022 (Figure 1). The United States Environmental Protection Agency (U.S. EPA) is tasked with setting the biofuels standards on an annual basis; in recent years, the cellulosic biofuels targets have been a focus of debate because the technology has not developed as assumed. U.S. EPA is allowed under the Energy Independence and Security Act to reduce targets, and has done so in 2010, 2011, and 2012. The 2013 cellulosic biofuel targets are currently under consideration at U.S. EPA; the 2013 comment period ended in April 2013, though the Energy Independence and Security Act directs U.S. EPA to issue standards before the beginning of the compliance year. In addition to increasing the targets for renewable fuel, RFS2 required that lifecycle emissions of advanced biofuels and biomass-based diesel be at least 50 percent less than the baseline lifecycle greenhouse gas emissions for gasoline and diesel, to be determined by U.S. EPA percent reduction in lifecycle greenhouse gas emissions and cellulosic biofuel must achieve at least a 50 percent reduction.[1]

[1] Energy Independence and Security Act of 2007 http://www.gpo.gov/fdsys/pkg/BILLS-110hr6enr/pdf/BILLS-110hr6enr.pdf

Figure 1: Energy Independence and Security Act Mandated Renewable Fuel Volumes



Source: National Renewable Energy Laboratory (NREL)

Low Carbon Fuel Standard (LCFS): California's LCFS requires a 10 percent reduction in the carbon intensity of transportation fuels by 2020[2]. The LCFS was established by executive order in 2007 and the first compliance year was 2011 (Figure 2). Unlike the RFS, the LCFS mechanism is based on a reduction in carbon intensity; as such, in addition to biofuels, compressed natural gas, electricity, and hydrogen fuels are eligible to contribute.

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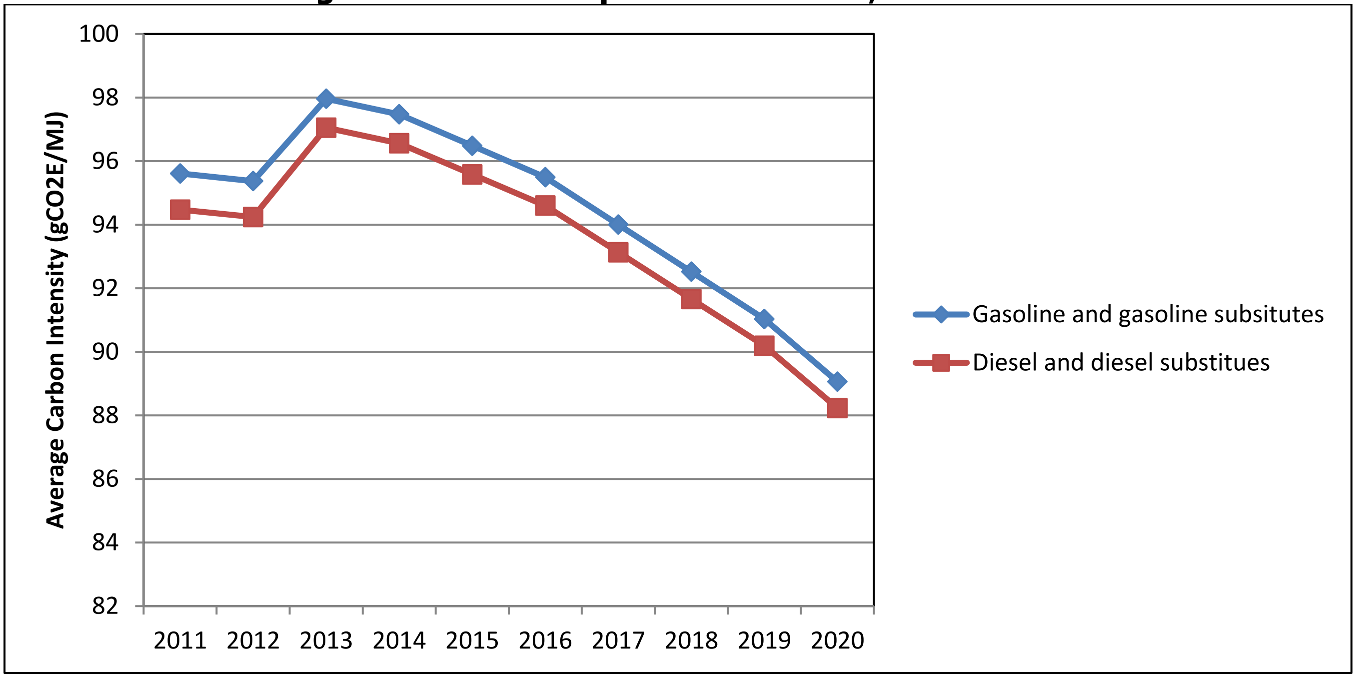
[2] ARB. Low Carbon Fuel Standard Regulation, Final Regulation Order. California Air Resources Board. https://ww3.arb.ca.gov/regact/2011/lcfs2011/lcfs2011.htm

Figure 2: LCFS Compliance Schedule, 2011-2020



Source: NREL

California's Emissions Trading Program ("AB32" or "Cap and Trade"), established in response to AB32, requires greenhouse gas emissions to be reduced to 1990 levels by 2020. The program regulates upstream emitters, including electric utilities and large industrial facilities, as well as distributors of transportation, natural gas, and other fuels. Electric utilities and large industrial facilities begin compliance in 2013, while fuel distributors begin compliance in 2015.

While the program has large goals for reducing greenhouse gas (GHG) emissions, the impact on the transportation sector is expected to be limited. This is because of the price ceiling of $70/ton of carbon, which translates to $0.70 per gallon of gasoline.[3] That is "not enough to motivate oil companies to switch to alternative fuels or to induce consumers to significantly reduce their oil consumption, but it is still important to establish the principle of placing a price on carbon."[3]

[3] Sperling, D., and Nichols, M. 2012. "California's Pioneering Transportation Strategy." Issues in Science and Technology. Winter 2012. p. 59-66. Equates to a conversion factor of 10,000 grams CO_2 per gallon.

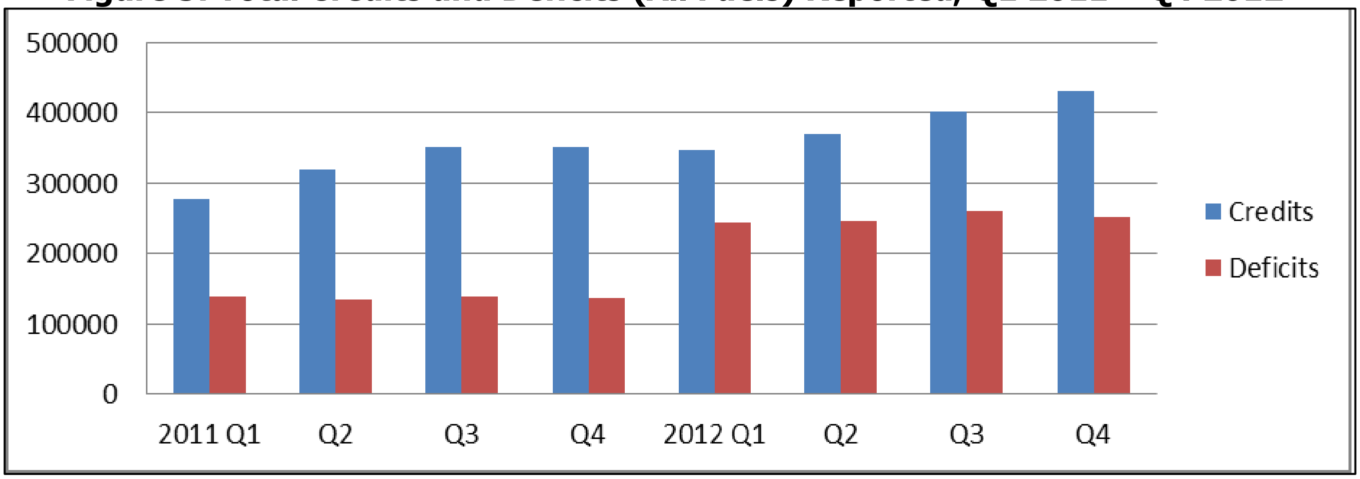
Policy Impacts

Policy effectiveness can in part be measured by whether policy targets were achieved. This section explores policy impacts from the RFS2 and the LCFS.

In the case of the RFS2, the largest gap has been with the cellulosic biofuel targets. U.S. EPA is allowed to adjust the targets on an annual basis and reduced the cellulosic biofuel target substantially for 2012—from 500 million gallons to 8.65 million gallons. Actual production was only about 20,000 gallons. Further, in January 2013, the U.S. Court of Appeals for the DC Circuit vacated the 2012 cellulosic biofuel requirements, remanding the rule to U.S. EPA; U.S. EPA has not yet taken further action.[4]

In California, the LCFS targets are being achieved, as measured by the surplus of credits in recent quarters (Figure 3). In 2011 and 2012, enough excess credits were generated to fulfill the projected 2013 obligation.[5]

Figure 3: Total Credits and Deficits (All Fuels) Reported, Q1 2011 – Q4 2012



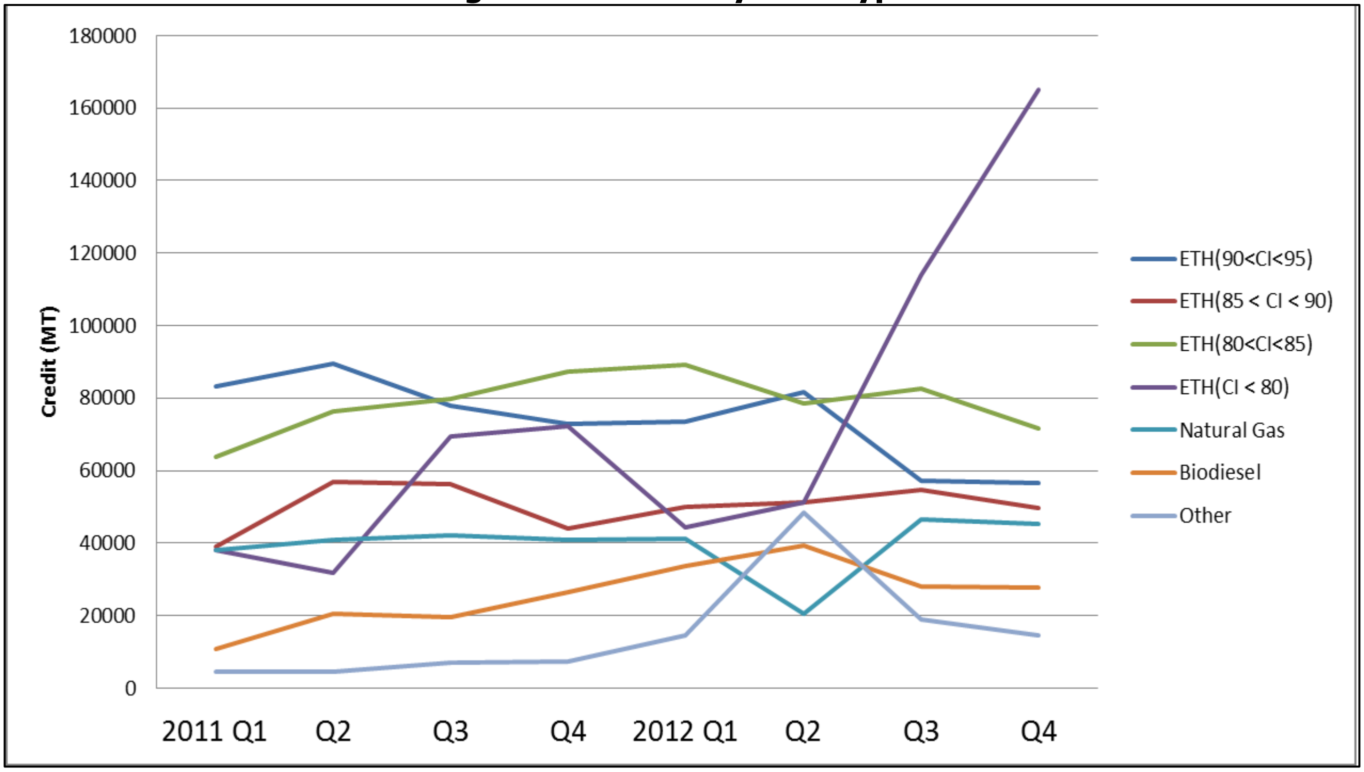
Source: ARB

Ethanol has remained the largest provider of LCFS credits since the standard was implemented in 2011 (see Figure 4). Additional sources have included natural gas, biodiesel, and "other," which includes electricity and renewable diesel.

[4] In American Petroleum Institute vs. U.S. EPA, the Court found that U.S. EPA's methodology for projecting cellulosic biofuels "did not take neutral aim at accuracy, [and] it was an unreasonable exercise of agency discretion."
http://www.cadc.uscourts.gov/internet/opinions.nsf/A57AB46B228054BD85257AFE00556B45/$file/12-1139-1417101.pdf

[5] ARB. "2012 LCFS Reporting Tool (LRT) Quarterly Data Summary – Report No. 4." California Air Resources Board
https://ww2.arb.ca.gov/sites/default/files/classic//fuels/lcfs/dashboard/quarterlysummary/20130329_q4datasummary.pdf

Figure 4: Credits by Fuel Type



Source: ARB

Credit prices for LCFS have ranged from $10/MT to $36/MT, according to CARB. In 2012, there were 32 trades, ranging in price from $10-$31/MT. In the first quarter of 2013, there were 13 trades, ranging from $25-$36/MT.[5]

Additional Considerations

In addition to the compliance status, other elements can influence the success of a policy.

Renewable Fuels Standard- The RFS2 has faced serious challenges from industry and others. The target has been deemed too high by critics, who petition U.S. EPA to lower the targets. There is considerable policy uncertainty due to U.S. EPA's ability to adjust annual targets and the actions of industry to advocate for repealing the policy entirely.

Fraud in the Renewable Identification Number (RIN) market has also undermined the RFS2 program. In response to the fraud, U.S. EPA has proposed a voluntary third-party quality assurance program. The program would establish qualifications for third-party auditors, and audit requirements. Purchasers of RINs that were part of the program could provide "an affirmative defense against liability for civil violations for transferring or using invalid RINs."[6]

There has also been concern about what will happen to the RIN market as the U.S. begins to hit the blend wall. The blend wall is expected to limit the amount of ethanol use in the United States, and in order to expand the market, more E15 and E85 (85 percent ethanol and 15

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[6] U.S. EPA Finalizes Voluntary Quality Assurance Plan for Renewable Fuel Standard Program https://www.epa.gov/renewable-fuel-standard-program/epa-finalizes-voluntary-quality-assurance-plan-renewable-fuel

percent gasoline) sales could be required, though this will require infrastructure upgrades and market demand.

Low Carbon Fuel Standard- The California Air Resources Board, in its 2011 Program Review of the LCFS, determined through its Advisory Panel that mid-term LCFS targets are achievable under a variety of conditions. However, ARB also determined that further work investigating the possibility of including flexible compliance mechanisms was warranted.[7]

Comparison of Subsidies

A few studies have attempted to quantify the difference between subsidies for petroleum and renewable fuels. The work to date has focused on comparing petroleum to ethanol, rather than looking at hydrogen, electric, or other non-petroleum fuels. This section will summarize the results of those studies.

Before examining subsidy comparisons, it is important to consider the definition of "subsidy." One interpretation of subsidy includes the following:

- Tax policy (e.g., ethanol tax credit)
- Regulation (e.g., low carbon fuel standard)
- Research and development
- Market activity
- Government services[8]
- Disbursements (e.g., grants)

Many studies focus primarily on subsides that directly impact the federal budget, including tax policy, research and development, and disbursements.

Subsidies for the oil and gas industry have been in existence for nearly 100 years and are driven by tax policy. In 1916, the expensing of intangible drilling costs and dry hole costs was introduced. This provision allows for deduction of intangible drilling costs in the first year, rather than being capitalized and depreciated over time.[9] In 1926, the "percentage depletion

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[7] ARB. "Low Carbon Fuel Standard 2011 Program Review Report." December 8. https://ww2.arb.ca.gov/our-work/programs/low-carbon-fuel-standard.

[8] While nearly all calculations rely on examination of the tax code or federal budget allocations, some analysis has focused on non-traditional types of subsidies, such as government services. Mass (2010) examined Defense Department spending on the cost to keep aircraft carriers patrolling the Persian Gulf at $7.3 trillion between 1976 and 2007. Typically, such government services are not included as part of the analysis of the cost of petroleum use (e.g., analysis of CAFE standards).

[9] Sherlock, M. 2010. "Energy Tax Policy: Historical Perspectives on and Current Status of Energy Tax Expenditures." Congressional Research Service. R41227.

provision" began. This provision allows deduction "of a fixed percentage of gross receipts rather than a deduction based on the actual value of the resources extracted."[10]

Subsidies for biofuels have been examined in relation to natural gas and petroleum. U.S. EIA's estimation of subsides of biofuels has been highly criticized.[11] U.S. EIA examined direct federal financial interventions and subsides and concluded that natural gas and petroleum liquids were subsidized at a level of $2.8 billion in FY2011, which includes direct expenditures, tax expenditures, research and development, and the federal & RUS electricity program, while biofuels were subsidized at a level of $6.6 billion, primarily from tax expenditures (Table 1). Figures for FY2007 were $2.0 billion for natural gas and petroleum liquids and $4.0 billion for biofuels[12]. U.S. EIA enumerates the types of subsidies that are not included in its report.

Table 1: U.S. EIA Analysis of the Value of Energy Subsidies by Major Use

	FY2007 (2010$, billions)	FY2010 (not ARRA), (2010$, billions)	ARRA (2010$, billions)
Natural Gas/Petroleum Liquids	2.0	2.8	-
Coal	4.0	1.3	0.1
Nuclear	1.7	2.4	0.1
Biofuels	4.0	6.5	0.2
Non-Biofuel Renewables	1.1	2.0	6.0
Electric Grid	1.1	0.5	0.5
Conservation	0.4	0.3	6.3
End-use	3.6	6.7	1.5

Source: NREL

Other work has focused on the level of subsidy provided to a technology as it is starting up. Instead of examining subsidy levels for different technologies in a given year, for example, subsidies for different technologies are examined over the first 30 years since their inception.

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[10] Pfund, N. and Healey, B. 2011. "What Would Jefferson Do? The Historical Role of Federal Subsidies in Shaping America's Energy Future." DBL Investors. http://www.dblpartners.vc/wp-content/uploads/2012/09/What-Would-Jefferson-Do-2.4.pdf?597435=&48d1ff=

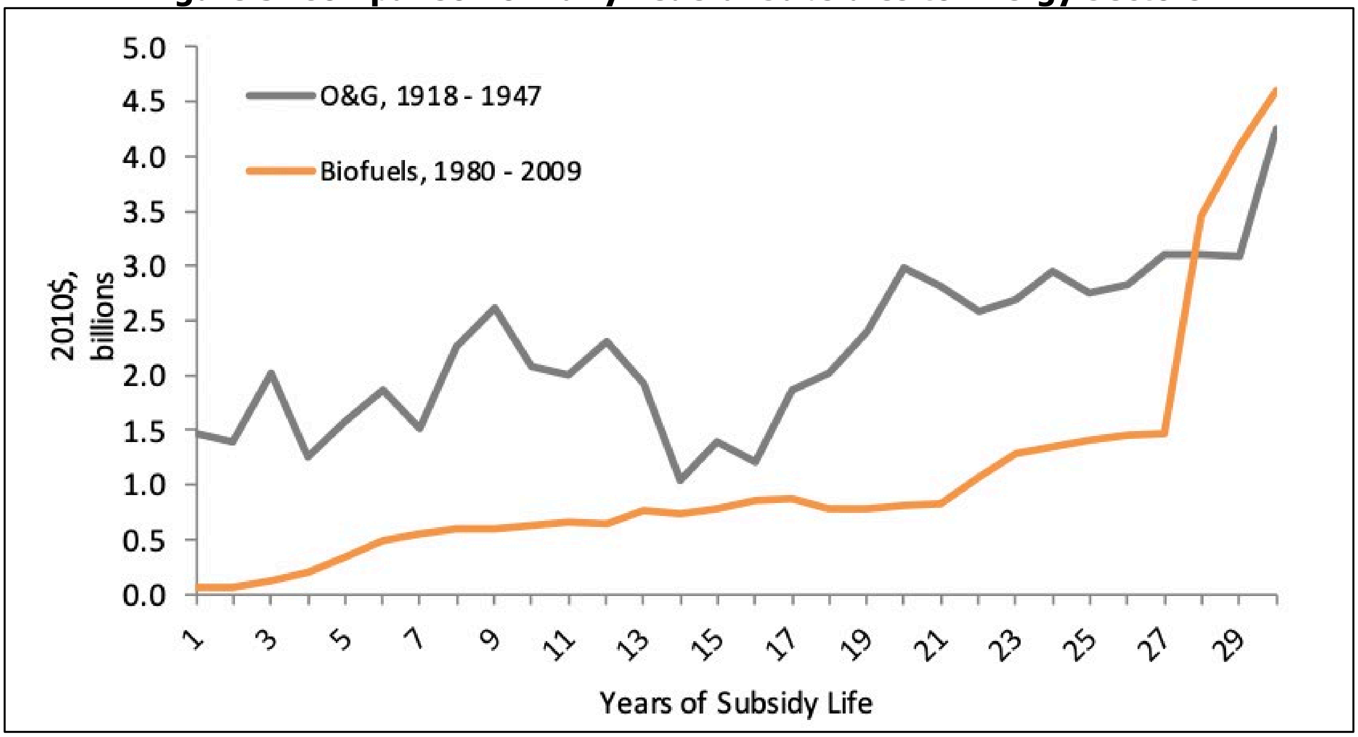
[11] Schor, E. 2011. "Energy Subsidy Battle Reignites as Debt Deal Preserves Tax Breaks." New York Times. August 1. https://archive.nytimes.com/www.nytimes.com/gwire/2011/08/01/01greenwire-energy-subsidy-battle-reignites-as-debt-deal-p-79083.html?pagewanted=print

[12] U.S. EIA. 2011. "Direct Federal Financial Interventions and Subsidies in Energy in Fiscal Year 2010." Energy Information Administration July. http://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf. Accessed May 1, 2013.

By examining the first thirty years of a subsidy's existence, it was found that federal subsidies for oil and gas outweighed those for biofuels until the mid-2000s[10] (Figure 5).

Figure 5 shows the subsidy value in 2010 dollars over the first 30 years of each technology's existence (for oil and gas the timeframe is 1918-1947, while for biofuels the timeframe is 1980-2009).[10] Note that this figure does not include 2012 data, from after the expiration of the Volumetric Ethanol Excise Tax Credit (VEETC – also known as the ethanol blender's tax credit). The VEETC began in the 1970s, providing $0.60 per gallon to ethanol fuel blenders. In 2011 the credit was valued at $0.46 per gallon and expired on December 31, 2011. The ethanol blender's tax credit was estimated to cost $6 billion in 2011.

Figure 5: Comparison of Early Federal Subsidies to Energy Sectors



Source: NREL

An earlier GAO report examined the tax incentives for petroleum versus ethanol fuels[13]. It found that tax incentives ranged from about $135 billion to $150 billion for the petroleum industry and $8 billion to $12 billion for the ethanol industry, over the life of the tax incentives as of 2000 (Table 2).

[13] GAO. 2000. "Petroleum and Ethanol Fuels: Tax Incentives and Related GAO Work." General Accounting Office GAO/RCED-00-301R.

Table 2: GAO Estimates of Revenue Loss due to Tax Incentives for Petroleum and Ethanol Fuels

Tax incentive	Summed over years	Adjusted to year 2000 dollars (millions)
Petroleum industry		
Excess of percentage over cost depletion	1986-2000	$81,679-$82,085
Expensing of exploration and development costs	1968-2000	$42,855-$54,580
Alternative (nonconventional) fuel production credit	1980-2000	$8,411-$10,542
Oil and gas exception from passive loss limitation	1988-2000	$1,065
Credit for enhanced oil recovery costs	1994-2000	$482-$1,002
Expensing of tertiary injectants	1980-2000	$330
Ethanol industry		
Partial exemption from the excise tax for alcohol fuels	1979-2000	$7,523-$11,183
Income tax credits for alcohol fuels	1980-2000	$198-$478

Source: NREL

While these studies provide a view of subsidies through 2000 or 2009, recent years have seen notable changes in subsidies for renewable fuel. As mentioned earlier, the VEETC expired at the end of 2011. The biodiesel blending tax credit, which provided $1.00 per gallon of biodiesel blended, has faced uncertainty in policy—it was allowed to expire at the end of 2009, then renewed at the end of 2011 and made retroactive for all of 2010. Partly as a result of the expiration in 2009, biodiesel production declined in 2010.[14]

Policy-Driven Effects on In-state Fuel Production

This section examines how selected policy-driven incentive programs create financial resources for production.

The policies examined here are the RFS2, the California LCFS, and the California Cap and Trade Program. Table 3 summarizes features of each policy that are relevant to its effect in creating financial resources for biofuels production in the state of California. All three policies are in effect in 2013, although Cap and Trade does not yet apply in the fuels sector and the RFS2 is not reaching the annual levels of renewable fuel established in the legislation. All three policies are market-based: the financial resource is based upon credits that regulated parties

[14] The cellulosic biofuel producer tax credit is available through 2013, providing $1.01 per gallon.

are required to obtain in amounts related to the quantities of certain activities, and that are allocated or created according to rules that are intended to constrain supply, encourage trading, and avoid excessive costs.[15] The tradable credits are called RINs for the RFS2, LCFS credits for the LCFS, and compliance instruments (allowances and offsets) for the Cap and Trade program.

Tradable credit markets can exhibit behavior typical of commodity markets, such as prices mediating a balance between supply and demand as they respond to conditions of scarcity or surplus, speculation about future values, and interactions among markets for related goods. Tradable credit markets also have features that are not typical of commodity markets, including a higher level of policy risk, because the market could be altered by law at any time; ceiling prices or ceiling and floor prices that may limit the price range within which the market operates; and definitions of credits that establish standards such that value depends on whether or not a standard is met, and so may be discontinuous (e.g., a fuel either meets or does not meet a greenhouse gas reduction standard, and the associated credit value depends on meeting that standard; some commodities have more continuous pricing based on continuous measures of quality). In addition, to the extent that tradable credit markets are intended to force new technologies into the market, commercialization of transformative new technologies may play a different role than in a typical commodity market. For example, the cost and timing of bringing advanced biofuels to market is a critical factor in the development of RIN markets.

The rest of this section discusses decisions that could help increase fuel production, the value that tradable credits might offer to those decision-makers, and briefly examines RIN, LCFS credit, and cap and trade compliance instrument markets.

Construction of In-state Production Capacity

Financial resources associated with tradable credits could provide value to decisions that include construction of in-state fuel production capacity; retrofitting of fuel production capacity to produce renewable, low-carbon, and less-emitting fuels; the rate of production at existing facilities in terms of volume during a given time period; and the idling of production capacity. Construction of in-state fuel production capacity entails capital investment on the order of $100 million for a new advanced biorefinery with commercial-scale production in the range of 10 to 20 million gallons per year (Advanced Ethanol Council 2013). New advanced biorefineries cost between $10 and $20 per gallon of production capacity (not per gallon of production) for pioneer plants, and cost reductions may be expected as more commercial plants are installed. Such an investment would be financed through debt and equity investments from a variety of types of investors, each with its own fuels market interests, risk tolerance, and tax position. For example, businesses with fuels-related business lines evaluate biofuels production investment opportunities in light of their existing related physical capital, human capital, horizontal and vertical integration opportunities, and strategic aims. These businesses may be obligated parties under the various regulations, and thus able to use the resulting tradable

[15] For a discussion of features of cap and trade programs that create tradable credit markets, see U.S. EPA (2003). "Tools of the Trade: A Guide to Designing and Operating a Cap and Trade Program for Pollution Control." EPA430-B-03-002, Available: https://www.epa.gov/sites/production/files/2016-03/documents/tools.pdf

credits to help meet their compliance requirement. Investors, such as venture capital, may seek early equity positions that they can exit at a high rate of return commensurate with the high risk. Investors with significant tax liabilities value opportunities for tax write-offs, such as accelerated depreciation of capital, more highly than others.

A revenue stream from tradable credits could be taken into account in fuel production capacity construction decisions, alongside the expected revenue from fuel sales. Tradable credits generate a future revenue stream; its current value is calculated by applying a discount rate. For investors who would use the tradable credits themselves, the market value would still apply, though the transaction costs would be less. An investor could use various methods to take that value into account in determining whether a prospective investment had a sufficiently attractive rate of return. As a simple example, an investor could estimate its contribution in a net present value calculation that allows comparison of costs and revenues, current and future, on a consistent cost basis, or other more complex metrics and methods could be used in the investment decision. In any case, the key effect of the tradable credits is that they might offer a future revenue stream above and beyond that from the fuel itself.

Retrofitting of Existing In-state Petroleum Capacity

Petroleum capacity retrofit decisions necessarily involve incumbent owners of existing capacity, with associated opportunities as described above; in other respects, the impact of tradable credits is similar.

Volume of Production

How much fuel to produce at California facilities, utilizing production capacity that has already been constructed, is another key decision that policy could seek to influence. The decision-maker in this case is the owner/operator of the production facility, and the key financial metric is no longer adequate return on investment, but whether or not expected marginal revenue is greater than the variable operating cost of the facility. A national or international firm with multiple production assets may also consider whether to produce fuel in-state or out-of-state for the California market, optimizing production across facilities and taking into account variable operating costs as well as geographic variation in price. In recent years, it has been cost-competitive to deliver Midwestern ethanol to California by rail, and it is more cost-effective to transport ethanol than to transport feedstock. Because RFS2 is implemented nationally, RINs may be traded both within and outside of the state; there is no requirement for in-state use or production for compliance. Cap and trade compliance instruments may also be traded outside of state boundaries with Western Climate Initiative partners, once the trading system is in place.[16]

Idling or Conversion of Production Capacity

The suite of policies of interest stratifies incentives for different types of biofuels production; different biofuels receive different incentives. Both relative incentives and relative technology costs may change over time, such that decisions might be made to idle or convert certain

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[16] Western Climate Initiative Cap & Trade Program
http://westernclimateinitiative.org/index.php?option=com_content&view=article&id=32:the-wci-cap-a-trade-program&catid=1:captrade&Itemid=47

biofuels production capacity. While starch-based ethanol production in quantities up to the blend wall is likely to be cost competitive with other fuels, competition among different types of advanced biofuels could occur, possibly prompting decisions to idle or convert capacity.

The value of the tradable credits to a fuels production decision-maker depends upon eligibility, mechanism, transaction cost, timing, and risk. Table 3 summarizes these factors. The critical consideration for an investor is the risk that the tradable credit revenue stream will not occur at the expected level. If none of the other factors presents a barrier to receiving the revenue stream, risks due to policy and market issues remain. With markets that are created by legislation, there is always the risk that policy could change, doing away with the tradable credits altogether, or reducing their value such that the associated revenue stream is negligible. In addition, market risks such as price volatility and competition with alternative providers add to the investors' risks.

Table 3: Summary of Tradable Credit Features Relevant to the Value

	RIN	**LCFS**	**Cap and trade**
Eligibility/Regulated entity	Businesses: Obligated parties include fuel producers, blenders, importers (with some exceptions for small refineries) of gasoline and diesel. Geography: All states except Alaska.	Businesses: Oil refiners and importers Geography: California	Businesses: Large GHG sources, including factories, oil refineries, cement producers, and electric generators. Geography: California
Mechanism	RINs are generated by producer or importer of fuel. Obligated parties must generate or purchase enough RINs to match the requirement set by U.S. EPA. True-up occurs each calendar year.	Each obligated party is assigned a declining number of GHG emissions per unit of fuel energy each year. Obligated parties can trade emissions credits.	Places a declining cap on the level of GHG emissions that can be emitted by each obligated party per year. Obligated parties can trade emissions credits. There is a price floor of $10/ton of carbon and ceiling of $70/ton of carbon through 2020.
Transaction cost	EPA provides a central exchange, reducing costs of trading. There are private recordkeeping costs and commercial vendors of recordkeeping services (RINSTAR).	ARB maintains the LCFS reporting tool and publishes contact information for all parties reporting transactions. Biofuel production facilities report carbon intensities of fuels.[2]	The Compliance Instrument Tracking System Service supports transfers of credits between obligated parties. Private entities facilitate brokering of credits.
Timing	RFS2 started in 2010. Final rule dates 3/26/2010 - 2010	Executive Order signed in January 2007 10% reduction in carbon content of fuel by 2020	Program started on January 1, 2012 (reporting only); compliance obligations begin with 2013 emissions for electric utilities and large industrial

	RIN	LCFS	Cap and trade
	12/9/2010 - 2011 1/9/2012 – 2012 2/7/2013 – 2013 (proposed, not final)		facilities, and in 2015 for distributors of transportation, natural gas, and other fuels.
Risks	EPA has discretion to set the standard level and alternative compliance cost (credit waiver) each year. 11/30 deadline to do so is not always met. Volatility in renewable / biofuel production cost. Competition with other biofuels producers. Competition with imports.	Legal risk: The LCFS has been challenged on both constitutional and administrative grounds. Future price of credits is uncertain. Competition with other biofuels producers. Competition with imports.	Price ceiling is likely not enough to drive change in the transportation sector.

Source: NREL

Of the tradable credit markets discussed here, RIN markets are the most established, with a total market value in the billions of dollars per year. RIN markets interact with each other, and other policies influence RIN value and compliance strategy. The four kinds of RINs established by RFS2 are shown in the rows of Table 4. Among these different RINs, a price hierarchy exists, such that Renewable fuel RINs always will cost less than or equal to advanced biofuel, biodiesel, or cellulosic RINs, and Advanced biofuel RINs will always cost less than or equal to the lesser of cellulosic RINs and biodiesel RINs times a conversion factor. Each year, the U.S. EPA has established volumetric requirements for each RIN market, and in the case of cellulosic biofuel RINs, has established a dollar value at which compliance credits will be available for cellulosic biofuel, as shown in Table 4. These compliance credits for cellulosic biofuels were necessary because the market had not generated this kind of credit.

Table 4: Publication of Annual RFS2 Regulatory Requirement in Federal Register, Required Volume, Required Percent of Fuel, and Compliance Credit Price Established by Regulation for Cellulosic Biofuel

	2010	**2011**	**2012**	**2013**	**Price Range**
Source	Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program http://www.gpo.gov/fdsys/pkg/FR-2010-03-26/pdf/2010-3851.pdf	Regulation of Fuels and Fuel Additives: 2011 Renewable Fuel Standards http://www.gpo.gov/fdsys/pkg/FR-2010-12-09/pdf/2010-30296.pdf	Regulation of Fuels and Fuel Additives: 2012 Renewable Fuel Standards http://www.gpo.gov/fdsys/pkg/FR-2012-01-09/pdf/2011-33451.pdf	Regulation of Fuels and Fuel Additives: 2013 Renewable Fuel Standards http://www.gpo.gov/fdsys/pkg/FR-2013-02-07/pdf/2013-02794.pdf	Felt and Radhakrishnan[17]; Irwin and Good[18]
Cellulosic biofuel (D3, D7)	5.04 M gal (0.004%) [$1.56/credit]	6.6 M gal (0.003%) [$1.13/credit]	8.65 M gal (0.006%) [$0.78/credit]	14 M gal (0.008%) [$0.42/credit]	As shown
Biomass-based diesel (D4)	(1.10%) Combined with advanced biofuel into a single 1.15 B gal requirement, based on 0.5 B gal requirement for diesel and 0.6 B gal requirement for advance biofuel	0.8 B gal (0.69%)	1.0 B gal (0.91%)	1.28 B gal (1.12%)	$0.88 – $1.97

[17] Felt, J. and Radhakrishnan, R. 2012. "What's Wrong With RIN Markets?" Available: http://www.renewableenergyworld.com/rea/news/article/2012/06/whats-wrong-with-rin-markets, accessed 5/15/2013.

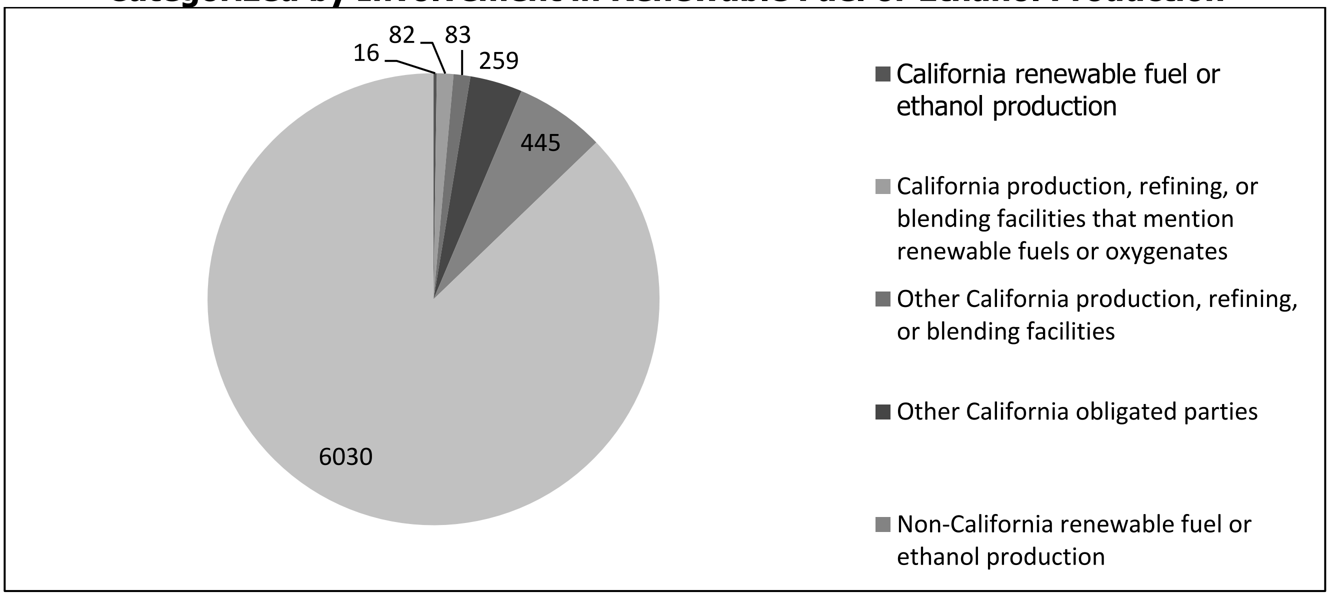
[18] Irwin, S. and Good, D. 2013. "Exploding Ethanol RINs Prices: What's the Story?" Available: http://farmdocdaily.illinois.edu/2013/03/exploding-ethanol-rins-prices.html, accessed 5/15/2013.

	2010	2011	2012	2013	Price Range
Advanced biofuel (D5)	(0.61%)	1.35 B gal (0.78%)	2.0 B gal (1.21%)	2.75 B gal (1.60%)	$0.43 - $1.27
Renewable fuel (D6)	11.1 B gal (8.25%)	13.95 B gal (8.01 %)	15.2 B gal (9.23%)	16.55 B gal (9.63%)	$0 – 0.70

Sources: NREL

In considering the potential for revenue from tradable credit markets to encourage growth of California production, a key question is, "How does in-state production cost competitiveness compare to out-of-state production?" This question is not answered directly here, but the database of RFS2 registered parties[19] provides some data on numbers of firms that are categorized as renewable fuel or ethanol producers (Figure 6).

Figure 6: Numbers of Registered Parties within and Outside of California, Categorized by Involvement in Renewable Fuel or Ethanol Production



Source: NREL

The 16 firms with California addresses and California production that U.S. EPA lists as RFS2 approved renewable fuel providers are listed below (Table 5).[20] In addition, R Power Biofuels has a California address but does not list a California production facility, and Dallas Clean Energy has a California address but lists production only in Texas.

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[19] U.S. EPA. 2013. Database of RFS2 Registered Parties. Accessed May 15, 2013. https://cdxnodengn.epa.gov/cdx-otaq-reg-II/action/reportExternal/Part80FuelsProgramslist

[20] U.S. EPA. 2013. Fuels Reporting Registration. Accessed: June 10, 2013. http://epa.gov/otaq/fuels/reporting/programsregistration.htm

Table 5: RFS2 Approved Renewable Fuel Providers in California

3782	ACCU CHEM Conversion, Inc
3566	Aemetis Advanced Fuels Keyes, Inc.
4935	AMERICAN BIODIESEL INC
4881	BLUE SKY BIOFUELS, LLC
7354	GFP Ethanol, LLC
3667	Ecolife Biofuels, LLC
3881	Extreme Green Technologies, Inc.
3885	GeoGreen Biofuels, Inc,
9871	IMPERIAL WESTERN PRODUCTS INC
5038	KERN OIL & REFINING CO
7768	NEW LEAF BIOFUEL, LLC
3697	Pacific Ethanol Holding Co LLC
7514	PROMETHEAN BIOFUELS COOPERATIVE CORPORATION
3717	Simple Fuels Biodiesel
4018	USL PARALLEL PRODUCTS OF CALIFORNIA
4667	YOKAYO BIOFUELS INC

Source: NREL

Gap Analysis

This section presents a gap analysis that identifies where funds or resources are being provided to each advanced fuel technology type. Results are presented for the United States and California.

Historical Market Share and Production Capacity

Among the fuels of interest in this section (ethanol, biodiesel, infrastructure-compatible biofuels, renewable methane and renewable hydrogen), only ethanol and biodiesel have gained appreciable market share nationally and in California. Figure 7 through Figure 9 display the historical development of production and consumption of these fuels.

Figure 7 places bioenergy use in context of the overall primary energy use in the U.S. transportation sector.[21] Primary energy is the energy content of the fuel input. Petroleum use is plotted on the right-hand axis, which is an order of magnitude greater than the left-hand axis that is used for the other fuels. The primary natural gas use that is shown here is its use as an energy source for natural gas pipeline operations, not use in vehicles. Electricity includes both retail sales and system losses. The biomass category includes fuel ethanol without the energy content of the denaturant and diesel. Additional information on U.S. and global renewable fuels is shown in the 2011 Renewable Energy Data Book.[22]

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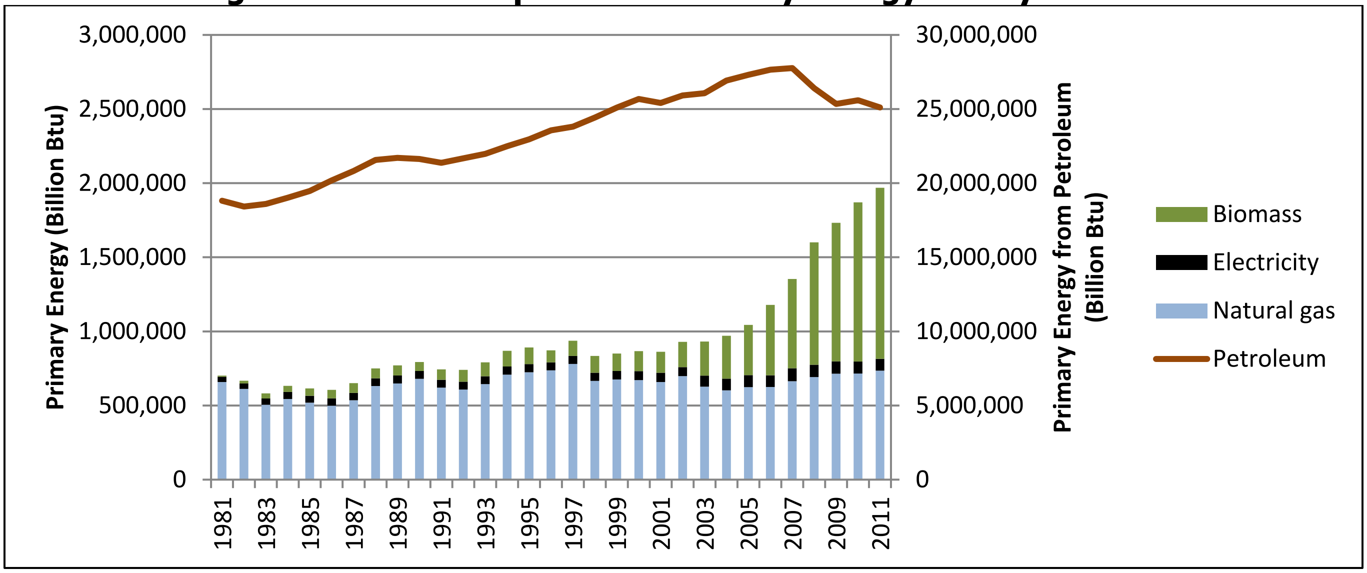
[21] U.S. EIA. 2012a. Annual Energy Review, Table 2.1e, stb0201e, U.S. Energy Information Administration, Available: accessed 5/22/2013, (AlternativeFuelsMarketDatawChart.xls) http://www.eia.gov/totalenergy/data/annual/showtext.cfm?t=ptb0201e

[22] NREL. 2013. Renewable Energy Data Book. http://www.nrel.gov/docs/fy13osti/54909.pdf, pp. 93-105.

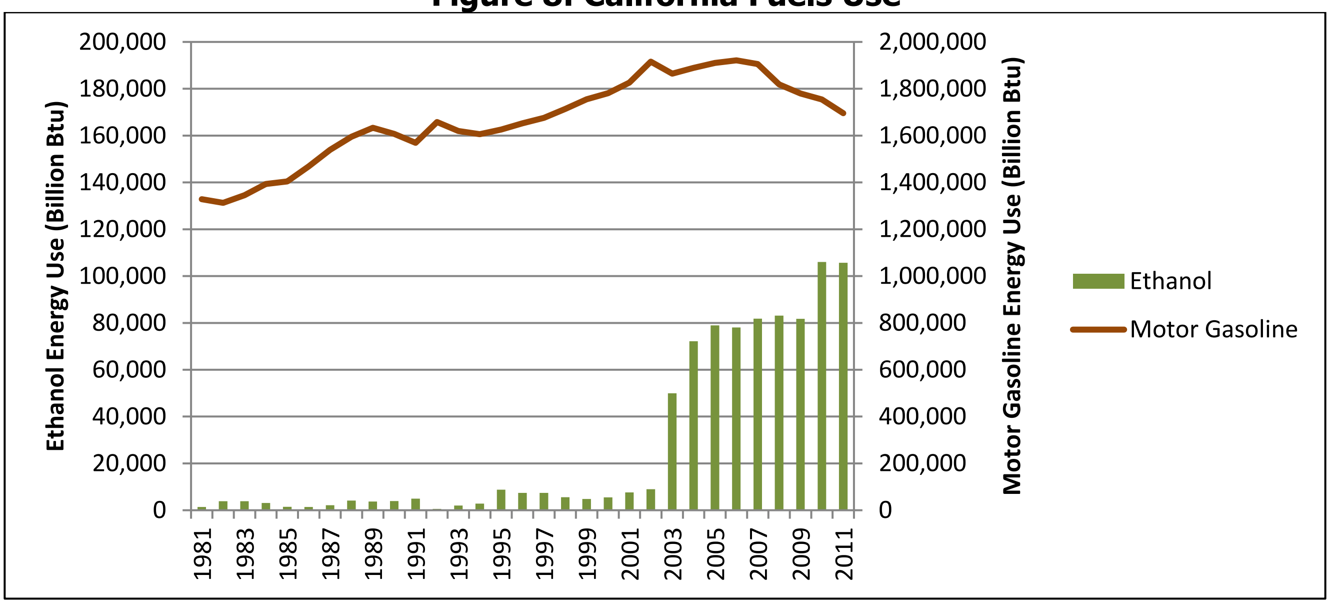
Figure 7: U.S. Transportation Primary Energy Use by Source



Source: U.S. EIA

Figure 8 shows a geographic, modal, and fuel sub-set of this overall transportation use: California motor vehicle gasoline and ethanol fuel use.[23] Motor gasoline use is plotted on the right-hand axis, which is an order of magnitude greater than the left-hand axis that is used for ethanol. Motor gasoline does not include energy from ethanol, and ethanol does not include denaturant.

Figure 8: California Fuels Use



Sources: NREL

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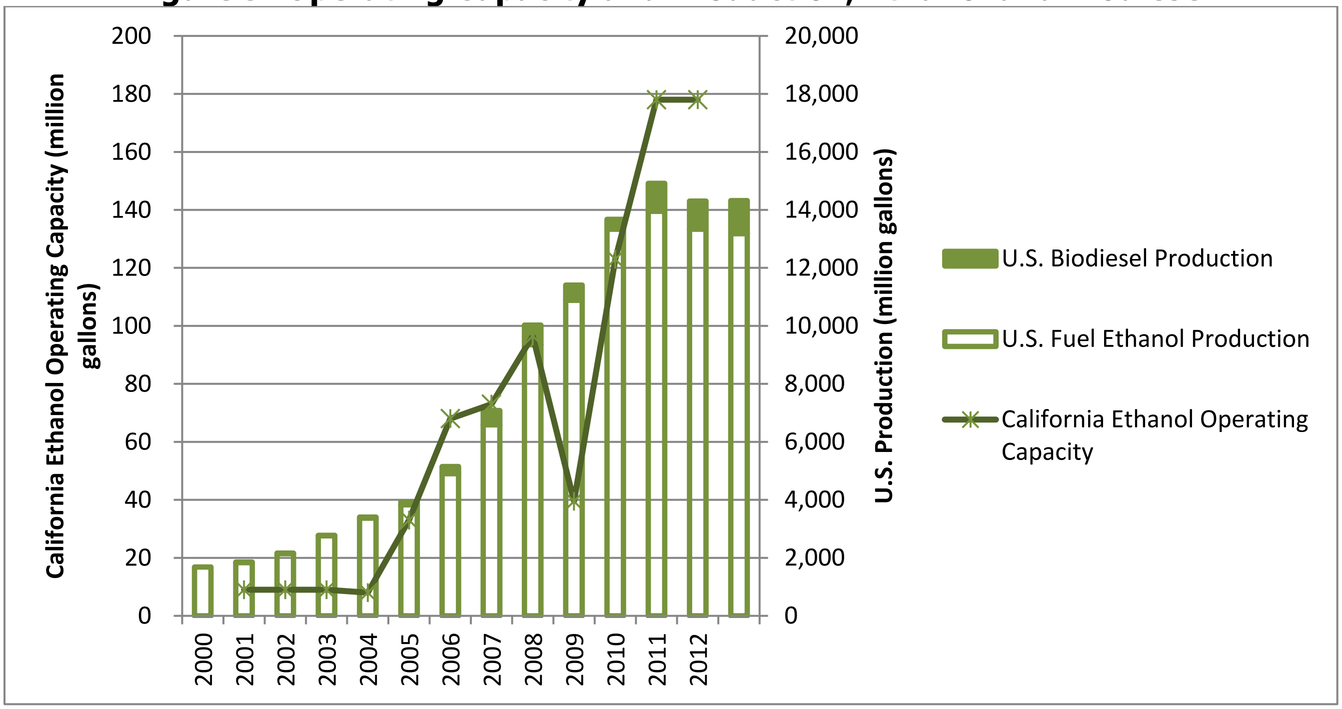
[23] U.S. EIA. 2010 and 2011. State Energy Data System. U.S. Energy Information Administration. Available: accessed 5/22/2013, http://www.eia.gov/state/seds/.

Figure 9 shows U.S. ethanol[24] and biodiesel production and California operating capacity for ethanol only.[25] U.S. production is plotted on the right-hand axis, which is an order of magnitude greater than the left-hand axis that is used for California ethanol operating capacity. This figure uses physical units, not adjusted for energy content.

Figure 9: Operating Capacity and Production, Ethanol and Biodiesel



Source: NREL

Investment

Investments made in the bio- and renewable-fuels industry include both private and public sources.

Private

Figure 10 shows California and U.S. reported private investment from venture capital and private equity sources, as reported in Bloomberg New Energy Finance in the "Biofuels" category.[26] This is a limited dataset: only publicly disclosed data are included. However, this data source does indicate considerable private investment of nearly $7 trillion in U.S. biofuels, and more than $3 trillion in California biofuels, a considerable share of the U.S. total.

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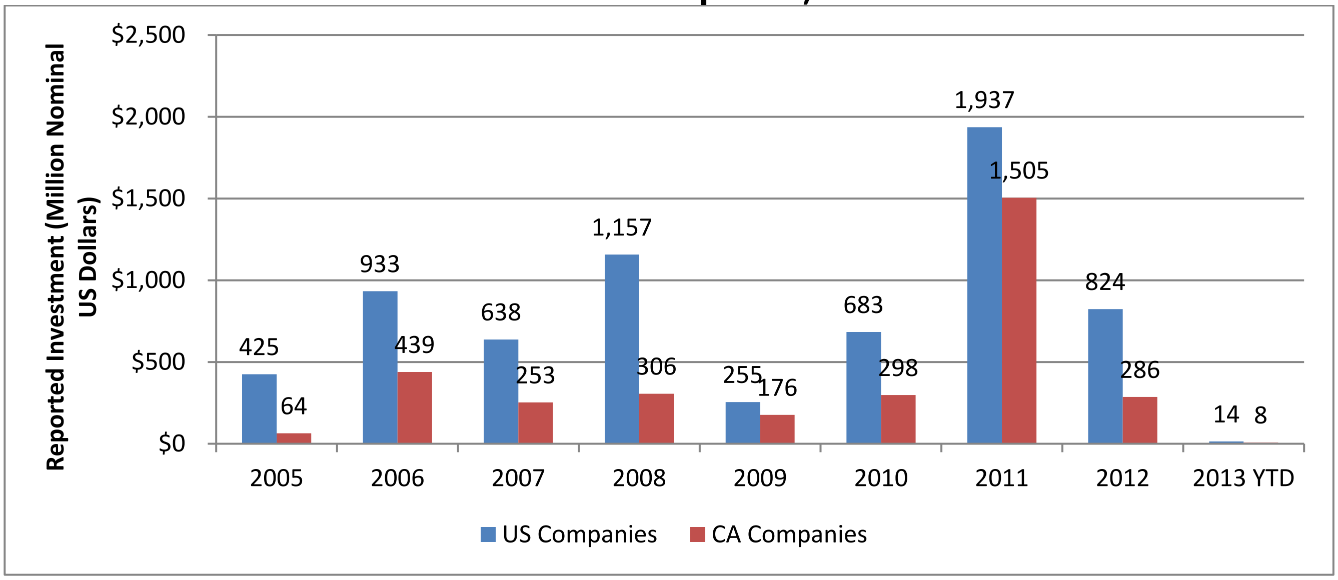
[24] Renewable Fuels Association. 2013. California Ethanol Operating Capacity: Renewable Fuels Association. Ethanol Industry Outlooks. https://ethanolrfa.org/wp-content/uploads/2015/09/RFA-2013-Ethanol-Industry-Outlook1.pdf

[25] U.S. EIA. 2013. U.S. Production Data. Short-term Energy Outlook, Custom Table Builder, Biofuels. U.S. Energy Information Administration. http://www.eia.gov/forecasts/steo/query/

[26] Bloomberg New Energy Finance. 2013. (2005-2013 VCPE US Biofuels_v2.xls)

Figure 10: Reported Private Equity and Venture Capital Investment in U.S. and California Biofuel Companies, 2005-2013



Source: NREL

Because this data set is incomplete, totals, trends, and relative California shares should all be viewed as inconclusive. If additional detail is desired, it would be possible to cross-reference this dataset with other sources to identify the share of projects reported elsewhere (e.g., Biofuels Digest Advanced Biofuels Database[27]) for which private funding is reported; use that to determine whether there appears to be reporting bias that is influencing the share of California relative to U.S. private investment; and categorize reported investment by pathway or product type.

In addition to the "Biofuels" category, Bloomberg New Energy Finance reports $9.5 million of venture capital investment in hydrogen production in 2010 and an undisclosed amount in 2009 (both funding Sun Catalyx, a Massachusetts-based firm).[26] Biomethane received $6 million in private equity in 2011. The same limitations apply to this data as well.

Public

A Congressional Research Service review summarizes the FY2012 status of funding for federal biofuels incentives programs, as shown in Table 6.[28] Expiration dates that were extended after publication of that review are noted. Table 7 provides a snapshot of federal subsidies by type in two earlier years, 2007 and 1999.[29]

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[27] Biofuels Digest. 2012. "Advanced Biofuels Tracking Database," https://www.biofuelsdigest.com/bdigest/2011/01/14/10-advanced-biofuelsprojects-now-planned-in-advanced-biofuels/.

[28] Yacobucci, Brent D. 2012. Biofuels Incentives: A Summary of Federal Programs. Congressional Research Service, https://crsreports.congress.gov/product/pdf/R/R40913, 7-5700, R40110

[29] U.S. EIA. 2008. Federal Financial Interventions and Subsidies in Energy Markets 2007. Service Report, Report #:SR/CNEAF/2008-01, April 2008. U.S. Energy Information Administration. https://www.eia.gov/analysis/requests/2008/subsidy2/pdf/subsidy08.pdf

Table 6: FY 2012 Status of Funding for Federal Biofuels Incentives Programs

Administering Agency	Program	Original Authorizing Legislation	FY2012 Appropriation ($ millions)	Expiration Date
United States Environmental Protection Agency (U.S. EPA)	Renewable Fuel Standard***	109-58§1501		
Internal Revenue Service	Volumetric Ethanol Excise Tax Credit**	108-357§301		12/31/2011
	Small Ethanol Producer Credit**	101-508		12/31/2011
(Extended in the provisions of the American Taxpayer Relief Act of 2012, Public Law 112–240, that modify 26 USC § 40A.)	Biodiesel Tax Credit*	108-357		12/31/2013
	Small AgriBiodiesel Producer Credit*	109-58		12/31/2013
	Renewable Diesel Tax Credit*	109-58		12/31/2013
([b] Extended in the provisions of the American Taxpayer Relief Act of 2012, Public Law 112–240, that modify 26 USC § 40(b)(6).)	Credit for Production of Cellulosic Biofuel	110-246		1/1/2014
	Special Deprecation Allowance for Cellulosic Biofuel Plant Property	109-432		12/31/2012
	Alternative Fueling Station Credit***	109-58§1342		12/31/2011
Department of Agriculture	Biorefinery Assistance	110-246§9001		12/31/2012
	Repowering Assistance	110-246§9001		12/31/2012
	Bioenergy Program for Advanced Biofuels	110-246§9001	65	12/31/2012
	Feedstock Flexibility Program for Producers of Biofuels (Sugar)	110-246§9001		
	Biomass Crop Assistance Program	110-246§9001	17	12/31/2012
	Rural Energy for America Program***	110-246§9001	25.4	12/31/2012

Administering Agency	Program	Original Authorizing Legislation	FY2012 Appropriation ($ millions)	Expiration Date
	Biomass Research and Development	106-224	40	12/31/2015
United States Department of Energy (U.S. DOE)	Biorefinery Project Grants	various	175	
	Loan Guarantees for Ethanol and Commercial Byproducts from Various Feedstocks	109-58§§1510, 1511, 1516		Varies
	DOE Loan Guarantee Program (administrative expense to be offset by loan fees) ***	109-58, Title XVII	38	
	DOE Loan Guarantee Program (loan authority, FY2008-FY2009) ***	109-58, Title XVII	100	
	DOE Loan Guarantee Program (loan authority for renewable energy and energy efficiency) ***	109-58, Title XVII	10	
	Cellulosic Ethanol Reserve Auction (FY2008 administrative funds)	109-58§942	5	8/8/2015
U.S. Customs and Border Protection	Import Duty for Fuel Ethanol**	96-499		12/31/2011
Department of Transportation	Flexible Fuel Vehicle Production Incentive (by model year)***	94-163		2019

***= Renewable or Bio-Diesel; **= Ethanol; ***= Renewable/Alternative Fuel**

Source: NREL

Table 7: Energy Subsidies and Support by Type and Fuel (million 2007 dollars)

	Renewables (Bioenergy) (FY2007)	Renewables (Bioenergy) (FY1999)	Detail (FY2007)	Detail (FY1999)	Detail Sub-categories	Status
Direct Expenditures	5	5				
Tax Expenditures	3970 (3220)	1000 (939)	2990	921	Excise Tax/VEETC	Expired
			690	61	New Technology Credit	
			180		Biodiesel and Small Agri-Biodiesel Producer Tax Credit	Extended to 12/31/2013
			60		Credit Holding for Clean Renewable Energy Bonds	
			50	18	Alcohol Fuel Credit	Cellulosic biofuel production credit extended to 1/1/2014
Research and Development	727 (246)	412 (116)				
Federal Electricity Support	173					
Total	4875	1417				

Source: NREL

Firms

Existing, commercial-scale ethanol, biodiesel, and renewable diesel firms, while vulnerable to policy and market risks, are relatively well-established. Major, costly federal market incentives, such as VEETC and Biodiesel tax credit, have expired or face considerable uncertainty.

Firms that produce cellulosic ethanol, advanced/infrastructure compatible biofuel, renewable hydrogen, and renewable methane are more likely targets for further public incentives. Substantial fluidity and potential for continued change is apparent among advanced bio- and renewable-fuel firms. In its regulatory discussions of cellulosic biofuels, U.S. EPA has cited the firms shown in
Table 8 in calculating expected production each year.

Table 8: Potential Cellulosic Biofuel Firms and Design Capacities (million gallons per year) Noted in U.S. EPA RFS2 Regulations

	2013[30]	2012[31]	2011[32]	2010[33]
Abengoa	24			X
BP	X			
Coskata	X			X
DuPont Danisco	X		0.25	
Fiberight	6	6	6	
INEOS Bio	8	8		
KL Energy	X	1.5	1.5	1.5
KiOR	11	10	0.2	
POET	X			X
American Process		0.9		
Fiberight				X
ZeaChem		0.25		
Range			4	X
Projected available or potential volume	14	8.65	6.6	

Source: NREL

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30 U.S. EPA Table II.C.6–1—Projected Available Cellulosic Biofuel for 2013. X denotes projects listed elsewhere in document, shown in this table as "various." http://www.gpo.gov/fdsys/pkg/FR-2013-02-07/pdf/2013-02794.pdf.

31 U.S. EPA Table II —B.6–1—Cellulosic Biofuel 2012 Projected Available Volume. http://www.gpo.gov/fdsys/pkg/FR-2012-01-09/pdf/2011-33451.pdf.

32 U.S. EPA Table II.A.4–1—Projected Potential Volume of Cellulosic Biofuel Production in 2011. http://www.gpo.gov/fdsys/pkg/FR-2010-12-09/pdf/2010-30296.pdf.

33 U.S. EPA did not develop its own table of projected or potential cellulosic biofuel production for 2010. Companies marked with X are listed in a table of 23 possible biofuels companies, along with projections to 2014. Regulation of Fuels and Fuel Additives: Changes to Renewable Fuel Standard Program http://www.gpo.gov/fdsys/pkg/FR-2010-03-26/pdf/2010-3851.pdf.

In the Advanced Biofuels Database (July 2012 version), there are just over 300 projects listed globally, 62 in the United States, and 2 in California (many project sites are not designated.) Initial inspection does not reveal overlap between the current California RIN-generating registered entities and the developers of projects in the Advanced Biofuels Database, or the biofuels firms listed in Bloomberg New Energy Finance with private funding actions.[26] While differences in names across different data-sources could mask shared ownership, this lack of overlap also indicates that California advanced biofuels technology firms have not yet begun to supply California markets. There is modest overlap between the Advanced Biofuels Database and the Bloomberg New Energy Finance private funding actions; projects that appear in the Advanced Biofuels Database but not in Bloomberg New Energy Finance may have received unreported private funding (or names may be inconsistent), and projects that appear in Bloomberg New Energy Finance but not in the Advanced Biofuels Database may be insufficiently advanced for reporting in that database (or names may be inconsistent). The Advanced Biofuels Database does not include renewable hydrogen and renewable methane production.

The 16 firms with California addresses and California production that U.S. EPA lists as RFS2-approved renewable fuel providers were listed previously in Table 5. Power Biofuels has a California address but does not list a California production facility, and Dallas Clean Energy has a California address but lists production only in Texas. Another list obtained from Robert Anderson of U.S. EPA also lists High Mountain Fuels, LLC Altamont Liquified Biogas Plant in Livermore, CA, which is producing biogas RINS as advanced biofuel.

The 39 organizations receiving private funding as listed in Bloomberg New Energy Finance are listed in Table 9.

Table 9: Organizations Receiving Private Funding

5980	Agilyx Corp
5656	Agrivida Inc
5964	Algaeventure Systems Inc
6406	Algenetix Inc
5940	Cellana Inc
6338	Cobalt Technologies Inc
5616	Coskata Inc
6402	D2 Renewable Inc
5006	Easy Energy Systems Inc
5216	Edeniq Inc
5454	E-Fuel Corp
5492	Elevance Renewable Sciences Inc
5250	Endicott Biofuels II LLC

5378	EPEC Biofuels Holdings
5452	Ever Cat Fuels LLC
5602	Genomatica Inc
3901	Glycos Biotechnologies Inc
5408	Incitor Inc
5066	Initio Fuels LLC
5562	Inventure Chemical Inc
6102	Liquid Light Ltd
5366	LS9 Inc
5468	Mascoma Corp
4992	Primus Green Energy Inc
5472	Propel Fuels Inc
5986	Proterro Inc
5362	Pure Biofuels Corp
5162	Rational Energies LLC
5604	Renmatix Inc
5150	Sapphire Energy Inc
4674	SG Biofuels Inc
5510	Solix BioSystems
5140	Standard Ethanol LLC
6340	SweetWater Energy Inc
5142	Thar Energy LLC
5198	Verdezyne Inc
5878	ZeaChem Inc
6370	ZeaKal Inc

Source: NREL

The California projects in the Advanced Biofuels Database are Rentech and Solena.

Discussion

This gap analysis faces significant data limitations. To conduct a thorough gap analysis, investment data would be generally available and readily categorized by source (public, private), fuel, production technology, supply chain element, level of development of industry player receiving investment (commercial, pre-commercial, research and development), and geography. This data could then be compared with estimates of investment needed to advance specific goals. Investment data at this level of detail does not exist and would be challenging to obtain. A particularly significant data gap may be on the private investment side, as reporting requirements do not extend to many of the potential biofuels investors. This may be particularly challenging for newly emerging fuels and technologies, for which it is also difficult to estimate investment needs because of remaining technological risks at earlier stages of process development.

Market data, particularly production data, indicate that ethanol and biodiesel are both well-established fuels. Although both of these markets benefit from regulatory support from RFS2, most public incentives have or are soon scheduled to be phased out. If and when that occurs, the market competitiveness of ethanol will increasingly depend upon its competitiveness as an energy source and its competitiveness for enhancing octane.[34] Cellulosic biofuels, including both ethanol and infrastructure-compatible fuels, as well as renewable natural gas and renewable hydrogen, are not well-established in the commercial marketplace. One indicator of this is the regulatory history of cellulosic biofuel RIN markets for RFS2 compliance. The success of cellulosic biofuel production firms would establish these fuels commercially and help address concerns about this part of aspect RFS2. This sector faces a need for private investment to reach commercial-scale production, coupled with significant regulatory and market risks that may discourage such investors. Less-advanced biofuel and renewable fuel production processes also may need pre-commercial investments to support research and development, pilot plant development, and demonstration-scale production, if these processes are to continue to advance towards commercialization.

If investment gaps exist mostly among cellulosic biofuels, renewable natural gas, and renewable hydrogen, public investment across those fuels and their production technologies could be made to address those gaps. Allocation of such investment would likely need to consider policy objectives, market development, and technological risk, among other factors.

[34] One comparison is published in Greunspecht (2013). It should be noted that the comparison shows only one set of prices (Iowa ethanol and Gulf Coast gasoline), which is not reflective of regional pricing variation.

CHAPTER 3: Feedstocks

This section is divided in three sub-sections as they relate to the production of various fuels through different conversion processes. Lignocellulosic biomass is used to produce ethanol (called cellulosic ethanol when produced from these feedstocks), hydrogen, and "drop-in" fuels (renewable gasoline, diesel and jet fuel). Fats, oils and greases are used to produce biodiesel and drop-in fuels. Biogas is used to produce renewable natural gas (RNG) and hydrogen.

Lignocellulosic Biomass

Lignocellulosic biomass refers to plant material composed of carbohydrate polymers (cellulose and hemicellulose) and an aromatic polymer (lignin). This section focuses on waste and purposely grown biomass—in other words, the sustainable portion of plant biomass and not the virgin biomass resources (all naturally-occurring terrestrial plants) or crops grown for food and feed. The potential of agricultural resources, woody biomass, and dedicated energy crops in California is examined below.

Agricultural Resources

The main sources of sustainable biomass from agriculture in California are residues from crop and livestock production. Crop residues are the main focus here; livestock residues (animal manure) are examined later in the biogas section. Crop residues are generally divided into two categories: harvesting and processing residues. Harvesting residues are those remaining on the field after harvesting, such as straw and leaves. Processing residues are those available after further processing of the crops into food materials, such as husks and shells. A recent study estimated the amount of crop residues in California by county.[35] It estimates that nearly 2 million bone dry tons (BDT) of residues from field and seed crops (e.g., corn, wheat, rice, cotton, alfalfa seed) are technically available per year. In addition, about 128,000 BDT/year of leaf, vine, and other plant residuals are technically available from vegetable crops. Most of these harvesting residues are concentrated in the Central Valley. The top five producing counties of residues from field and seed crops include Colusa, Fresno, Kings, Sutter, and Butte. Harvesting residues from vegetable crops come primarily from Fresno, Imperial, Monterey, and San Joaquin counties.

It is estimated the amount of technically available rice hulls and cotton gin trash – about 297,000 BDT/year and 103,000 BDT/year, respectively.[35] Rice hulls are collected primarily from Colusa, Butte, Sutter, and Glenn counties, while cotton gin waste is predominately collected in Fresno, King, and Kern counties. Another recent study examined the almond and walnut residue production in the state.[36] It estimates that about 2 million BDT of almond hulls, 496,000 BDT of almond shells, and 199,000 BDT of walnut shells are produced in the state per

[35] Williams, R., Gildart, M., Yan, L., Jenkins, B. 2008. "An Assessment of Biomass Resources in California", March 2008, http://biomass.ucdavis.edu/files/reports/2008-cbc-resource-assessment.pdf

[36] Amon, R., Jenner, M., El-Mashad, H., Williams, R., and Kaffka, S. 2011 (DRAFT report). California's Food Processing Industry: Organic Residue Assessment. California Energy Commission. CEC PIER Contract 500-08-017.

year. The study points out that essentially all almond hulls are used in livestock feed. Shells are used for animal bedding, construction materials, and as feedstock in biomass power plants. About 86 percent of almonds in California are grown in the San Joaquin Valley and most of the balance is grown in the Sacramento Valley.[36] Leading counties include Kern, Fresno, and Stanislaus. Walnuts are produced throughout the Central Valley — San Joaquin, Yuba, and Butte are some of the top-producing counties.

Woody Biomass

This category of biomass resources includes the residues associated with forestry operations such as logging, forest restoration and maintenance, lumber production, and trimming or removal of orchards and grapevines.

Williams et al. (2008) estimated the technically available logging slash, biomass from forest thinning (stand improvement and fuels reductions operations), mill residues, shrub or chaparral, and orchard and vineyard prunings. The authors define logging slash as branches, tops, and other materials removed from trees during timber harvest and estimate the technical potential in California at about 4.3 million tons. These resources are predominately in Humboldt, Mendocino, Siskiyou, Shasta, and Trinity counties. The study defines forest thinnings as the "non-merchantable components extracted during harvest activities and include understory brush, small diameter tree boles, and other material transported to the mill that cannot produce sawlogs. Thinning refers to silvicultural treatments designed to reduce crowding and enhance overall forest health and fire resistance." Estimated technical potential of forest thinnings in California is about 4.1 million tons, with Humboldt, Mendocino, Siskiyou, Shasta, and Trinity as leading counties. Sawmill residues include bark, sawdust, planer shavings, and trim ends produced as byproduct at sawmills and other forest products manufacturing operations. The report estimated the technical potential at about 3.3 million tons.[35] These resources are prevalent in Siskiyou, Plumas, Humboldt, Shasta, and Trinity counties. The study notes that "shrub or chaparral is comprised of mostly shrubby evergreen plants adapted to the semi-arid desert regions of California, especially in the south parts of the state. Shrublands range over a large area but so far there has been little development of this biomass for energy. Because shrub biomass has no current commercial value, it is only available as an energy resource through habitat improvement activities (such as thinning) or fuel treatment operations designed to reduce wildfire risks." It estimates this resource potential at about 2.6 million tons. Leading counties include San Bernardino, Lassen, Riverside, and San Diego. Orchard and vineyard prunings are estimated at about 1.7 million tons per year, concentrated primarily in Fresno, Tulare, Kern, San Joaquin, and Madera counties. The study points out that close to 1 million tons of prunings are currently used as fuel in power plants, blended with other fuels such as urban wood and forest materials.

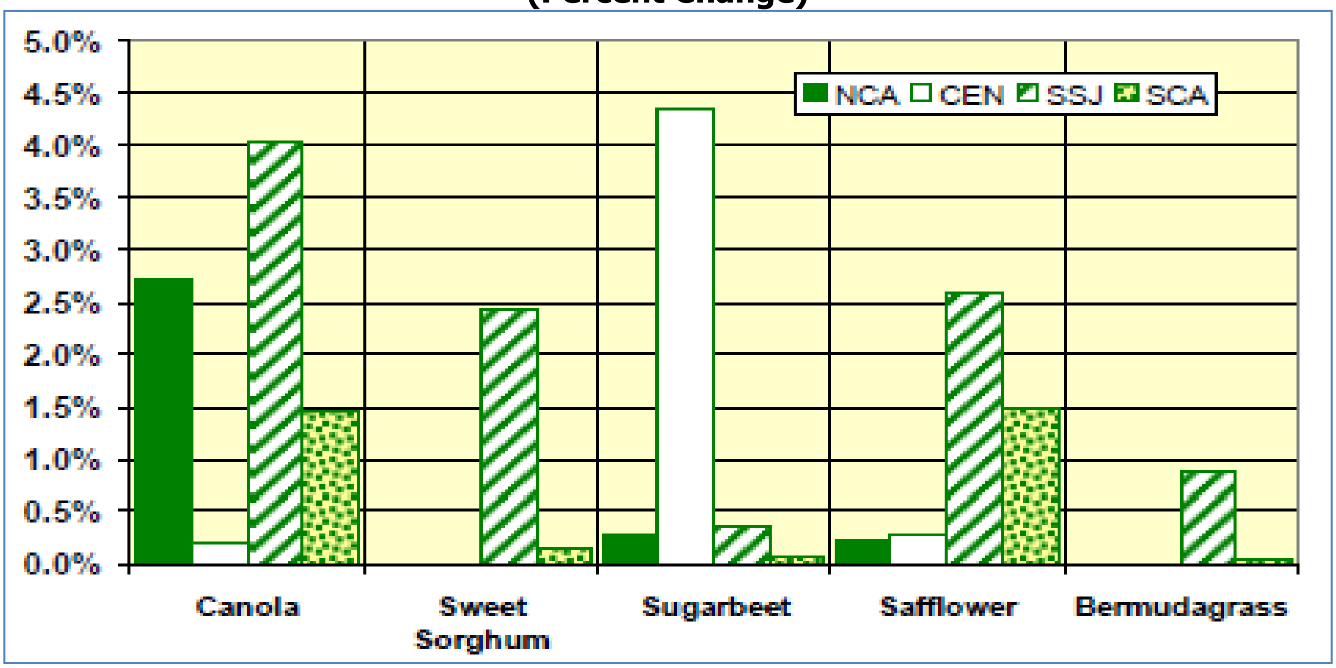
Municipal Solid Waste

The biomass material landfilled in California was estimated at about 9 million tons in 2007.[35] This includes brown material (construction and demolition wood, paper and cardboard, prunings and trimmings, branches and stumps) and green material (leaves, grass, food waste, and other organics including biosolids). The brown material represents 76 percent of the total landfilled biomass material. Naturally, highly populated counties such as Los Angeles, Orange, San Diego, San Bernardino, and Riverside are associated with large amounts of organic waste generation.

Dedicated Energy Crops

This category of biomass resources includes perennial grasses, trees, and annual crops grown for energy purposes. Currently, dedicated energy crops are not produced at commercial scale in California. Dedicated crops could be grown on existing agricultural lands but might also be grown on marginal lands.[35] There have been field trials with oil crops and salt-tolerant species on marginal lands throughout the state. Dedicated energy crop yields vary depending on the crop type, water availability, soil conditions, climate, and other factors. Water is likely to be a limiting resource in the state and on marginal lands[37]. A study evaluated the feasibility and likely locations of five purpose-grown biofuel feedstock crops in California – canola (new crop), sweet sorghum (new crop), sugar beets, safflower, and bermuada grass – using a mathematical programming model created to analyze economically optimal crop rotations on the state's diverse farms.[38] The results of this analysis show that energy crops are adopted at different rates in different regions (Figure 11). Another conclusion was that when relative prices are sufficiently favorable, some new crops result in widespread adoption and a decrease in overall irrigation water use.

Figure 11: Region-Level Response to Energy Crops Introduction in a Long Term (Percent Change)



Northern California (NCA) includes the Sacramento Valley and intermountain areas, Central California (CEN) includes the northern San Joaquin Valley and part of the Delta, South San Joaquin Valley (SSJ), and Southern California (SCA) includes largely the Imperial Valley.

Source: NREL

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[37] Jenkins, B. et al. 2005. "Biomass Resource Assessment in California", April 2005, https://ww2.energy.ca.gov/publications/displayOneReport_cms.php?pubNum=CEC-500-2005-066-D

[38] Jenner, M., Kaffka, S. 2012. "Energy Crop Assessment in California Using Optimization Modeling", Draft Report, March 2012, https://biomass.ucdavis.edu/wp-content/uploads/09-20-2013-Energy-Crop-Assessment-in-California-Using-Optimization-Modeling.pdf

Fats, Oils, and Greases

Fats, oils, and greases are feedstocks used for the production of biodiesel and renewable diesel/jet fuel. This category of biomass resources includes vegetable oils, animal fats, used cooking oil and other waste greases, as well as algae oil. The animal fats and waste greases are generally low in cost and largely used in livestock feed or pet food markets.

Vegetable Oils

Oil crops currently grown in California include cottonseed, safflower, and sunflower. Cottonseed production in California was about 530,000 tons in 2011.[39] Cotton is grown primarily in the San Joaquin Valley, Palos Verde Valley, and Sacramento Valley. In 2011, about 63 percent of the U.S. safflower was grown in the state, nearly 53,200 tons.[40] San Joaquin and Sacramento Valley are the primary locations where the crop is produced. California's sunflower seed for oil production was about 19,750 tons in 2011 (preliminary estimate,).[41] The crop is grown in Sacramento Valley, mainly in Yolo, Solano, Colusa and Sutter counties.

An ongoing project in California is researching the feasibility of growing canola and mustard crops on marginal lands (poor soils and limited water availability). The trials are led by the United States Department of Agriculture Agricultural Research Service and to date, the two oilseed crops have produced about 2 tons of seed per acre, which is comparable to the yields seen in other regions of the United States and Canada.[42] Camelina is another crop considered by the biofuels industry in the state, primarily as a rotational crop on dry lands. Fresno County's Economic Opportunities Commission is partnering with Fresno State University and private energy firms, such as Sustainable Oils (acquired by Global Clean Energy Holdings, Inc. in March 2013) and Honeywell UOP, to assist with recruitment of farmers interested in participating in field testing camelina. The goal is to identify ideal circumstances in which camelina can be grown profitably in the San Joaquin Valley, including selenium-saturated areas.[43] State farm officials and the United States Department of Agriculture's Biomass Crop Assistance Program have provided financial incentives to farmers to encourage camelina growing. Other oil seed crops considered in California include pennycress and castor beans, currently being researched by United States Department of Agriculture's Agricultural Research Service and University of California, Davis Cooperative Extension.

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[39] United States Department of Agriculture. 2012. California Cottonseed, 1910-2011, U.S. Department of Agriculture, March 2012, https://www.nass.usda.gov/Publications/Highlights/2015/Highlights_Cotton.pdf

[40] AgMRC. 2012. "Safflower", November 2012, Agricultural Marketing Resource Center http://www.agmrc.org/commodities__products/grains__oilseeds/safflower

[41] United States Department of Agriculture. 2012. 2011 California Sunflower Seed for Oil Preliminary County Estimates, U.S. Department of Agriculture, March 2012,

[42] Biodiesel Magazine. 2011. California canola, mustard trials show promise, September 2011, http://www.biodieselmagazine.com/articles/8025/california-canola-mustard-trials-show-promise

[43] EOC. 2012. Board of Commissioners Meeting, Economic Opportunities Commission of Fresno County. February 2012, https://fresnoeoc.org/board/agenda/

Waste Grease

Restaurants, institutional and commercial kitchens, and other similar operations generate large amounts of grease. Generally, waste grease is divided into two major categories: yellow grease and brown grease. Yellow grease is defined as used cooking oil collected from food service facilities. Yellow grease is stored in special containers for pickup by the recycler; there is no contact with wastewater. Brown grease is defined as oil collected from grease removal devices, such as interceptors or traps, installed in commercial, industrial, or municipal sewage facilities and designed to separate grease and oil from wastewater.

Yellow and brown grease in California can be estimated using per capita waste grease generation. It is estimated that about 22 pounds of waste oils (9 pounds of yellow grease and 13 pounds of brown grease) are generated per person per year in metropolitan areas.[44] According to the 2010 Census, urban population in California was about 35.4 million, thus some 389,000 tons of waste oils are estimated to be produced per year.[45]

Animal Fats

Animal fats are derived as byproducts from meat-processing facilities. These include edible and inedible tallow from processing cattle, lard/choice white grease from swine processing, and poultry fat from the processing of chicken, turkey and other birds. A study by the Western Governors Association estimated the amount of edible and inedible tallow in California at about 47,000 tons per year.[46] About 2.5 million hogs were slaughtered in 2012.[47]

A typical slaughter weight is around 250 pounds and a 250-pound hog usually yields about 12.3 percent of its weight (or about 30.75 pounds) in lard.[48] Thus, an estimated 38,000 tons of lard were produced in the state last year. According to the U.S. Poultry and Egg Association, about 266 million chickens were slaughtered in California in 2012.[49] This number corresponds to roughly 14,660 tons of chicken fat.

Microalgae

Algae are a potential aquatic oil crop but may also yield carbohydrates that can be converted to sugar; thus, algae can be used to produce biodiesel, renewable diesel, gasoline, or jet fuel

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[44] Wiltsee, G. 1998. "Urban Waste Grease Resource Assessment", November 1998, https://www.nrel.gov/docs/fy99osti/26141.pdf

[45] U.S. Census Bureau. 2012. "Growth in Urban Population Outpaces Rest of Nation, Census Bureau Reports", March 2012, http://www.census.gov/newsroom/releases/archives/2010_census/cb12-50.html

[46] WGA. 2008. Western Governors Association, "Biomass Resource Assessment and Supply Analysis for the WGA Region", November 2008, http://www.fpl.fs.fed.us/documnts/pdf2008/fpl_2008_gordon001.pdf

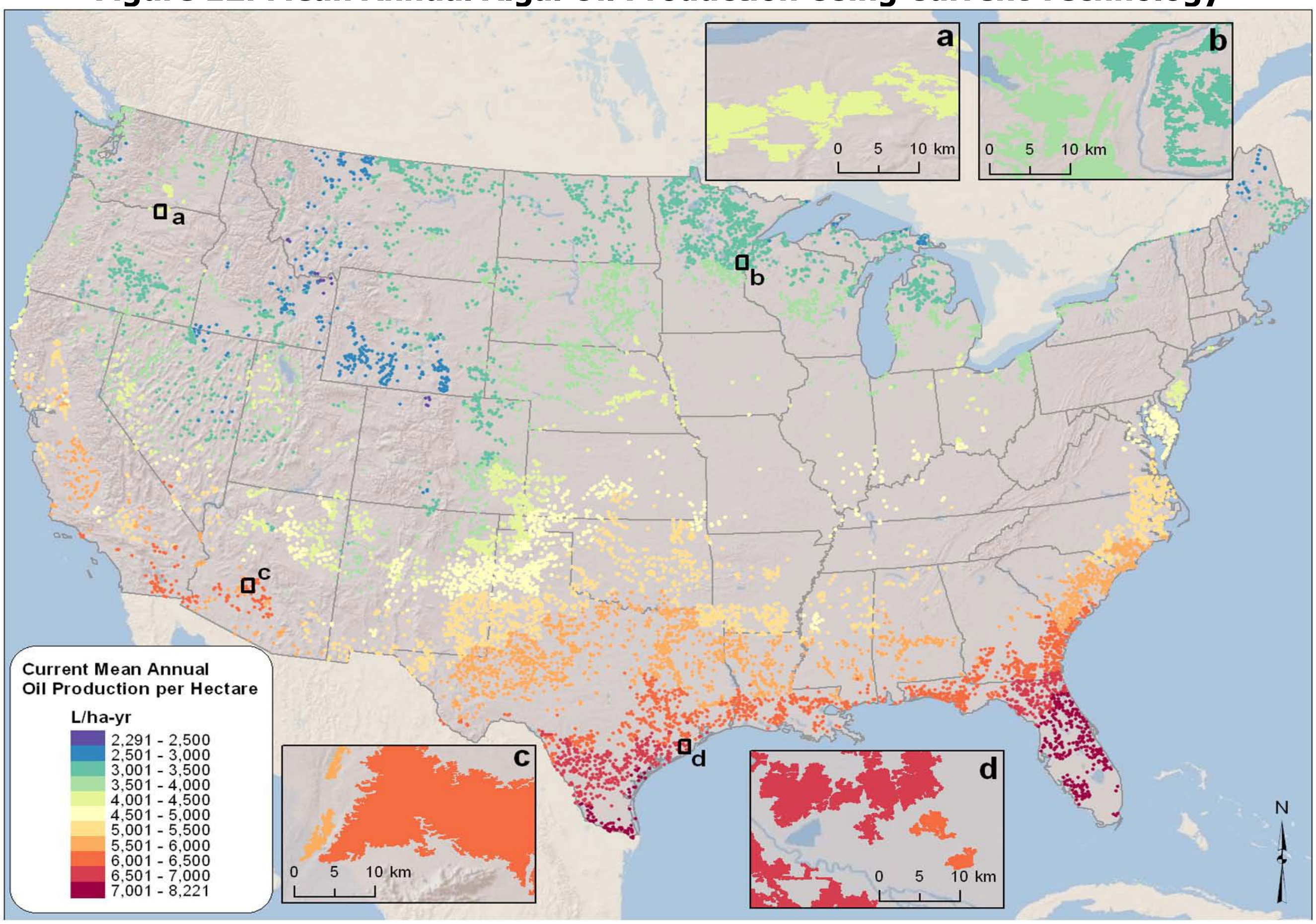
[47] United States Department of Agriculture. 2013. Quick Stats Tool, Annual Slaughter for Hogs 2012, U.S. Department of Agriculture, Accessed April 2013, http://www.nass.usda.gov/Quick_Stats/

[48] IAMP. 1924. "Lard is in important factor in modern hog production", Institute of American Meat Packers. Meat and Livestock Digest, Vol. 5 No. 1, August 1924.

[49] USPEA. 2013. Young Meat Chickens Slaughtered in 2012, U.S. Poultry & Egg Association. Accessed April 2013, http://www.uspoultry.org/economic_data/

through various conversion pathways. This feedstock has received increased attention in recent years. Given the right resources—suitable climate, availability of water, carbon dioxide (CO_2) and other nutrients—algal oil productivity can be quite high. A recent study examined the algal oil productivity at different locations in the United States.[50] Figure 12 illustrates the results of this analysis. The pattern shows a strong linkage to climate and topography—locations with warm temperatures and flat terrain are most productive. The algal oil potential in the state of California ranges from about 3,500 to 6,500 liters/ha/year, equivalent to about 315 to 585 gallons/acre/year. As a reference, soybean oil productivity is about 48 gallons/acre/year.[51]

Figure 12: Mean Annual Algal Oil Production Using Current Technology



Source: NREL

Biogas

Biogas is the gaseous product of anaerobic digestion, a biological process in which microorganisms break down biodegradable material in the absence of oxygen. Biogas is

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[50] Wigmosta, M., Coleman, A., Skaggs, R., Huessemann, M., Lane, L. 2011. "National Microalgae Biofuel Production Potential and Resource Demand", Water Resources Research, (47), https://agupubs.onlinelibrary.wiley.com/doi/full/10.1029/2010WR009966

[51] Journey to Forever. 2013. Vegetable Oil Yields, Accessed May 2013, http://journeytoforever.org/biodiesel_yield.html

composed primarily of methane (CH_4) and CO_2 and may have some amounts of hydrogen sulfide (H_2S), ammonia (NH_3), water (H_2O), nitrogen (N_2), oxygen (O_2), and hydrogen (H_2). Biogas can be produced from many sources. These include landfills, animal manure, wastewater treatment plants, and waste from the food-processing industry which are examined below.

Biogas can also be produced from lignocellulosic material through either dry fermentation, a well-developed technology in Europe, or thermochemical conversion processes, which are at pre-commercial level of development (see Chapter 4 for more information). Biogas can be upgraded to pipeline-quality gas to substitute for fossil natural gas in residential, commercial, and industrial applications, or it can be used for electricity generation. Biogas can also be used as a transportation fuel in the form of compressed or liquefied RNG (see Chapter 4).

The California Biomass Collaborative estimated the landfill gas generation potential in California, from more than 300 major landfills, at between 118 and 156 billion cubic feet per year (BCF/year).[52] The methane equivalent is 59 to 78 BCF/year or between 1.2 and 1.6 million tons per year. As of June 2012, there were 75 landfills in California capturing biogas.[53] Most of these landfills use biogas to produce electricity; only two landfills use biogas to produce transportation fuels (liquefied and compressed renewable natural gas)—Altamont Landfill & Resource Recovery in Livermore, Alameda County, and Central Disposal Site in Petaluma, Sonoma County. About 36 landfills in the state are designated as "candidate" landfills by the U.S. EPA, meaning that these sites could support landfill gas projects (Table 10). U.S. EPA defines a candidate landfill as "one that is accepting waste or has been closed for five years or less, has at least one million tons of waste, and does not have an operational or under-construction project; candidate landfills are also designated based on actual interest or planning." [53]

[52] CBC. 2005. "Biomass Resource Assessment in California", California Biomass Collaborative. April 2005, https://ww2.energy.ca.gov/publications/displayOneReport_cms.php?pubNum=CEC-500-2005-066-D

[53] U.S. EPA. 2012b. Landfill Outreach Methane Program "Energy Projects and Candidate Landfills", http://www.epa.gov/lmop/projects-candidates/index.html, June 28 2012

Table 10: Candidate Landfills in California

Landfill Name	Landfill City	Landfill County	Waste In Place (tons)	Year Landfill Opened	Landfill Closure Year	Landfill Owner Organization
Sunshine Canyon Landfill	Sylmar	Los Angeles	35,132,654	1961	2037	Republic Services, Inc.
Fink Road LF	Crows Landing	Stanislaus	34,000,000	1973	2010	Stanislaus County, CA
Frank R. Bowerman SLF	Irvine	Orange	31,000,000	1989	2053	County of Orange - OC Waste & Recycling, CA
Tri-Cities Landfill	Fremont	Alameda	16,814,600	1967	2011	Waste Management, Inc.
Avenal LF	Avenal	Kings	15,600,000	N/A	2020	City of Avenal, CA
Vasco Road SLF	Livermore	Alameda	13,859,578	1962	2019	Republic Services, Inc.
American Avenue Disposal Site	Kerman	Fresno	10,940,996	1971	2059	Fresno County, CA
Lamb Canyon Disposal Site	Beaumont	Riverside	9,202,200	1970	2040	Riverside County, CA
San Timoteo Sanitary Landfill	Redlands	San Bernardino	6,844,500	1995	2016	San Bernardino County, CA
Edom Hill Disposal Site	Desert Hot Springs	Riverside	6,100,000	1967	2004	Riverside County, CA
Antelope Valley Public LF	Palmdale	Los Angeles	6,094,095	1958	2027	Palmdale Disposal Company, Inc.
Highway 59 Disposal Site	Merced	Merced	4,816,019	1972	2030	Merced County, CA
Arvin SLF	Arvin	Kern	4,171,392	1971	2003	Kern County, CA
Kirby Canyon Recycling & Disposal Facility	Morgan Hill	Santa Clara	3,800,000	1986	2035	Waste Management, Inc.
China Grade SLF	Bakersfield	Kern	3,608,940	1983	1992	Kern County, CA
North County Recycling Center and Sanitary LF	Lodi	San Joaquin	3,480,000	1991	2048	San Joaquin County, CA
Lancaster Landfill	Lancaster	Los Angeles	3,392,730	1954	2036	Waste Management, Inc.
Shafter-Wasco SLF	Shafter	Kern	3,164,654	1972	2056	Kern County, CA
West Central LF	Anderson	Shasta	3,120,000	1982	2030	Shasta County, CA
Ridgecrest-Inyokern SLF	Ridgecrest	Kern	3,013,520	1969	2024	Kern County, CA
Foothill Sanitary Landfill, Inc.	Linden	San Joaquin	2,460,000	1965	2082	San Joaquin County, CA
Red Bluff Landfill	Red Bluff	Tehama	1,872,178	1956	2052	Tehama County, CA
Cummings Road Landfill	Eureka	Humboldt	1,825,212	1935	2000	Humboldt Waste Management Authority, CA
Bonzi SLF	Modesto	Stanislaus	1,800,000	1967	2017	Rudi Bonzi Inc
Tehachapi SLF	Tehachapi	Kern	1,649,600	1973	2015	Kern County, CA
Pacheco Pass SLF	Gilroy	Santa Clara	1,316,000	1950	2010	Recology
Fairmead Solid Waste Disposal Site	Chowchilla	Madera	1,200,000	1958	2033	Madera County, CA
Anderson Solid Waste Disposal Site	Anderson	Shasta	1,035,000	1976	2065	Republic Services, Inc.
Amador County SLF	Ione	Amador	1,013,553	N/A	2006	Amador County, CA
Redwood SLF	Novato	Marin	1,000,000	1958	2031	Waste Management, Inc.
Ramona LF	Ramona	San Diego	947,800	1969	2009	Republic Services, Inc.
Healdsburg Landfill	Healdsburg	Sonoma	900,000	1971	1989	Sonoma County, CA
Vandenberg Air Force Base LF	Vandenberg AF Base	Santa Barbara	896,374	1941	2064	United States Air Force
Johnson Canyon Landfill	Gonzales	Monterey	430,000	1976	2042	Salinas Valley Solid Waste Authority, CA
CWMI - KHF (MSW Landfill B-19)	Kettleman City	Kings	N/A	N/A	2094	Chemical Waste Management
Forward Inc. Landfill	Manteca	San Joaquin	N/A	N/A	2028	Republic Services, Inc.

Source: U.S. EPA

California has an excellent market potential for biogas production from dairy. There are more than 1,700 dairy farms in the state,[54] of which about 889 are considered good candidates for biogas projects, able to generate about 16.5 BCF/year of methane (341,000 tons/year).[55]

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[54] Amon, R., Jenner, M., El-Mashad, H., Williams, R., and Kaffka, S. 2011 (DRAFT report). California's Food Processing Industry: Organic Residue Assessment. California Energy Commission. CEC PIER Contract 500-08-017.

[55] U.S. EPA. 2011. "Market Opportunities for Biogas Recovery Systems at U.S. Livestock Facilities", November 2011, https://www.epa.gov/sites/production/files/2018-06/documents/epa430r18006agstarmarketreport2018.pdf

Despite this, there are currently only 11 operating biogas-capturing dairy farms in the state.[56] Of these, only one produces vehicle fuel—Hilarides Dairy located in Lindsay, Tulare County. The remaining dairies use the captured biogas to produce electricity. Dairy farming in California is concentrated primarily in the San Joaquin Valley.

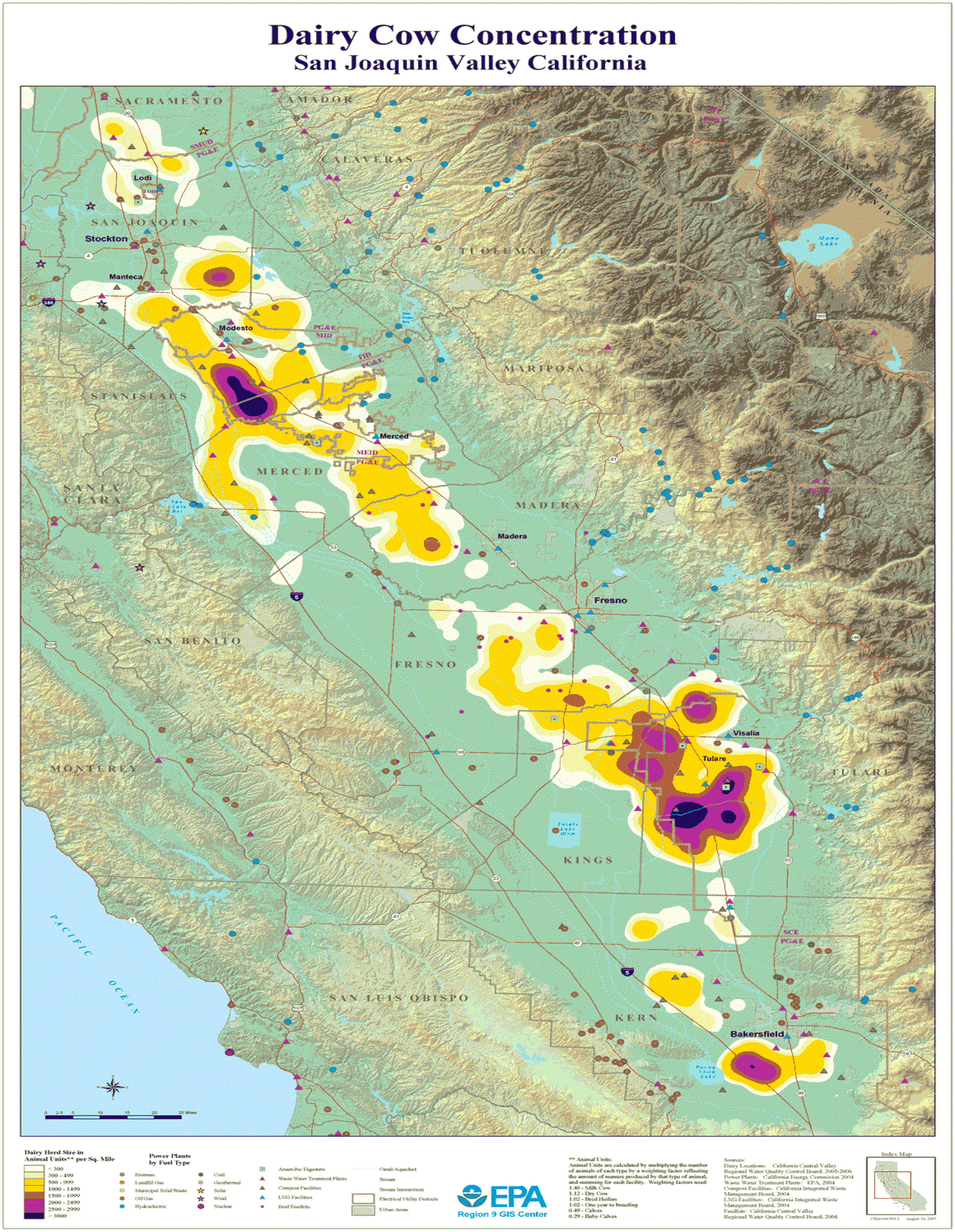
[56] ARB. Dairy and Livestock Greenhouse Gas Emissions Working Group, California Air Resources Board, https://ww2.arb.ca.gov/our-work/programs/dairy-and-livestock-wg

Figure 13 illustrates the density of dairy cows in the Valley with different colors representing animal units per square mile.[57] A recent study by the California Biomass Collaborative points out that the existing manure digester projects utilize less than 1 percent of technically available energy from manure.[58] The study estimates that about 4.5 million dry tons of animal manure is available in the state (from cattle, poultry, horse, and pig manure), concentrated primarily in the Central Valley.

[57] University of California Davis "Managing Dairy Manure in the Central Valley of California" http://groundwater.ucdavis.edu/files/136450.pdf

[58] Kaffka, S., Amon R., Button, J., Jenner, M., Jenkins, B., Wickizer, D. 2011. "California Biomass Collaborative (CBC) summary of current biomass energy resources for power and fuel in California", May, 2011, https://biomass.ucdavis.edu/wp-content/uploads/09-20-2013-2012-01-summary-of-current-biomass-energy-resources.pdf

Figure 13: Dairy Cow Concentration in the San Joaquin Valley, California



Source: U.S. EPA

Some wastewater treatment plants use anaerobic digestion to break down sewage sludge and eliminate pathogens in wastewater. In the process, biogas is created as a byproduct that could be captured and used as an energy source. In its 2005 assessment, the California Biomass Collaborative indicated that more than 240 wastewater treatment plants in California treat sewage and other wastewater prior to discharge. The biogas resource potential from wastewater treatment was estimated at 16 BCF/year with a methane concentration of 60 percent, thus about 9.6 BCF/year (198,000 tons/year) methane equivalent. California Biomass Collaborative reported that at the end of 2011 there were 140 wastewater treatment plants with anaerobic digesters, 94 of which used the methane locally.[59]

Biogas can also be produced from food-processing industrial waste. A recent study estimated that 12.8 BCF/year of biogas could be produced from the following food-processing activities: fruit and vegetable canneries, dehydrated and fresh/frozen fruit and vegetable processors, dairy creameries, wineries, and meat processors[54] (Table 11). Assuming that methane content is about 60 percent of total biogas, the methane potential from the food-processing industry comes to about 7.7 BCF/year (or 159,000 tons). The study gives more details by county and points out that most of these resources are not readily available for energy conversion, particularly the residues from cheese manufacturing and animal processing, given their high value as byproducts. The authors conclude that the most promising resources are those from the fruit and vegetable processing industries.

Table 11: Biogas Potential from Food-Processing Resources in California

Food-Processing Sector	Wastewater		High Moisture Solids		Low Moisture Solids	
	MMscf	MMBtu	MMscf	MMBtu	MMscf	MMBtu
Fruits and Vegetables						
Cannery	968	613,030	608	385,280	875	554,240
Dehydrated F&V	47	29,850	291	184,510	1,406	890,340
Fresh/Frozen F&V	487	308,390	332	210,340	N/A	N/A
Subtotal, Fruits and Vegetables	**1,502**	**951,270**	**1,232**	**780,130**	**2,281**	**1,444,580**
Meat Processing						
Poultry	133	84,290	1,649	1,044,260		
Red Meat	507	320,920	2,419	1,532,560		
Subtotal, Meat Processing	**640**	**405,210**	**4,068**	**2,576,820**		
Creamery						
Milk	298	188,740				
Cheese	359	227,590				
Ice cream/Butter	105	66,480				
Subtotal, Creamery	**762**	**482,810**				
Other						
Winery	117	74,000	2,229	1,411,810		
Total	**3,020**	**1,913,290**	**7,528**	**4,768,760**	**2,281**	**1,444,580**

MMscf – million standard cubic feet; MMBtu – million British thermal units.

Source: NREL

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[59] CBC. 2011. Biomass Facilities Database, California Biomass Collaborative. December 1st, 2011, http://biomass.ucdavis.edu/tools/

Food waste substrates may also be used in animal digesters or wastewater treatment plants to improve methane generation in a process known as co-digestion. Co-digestion is the addition of energy-rich organic waste materials such as food scraps and fats, oils, and greases to an existing anaerobic digestion facility. By doing so, resources are diverted from landfills and/or sewer pipes, reducing methane emissions from landfills and providing a renewable energy source.

Total Biomass Resources

Table 12 summarizes the total biomass resources available in California. As noted earlier, these are estimates of technical potential, that is, amounts of feedstock that would be physically and technologically feasible to produce. These are not estimates of gross potential (the maximum, theoretical biomass resource potential) or market potential (e.g., assessing market benefits, barriers to implementation, competition with other energy sources, and legislative climate).

Of the lignocellulosic material, woody biomass (forest thinnings, logging slash, sawmill residues, shrub/chaparral and orchard/vineyard prunings) is by far the largest contributor, representing about 61 percent of the total. As stated in Chapter 6, about 691 million gasoline gallon equivalent (Mgge) of ethanol could be produced in California from woody biomass via thermochemical conversions, or 640 Mgge of renewable gasoline could be produced through the methanol-to-gasoline pathway. This potential does not include resources currently used for power generation. California consumed about 1.8 billion gallons of gasoline in 2012.[25] Thus, in-state biomass-derived fuels could displace between 38 percent and 35 percent of the state's current gasoline consumption.

California could produce about 179 million gallons of biodiesel or 146 million gallons of renewable diesel from locally-sourced fats, oils, and greases.[60] About 4 billion gallons of diesel are used in California every year, of which 67 percent is on highways.[61] Thus, assuming that all material is available for fuel production, the potential amount of biodiesel and renewable diesel from fats, oils, and greases could replace about 7 percent and 5.5 percent, respectively, of current diesel consumption on highways.

If all technically available biogas resources were fully utilized, California could produce about 2 million tons (equivalent to approximately 102 BCF) of methane per year. The state consumed about 15.5 BCF of natural gas in the transportation sector in 2012.[62] Thus, the technical potential for RNG using biogas sources represents a significant share of the transportation sector.

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[60] About 300 gallons of biodiesel, using a transesterification process, could be produced per ton of fats, oils, and greases (average industry practices). About 245 gallons of renewable diesel could be produced per ton of triacylglycerol oil via hydroprocessing.

[61] U.S. EIA. 2012d. Sales of Distillate Fuel Oil by End Use, November 2012, http://www.eia.gov/dnav/pet/pet_cons_821dst_dcu_SCA_a.htm

[62] U.S. EIA. 2013i. Natural Gas Consumption by End Use, May 2013, U.S. Energy Information Administration. http://www.eia.gov/dnav/ng/ng_cons_sum_dcu_SCA_a.htm (b)

Table 12: Total Biomass Resources in California

Biomass Resource	tons/year
Lignocellulosic Biomass	
Crop residues (field and seed crops)	2,000,000
Crop residues (vegetable crops)	128,000
Rice hulls	297,000
Cotton gin trash	103,000
Almond shells	496,000
Walnut shells	199,000
Logging slash	4,300,000
Forest thinnings	4,100,000
Sawmill residues	3,300,000
Shrub or chaparral	2,600,000
Orchard and vineyard prunings	1,700,000
MSW (brown material)	6,898,664
Total Lignocellulosic Biomass	**26,121,664**
FOG	
Cottonseed oil	85,000
Safflower oil	14,151
Sunflower oil	7,900
Waste oils (yellow and brown grease)	389,000
Beef tallow	47,000
Lard	38,000
Chicken fat	14,660
Total FOG	**595,711**
Methane	
LFG	1,400,000
Dairy farms	341,000
WWTP	198,000
Food-processing waste	159,000
Total Methane	**2,098,000**

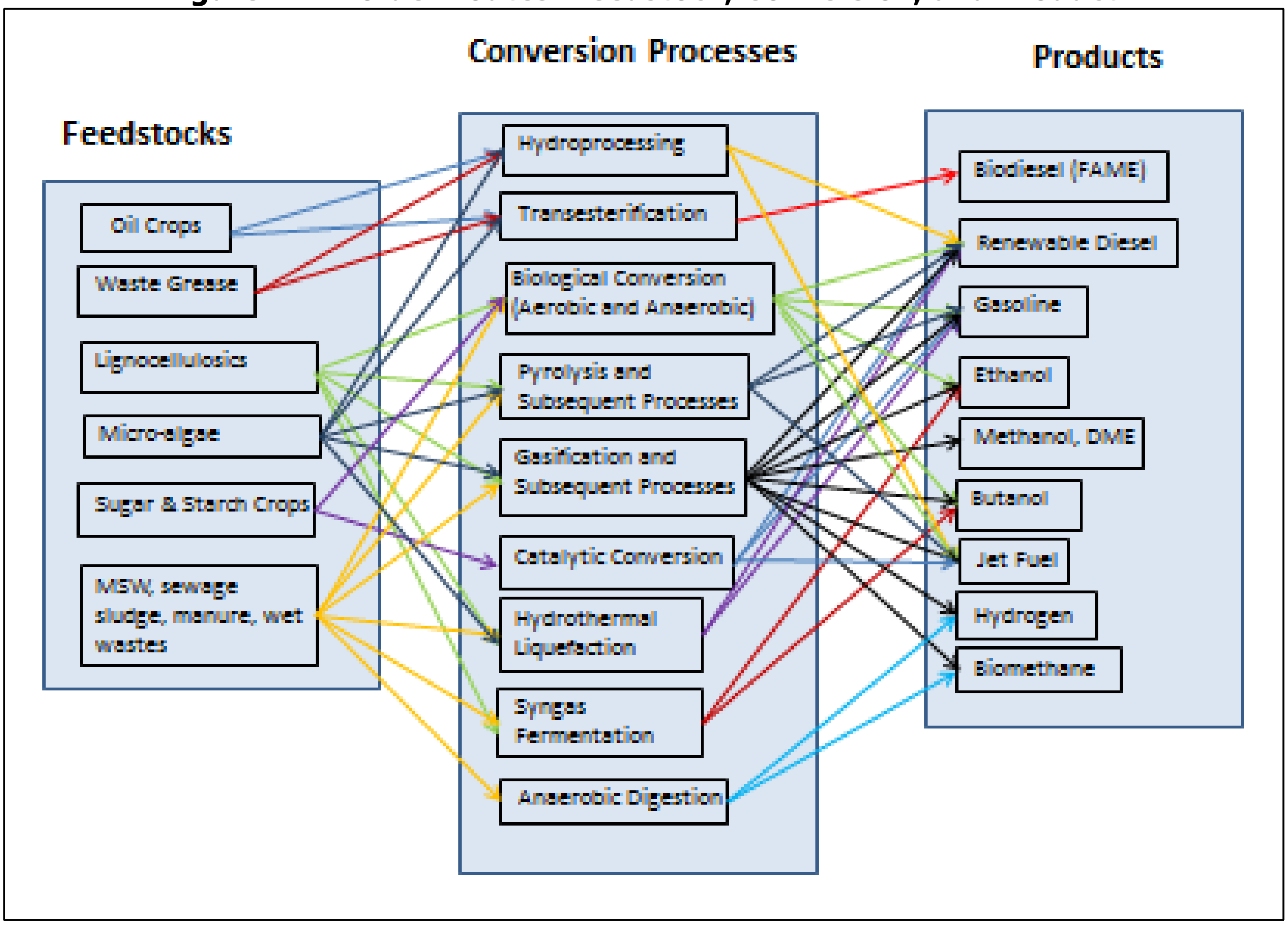
Source: NREL

CHAPTER 4:
Fuel Production Processes

Overview of Fuel Production Processes

Many processes are used to convert biomass feedstocks to renewable fuels. They vary based on chemical composition of the feedstock and the desired fuel product. As the subsequent sections of Chapter 4 are separated by fuel product, Figure 14 demonstrates the plethora of feedstock and conversion process routes that can lead to each product.

Figure 14: Biofuel Routes: Feedstock, Conversion, and Product



Source: NREL

A brief overview is given here of the processes based on technology conversion pathway. As shown in Figure 14 there are many overlaps in conversion processes and final fuel products because in many of the processes, the final fuel product can be varied with minor process modifications.

Biochemical Conversion Processes

The conversion of biomass to usable sugars via biochemical processes is and has been a topic of pique interest in recent years. This is the process most commonly used for the production of ethanol from corn and is widely researched for the production of ethanol from corn stover and other lignocellulosic feedstocks. The hydrolysis and fermentation process is described in detail by Humbird.[63] With recent interest in drop-in fuels this process has been varied by changing the fermentation process to more of an aerobic respiration process which can produce hydrocarbon fuels, specifically in the diesel range. For more information on this process see "Fermentation of Sugars to Hydrocarbons" [64] or "Biological Conversion of Sugars to Hydrocarbons Technology Pathway".[65]

The biochemical conversion process of enzymatic hydrolysis uses a mixture of enzymes to break down the cellulose fibers ultimately into glucose monomers.[63] The resulting glucose and other sugars can go on to form the following fuel products:

1. Ethanol via fermentation
2. Hydrocarbons via aerobic biological conversion
3. Hydrocarbons via catalytic conversion

The lignin and other residual products are typically utilized to provide process heat and power.

Thermochemical Conversion Processes

Thermochemical conversion occurs via two main processes. The first is gasification, which leads to a syngas followed by alcohol and possible subsequent fuel syntheses. The second is pyrolysis, which produces a bio-oil. Both will be discussed in this section.

Gasification – Gasification is practiced commercially worldwide using coal and petroleum as feedstocks. Biomass gasification was used in Europe during World War II to produce fuel for more than a million vehicles.[66] However, it has not been commercially practiced since then. Currently there are many demonstration systems making syngas suitable for producing fuels.

Gasification of the biomass feedstock yields a syngas containing H_2 and carbon monoxide (CO). The syngas proceeds through tar reforming to reform any tars, methane, or hydrocarbons to CO and H_2. The reformed syngas goes through a quench to remove

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[63] Humbird, D.; Davis, R.; Tao, L.; Kinchin, C.; Hsu, D.; Aden, A.; Schoen, P.; Lukas, J.; Olthof, B.; Worley, M.; Sexton, D.; Dudgeon, D. 2011. Process Design and Economics for Biochemical Conversion of Lignocellulosic Biomass to Ethanol: Dilute-Acid Pretreatment and Enzymatic Hydrolysis of Corn Stover. 147 pp.; NREL Report No. TP-5100-47764.

[64] EERE. 2012. "Fermentation of Sugars to Hydrocarbons." Bioenergy Technologies Office, US Department of Energy, Energy Efficiency and Renewable Energy. 2012. https://www.energy.gov/sites/prod/files/2014/04/f14/biological_conversion_of_sugars_to_hydrocarbons.pdf

[65] Davis, Ryan, Mary Biddy, Eric Tan, and Susanne Jones. 2013. Biological Conversion of Sugars to Hydrocarbons Technology Pathway. NREL and PNNL, March 2013. http://www.nrel.gov/docs/fy13osti/58054.pdf.

[66] Stiles, Dennis L., Susan A. Jones, Rick J. Orth, Bernard F. Saffell, and Yunhua Zhu. 2008. "Biofuels in Oregon and Washington: A Business Case Analysis of Opportunities and Challenges". PNNL-17351. Richland, WA: Pacific Northwest National Laboratory. http://www.osti.gov/energycitations/product.biblio.jsp?query_id=1&page=0&osti_id=963246.

particulates and other contaminants. Detailed information on this process can be found in Dutta 2011.[67]

Syngas can be converted to the following fuels:

1. Ethanol via mixed alcohols
2. Ethanol or butanol via syngas fermentation
3. Diesel or jet fuel via Fischer-Tropsch synthesis
4. Methanol, which can subsequently be converted to a range of fuels including dimethyl ether (DME), gasoline, diesel, and jet fuel (via Methanol-to-Gasoline or Mobil Olefins-to-Gasoline/Diesel)
5. Gaseous fuels including biomethane and hydrogen

Pyrolysis and Liquefaction – Both pyrolysis and liquefaction processes have had limited practice in the production of fuel for boilers or stationary power, but the resulting oils can also be upgraded to liquid transportation fuel.[66] Both processes convert primarily lignocellulosic feedstock to fuels. Due to the different process conversions, the severity of the bio-oil may vary, and thus different upgrading configurations may be required. However, these different upgrading configurations involve similar de-oxygenation chemistry.[66]

Transesterification and Hydroprocessing Conversion Processes

Transesterification and hydroprocessing processes produce biodiesel and renewable diesel from oil-based fats, oils and greases. Because oil crops and waste greases have greater similarities with their corresponding fuel products, these processes tend to be less complex.

Potential Conversion Processes for Algae

With sunlight and carbon dioxide, microalgae produce triglycerides that can then be converted to biodiesel or renewable diesel via transesterification or hydroprocessing, respectively.[65] Other conversion routes being pursued for algae include hydrothermal liquefaction, pyrolysis, and gasification.

Advanced Ethanol and Gasoline Substitutes

Gasoline is the most-consumed liquid fuel in the United States. U.S. EIA estimated that in 2011, California's consumption of motor gasoline (including ethanol) was 1,770.1 trillion Btu (14.16 million gallons), accounting for 9 percent.[68] Ethanol is the most developed, commercially available gasoline alternative and currently holds approximately 10 percent of the gasoline market share in the United States. Beyond ethanol, renewable gasoline,

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[67] Dutta, A., M. Talmadge, J. Hensley, M. Worley, D. Dudgeon, D. Barton, P. Groenendijk, et al. 2011. "Process Design and Economics for Conversion of Lignocellulosic Biomass to Ethanol". TP-5100-51400. NREL. http://www.nrel.gov/docs/fy11osti/51400.pdf.

[68] U.S. EIA. 2010 and 2011. State Energy Data System. U.S. Energy Information Administration. Available: accessed 5/22/2013, http://www.eia.gov/state/seds/.

methanol, and DME[69] all could substitute for fossil-fuel-based gasoline.[70] Of these, renewable gasoline is the only product that can be considered a 'drop-in' fuel replacement. Gasoline substitutes vary in nature and thus have different energy contents, or energy densities. Energy density is of interest because it determines distance per unit volume or weight for a given engine or vehicle. Table 13 shows the energy densities of gasoline, ethanol, and gasoline substitutes.[71]

Table 13: Energy Densities

Fuel	**Energy Density (megajoule (MJ)/kilogram (kg))**
Gasoline	46
Renewable Gasoline	44
Ethanol	25
Methanol	21
DME[72]	28
Butanol[73]	41

Source: NREL

Process Conversion Technologies for Gasoline Replacements

Ethanol

Ethanol is an alcohol-based fuel that can be blended with gasoline. It is made by fermenting and distilling starch and sugar crops such as corn, sugar cane, and sugar beets. It can also be made from the sugars in "cellulosic biomass" such as trees and grasses. Ethanol can also be produced by the thermochemical process of gasification. The syngas from biomass gasification can be converted to ethanol via catalysis for mixed alcohol synthesis or biologically through fermentation.

In the United States, ethanol is typically blended into gasoline at the 10 percent level, which is also called gasohol or E10 and can run in light- and heavy-duty on-road internal combustion engines without modification. Most gasoline in the United States is E10. Flex-fuel vehicles can

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[69] Phillips, S. D., J. K. Tarud, M. J. Biddy, and Dutta, A. 2011. Gasoline from Wood via Integrated Gasification, Synthesis, and Methanol-to-Gasoline Technologies. TP-5100-47594. NREL, January 2011. http://www.nrel.gov/docs/fy11osti/47594.pdf.

[70] Bunting, Bruce, Bunce, Mike, Barone, Teresa, and Storey, John. 2010. Oak Ridge National Laboratory (ORNL), September 30, 2010.

[71] U.S. EIA. 2013. "Few transportation fuels surpass the energy densities of gasoline and diesel." Today in Energy. February 14. http://www.eia.gov/todayinenergy/detail.cfm?id=9991.

[72] BioDME. 2013. "About DME." http://www.biodme.eu/about-dme.

[73] BioButanol. 2013. "Biobased Butanol Info." http://www.biobutanol.com/.

run on E85 (85 percent ethanol and 15 percent gasoline) or regular (E10) gasoline. Ethanol has a lower energy density than gasoline; thus flex-fuel vehicles running on E85 see approximately a 25-30 percent decrease in miles per gallon, and vehicles running on gasohol tend to see a 3-4 percent decrease in miles per gallon.[74] Ethanol is a legally registered fuel when it meets specifications for American Society for Testing and Materials (ASTM) D4806 (standard or regular) and ASTM D5798 (E85). These ethanol percentages are estimations, not exact percentages.

Grain Ethanol Production

The feedstock is received, conveyed, hammer milled, then metered to a continuous liquefaction tank, where it is mixed with condensate and enzymes. This mixture proceeds to saccharification then is fermented, with an addition of yeast, for approximately 40-50 hours. Distillation is utilized to recover the ethanol, which is 12 percent by volume leaving fermentation.[75] The feedstock for this process is most often corn but can also be wheat, milo, or sugarcane. This process is both commercially available and widely utilized. A significant challenge for this process is the use of edible starches and sugars to produce fuel, often referred to as "food vs. fuel". Companies to note in this area: Archer Daniels Midland, Phoenix Biofuels, EdeniQ.

Production of Cellulosic Ethanol from Fermentation

The cellulosic feedstock, frequently corn stover, goes through size reduction followed by pretreatment and detoxification. This is followed by enzymatic hydrolysis (or saccharification) coupled with co-fermentation. Subsequent distillation recovers the ethanol product.[76] Other cellulosic feedstocks include non-food-based feedstocks such as crop residues, wood residues, dedicated energy crops, and industrial and other wastes. However, it is difficult to release the sugars from cellulosic feedstocks for conversion to ethanol. As shown by the large number of companies investigating and working with this process, it is of high interest. Companies to note in this area: Haldor Topsoe, Abengoa, POET, Blue Sugars, BP Biofuels, Dupont, EdeniQ, Fiberight, BlueFire, Verenium, Beta Renewables, Blue Sugars, DuPont Biofuels Solutions, BP Biofuels, American Process, Archer Daniels Midland, ICM, and Algenol. Many of these companies plan to initiate commercial-scale production in 2013 and 2014.

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[74] U.S. DOE. 2013a. "Ethanol." U.S. Department of Energy. April 19, 2013. http://www.fueleconomy.gov/feg/ethanol.shtml.

[75] McAloon, A., F. Taylor, W. Yee, K. Ibsen, and R. Wooley. 2000. "Determining the Cost of Producing Ethanol from Corn Starch and Lignocellulosic Feedstocks." Golden, CO: National Renewable Energy Laboratory, October 25, 2000. http://www.osti.gov/energycitations/product.biblio.jsp?query_id=1&page=0&osti_id=766198.

[76] Aden, A., M. Ruth, K. Ibsen, J. Jechura, K. Neeves, J. Sheehan, B. Wallace, L. Montague, A. Slayton, and J. Lukas. 2002. "Lignocellulosic Biomass to Ethanol Process Design and Economics Utilizing Co-Current Dilute Acid Prehydrolysis and Enzymatic Hydrolysis for Corn Stover." Golden, CO: National Renewable Energy Laboratory, June 1, 2002. http://www.osti.gov/energycitations/product.biblio.jsp?query_id=2&page=0&osti_id=15001119.

Cellulosic Ethanol from Gasification

Gasification of the cellulosic feedstock yields a syngas containing H_2 and CO. The syngas goes through tar reforming to convert tars, methane, or hydrocarbons to CO and H_2; particulates and other contaminants are removed by a quenching and scrubbing process; and a synthesis catalyst is used to convert the cleaned syngas either directly to ethanol or to mixed alcohols with subsequent separation of ethanol.[67] Woody residues are the primary feedstock for this process but other cellulosic feedstocks such as crop residues, energy crops, municipal solid waste, and other waste streams can be used. An important challenge for this process is the removal of tars in order to protect the alcohol synthesis catalysts. Companies to note in this area: Fulcrum, Enerkem, Haldor Topsoe, ThermoChem Recovery, Renewable Energy Institute International, and Rentech.

Production of Cellulosic Ethanol from Gasification/Fermentation

Syngas from gasification enters a fermentation broth with a microbe that produces ethanol—combining thermochemical and biochemical conversion processes to obtain ethanol from cellulosic feedstocks. The key to this technology is the ethanol-producing microbe, which can be very sensitive to process variations or impurities in the gas. This technology is moving toward commercialization with plants opening in 2012 (IneosBIO), 2013 (Lanzatech), and early 2014 (Coskata). Companies to note in this area: Lanzatech, Coskata, IneosBIO.

Production of Cellulosic Ethanol from Consolidated Bioprocessing

Biological conversion is consolidated into a single step without added cellulase enzymes. The key to this single-step process is the microorganisms, and their development is challenging. The microoganisms must utilize cellulose and other fermentable compounds in pretreated biomass with high conversion rates and must produce the desired product at high yield and titer.[77] The ability to genetically compile several complex biosynthetic pathways into a single cell simplifies the process and raw material requirements.[78] This process is moving to the commercial scale through a partnership between Valero and Mascoma set to be completed in 2013. Companies to note in this area: Mascoma.

Renewable Gasoline

Renewable gasoline (also known as biogasoline or green gasoline) is a collection of gasoline-range hydrocarbons derived from biomass. The similarities between renewable gasoline and petroleum gasoline qualify it as a 'drop-in' fuel, thus it is functionally equivalent to gasoline and can be used in existing vehicles and infrastructure. Currently, renewable gasoline processes are primarily at the lab, pilot, and demonstration scales.

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[77] Lynd, Lee R, Willem H van Zyl, John E McBride, and Mark Laser. 2005. "Consolidated Bioprocessing of Cellulosic Biomass: An Update." Current Opinion in Biotechnology 16, no. 5 (October 2005): 577–583. doi:10.1016/j.copbio.2005.08.009.

[78] Steen, Eric J., Yisheng Kang, Gregory Bokinsky, Zhihao Hu, Andreas Schirmer, Amy McClure, Stephen B. del Cardayre, and Jay D. Keasling. 2010. "Microbial Production of Fatty-acid-derived Fuels and Chemicals from Plant Biomass." Nature 463, no. 7280 (January 28, 2010): 559–562. doi:10.1038/nature08721.

Renewable Gasoline via Pyrolysis

A route to renewable gasoline is to convert lignocellulosic biomass via pyrolysis. In the pyrolysis process organic material is decomposed in the absence of oxygen to produce char, gas, and a liquid product rich in oxygenated hydrocarbons. Pyrolysis is performed over a range of temperatures and residence times to optimize the desired product. In the case of fast pyrolysis, the biomass is heated to approximately 500°C in less than 1 second and then rapidly cooled. For catalytic fast pyrolysis, direct liquefaction of biomass by pyrolysis and pyrolysis vapor upgrading can occur in the same vessel (in-situ catalytic fast pyrolysis) or in separate vessels (ex-situ catalytic fast pyrolysis). The liquid product, bio-oil, is a mixture of liquids spanning the gasoline and diesel range and some byproduct gas. The gasoline and diesel range products are upgraded for blending into finished fuel.[79] Important needs for the success of this process are the development of catalysts with improved yields, stability, and lifetimes, and optimized hydrotreatment of catalytic fast pyrolysis bio-oils.[80] KiOR's Columbus commercial plant began making shipments of renewable gasoline and diesel in early 2013.[81] Other commercialization plans for pyrolysis are in the 2013-to-2015-time frame. Companies to note in this area: Dynamotive, KiOR, UOP, Evergent, Ensyn.

Renewable Gasoline from Integrated Hydropyrolysis with Hydroconversion

The lignocellulosic feedstock is converted to gas and liquid in the presence of hydrogen in a pressurized fluid-bed hydropyrolysis reactor. The vapor from this stage is directed to a hydroconversion unit that removes oxygen, and thus produces deoxygenated gasoline and diesel products. The hydrogen required for the hydropyrolysis process is obtained by condensing the liquid and the C3- gas from the process, which is then sent to an integrated steam reformer.[82] Catalyst life and stability are important research areas for process success. A 50 kg/day pilot scale demonstration was completed in 2012 by GTI. Further research of this process is being pursued by RTI within the National Advanced Biofuels Consortium. Research organizations to note in this area: GTI, RTI. Companies to note in this area: Cri Criterion/Shell.

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[79] Jones, S.B.; Valkenburg, C.; Walton, C.; Elliot, D.C.; Holladay, J.E.; Stevens, D.J.; Kinchin, C.; Czernik, S. 2009. "Production of Gasoline and Diesel from Biomass via Fast Pyrolysis, Hydrotreating and Hydrocracking: A Design Case." Richland, WA: Pacific Northwest National Laboratory, 2009. http://www.osti.gov/energycitations/product.biblio.jsp?query_id=0&page=0&osti_id=949907.

[80] Biddy, Mary, Abhijit Dutta, Susanne Jones, and Aye Meyer. 2013b. "In-Situ Catalytic Fast Pyrolysis Technology Pathway." NREL and PNNL, March 2013. http://www.nrel.gov/docs/fy13osti/58056.pdf.

[81] Biomass Magazine. 2013. "KiOR Production Facilities." Accessed May 27, 2013. http://biomassmagazine.com/articles/9482/kior-to-double-production-capacity-at-mississippi-plant.

[82] Marker, Terry, Michael Roberts, Martin Linck, Larry Felix, Pedro Ortiz-Toral, Jim Wangerow, Eric Tan, John Gephart, and David Shonnard. 2013. "Biomass to Gasoline and Diesel Using Integrated Hydropyrolysis and Hydroconversion." DOE/EE0002873. Washington, DC: U.S. Department of Energy, January 2, 2013. http://www.osti.gov/energycitations/product.biblio.jsp?query_id=3&page=0&osti_id=1059031

Renewable Gasoline from Gasification and Methanol-to-Gasoline or Mobil Olefins-to-Gasoline/Diesel

Renewable gasoline from gasification can be produced via MTG (Methanol-to-Gasoline) or Mobil olefins-to-gasoline/diesel processes, both developed by Mobil. In addition, other companies have developed variations of the Methanol-to-Gasoline technology. Biomass gasification heats the cellulosic biomass (primarily woody residues), which produces a synthesis gas rich in H_2 and CO. The synthesis gas is then converted to methanol via a copper/zinc oxide/alumina catalyst. The subsequent Methanol-to-Gasoline or Mobil Olefins-to-Gasoline/Diese; processes convert the methanol to the desired gasoline or diesel product by use of zeolite catalysts.[83] This occurs via olefins in the Mobil Olefins-to-Gasoline/Diesel case and via DME in the Methanol-to-Gasoline case. Mobil ran a commercial plant producing Methanol-to-Gasoline in New Zealand and a pilot Mobil Olefins-to-Gasoline/Diesel facility in Germany in the 1980s (both using natural gas). In the case of the Methanol-to-Gasoline process, the ability to use a fluidized-bed reactor instead of several fixed-bed reactors significantly improves the economics, but this has not been proven commercially and thus is an important research topic. Companies to note in this area: Exxon Mobil, Primus Green, Sundrop, and CORE BioFuel.

Renewable Gasoline from Fermentation

Cellulosic feedstock is converted to renewable gasoline through the same steps as the ethanol from fermentation process, including pretreatment, enzymatic hydrolysis and conditioning, and fermentation. The largest variation from the ethanol process is in the fermentation step. For ethanol production, the conversion step proceeds via anaerobic fermentation, but for hydrocarbons (including renewable gasoline) this step proceeds via aerobic respiration. Important areas of research for this process include improving the tolerance of microbes to impurities, maximizing sugar utilization and microbe performance, and developing routes for lignin utilization.[65] Companies to note in this area: Terrabon (with plans to go commercial in 2014).

Renewable Gasoline from Catalysis of Lignocellulosic Sugars

The carbohydrate feedstock is pretreated, catalytically hydrotreated, then fed to the reactor where it reacts with water over a catalyst. Subsequent processes include utilization of a modified ZSM-5 zeolite catalyst to produce renewable gasoline.[84] Catalytic conversion has the flexibility to use a range of biomass-derived deconstruction products. This is an advantage compared to fermentation because the deconstruction products are harmful to the fermentative microorganisms. Important areas of research for this process are the design of

[83] Tabak, S. A., A. A. Avidan, and F. J. Krambeck. 1986. "Production of Synthetic Gasoline and Diesel Fuel from Nonpetroleum Resources." Am. Chem. Soc., Div. Gas Fuel Chem., Prepr.; (United States) 31:2 (April 1, 1986). https://www.osti.gov/biblio/5753027

[84] Virent. 2013. "Our Technology." Virent, Inc. Accessed April 19, 2013. http://www.virent.com/technology/.

catalysts with enhanced selectivities toward gasoline slates as well as production of hydrolysate streams tailored for catalytic upgrading.[85] Companies to note in this area: Virent.

Renewable Gasoline from Hydrothermal Liquefaction

In the process of hydrothermal liquefaction (liquification), biomass undergoes 15 minutes in supercritical water (at 400°C and high pressure) where it is broken down into a bio-oil. Subsequently the bio-oil can be hydrogenated or thermally upgraded to obtain gasoline fuels using hydroprocessing that is similar to refinery technology.[86] However, the quality of the oil can affect possible acceptance by refineries for integration with their refinery technology. Feedstocks for hydrothermal liquefaction include whole algae, a variety of waste streams, and cellulosic feedstocks. A newer area of research for hydrothermal liquefaction is refining the oil produced to gasoline. Companies to note in this area: New Oil.

Other Gasoline Substitutes

Methanol via Gasification

Biomass undergoes gasification, but subsequent to tar reforming and quench, the synthesis gas is converted to methanol via a copper/zinc oxide/alumina catalyst. Syngas cleanup, including sulfur removal, is important in maintaining the methanol synthesis catalyst. Companies to note in this area: Enerkem.

Methanol via Biodiesel

A byproduct of the biodiesel process is glycerin, which can be converted to methanol.[87] As methanol is needed in the production of biodiesel, converting the glycerin to bio-methanol helps to make the biodiesel process even more environmentally friendly. A significant limitation to this process is that it only produces methanol for its own process. Companies to note in this area: BioMCN

Dimethyl ether (DME)

Though typically recognized as a diesel and liquefied petroleum gas substitute, DME can also serve as a gasoline substitute. The Research Octane Number of DME is low, approximately 35. However, desired octane ratings can be met by mixing DME with propane (research octane number of approximately 110).[88] DME is produced via biomass gasification, methanol synthesis, and methanol dehydration. Companies to note in this area: ChemRec, Total, Haldor Topsoe.

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[85] Biddy, Mary, and Susanne Jones. 2013. "Catalytic Upgrading of Sugars to Hydrocarbons Technology Pathway" March 2013. http://www.nrel.gov/docs/fy13osti/58055.pdf.

[86] Science Daily. 2013. "Hydrothermal Liquefaction: The Most Promising Path to Sustainable Bio-oil Production." Science Daily, February 6, 2013. http://www.sciencedaily.com/releases/2013/02/130206162229.htm.

[87] Methanol Institue. 2013. "Methanol: BioMCN and Bio-Methanol." Methanol Institute. Accessed April 19, 2013. https://www.methanol.org/renewable-methanol/

[88] Olah, George A., Alain Goeppert, and G.K. Surya Prakash. 2009. "Beyond Oil and Gas: The Methanol Economy" Wiley-VCH, 2009. https://onlinelibrary.wiley.com/doi/book/10.1002/9783527627806

Biobutanol

Butanol may be used as a fuel in an internal combustion engine designed for gasoline, in blends up to 85 percent without modification.[89] Biobutanol (biomass-based butanol) is a second-generation alcohol fuel. It is produced via fermentation of biomass sources including corn grain, corn stover, and other feedstocks. Microbes are utilized to break down the sugars produced from the biomass into various alcohols, including ethanol and butanol.[73] A recent trend is to convert current ethanol plants to biobutanol/isobutanol plants. Companies to note in this area: Cobalt, Gevo.

Production Facilities and Key Suppliers

Ethanol Production Facilities

The U.S. ethanol supply has grown dramatically in recent years, increasing from approximately 1 billion gallons in 1996 to more than 14 billion gallons by 2010,[90] as shown in Figure 15. Table 14. California currently produces approximately 255 million gallons per year from seven production facilities, as shown in Table 14. California ethanol production accounts for almost 2 percent of the U.S. production.[91] Advanced ethanol and biobutanol production facilities are also emerging.[92]

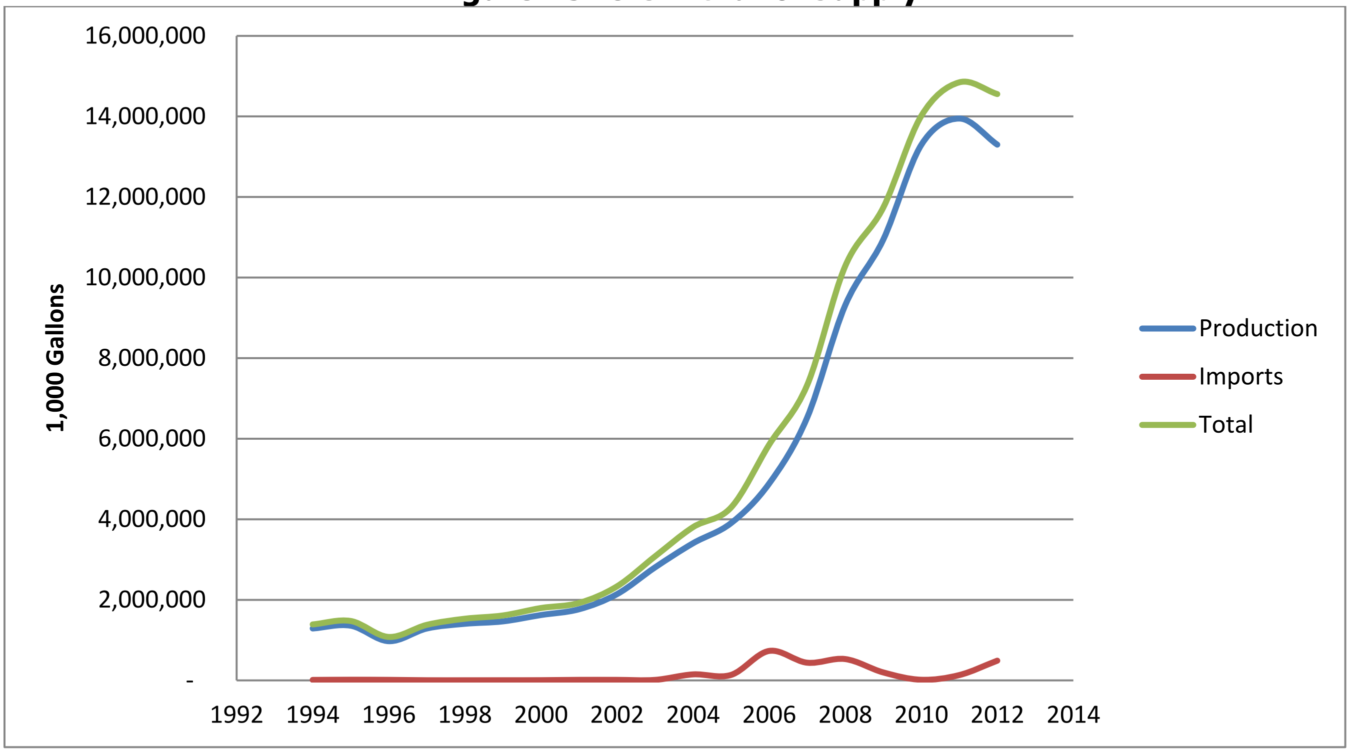
[89] European Biofuels. 2013. "Biobutanol." Technology Platform. Accessed June 13, 2013. https://www.etipbioenergy.eu/value-chains/products-end-use/products/biobutanol

[90] United States Department of Agriculture ERS. 2013b. "U.S. Bioenergy Statistics," April 15, 2013. http://www.ers.usda.gov/data-products/us-bioenergy-statistics.aspx#.UXGXaytAQcg

[91] NREL. 2013a. "BioFuels Atlas | Maps.nrel.gov." Accessed April 19, 2013. http://maps.nrel.gov/biomass.

[92] Nebraska Energy Office. 2012. "Ethanol Facilities: Capacity by State and Plant." Official Nebraska Government Website, October 17, 2012. http://www.neo.ne.gov/statshtml/122.htm.

Figure 15: U.S. Ethanol Supply



Source: NREL

Table 14: California Ethanol Production Facilities

Company	Location	Feedstock	Capacity
Aemetis	Keyes, CA	Corn	55 Mgpy
Altra Biofuels Phoenix Bio Industries	Goshen, CA		Capacity 31.5 Mgpy (idle)
Calgren Renewable Fuels	Pixley, CA	Corn	60 Mgpy
Golden Cheese Company of California	Corona, CA	Cheese Whey	5 Mgpy
Pacific Ethanol	Stockton, CA	Corn	60 Mgpy
Pacific Ethanol	Madera, CA		40 Mgpy capacity (idle)
Parallel Products	Rancho Cucamonga, CA	Corn	3 Mgpy

Source: NREL

Error! Not a valid bookmark self-reference. includes a list of California's advanced ethanol production facilities and Table 16 shows biobutanol production facilities.[27]

Table 15: Advanced Ethanol Production Facilities

Company	Location	Feedstock	Technology	Status (based on company-supplied information)
Fulcrum	Pleasanton, CA, first commercial in Nevada	Municipal solid waste	Gasification	Pilot (0.01 Mgpy) First commercial (10.5 Mgpy) in 2013
EdeniQ	Visalia, CA		Enzymatic Hydrolysis	Pilot and 0.8 Mgpy demonstration
BlueFire Renewables	Lancaster, CA, first commercial in Mississippi	Municipal solid waste, Woody Biomass	Acid Hydrolysis	Pilot (0.01 Mgpy) First commercial (19 Mgpy) scheduled for 2015
AE Advanced Biofuels Keyes	Keyes, CA			Demonstration (0.5 Mgpy)

Source: NREL

Table 16: Biobutanol Production Facilities

Company	Location	Feedstock	Technology	Status (based on company-supplied information)
Cobalt	Sausalito, CA	Corn	Fermentation	Pilot (0.01 Mgpy) Demonstration (3 Mgpy) in 2012
Gevo	Based in Englewood, Colorado, demonstration in Missouri, first commercial in Minnesota	Multi-Feedstock	Fermentation	Demonstration (1 Mgpy) Commercial producing biobutanol in mid-2012, plans to return to ethanol production while refining biobutanol production process (Gevo 2012)
American Process	Alpena, Michigan		Enzymatic Hydrolysis	Demonstration (0.47 Mgpy) in 2012

Source: NREL

These three companies are the key California producers of ethanol:

- Pacific Ethanol - Pacific Ethanol owns an 83 percent interest in and operates four ethanol plants in the Western United States. The four ethanol production facilities are located in California, Oregon, and Idaho, and their combined capacity is 200 million gallons per year. The Columbia plant in Boardman, Oregon, the Magic Valley plant in Burley, Idaho, and the Stockton plant in Stockton, California, are currently operating at full capacity. The Madera, California, plant is not currently operating.[93]
- Calgren - Calgren operates the longest running fuel ethanol plant in California, supplying ethanol, distiller's grains, and corn oil to areas in and around Bakersfield and Fresno, California, since 2009.[94] Calgren produces 60 million gallons per year of ethanol in Pixley, California.
- Aemetis – Aemetis, based in Cupertino, California, produces renewable fuels (ethanol and biodiesel), biochemicals (glycerin), and food and feed (distiller's grain and edible oils). Aemetis operates a 55 million gallon per year facility in Keyes, California that manufactures renewable ethanol for use as a transportation fuel. Aemetis scientists are working toward non-food-based ethanol with their Ambient Temperature Starch/Cellulose Hydrolysis process to produce renewable ethanol from renewable non-food feedstock.[95] Their biodiesel and glycerin production occurs in Kakinada, India.

Renewable Gasoline Production Facilities

Renewable gasoline is a relatively newer area of research and development. Thus, most production facilities are currently at the pilot and demonstration scales, with goals to reach commercial scale by the 2015-time frame. 27

[93] Pacific Ethanol. 2013. "About the Company." Accessed April 19, 2013. http://www.pacificethanol.net/site/index.php/about/.

[94] Chicago Business Journal. 2013. "Chromatin, Calgren Partner on Sorghum for Ethanol Production." Chicago Busineess Journal, February 25, 2013. http://www.bizjournals.com/chicago/news/2013/02/25/chromatin-calgren-partner-on-sorghum.html?page=all.

[95] Aemetis. 2013. "Ethanol." Aemetis, Inc. Accessed July 2013, http://www.aemetis.com/products/ethanol/.

Table 17 includes a list of renewable gasoline production facilities (within and outside of California).[27]

Table 17: Renewable Gasoline Production Facilities

Company	Location	Feedstock	Technology	Status
Primus Green[96]	New Jersey	Mixed biomass, natural gas	Syngas-to-green gasoline (variation of Methanol-to-Gasoline)	Demonstration plant under construction to produce 3.2 Mgpy in 2014 and commercial plant to produce 20 Mgpy in 2016
CORE BioFuel	B.C. Canada	Wood waste	Gasification	Pilot plant up in 2013, and commercial plant set to produce 18 Mgpy in 2016
Sundrop Fuels	Colorado based, first commercial plant in Alexandria, Louisiana	Wood waste, mixed biomass, natural gas	Gasification, Methanol-to-Gasoline	First commercial set for 50 Mgpy in 2014
Terrabon	Bryan, TX	Municipal solid waste	Fermentation	0.05 Mgpy demonstration plant operational since 2010, first commercial set for 20 Mgpy in 2014
Cool Planet[97]	Thousand Oaks, CA	Corn stover, wood chips, non-food energy crops	Catalytic conversion	First commercial set for 2 Mgpy in 2013
KiOR	Texas, first commercial plant in Mississippi	Wood chips	Pyrolysis	First commercial confirmed active in early 2013,[81] set to produce 62.5 Mgpy

Source: NREL

[96] Lane, Jim. 2012. "Gasoline's Comeback in the Bio-based Era: 5 Cleantech Companies Vie for Green Gasoline Breakthroughs." Biofuels Digest, March 15, 2012. http://www.biofuelsdigest.com/bdigest/2012/03/15/gasolines-comeback-in-the-bio-based-era-5-cleantech-companies-vie-for-green-gasoline-breakthroughs/.

[97] Business Wire. 2013. "Cool Planet to Explore Strategic Options With Carbon Negative Fuels Technology." Cool Planet. Accessed April 19, 2013. https://www.businesswire.com/news/home/20191217005692/en/Cool-Planet-to-Explore-Strategic-Options-With-Carbon-Negative-Fuels-Technology.

Key E85 Suppliers

There are more than 2,300 E85 filling stations in the United States, 64 (2 percent-3 percent) of which are in California. Below is a list of the companies with E85 stations. Several of the E85 filling stations are co-owned and thus are listed under both entities.[98]

Propel Fuels (30 E85 filling stations)

California-based Propel Fuels offers alternative fueling stations in both California and Washington. Propel stations offer the consumer a selection of both conventional and alternative fuels. Their clean mobility centers offer a variety of fuels along with several other sustainable transportation services such as free air for tires, carbon offset offerings, rideshare and community transportation resources, bicycle tuning stations, and recycling at the pump. Propel Fuels has the following state and federal partners: U.S. DOE, California Department of General Services, CEC, and Clean Cities Coalitions. Their leading fleet partners include the U.S. Postal Service, CALTRANS, Department of Veterans' Affairs, California Highway Patrol, and Enterprise Fleet Services.[99]

Pearson Fuels (14 E85 filling stations)

California-based Pearson Fuels opened the nation's first alternative fuel station in 2003. They also offered the first ethanol station to California and the first biodiesel station to San Diego. At limited locations they also offer propane fueling and electric vehicle charging.[100]

Pacific Pride (5 E85 filling stations)

Oregon-based Pacific Pride is the nation's largest cardlock fueling network. Pacific Pride serves fleets and offers them reduced fuel costs. They have more than 1,000 retail locations.[101]

Shell (10 E85 filling stations)

Shell is a global enterprise consisting of energy and petrochemicals companies.[102] All Shell stations offering E85 in California are co-owned by Propel Fuels.[98]

Chevron (7 E85 filling stations)

Chevron produced an average of 2.61 million barrels of oil-equivalent per day and had a global refining capacity of 1.95 million barrels of oil per day in 2012.[103] Chevron has partnered with

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[98] AFDC. 2013g. "Ethanol Fueling Station Locations." Fuels and Vehicles. Alternative Fuels Data Center. Accessed June 5, 2013. http://www.afdc.energy.gov/fuels/ethanol_locations.html.

[99] Propel Fuels. 2013. "About Us – Propel Fuels." Propel Fuels. Accessed June 5, 2013. http://propelfuels.com/about_us/.

[100] Pearson Fuels. 2013. "Pearson Fuels Feel Good Fueling Up." Accessed June 5, 2013. http://www.pearsonfuels.com/.

[101] Pacific Pride. 2013. "About Us." Accessed June 5, 2013. http://pacificpride.com/about-us/.

[102] Shell Global. 2013. "About Shell." Accessed June 5, 2013. https://www.shell.com/about-us.html

[103] Chevron. 2013a. "Company Profile." Accessed June 5, 2013. http://www.chevron.com/about/leadership/.

Weyerhaeuser Co. in Catchlight Energy LLC, a company focused on next-generation renewable fuels from forest-based sources.[104]

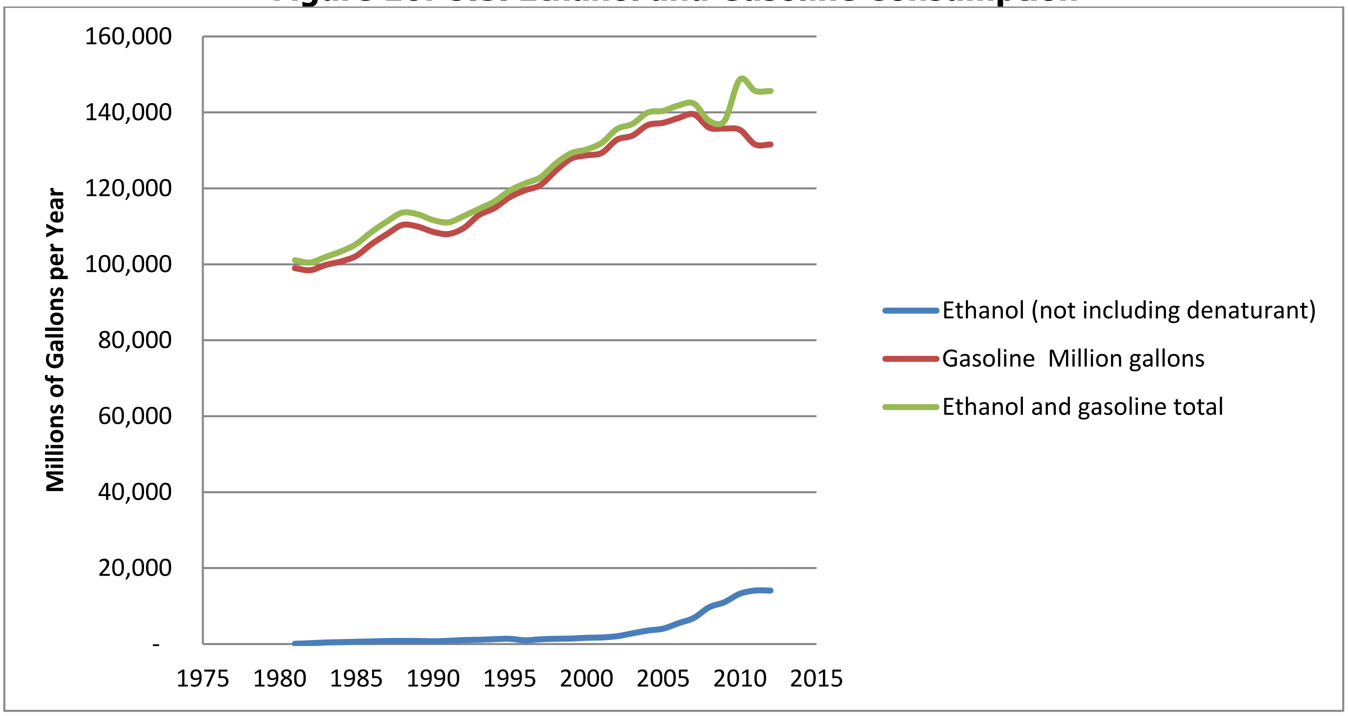
Market Evaluation

Currently ethanol is the only gasoline substitute produced at a commercial scale. U.S. ethanol consumption has grown tremendously and currently maintains approximately 10 percent of the U.S. market share (as shown in Figure 16 and =Figure 17).[105]

Ethanol has reached this percentage of the market with two integration methods[106]:

- Low-level blends (E10).
- High-level ethanol blends (E85). E85 is primarily used in the Midwest, where most corn(grain)-based ethanol is currently produced.

Figure 16: U.S. Ethanol and Gasoline Consumption



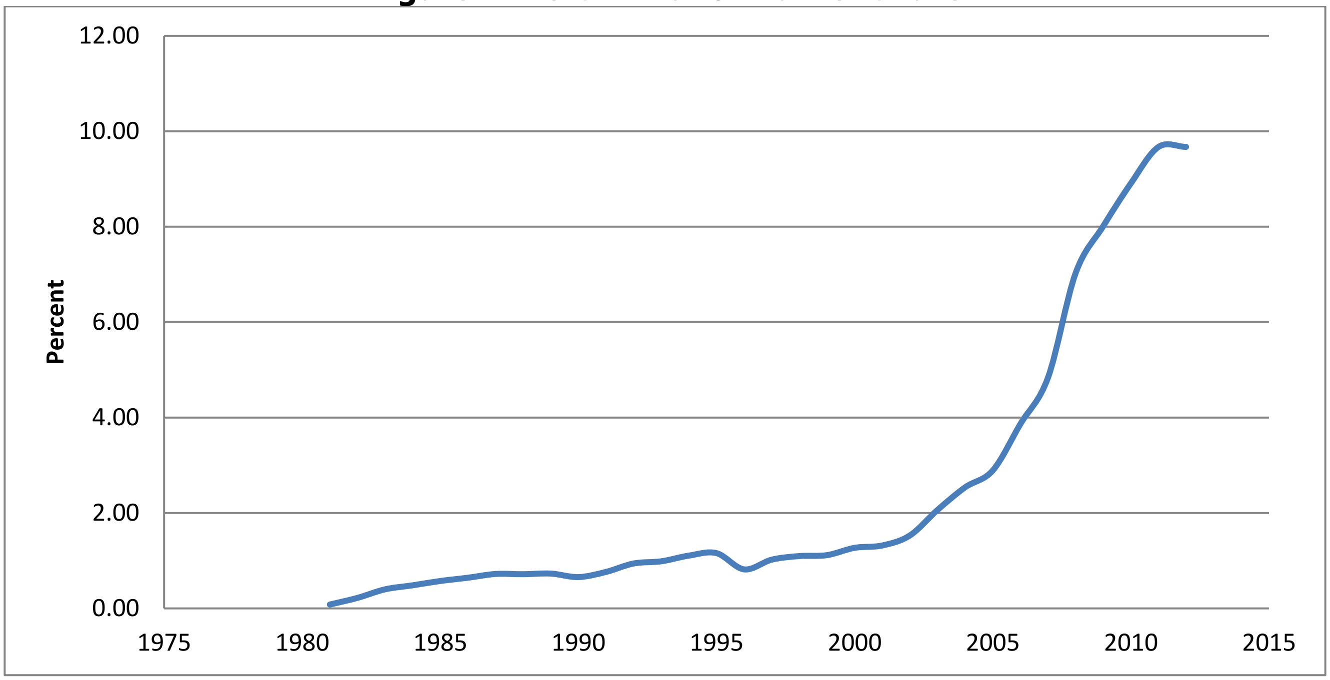
Source: NREL

[104] Chevron. 2013b. "Renewable Energy." Accessed June 5, 2013. https://www.chevron.com/sustainability/environment/renewable-energy

[105] United States Department of Agriculture ERS. 2013a. "Fuel Ethanol and Gasoline Consumption and Market Share," n.d. www.ers.usda.gov/datafiles/US_Bioenergy/Prices/table16.xls.

[106] DOE. 2012. "Biomass Program: End-Use Markets." U.S. Department of Energy. Biomass Program, January 5, 2012. https://www.energy.gov/eere/bioenergy/distribution-infrastructure-and-end-use

Figure 17: U.S. Ethanol Market Share



Source: NREL

Discussion

Ethanol production and use has grown tremendously in the last decade in the United States. It is blended into gasoline in target ratios of 10 and 85 percent. Many think the current U.S. ethanol use, at almost 14 billion gallons per year, is close to the 'blend wall' because ethanol is already mixed at 10 percent into most gasoline, the current legal blend limit in the U.S. One way to grow the ethanol market is to increase incentives and sales of E85. However, the cost of E85 is an important issue in increasing E85 sales. Recent estimates of E85 costs are $3.30/gallon, approximately $0.30/gallon cheaper than gasoline. However, on an energy equivalent basis, E85 costs $4.65/gallon gasoline equivalent and thus is more expensive to utilize as a fuel.[107]

Another possible way to grow the market would be to increase the standard E10 blend to E11 or E15. [108] The challenge is the warranty void warnings by some car manufacturers for ethanol blends greater than 10 percent.[109]

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[107] Clean Cities. 2013a. "Clean Cities Alternative Fuel Price Report." U. S. Department of Energy, Energy Efficiency and Renewable Energy, April 2013. http://www.afdc.energy.gov/uploads/publication/alternative_fuel_price_report_april_2013.pdf.

[108] Levi, Michael. 2013. "Energy, Security, and Climate » A Way Around the Ethanol Blend Wall?" Council on Foreign Relations - Energy, Security, and Climate, April 9, 2013. http://blogs.cfr.org/levi/2013/04/09/a-way-around-the-ethanol-blend-wall/.

[109] AAA NewsRoom. 2013. "New E15 Gasoline May Damage Vehicles and Cause Consumer Confusion | AAA NewsRoom." Accessed May 27, 2013. https://www.prnewswire.com/news-releases/new-e15-gasoline-may-damage-vehicles-and-cause-consumer-confusion-181515141.html

Other general limitations to growing the ethanol market include the following:

- Most ethanol is produced in the middle of the country, but 80 percent of the population lives along the coasts.
- Ethanol transport is limited to rail (primary transport) and truck (secondary transport). This is because it picks up excess water and impurities and thus is non-ideal for current pipelines.[110]
- Economically, at this time, the choice to dispense ethanol does not lead to a clear advantage.[111]

There are mixed reviews on the on the environmental effects of ethanol vs. gasoline. Proponents of ethanol advocate that ethanol is more environmentally friendly because it burns cleaner, producing fewer total toxins and lower levels of ozone-forming volatile organic compounds compared to gasoline. And it emits less oxides of nitrogen (NO_x) and particulate matter.[112] In 2011, the Coordinating Research Council conducted emissions tests for flex-fuel vehicles with increasing ethanol blends. The following are some of their findings[113]:

- The average emissions did not indicate a statistically significant emission trend in either direction with increasing ethanol level for cold start emission evaluation.
- The average non-methane hydrocarbon emissions decreased approximately 50-60 percent for E85 when compared to E6.
- The CO and NO_x emissions did not demonstrate a trend by increasing the ethanol level.

Renewable gasoline has its own unique set of growth opportunities and challenges. Renewable gasoline has tremendous potential in that it is a drop-in fuel and thus can utilize existing vehicles and infrastructure without modifications. Its current limitations are associated with the newness of the technologies. These technological challenges are grouped by conversion process technology in the following lists.

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[110] Halperin, Alex. 2006. "Ethanol: Myths and Realities." BusinessWeek: Technology, May 18, 2006. http://www.businessweek.com/stories/2006-05-18/ethanol-myths-and-realities.

[111] Vimmerstedt, Laura J., Brian Bush, and Steve Peterson. 2012. "Ethanol Distribution, Dispensing, and Use: Analysis of a Portion of the Biomass-to-Biofuels Supply Chain Using System Dynamics." PLoS ONE 7, no. 5 (May 14, 2012): e35082. doi:10.1371/journal.pone.0035082.

[112] Clean Cities, 2013b. Flexible Fuel Vehicles.

[113] Haskew, Harold M., and Thomas F. Liberty. 2011. EXHAUST AND EVAPORATIVE EMISSIONS TESTING OF FLEXIBLE-FUEL VEHICLES. Coordinating Research Council, August 2011.

Pyrolysis

- Advancing vapor phase upgrading reactors and processes for ex-situ catalytic fast pyrolysis in order to retain the maximum amount of carbon in the liquid while removing highly reactive oxygen species.[114]
- Combining pyrolysis with upgrading in a single vessel (in-situ catalytic fast pyrolysis).[80]
- Characterizing the final fuel product to determine if it is of sufficient quality to use as a blendstock.[80] [114]

Biochemical Conversion of Sugars to Hydrocarbons Maximizing sugar (and/or carbon) utilization and microbe metabolic performance.[65]

Syngas Upgrading to Hydrocarbons

- Developing catalysts with increased selectivity to molecules with carbon chains in the gasoline and diesel range, while minimizing unwanted side products, including light gases and coke.[115]

Advanced Diesel Substitutes

Distillate fuel oils, including diesel and heating oil, rank second behind gasoline as the most-consumed liquid fuels in the United States. California is the country's second largest user of No.2 Diesel with sales for on-highway use with approximately 2.6 billion gallons in 2010.[116] [117]

Biodiesel and renewable diesel are biomass-based fuels in and entering the marketplace to supplement and replace petroleum-based diesel. Biodiesel is a diesel substitute that is made from renewable sources, such as vegetable oils, animal fats or recycled restaurant grease. It consists of fatty acid alkyl esters, such as fatty acid methyl esters and long-chain mono alkyl esters.[118] Biodiesel that meets ASTM D6751 is a legally registered fuel and fuel additive. However, because it is chemically different from diesel, it does not as qualify as a 'drop-in'

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[114] Biddy, Mary, Abhijit Dutta, Susanne Jones, and Aye Meyer. 2013a. Ex-Situ Catalytic Fast Pyrolysis Technology Pathway. NREL and PNNL, March 2013. http://www.nrel.gov/docs/fy13osti/58050.pdf.

[115] Talmadge, Michael, Mary Biddy, Abhijit Dutta, Susanne Jones, and Aye Meyer. 2013. Syngas Upgrading to Hydrocarbon Fuels Technology Pathway. NREL and PNNL, March 2013. http://www.nrel.gov/docs/fy13osti/58052.pdf.

[116] U.S. EIA. 2013k. "Product Supplied." Petroleum and Other Liquids. Energy Information Administration. Accessed March 5. http://www.eia.gov/dnav/pet/pet_cons_psup_dc_nus_mbbl_a.htm.

[117] U.S. EIA. 2012c. "Distillate Fuel Oil and Kerosene Sales by End Use." Petroleum & Other Liquids. U.S. Energy Information Administration. November 30. http://www.eia.gov/dnav/pet/pet_cons_821use_dcu_SCA_a.htm.

[118] AFDC. 2013c. "Biodiesel Benefits and Considerations." Alternative Fuels Data Center. Accessed May 28. http://www.afdc.energy.gov/fuels/biodiesel_benefits.html?__utma=1.1507119440.1369779365.1369779365.1369779365.1&__utmb=1.0.10.1369779365&__utmc=1&__utmx=-&__utmz=1.1369779365.1.1.utmcsr=%28direct%29|utmccn=%28direct%29|utmcmd=%28none%29&__utmv=-&__utmk=193566637

fuel. 'Drop-in' fuels meet existing diesel, gasoline, and jet fuel specifications for the ability to 'drop-in' to existing infrastructure and vehicles.

Renewable diesel is the collection of diesel fuel substitutes derived from biomass that are not esters, distinguishing it from biodiesel. Renewable diesel is sufficiently similar to petroleum diesel such that it meets ASTM D975, the specification set for petroleum-based diesel, thus qualifying renewable diesel as a 'drop-in' fuel.

Biomass-based diesel, including biodiesel and renewable diesel, reduces emissions of pollutants that impact air quality, including unburned hydrocarbons, CO, sulfates, polycyclic aromatic hydrocarbons, particulate matter and others. B20 has been shown to reduce emissions of particulate matter by 10 percent, CO by 11 percent, and unburned hydrocarbons by 21 percent.

Quality of biomass-based diesel is important. NREL monitors biodiesel quality by sampling at producers and terminals. The most recent study shows that 95 percent of biodiesel is meeting ASTM D6751 specifications. This has been a noteworthy success. It is a significant improvement compared to the 2006 study which reported that 40 percent of biodiesel met the ASTM D6751 specifications. Failures to meet specifications were primarily due to excess glycerin and exceeding flash point requirements.[119] The failures to meet specifications in 2006 caused quality issues and filter clogging. This spawned passage of the Cold Soak Filtration Test, an important improvement in biodiesel testing.[120]

Another important aspect regarding biomass-based diesel is the energy density (or energy content). This determines the distance a vehicle can go per unit mass or volume of fuel (vehicle dependent). Energy density varies slightly between diesel, biodiesel and renewable diesel, as shown in

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[119] Alleman, Teresa L., Lisa Fouts, and Gina Chupka. 2013. "Quality Parameters and Chemical Analysis for Biodiesel Produced in the United States in 2011". Technical Report NREL/TP-5400-57662. NREL. http://www.nrel.gov/docs/fy13osti/57662.pdf.

[120] Biodiesel Magazine. 2013. Latest NREL quality survey shows 97 percent on spec. Accessed May 28. http://www.biodieselmagazine.com/articles/8989/latest-nrel-quality-survey-shows-97-percent-on-spec.

Table 18. Renewable diesel is quite close to fossil-fuel based diesel with 95 percent of its energy density. Biodiesel contains approximately 80 percent of the energy density.

Table 18: Energy Densities of Diesel Substitutes

Fuel	**Energy Density (MJ/kg)**	**Oxygen Content**	**Cetane Number**
Diesel	48.1		45[121]
Renewable Diesel	45.7[122]		90-100[123]
Biodiesel	37.8	10% greater than Diesel[124]	45-47[125]
DME	28[72]		60[72]

Source: NREL

Process Conversion Technologies for Biodiesel and Renewable Diesel

Biodiesel

Biodiesel is a diesel substitute that is used to fuel compression-ignition engines that run on petroleum diesel. Biodiesel production utilizes the process of transesterification to convert vegetable oils, animal fats, algae oil, or recycled restaurant grease into a product consisting of fatty acid alkyl esters, fatty acid methyl esters, or long-chain mono alkyl esters.[126] In the transesterification process, the triglycerides are reacted with an alcohol, methanol or ethanol, in the presence of an alkaline catalyst.[127] In this process, glycerin is produced as a byproduct.[123] Biodiesel that meets ASTM D6751 specifications is a legally registered fuel and fuel additive.

Biodiesel can be blended and used in many different concentrations, including several that are commonly marketed: B100 (pure biodiesel), B99 (99 percent biodiesel, 1 percent petroleum

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[121] Hannula, Ilkka, and Esa Kurkela. 2013. "Liquid Transportation Fuels via Large-scale Fluidised-bed Gasification of Lignocellulosic Biomass". VTT Technical Research Centre of Finland.

[122] Biodiesel Magazine. 2007. "ConocoPhillips Begins Production of Renewable Diesel." Biodiesel Magazine. March 15. http://www.biodieselmagazine.com/articles/1481/conocophillips-begins-production-of-renewable-diesel.

[123] NREL. 2006. National Renewable Energy Laboratory. "Biodiesel and Other Renewable Diesel Fuels (Factsheet)". NREL/FS-510-40419. Golden, CO. http://www.nrel.gov/docs/fy07osti/40419.pdf.

[124] Ciolkosz, Daniel. 2009. "What's So Different About Biodiesel Fuel?" Penn State University. Renewable and Alternative Energy Fact Sheet. https://extension.psu.edu/whats-so-different-about-biodiesel-fuel

[125] Van Gerpen, Jon. 2013. "Cetane Number Testing of Biodiesel." Accessed May 30. https://www.biodieseleducation.org/Literature/Journal/2006_Van_Gerpen_Cetane_number_testin.pdf

[126] Oilgae. 2013. "Transesterification." Accessed April 24. http://www.oilgae.com/ref/glos/transesterification.html.

[127] AFDC. 2013e. "Biodiesel Fuel Basics." Alternative Fuels Data Center. April 19. http://www.afdc.energy.gov/fuels/biodiesel_basics.html.

diesel), B20 (20 percent biodiesel, 80 percent petroleum diesel), B5 (5 percent biodiesel, 95 percent petroleum diesel) and B2 (2 percent biodiesel, 98 percent petroleum diesel). B2 and B5 meet the conventional diesel fuel specifications (ASTM D975) and thus are approved for safe operation in any compression-ignition engine designed to be operated on petroleum diesel. Biodiesel blends between B6 and B20 must meet prescribed quality standards—ASTM D7467 and generally do not require engine modifications.[128] B100 needs to meet ASTM D6751 specifications.

Producing biodiesel via transesterification is a mature process because it is commercially available with U.S. production at approximately 1 billion gallons annually in 2011. A primary challenge for this process is that the esters that make up biodiesel have fundamental differences from petroleum-based diesel which result in blending ceilings, lack of infrastructure compatibility, and vehicle modifications. Another challenge is the concern that biodiesel production would cause undesirable land use changes, possibly increasing food prices or adversely impacting environmental values because a portion biodiesel produced today comes from virgin vegetable oils. Approximately 50 percent of biodiesel comes from soybean oil alone.[119] However, some biodiesel is produced from recycled oils and thus does not compete with food production for land.

Algae transesterification to produced biodiesel is a newer area of research for the transesterification technology. Companies to note in this area: Seambiotic, Solix, Algae Tec, Aurora Algae, BARD, BioProcess Algae, Cellan, ENN, Kumho Petrochemical, LiveFuels, MBD Energy, Pond Biofuels, Solix.

Renewable Diesel

Renewable diesel (also called green diesel) is the collection of biomass-based diesel fuel substitutes that are not esters, thus distinguishing it from biodiesel. The molecular properties of renewable diesel are sufficiently similar to petroleum diesel which yields great advantages, including: the ability to be used in any concentration and to utilize existing delivery infrastructure. The similarities between renewable diesel and petroleum diesel also qualify renewable diesel as a 'drop-in' fuel because it meets ASTM D975.

However, in contrast to the commercial production of biodiesel (approximately 1 billion gallons per year in the U.S.) renewable diesel and jet fuel processes are less developed and are primarily at the lab, pilot, and demonstration scales (less than 1 million gallons per year, with the exception of a 75 million gallons per year plant in Louisiana by Dynamic Fuels). Internationally, NesteOil has a production capacity of over 400 million gallons per year with their plants in Singapore and Finland using NExBTL.

Renewable Diesel from Hydroprocessing

Renewable diesel can utilize the traditional hydroprocessing used in petroleum refineries to produce a premium diesel fuel from fatty acids (oils, fats, and greases). The product fuel contains no sulfur and has a cetane number of 90-100.[123] In hydroprocessing, the feedstock is

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[128] U.S. DOE. 2013b. "Green Gasoline from Wood Pilot Biorefinery Demonstration Project." Haldor Topsoe Inc. Pilot Project. U.S. Department of Energy. Accessed June 9. https://www.gti.energy/wp-content/uploads/2018/10/Green-Gasoline-from-Wood-Pilot-Biorefinery-Demo-Project_05-2014.pdf.

reacted with hydrogen at elevated temperatures of 600-700°F and pressures of 40-100atm in the presence of a catalyst.[123] The reaction time is approximately 10-60 minutes. The diesel must be produced as a dedicated feed in a stand-alone process, in order to qualify as a renewable fuel (according to the RFS). However, the feedstock can also be hydroprocessed as a co-feed with petroleum.[129] The product fuel can be blended directly into regular low-sulfur diesel to any level and still meet specification standards. This process is the renewable diesel process currently commercially available, for example by Dynamic Fuels and NesteOil. Companies to note in this area: Conoco Phillips Co., Neste Oil, Dynamic Fuels, LLC, Diamond Green Diesel, Valeros, Honeywell, UOP, Emerald Biofuels, Sapphire.

Renewable Diesel from Pyrolysis

A route to renewable diesel is to convert lignocellulosic biomass via pyrolysis. Pyrolysis is the thermal decomposition of organic material in the absence of oxygen to produce char, gas, and a liquid product rich in oxygenated hydrocarbons. Pyrolysis is performed over a range of temperatures and residence times to optimize the desired product. In the case of fast pyrolysis, the biomass is heated to approximately 500°C in less than 1 second, and then rapidly cooled. A sub-category is Catalytic Fast Pyrolysis, direct liquefaction of biomass by pyrolysis and pyrolysis vapor upgrading, which can occur in the same vessel (In-Situ catalytic fast pyrolysis) or in separate vessels (Ex-Situ catalytic fast pyrolysis). The inclusion of vapor phase upgrading can produce a lower-oxygen-content intermediate with lower associated water.[114] The liquid product, bio-oil, obtained is a mixture of liquids spanning the gasoline and diesel range and some byproduct gas, along with approximately 20 percent water.[130] The gasoline and diesel range products are upgraded to diesel and are suitable for blending into finished fuel.[79] Catalysts with improved yields, stability, and lifetimes, along with optimizing catalytic fast pyrolysis.[80] KiOR's[81] Companies and research organizations to note in this area: Envergent (UOP/Ensyn), Dynamotive, KiOR, GTI, RTI.

Renewable Diesel from Hydrothermal Liquefaction

In the process of hydrothermal liquefaction biomass undergoes 15 minutes in supercritical water (at 400°C and high pressure) where it is broken down into a bio-oil. Subsequently the bio-oil can be hydrogenated or thermally upgraded to obtain diesel fuels using hydroprocessing that is similar to refinery technology.[86] Refinery integration acceptance can be dependent upon oil quality. Feedstocks for hydrothermal liquefaction include whole algae, a variety of waste streams, and cellulosic feedstocks. A newer area of research for hydrothermal liquefaction is refining the oil produced to the desired diesel product. Companies to note in this area: New Oil, Enertech Environmental, Biodiesel BV (Netherlands).

Renewable Diesel from Gasification and Fischer-Tropsch

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[129] Milbrandt, A., C. Kinchin, and A. Aden. "Feasibility of Producing and Using Biomass-Based Diesel and Jet Fuel in the United States". Golden, CO: National Renewable Energy Laboratory. https://www.nrel.gov/docs/fy14osti/58015.pdf

[130] Prins, W. and Bridgwater, T. 2010. Progress in fast pyrolysis technology. Topsoe Catalysis Forum 2010, Munkerupgaard, Denmark, 19 to 20 August 2010. https://info.topsoe.com/topsoe-catalysis-forum-overview

Another route to renewable diesel from cellulosic biomass is via gasification followed by the Fischer-Tropsch process. Biomass gasification involves heating the biomass in a circulating fluidized bed gasifier, producing a synthesis gas rich in H_2 and CO. The syngas proceeds through reforming, quenching, and acid gas removal. The cleaned synthesis gas is catalytically converted into a liquid intermediate that is further processed and refined to produce diesel in the Fischer-Tropsch process. For a diesel end-product, a low temperature reaction with a cobalt catalyst is utilized.[66] Companies to note in this area: Flambeau River Biofuels, Clear Fuels/Rentech, TRI, Dynamic Fuels and Solena.

Renewable Diesel from Gasification and Mobil Olefins-to-Gasoline/Diesel

Renewable diesel and jet fuel from gasification can be produced via Mobil Olefins-to-Gasoline/Diesel. Biomass gasification produces a synthesis gas rich in H_2 and CO by heating the biomass. After syngas cleanup, the synthesis gas is then converted to methanol over a copper/zinc oxide/alumina catalyst. The methanol is converted to olefins and subsequently to diesel utilizing a zeolite catalyst. Mobil Olefins-to-Gasoline/Diesel allows production of a high-quality diesel range (C_{10}-C_{20}) iso-olefinic product. [83] Companies to note in this area: ExxonMobil, KIT, and Lurgi.

Renewable Diesel from Biological Conversion of Sugars

This process utilizes cellulosic sugars for metabolic fuel production. The feedstock undergoes pretreatment and conditioning, enzymatic hydrolysis, hydrolysate clarification, and biological conversion, followed by product recovery. Because the diesel range hydrocarbon products have very low solubility in water and a lower density, the product separates into two liquid phases which can easily be separated. This is an advantage for the hydrocarbon products over ethanol. Important areas of research for this process include improving tolerance of microbes to impurities, maximizing sugar utilization and microbe performance and developing routes for lignin utilization.[65] Companies to note in this area: Amyris, Gevo, Butamax, Cobalt.

Renewable Diesel from Catalysis of Lignocellulosic Sugars

The carbohydrate feedstock goes through pretreatment to liberate the hemicelluloses sugars, followed by enzymatic hydrolysis. Subsequent purification is needed to remove the solids, typically by centrifugation or filtration, and proteins and inorganic compounds, possibly by ion exchange membranes. This is followed by de-watering to improve concentration. The subsequent catalytic conversion includes two steps: aqueous phase reforming followed by conversion over a ZSM-5 zeolite catalyst. The product from this process is hydrocarbon drop-in fuels, including renewable diesel.[90] Catalytic conversion has the flexibility to use a variety of biomass-derived deconstruction products. This is an advantage because the deconstruction products would be harmful to the microorganisms in fermentative processes. The design of catalysts with enhanced selectivities toward the sets of hydrocarbons that make up diesel, as well as production of hydrolysate streams tailored for catalytic upgrading are important areas of research for this process.[85] Companies to note in this area: Virent, Shell.

Renewable Diesel from Consolidated Bioprocessing

This process combines the production of saccharolytic enzymes, the hydrolysis of carbohydrate components present in pretreated biomass to sugars, and the fermentation of hexose and pentose sugars into a single-step. The key to this single-step process are the microorganisms, which must utilize cellulose and other fermentable compounds available from pretreated biomass with high rate and conversion, and which must produce the desired product at high yield and titer.[77] The ability to genetically compile several complex, biosynthetic pathways into a single cell simplifies the process and raw material requirements.[78] Companies to note in this area: LS9.

Renewable Diesel from Biological Conversion of Sugars via Heterotrophic Algae

This process is very similar to the process for Renewable Diesel from Biological Conversion of Sugars in that it contains pretreatment and conditioning, enzymatic hydrolysis and aerobic biological conversion. In this process the algae serves as the microbial catalyst for converting sugars to fuels, and thus the process is dependent on an alternate biomass source for the sugars. This process requires additional product recovery because the triglycerides are held within the whole algal cells, rather than being excreted. The fuel is recovered via wet extraction. The raw algal oil is essentially 100 percent triglycerides and is sent for upgrading in a hydrotreater for de-oxygenation and saturation to produce diesel-range fuel as a final product. Companies to note in this area: Solazyme.

Renewable Diesel and Biodiesel from Autotrophic Algae

Microalgae are photosynthetic microorganisms capable of converting CO_2 and sunlight into to Biodiesel, Renewable Diesel and Jet Fuel. Microalgae in cultivation ponds with input of CO_2 and sunlight produce 60 percent triglycerides after harvesting and extraction. The triglycerides can be converted to biodiesel via transesterification.[131] Alternatively, the oils can be used to produce a renewable or green diesel product by catalytic hydroprocessing.[131] In this process, the algae is the feedstock, in comparison to renewable diesel from heterotrophic algae where the algae serves as the microbial catalyst and not a feedstock. Companies to note in this area: Sapphire, Cellana, Seambiotic, OriginOil, Solix, Synthetic Genomics, Joule, LLC, Kent BioEnergy.

Dimethyl Ether as a Diesel Substitute

Dimethyl ether (DME) can serve as a diesel substitute, though it does not qualify as renewable diesel or biodiesel. Replacing diesel with DME reduces emissions, especially of particulate matter and NO_x.[88] DME is produced by biomass gasification, methanol synthesis and subsequent methanol dehydration by use of a zeolite catalyst. Companies to note in this area: Shell, Volvo, ChemRec, HaldorTopsoe, Total.

Straight Vegetable Oil as Diesel Substitute

Straight vegetable oil or mixtures have been utilized by some; however, it is not a legal motor fuel, nor does it meet biodiesel fuel specifications or quality standards. There are many

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[131] Pienkos, Philip T., and Al Darzins. 2009. "The Promise and Challenges of Microalgal-derived Biofuels." Biofuels, Bioproducts and Biorefining 3 (4): 431–440. doi:10.1002/bbb.159.

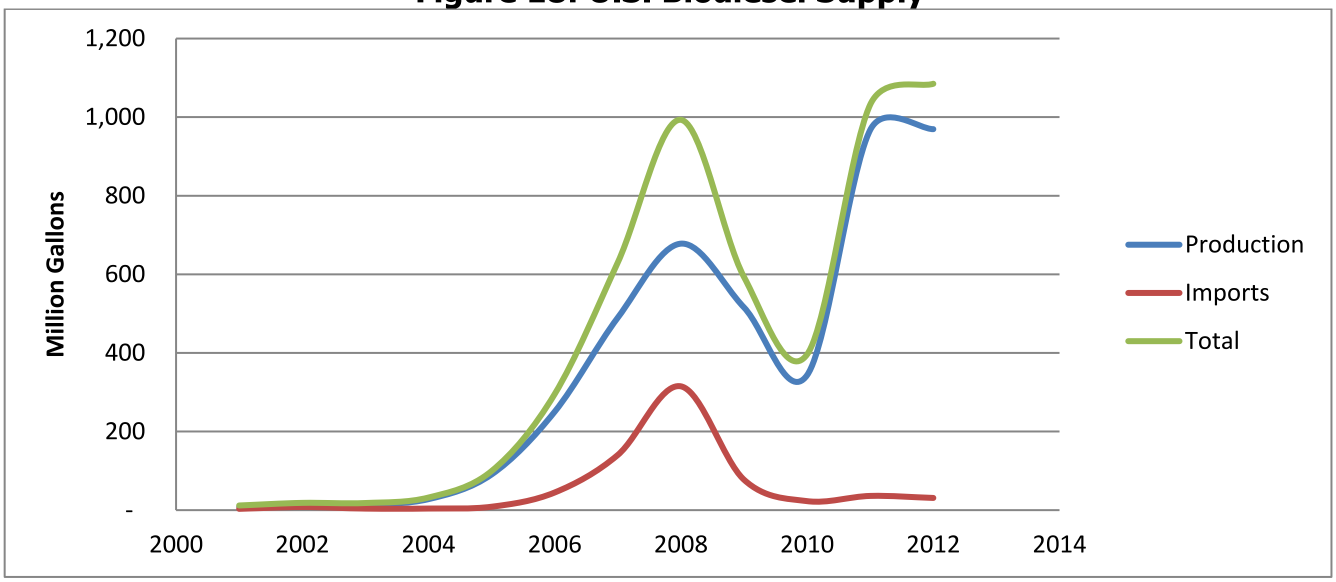
differences between it and biodiesel or No.2 diesel fuel. It has a higher viscosity, is more reactive to oxygen and has higher cloud point and pour point temperatures.[132]

Production Facilities and Key Suppliers

Biodiesel Production

Biodiesel production has fluctuated with an overall increase in recent years. In 2012, approximately 1 billion gallons of biomass-based diesel were produced in the United States.[55] The RFS2 and the $1.00 per gallon blender tax credit reinstatement in December 2010 revived the biodiesel industry from a US production of 343 million gallons in 2010 (as demonstrated in Figure 18).[129]

Figure 18: U.S. Biodiesel Supply



Source: NREL

The U.S. biodiesel production capacity is more than 1.8 billion gallons with about 160 plants registered with the United States Environmental Protection Agency (U.S. EPA). This is approximately 0.7-0.8 billion gallons greater than the current production.

California's annual biodiesel capacity is 91 million gallons.[133] According to Biodiesel Magazine (http://www.biodieselmagazine.com/), California has 17 biodiesel production facilities.

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[132] DOE. 2010. "Straight Vegetable Oil as a Diesel Fuel?" DOE/GO-102010-2989. U.S. Department of Energy. Washington, DC. https://www.nrel.gov/docs/fy14osti/54762.pdf.

[133] White, Ronald D. 2012. "U.S. Biodiesel Production Soars, but Crude Oil Is Still King." Los Angeles Times, June 22. http://articles.latimes.com/2012/jun/22/business/la-fi-mo-us-biodiesel-production-20120622.

Table 19 gives more information on these production facilities.

Table 19: California Biodiesel Production Facilities

Company	Location	Feedstock	Capacity (Million gallons per year)
Biodiesel Industries Ventura LLC	Ventura	Jatropha and Algae	0.1
Imperial Western Products	Coachella	Multi-Feedstock	12
Energy Alternative Solutions Inc.	Gonzales	Yellow Grease	1
Blue Sky Bio-Fuels Inc.	Oakland	Multi-Feedstock	4
Southern California Biofuel	Anaheim	Used Cooking Oil/Yellow Grease[134]	1
Bay Biodiesel LLC	San Jose	Virgin Oils/Yellow Grease	5
Community Fuels	Stockton	Multi-Feedstock, Including Soybean Oil, Algae Oil	13
Noil Energy Group Inc.	Commerce	Multi-Feedstock	5
Simple Fuels Biodiesel	Chilcoot	Yellow Grease	2
Yokayo Biofuels Inc.	Ukiah	Waste Vegetable Oils	0.5
EcoLife Biofuels LLC	San Jacinto	Multi-Feedstock	2.4
New Leaf Biofuel LLC	San Diego	Yellow Grease	2
Extreme Biodiesel Inc.	Corona	Multi-Feedstock	2
Crimson Renewable Energy LP	Bakersfield	Multi-Feedstock	25
Promethean Biofuels Co-op Corp.	Temecula	Used Cooking Oil	2.1
San Francisco Public Utilities Commission	San Francisco	Recycled Brown Grease[134]	0.365
R Power Biofuels LLC	Redwood City	Multi-Feedstock	1

Note: Yellow Grease is used cooking oil primarily from fryers. Brown Grease is waste vegetable oil, animal fat, and grease.

Source: NREL

[134] Burgess, M.N. 2010. "What to Do with Brown Grease?" Plumbing Systems & Design. April 2010.

Three key biodiesel producers in California are:

- Crimson Renewable Energy LP– Via transesterification Crimson Renewable Energy LP produces biodiesel utilizing a wide variety of feedstocks including vegetable oils, algae oil, waste cooking oils and animal fats. Crimson Renewable Energy completed its first biodiesel production facility in 2009 in Bakersfield, California. This biodiesel production facility has a capacity of 25 million gallons per year, and is the largest of its kind in California, and is the second largest in the western U.S. This facility was advanced in 2011 to handle a wider variety of raw materials, including ultra-low carbon feedstocks such as used cooking oils, waste animal fats, and waste corn oil derived from ethanol production. Additionally, it can fully utilize its crude glycerin by-product to produce 99 percent+ refined glycerin. In California, Crimson Renewable currently offers bulk biodiesel fuel to the wholesale market from distribution locations around the state.[135]
- Community Fuels– Community Fuels has been producing biodiesel since 2008. They use multiple feedstocks, including soybean oil, and have partnered with Solazyme to produce algae-based biodiesel.[136] Their fuel qualifies as an Advanced Biofuel through the U.S. EPA. Community Fuels' bio-refinery, located at the Port of Stockton in California, is one of the largest operating advanced bio-refineries in the Western U.S., with a capacity of 13 million gallons per year. It has been in continuous operation since 2008. The product is sold in bulk to the petroleum industry to be blended with petroleum-based diesel.[137]
- Imperial Western Products has a variety of products, including alternative fuels, tire products and pipe lubricants, commodities and animal feed. The Biotane Fuels Division of Imperial Western Products have been producing biodiesel since 2000 from animal fats and recycled vegetable oils, and thus does not compete for feedstock with food production.[138] The Biotane Fuels production facility located in Coachella, California has a 12 million gallon per year production capacity. Imperial Western Products has a BQ9000 accredited certification as both a biodiesel producer and as a marketer – the only facility west of Texas with this certification.[138]

Renewable Diesel and Jet Fuel Production Facilities

In comparison with biodiesel, the renewable diesel and jet fuel industry is just starting out and most of the facilities are not yet at commercial production capabilities. In contrast to the over 1 billion gallons of annual capacity of biodiesel, the production of renewable diesel was

[135] Crimson Renewable Energy. 2013a. "Solutions, Biodiesel." Accessed April 19. http://www.crimsonrenewable.com/biodiesel.php.

[136] Community Fuels. 2007. "Biodiesel Plant rising at Port of Stockton." Central Valley Business Journal. January 3. http://www.communityfuels.com/wp/wp-content/uploads/2014/01/CVBJ-11-2007-cropped.pdf

[137] Community Fuels. 2013. "Overview." Accessed April 19. http://www.communityfuels.com/Overview.html.

[138] Imperial Western Products. 2013. "Biotane Fuels Division." Accessed April 19. http://www.imperialwesternproducts.com/portfolio-item/biotane-fuels-division/.

approximately 76 million gallons in 2011. The principal contributor was Dynamic Fuels, operating in Louisiana who produced 75 million gallons.[129]

Table 20 lists California's renewable diesel production facilities.[27]

Table 20: California Renewable Diesel and Jet Fuel Production Facilities

Company	Location	Feedstock	Technology	Status
Amyris	Emeryville, CA (First commercial in Brazil)	Sugar	Fermentation	Pilot (0.01 Mgpy) First commercial (13 Mgpy) 2012
LS9	San Francisco, CA (First commercial in Brazil)	Sugar	Consolidated Bioprocessing	Pilot (0.1 Mgpy) First commercial (200 Mgpy) in 2015
Renewable Energy Institute International	Sacramento, CA		Gasification	Demonstration (0.35 Mgpy)
Rentech	Rialto, CA (Pilot and first commercial) Demonstration plant in CO	Cellulosic Feedstocks	FT	Pilot (0.15 Mgpy) Demonstration (8 Mgpy) First commercial (259 Mgpy) in 2017
Solena	Gilroy, CA (fifth commercial), first–fourth commercials international	Municipal solid waste	FT	Fifth commercial (16 Mgpy) in 2015 First–fourth commercials (79 Mgpy) in 2014-2016
TerViva	Oakland, CA	Seed Oil		Pilot (0.5 Mgpy) in 2015
AltAir	Bakersfield, CA (First commercial in Washington)	Camelina	Hydrotreating	Pilot (0.5 Mgpy) in 2015
Kent BioEnergy	Mecca, CA	Algae	Algal Oil Extraction	Pilot (0.01 Mgpy) in 2011

Company	Location	Feedstock	Technology	Status
Solazyme	South San Francisco, CA Demonstration in Illinois First–third commercials international	Algae	Hydroprocessing	Pilot (0.01 Mgpy) 2011 Demonstration (0.04 Mgpy) in 2012 First–third commercials (43 Mgpy) (2012-2013)
Cool Planet[97]	Thousand Oaks, CA	Corn stover, wood chips, non-food energy crops	Catalytic Conversion	First commercial (2 Mgpy) in 2013 (not specified renewable gasoline or diesel/jet fuel)

Source: NREL

Key producers of renewable diesel are:

- Dynamic Fuels - Dynamic Fuels dominates the U. S. renewable diesel production capacity with a 98 percent share. The United States production capacity of renewable diesel is 76 million gallons per year, 75 of which are from Dynamic Fuels 138-million-dollar plant in Louisiana. Dynamic Fuels is a joint-venture of Tyson Foods, Inc., and Syntroleum Corporation. They produce next-generation renewable, synthetic fuels from animal fats, greases, and vegetable oils that meet government specifications for diesel fuel ASTM D975. The primary feedstocks for this process are inedible tallow and yellow grease.[139] In 2011, Dynamic Fuels gained a contract with the U.S. Navy to supply 450,000 gallons of renewable fuel. The contract constitutes the single largest purchase of biofuel in government history. It will be used as part of the Navy's efforts to develop a "Green Strike Group" composed of vessels and ships powered by biofuel.
- Neste Oil – Neste Oil is the world's largest producer of renewable diesel. The company's first NExBTL production plant was commissioned in Finland at Neste Oil's Porvoo refinery in 2007. The second facility came on stream there in 2009. Both have a capacity of 190 000 metric tonnes per annum (67mgpy). In 2010, Neste Oil started up the world's largest NExBTL refinery in Singapore. The Singapore refinery has a capacity of 800,000 metric tonnes per annum (283mgpy).[140] In 2012 Neste Oil used a total of 2.1 million metric tonnes of renewable inputs, of which palm oil accounted for 65

[139] Dynamic Fuels. 2013. Accessed April 26. http://www.dynamicfuelsllc.com/.

[140] Neste Oil. "Production Technology." https://www.neste.com/about-neste/who-we-are/production

percent, waste and residues for 35 percent, and other vegetable oils under 0.5 percent.[141]

Key Suppliers of Biodiesel in the form of B20-B100

Nationwide there are over 300 filling stations offering biodiesel in blends of B20 and above. 16 percent of these stations, a total of 50, are located in California. Below is a list of the primary companies with biodiesel (B20 and above) filling stations. Several of the filling stations are co-owned and thus are listed under both entities.[142]

Propel Fuels (25 stations)

California based Propel Fuels is located in California and Washington. Propel stations offer both conventional fuels and alternatives, offering the consumer a selection of fuels. Their clean mobility centers offer a variety of fuels along with several other sustainable transportation services such as: free air for tires, carbon offset offerings, rideshare and community transportation resources, bicycle tuning stations, and recycling at the pump. Propel Fuels has the following state and federal partners: U.S. DOE, California Department of General Services, CEC, and Clean Cities Coalitions. Their leading fleet partners include U.S. Postal Service, CALTRANS, Department of Veterans' Affairs, California Highway Patrol, and Enterprise Fleet Services.[99]

Shell (5 stations)

Shell is a global enterprise consisting of energy and petrochemicals companies. Shell has around 87,000 employees in more than 70 countries and territories.[102] All E85 Shell stations offering B20 and higher in California are co-owned by Propel Fuels.[98]

Chevron (3 stations)

Chevron is a California-based petroleum products company that is the second largest energy company in the U.S. Chevron has about 10,000 California employees and operates four refineries in the state with combined production of over 900,000 barrels per day. Chevron has large production interests in the Permian Basin and Gulf of Mexico. Chevron has over 1,500 branded stations in California.[143]

Market Evaluation

Biodiesel has a plethora of end-users, including U.S. Department of Defense, commercial trucking, agriculture, municipal governments,[135] and the maritime industry.[144] The U.S.

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[141] NesteOil. 2013a. "Neste Oil Has Increased Its Use of Waste- and Residue-based Renewable Inputs by over 400,000 Tons." February 5. https://www.neste.com/neste-oil-has-increased-its-use-waste-and-residue-based-renewable-inputs-over-400000-tons

[142] AFDC. 2013f. "Biodiesel Fueling Station Locations." Fuels and Vehicles. Alternative Fuels Data Center. Accessed June 5. http://www.afdc.energy.gov/fuels/biodiesel_locations.html.

[143] Chevron Highlights of Operation https://www.chevron.com/worldwide/united-states

[144] Sims, Bryan. 2011. "Biodiesel Sets Sail." Biodiesel Magazine. June 14. http://www.biodieselmagazine.com/articles/7858/biodiesel-sets-sail.

Department of Defense is the world's largest single user of fuel[145] and also the world's largest user of biodiesel. As early as 2003, the U.S. Army, Navy, Air Force and Marines all used B20 at bases and stations throughout the country.[146] The military's biofuels effort is justified in its contribution to national security to reduce U.S. dependence on fossil fuels.[147] Hundreds of fleets across the country are using biodiesel blends and have reported no significant differences in performance, maintenance or fuel efficiency.[148] Ferries in California and Washington are already geared toward using biodiesel blends.[144] Another key end-user of biodiesel is light-duty vehicle use. B20 vehicle availability is increasing. Currently 80 percent of manufacturers selling diesel vehicles and equipment in the U.S. now warranty them for use with high-quality B20 biodiesel blends. The remainder, primarily European light duty diesel brands, are certified for B5 use.[149]

Discussion

Biodiesel

The U.S. biodiesel industry has grown quickly in the last decade from 9 million gallons produced in 2001 to over 1 billion gallons in 2011. By 2017, biodiesel demand is expected to double from 2011 levels.[150] U.S. biodiesel production capacity (Figure 19) is more than 1.8 billion gallons[129] and thus capacity is greater than current production of approximately 1 billion gallons and even greater than the current U.S. EPA mandate of 1.28 billion gallons in 2013.

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[145] National Business Aviation Association. 2012. "Senate Strikes Restriction on Military Biofuels Development.". December 3. https://nbaa.org/advocacy/legislative-and-regulatory-issues/minimizing-the-industrys-environmental-impact/senate-strikes-restrictions-on-military-biofuels-development/.

[146] "Alternative Fuels Program.". Texas Comptroller Office, Window on State Government. https://comptroller.texas.gov/programs/seco/programs/alt-fuels.php.

[147] Service, Robert F. 2012. "Congressional Negotiators Drop Biofuel Restrictions in U.S. Defense Bill." ScienceInsider. December 19. https://www.sciencemag.org/news/2012/12/congressional-negotiators-drop-biofuel-restrictions-us-defense-bill

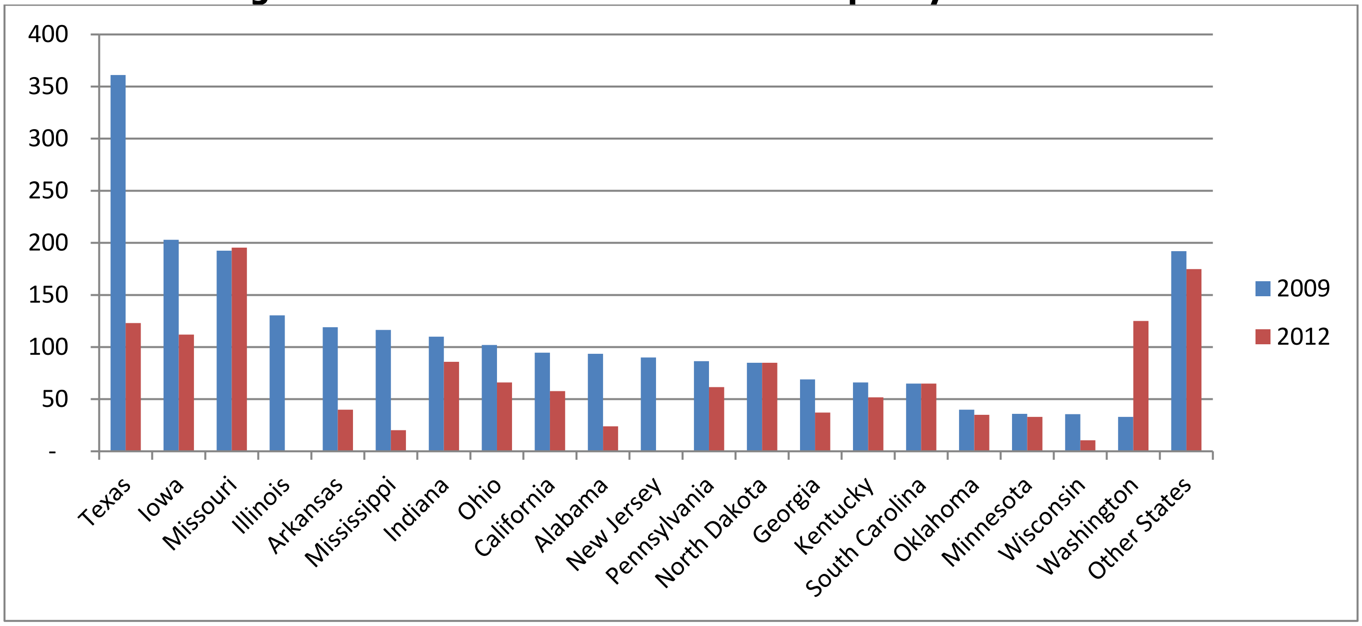
[148] Simon, Chad. 2009. "Fleets Put Biodiesel to the Test." Business Fleet. March. https://www.greenfleetmagazine.com/155348/fleets-put-biodiesel-to-the-test

[149] Weaver, Jennifer, and Kaleb Little. 2013. "GM's 2014 Chevy Cruze Adds to Growing List of B20-Ready Vehicles." Biodiesel.org. February 9. https://www.prnewswire.com/news-releases/gms-2014-chevy-cruze-adds-to-growing-list-of-b20-ready-vehicles-190557151.html

[150] Lucintel. 2012. "Growth Opportunities in the Global Biodiesel Market 2012–2017: Trends, Forecasts, and Market Share Analysis." February 2012.

The U.S. has exported more biodiesel than it imported over the last decade, primarily to Brazil, Europe, Canada, India and China.[151] As domestic consumption increases, along with European tariffs applied to all U.S. biodiesel,[152] U.S. biodiesel exports are decreasing.

Figure 19: U.S. Biodiesel Production Capacity 2009-2012



Source: NREL

One limiting factor to biodiesel growth is the need to transport via rail because for the most part, biodiesel is prohibited from petroleum product pipelines. Biodiesel contains oxygen and is made up of polar molecules. This polarity makes them behave differently and results in a greater affinity for water, dirt, and surfaces which can cause product quality problems.[70] There are a limited number of pipelines allowing low blends of biodiesel, including: the Kinder Morgan (through a portion of the Plantation Pipe Line system and also on its Oregon Pipeline[153] and the Colonial Pipeline (on a portion of its system in Georgia).[154] The existing infrastructure appears able to accommodate low blends of biodiesel product without product degradation and with only minimal possible modifications of heated systems at origin and delivery points in cold weather.[151]

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[151] U.S. EIA. 2012b. "Biofuels Issues and Trends". U.S. Energy Information Administration.Washington, DC. http://www.eia.gov/biofuels/issuestrends/pdf/bit.pdf.

[152] Voegele, Erin. 2011. "A Whole New World." Biodiesel Magazine. August 16. http://www.biodieselmagazine.com/articles/7996/a-whole-new-world.

[153] Kinder Morgan. 2013. "Products Pipelines." Accessed April 24. http://www.kindermorgan.com/business/products_pipelines/

[154] Platts. 2013. "Colonial Pipeline to Ship Biodiesel on Georgia Line by end-March." Accessed April 24. https://www.spglobal.com/platts/en/market-insights/latest-news/oil/031813-colonial-pipeline-to-ship-biodiesel-on-georgia-line-by-end-march.

Renewable Diesel

Renewable diesel and jet fuel production is expected to reach 1.2 billion gallons by 2015.[27] This is based on companies' statements and media releases. The reality of reaching this production level will depend on success of new and proven technologies, feedstock availability, production cost, and diesel demand.[129] It meets the specifications for No.2 diesel fuel, and thus it can utilize existing infrastructure and does not require vehicle modifications.

Renewable Natural Gas or Biomethane

RNG, also known as biomethane, is pipeline-quality gas that is fully interchangeable with fossil natural gas and can be used in its pure form or blended with conventional gas streams for use in vehicle engines.[155] RNG is essentially biogas that has been upgraded and purified. As mentioned earlier in Chapter 3, biogas is the gaseous product of the decomposition of organic matter. Conversion of biogas into RNG involves primarily removal of water, carbon dioxide, hydrogen sulfide, and other trace elements. The resulting biomethane, or RNG, has a higher content of methane than raw biogas (therefore higher energy content) which makes it comparable to conventional natural gas and thus a suitable energy source in applications that require pipeline-quality gas. RNG can be used as a renewable transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG). RNG can be considered a "drop-in" fuel for the natural gas vehicles currently on the road and can qualify as an Advanced Biofuel under RFS2.

Process Conversion Technologies for RNG or Biomethane

RNG is produced from various biomass resources, as outlined in Chapter 3, through a biochemical process such as anaerobic digestion or thermo-chemical process such as gasification.

Anaerobic Digestion (AD)

Anaerobic digestion (AD) is a biological process in which microorganisms break down biodegradable material in the absence of oxygen. One of the end products is biogas; there are also liquids that can be used for fertilizer or soil amendments, and digested solids that can be composted, utilized for livestock bedding, dried and pelletized for use as fertilizer or fuel, used as renewable construction material or converted into other products.

There are two types of AD, "wet" fermentation and "dry" fermentation, depending on the fraction of dry matter within the waste. The term fermentation is often used interchangeably with AD when describing the decomposition of organic material. "Wet" fermentation systems are the most widely used technology for biogas production today. These systems generally utilize high-moisture waste streams such as animal manure and wastewater. "Wet" fermentation systems often require pre-processing including, separation of non-organic material, liquefaction, sand separation and sanitization. There are a wide range of "wet" AD technologies available, from simple lagoons to upflow anaerobic sludge blanket technology and fluidized or expanded bed reactor systems.

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[155] NPC. 2012. "Renewable Natural Gas for Transportation: An Overview of the Feedstock Capacity, Economics, and GHG Emission Reduction Benefits of RNG as a Low-Carbon Fuel." National Petroleum Council. August 2012, http://www.npc.org/FTF_Topic_papers/22-RNG.pdf

"Dry" fermentation systems are capable of using various waste streams as input including those with high dry matter content such as the organic portion of Municipal solid waste, food waste, yard waste, agricultural waste, etc. In addition to feedstock flexibility, the "dry" fermentation systems provide other advantages such as smaller footprint, no pre-treatment, no conversion into a liquid substrate (thus less water use), shorter retention time, low energy and labor requirements. Available "dry" AD technologies include single-stage batch design and single-stage continuous/plug flow design. Until recently, "dry" fermentation technologies were not commercially available. Because of the benefits of these systems, several companies are involved in further developing these technologies and as a result, there are many successful applications worldwide.

Gasification

Gasification is the process of heating solid biomass with about one-third of the oxygen necessary for complete combustion to produce a mixture of CO and H_2, known as syngas (or synthesis gas). The gasification step is followed by gas conditioning/purification, synthesis and upgrading. A wide variety of feedstock can be gasified, including crop and forest residues, dedicated energy crops, Municipal solid waste, industrial waste, plastics, aluminum, etc. *Steam-oxygen gasification,* as the name implies, uses steam and oxygen in the reaction. This is a proven and commercialized method of gasification for the production of synthetic natural gas (SNG) from coal. *Catalytic steam gasification* is considered to be more energy-efficient than steam-oxygen gasification.[156] In this process, gasification and methanation (generation of methane) occur in the same reactor in the presence of a catalyst. The process was initially developed by Exxon in the 1970s, but it was not commercialized. Efforts are underway to further develop this process. Another thermochemical conversion process is *plasma gasification* – biomass is fed to a plasma converter at high temperatures and in the process the matter is broken down into basic elemental components in gaseous state (syngas). Another byproduct, remaining from the inorganic material, is a glass-like substance (slag) that can be used in production of tiles or road asphalt. This technology is in commercial use for waste disposal. Gasification of carbon-containing material in a hydrogen-rich environment is called *hydrogasification.* Hydrogasification for syngas production from coal and biomass has been used since the 1930s.[157] Researchers at the University of California, Riverside point out that the process requires high pressure or catalyst, which explains the lack of commercial success and interest.[158] Therefore, they focused their efforts on developing a more efficient process. In 2005, they began developing *steam hydrogasification*, a process that uses both steam and hydrogen in the reaction. It has been found that this process is 12 percent more

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[156] Chandel, M., Williams, E. 2009. "Synthetic Natural Gas (SNG): Technology, Environmental Implications and Economics". Duke University, January 2009, https://nicholasinstitute.duke.edu/climate/carbon-capture-and-storage/natgas

[157] NETL. 2013. "Gasification", National Energy Technology Laboratory. https://www.netl.doe.gov/research/coal/energy-systems/gasification/gasifipedia/specialapps

[158] University of California – Riverside. 2010. "Steam Hydrogasification Research Overview", Presentation at the Pacific Southwest Organic Residuals Symposium, September 2010, https://archive.epa.gov/region9/organics/web/pdf/4-park-shr2.pdf

efficient, with 18 percent lower capital costs, compared to other mainstream gasification technologies such as hydrogasification.[159]

Technology Developers

Below is a list of AD and gasification technology developers with links to companies' websites for more information. The list is not exhaustive – it is for illustration purposes. Most of these companies are based in Europe and this is where they mainly operate. However, some of these companies have also expanded worldwide and include offices and applications in the USA.

"Wet" AD

- BTA International GmbH - http://www.bta-international.de/en/home.html
- RosRoca –https://www.rosroca.es/en/
- WELtec-BioPower GmbH - http://www.weltec-biopower.co.uk/
- FARMATIC Anlagenbau GmbH - http://www.farmatic.com/
- EnviroChemie - https://www.envirochemie.com/en/

"Dry" AD

- KOMPOFERM - http://act-clean.eu/index.php/KOMPOFERM-dry-fermentation---Biowaste-Treat;100.44/1
- BEKON - https://www.bekon.eu/en/
- Axpo-Kompogas - https://www.axpo.com/ch/en/business/biomass-and-wood-energy/biomass.html
- Valorga - http://www.valorgainternational.fr/en/
- Clean World - http://www.cleanworld.com

"Wet and Dry" AD

- STRABAG Umweltanlagen GmbH former Linde-KCA Umweltanlagen GmbH - http://www.strabag-umweltanlagen.com/#!
- BIOFerm - https://www.biofermenergy.com/
- OWS - http://www.ows.be/biogas-plants/
- AAT - http://www.aat-biogas.at/en
- BioConstruct GmbH - http://www.bioconstruct.com/home.html
- UTS Biogastechnik GmbH - http://www.uts-biogas.com/en/home.html
- GICON Bioenergie GmbH - http://www.gicon-engineering.com/en.html

[159] Green Car Congress. 2011. "UC Riverside researchers receive two grants to advance steam hydrogasification reaction for waste-to-fuels", September 2011, http://www.greencarcongress.com/2011/09/shr-20110915.html

- Quasar Energy Group - http://www.quasarenergygroup.com/

There are several gasification technology development companies. Most are targeting the production of ethanol, such as Coskata (http://www.coskataenergy.com/), Enerkem (https://enerkem.com/), and Fulcrum (http://fulcrum-bioenergy.com/), or renewable gasoline such as CORE BioFuel (http://www.corebiofuel.com/) and Primus Green Energy (http://www.primusge.com/), or renewable diesel such as UHDE (http://gpscorp.net/portfolio/udhe-thyssenkrupp/), and TRI (https://tri-inc.net/) rather than the production of RNG for transportation. Viresco Energy LLC (https://www.virescoad.com/), a California-based company, has partnered with the UC-Riverside to further develop and demonstrate the viability of steam gasification technology. The syngas can be used to produce a number of energy products including RNG.

Production Facilities and Key Suppliers

RNG Production Facilities

While there are many biogas-capturing facilities in California, not all of them upgrade the biogas to RNG for use in transportation. According to the Air Resources Board, of the 11-operating biogas-capturing dairy farms in the state, only one produces vehicle fuel - Hilarides Dairy located in Lindsay, Tulare County.[56] The facility is using manure produced from 6,000 cows to generate about 300,000 cubic feet (cu ft.) of RNG per day. Vintage Dairy located in Riverdale, Fresno County is another dairy capable of producing RNG; however the facility is not operational at this time.

As of June 2012, there were 75 landfills in California capturing biogas.[53] Most of these landfills use biogas to produce electricity; only two landfills use biogas to produce RNG – Altamont Landfill & Resource Recovery in Livermore, Alameda County and Central Disposal Site in Petaluma, Sonoma County. Altamont facility is operated by Waste Management and produces up to 13,000 gallons of liquefied RNG per day—enough to fuel 300 of Waste Management's 491 LNG waste and recycling collection vehicles.[160] Compressed RNG is produced at the Central Disposal Site and it is used to fuel select vehicles in the Sonoma County Transit bus fleet. Compressed RNG was produced at Puente Hills Landfill in Industry, Los Angeles County but it was decommissioned in 2007. Frank R. Bowerman Sanitary Landfill in Irvine, Orange County was producing liquefied RNG, but the project is currently closed.

No RNG projects for transportation at wastewater treatment plants were identified at the time this report was written.

"Clean World Partners' Organic Waste Recycling Center at the South Area Transfer Station in Sacramento will convert 25 tons of food waste per day collected by Atlas Disposal from area food processing companies, restaurants and supermarkets into RNG. In 2013, the facility will be expanded to process 100 tons of waste per day, making it the largest commercial-scale, high solids AD system in the United States. When complete, the Organic Waste Recycling Center will replace 1 million gallons of diesel per year with RNG. Atlas' RNG Fueling Station will use the biomethane to fuel the company's clean-fuel fleet, as well as vehicles from area

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[160] Waste Management. 2013. Altamont Landfill and Resource Recovery Facility, Accessed March 2013, https://altamontlandfill.wm.com/index.jsp

jurisdictions and agencies. Natural gas produced from the initial 25-ton per day operation would fuel approximately 80 school buses for one year".[161]

The CEC's Clean Transport Program has recently awarded the following biomethane production projects. More information can be found on the CEC's Clean Transportation Program website (https://www.energy.ca.gov/programs-and-topics/programs/clean-transportation-program).

- "BioStar Systems, LLC has partnered with Sonoma County Water Agency and Sonoma County Transit to produce 240,000 cubic ft. of biogas per day using a waste reception and blending facility, high temperature anaerobic digestion, and a biogas condition and compression facility. This project will produce 148,000 cu ft. per day of pipeline quality biomethane to be used by the Sonoma County Transit fleet. Excess gas will be distributed to public compressed natural gas stations in the state. The feedstock used for this project will be dairy waste (75,000 gallons per day and food processor waste (66,000 gallons per day)."
- "City of San Jose and project partner, Harvest Power, will evaluate and potentially build and demonstrate a new gasification system that can turn urban wood waste, yard waste, and biosolids into natural gas that can be used as a transportation fuel."
- "CR&R, a large waste and recycling firm will construct and operate a 50,000 ton per year facility at the Perris Material Recovery and Transfer Station in Riverside County. This facility will process mixed Municipal solid waste from the City of Los Angeles using a wet separation technology from Arrow Ecology to separate recyclable materials from non-recyclable inert waste. Biodegradable materials will then be pumped into a two-stage anaerobic digestion system to produce biogas. Purac technology will clean the biogas, which will then be injected in the Sempra natural gas pipeline where it is used by Shell Energy North America for transportation fuel."
- "Eurisko Scientific LLC and the U.S. DOE's Argonne National Laboratory will partner with the Sacramento Municipal Utility District to demonstrate a process to increase production of biogas through anaerobic digestion while reducing the amount of CO_2 produced. Sacramento Municipal Utility District's Sacramento Regional Waste Water Treatment Plant in Elk Grove will be the demonstration site."
- "Placer County is partnering with G4 Insights, Inc. and others to turn wood waste from the forests of Placer County into biomethane. The renewable gas would be injected into the state's natural gas pipeline system and shipped to wherever it's needed for transportation and other uses. The project will determine the technical, economic and environmental feasibility of building commercial-scale conversion plants at several rural forest sites in the state."
- "High Mountain Fuels, LLC will produce transportation fuel from renewable landfill gas using second generation purification and liquefaction technologies. The resulting bio-

[161] Clean World Partners. 2012. Accessed June 2012, http://www.cleanworld.com/news/nations-largest-commercial-high-solid-waste-to-energy-digester-begins-construction/

LNG will fuel 500 waste hauling trucks. The project will take place at the Simi Valley landfill in Ventura County."

- "Northstate Rendering Company, Inc. is building an anaerobic digestion facility and biogas upgrading/compression system at their existing rendering facility in Oroville, CA. The facility will produce biogas that will be upgraded to RNG for use as a vehicle fuel for Northstate Rendering's fleet of delivery trucks."

Another potential project includes a partnership between the City of Napa and Napa Recycling & Waste Services, LLC. The project will take currently collected organic feedstock, produce biogas, and convert it to CNG. "The project will use Dry AD process to generate bio-methane from organic waste derived from a 50/50 blend of 20,000 tons per year of combined source separated municipal food waste and yard waste. Twenty thousand tons of organic material will produce approximately 111,891 diesel gallon equivalents (DGE), which would provide enough CNG to fuel 14 solid wastes and recycling collection vehicles per day".[162]

Additionally, Blue Line Transfer, Inc. proposes to produce CNG from the biogas generated from the organic portion of the Municipal solid waste from the cities of South San Francisco, Brisbane, Millbrae and the County of San Mateo. The facility will convert 9,000 tons per year of food waste and green waste into RNG that would be used by the South San Francisco Scavenger Co., Inc. refuse and recycling collection vehicle fleet.[162]

A project sponsored by San Joaquin Valley Air Pollution Control District is under way. Ruby Mountain Inc., a consulting firm, in partnership with Go2Water for biogas production and Energy Solutions for biogas upgrade, plan to demonstrate a small-scale biogas liquefaction system to produce LNG for vehicle fuel. Livestock manure is the likeliest feedstock option and the truck fueling facility would likely be built in the Fresno area.

Key Suppliers of RNG

Because RNG uses the same distribution system as conventional natural gas, a list of key natural gas suppliers for transportation in California is provided below. Some of these companies already include RNG in their portfolio. According to the Alternative Fuels Data Center, as of April 2013, there were 257 CNG and 42 LNG fueling stations in California.[163] Some of these stations are open to the public while others are privately owned. Most of the stations operated by the companies below are public. Major owners of private CNG stations include Waste Management, City of Los Angeles, and Camp Pendleton.

Clean Energy is the largest supplier of natural gas fuel for transportation in North America with about 360 fueling stations throughout the United States and Canada.[164] The company is

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[162] Zero Waste. 2013. Projects. Zhu, Y, SB Jones, MJ Biddy, RA Dagle, and DR Palo. 2012. "Single-Step Syngas-to-Distillates (S2D) Process Based on Biomass-Derived Syngas – A Techno-Economic Analysis." Bioresource Technology https://www.sciencedirect.com/science/article/abs/pii/S0960852412006293

[163] AFDC. 2013a. Alternative Fueling Station counts by State, Accessed April 2013, http://www.afdc.energy.gov/fuels/stations_counts.html, (a)

[164] Clean Energy. 2013a. About Us, Accessed April 2013, http://www.cleanenergyfuels.com (a)

constructing its first RNG fuel station in Sacramento for Atlas Disposal. Clean Energy, headquartered in Seal Beach CA, has about 71 CNG and 20 LNG stations in California.[163]

Pacific Gas & Electric Co. is an energy-based holding company headquartered in San Francisco, CA. Pacific Gas and Electric Corporation subsidiaries provide customers with public utility services, and services relating to the generation of energy, transmission of electricity and natural gas, generation of electricity, and the distribution of energy.[165] The company operates about 24 CNG stations in California.

San Diego Gas & Electric Co. is a regulated public utility that provides natural gas and electricity to San Diego and southern Orange counties. The company operates two CNG stations in San Diego and one in Carlsbad.

Southern California Gas Company, headquartered in Los Angeles, is the primary provider of natural gas to the region of Southern California. The company operates about 11 CNG stations in the region.

Trillium CNG provides fuel for thousands of natural gas vehicles every day, delivering more than 35 million gallons of CNG per year.[166] As of March 2013, the company operated 54 CNG stations (public and private) nationwide. About 30 of these stations are located in California. Trillium had 6 stations under construction, of which 2 were in California.

Market Evaluation

The use of RNG in California vehicles is negligible but growing, given the many production facility projects underway. This is also exemplified by the growth of natural gas fuel consumption by vehicles in California (Figure 20).[167]

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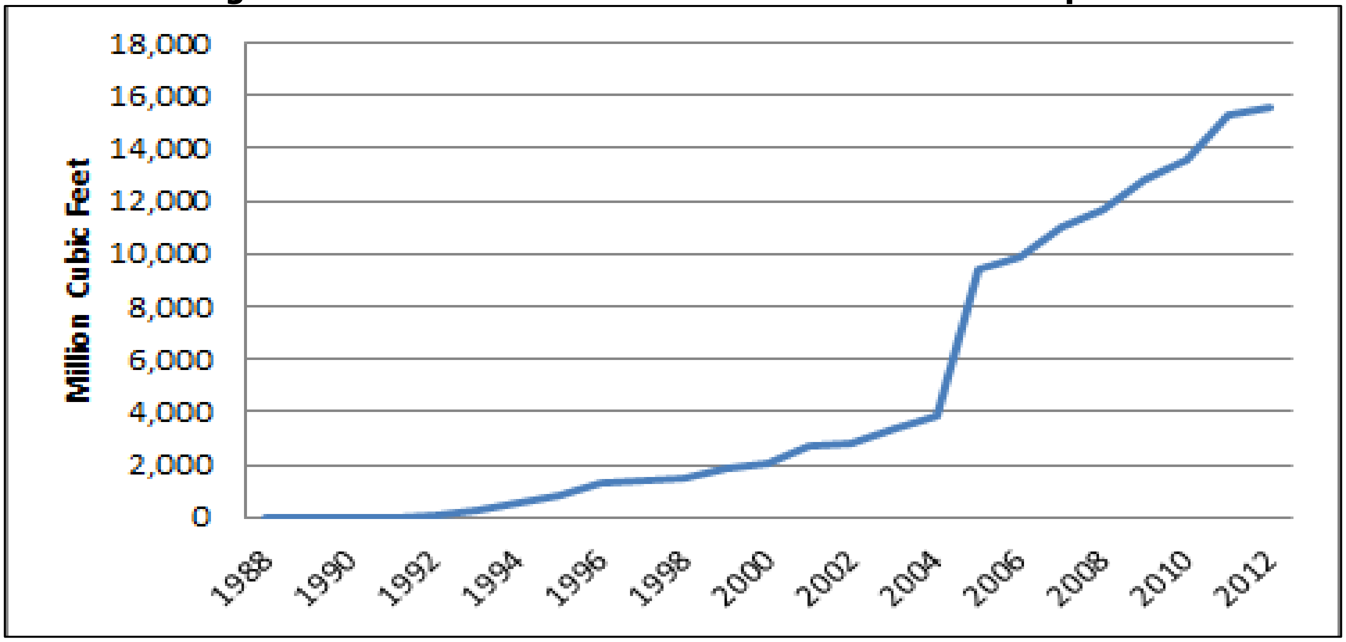
[165] Pacific Gas and Electric Corporation. 2013. About Us, Accessed March 2013, http://www.pgecorp.com/aboutus/

[166] Trillium CNG. 2013. About Us, Accessed March 2013, https://www.trilliumcng.com/en/about-us

[167] U.S. EIA. 2013c. California Natural Gas Vehicle Fuel Consumption, May 2013, http://www.eia.gov/dnav/ng/hist/na1570_sca_2a.htm (a)

Figure 20: California Natural Gas Vehicle Fuel Consumption



Source: NREL

At present, transit buses are the largest users of natural gas for vehicles. Transit fleets using CNG and LNG in California include Los Angeles County Metropolitan Transit Authority (Metro), San Diego Metropolitan Transit System, Big Blue Bus - Santa Monica, Omnitrans Bus System - San Bernardino, Orange County Transportation Authority, Santa Cruz Metropolitan Transit District (Santa Cruz Metro), etc. Metro has switched 99 percent of its overall transit bus fleet to CNG, and currently deploys America's largest CNG-powered clean air bus fleet—more than 2,500 buses.[168]

Waste collection is the fastest growing natural gas vehicles (NGV) segment. Existing fleets of refuse trucks running on natural gas include Waste Management, the City of Los Angeles, the City of Beverly Hills, Rainbow Disposal, Republic Services, and Napa Recycling. Other companies such as Atlas Disposal, Garden City Sanitation in Santa Clara, and Alameda County Industries in San Leandro are in a process of converting part of their fleet as well.

The use of natural gas by transfer vehicles (taxi/shuttle) is also growing. In the fall of 2011, California Yellow Cab (Orange County's premier taxicab company) became the first cab business in California to add CNG-powered Ford Transit Connect taxicabs to their fleet. In 2012, San Francisco Yellow Cab added 35 CNG taxis to their fleet.[169] Super Shuttle, already one of the country's leaders in the transition to CNG, is expanding its CNG fleet in California by over 100 new CNG vans.

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[168] Clean Energy. 2013b. Representative Transit Customers, Accessed March 2013, http://www.ruscom.com/cleanenergy/products_services/transitcustomers/index.html

[169] Clean Energy. 2013c. The Road to Natural Gas, February 2013, https://www.cleanenergyfuels.com/release-archive/clean-energy-releases-third-edition-of-the-road-to-natural-gas

The trucking industry has also started exploring the option of running its fleets on natural gas. Companies like UPS, FedEx, Ryder System, and YRC Freight are increasingly using CNG and LNG. UPS for example, has been using NGVs for over two decades and currently has more than 1,300 vehicles.[170] The company added 48 LNG trucks to its hubs in Ontario, California and Las Vegas in 2012. Wal-Mart Stores Inc., one of the nation's largest private carriers, has been using NGVs in California and plans to expand. Other retailers like Nike and Coca-Cola are also considering NGVs in their fleet. In 2012, "99 Cent" stores, Red Bull, Land O'Lakes and Cintas added LNG trucks to their CA fleets. At the end of 2011, AT&T deployed more than 3,400 CNG vehicles, with more than 2,100 of those vehicles in California.[171]

The use of natural gas by light-duty vehicle is negligible in the United States. Sales of Honda Civic NG, the only passenger vehicle on the market today, are highest in California and New York. Forbes reports that sales in 2012 were somewhere between 1,000 and 2,000.[172]

Techno-economic Analysis for Biomethane

The quality of biomethane varies depending on its origin, production process, and end use. In order to make costs data comparable, the biomethane costs presented here represent the costs of a pipeline quality gas (i.e., readily to be injected into a natural gas pipeline). The product gas must be free of unacceptable substances (e.g., H_2S) and must be pressurized to the pressure of the pipeline to which the gas production facility is interconnected. (Pipeline pressure typically varies from 200 to 1500 pounds per square inch, depending on the type of area, in which the pipeline is operating.[173]

United States Department of Agriculture investigated the cost of electricity and biogas production using manure-based AD systems based on an analysis of 38 installations in the U.S., which were grouped by typical digester configurations including covered anaerobic lagoons, plug-flow digesters, and continually stirred tank reactors (mixed digesters).[174] Using United States Department of Agriculture's data, Jalalzadeh estimated the cost of biomethane (including an upgrading cost of $3.2/gigajoule and 10 mile pipeline from production site to natural gas transmission line) at ~$6/gigajoule for covered lagoon, ~11/gigajoule for plug-flow, and ~$14/gigajoule for mixed digesters (all values are expressed in 2010 U.S. dollars)

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[170] Seeking Alpha. 2012. "U.S. Natural Gas Fund And CNG Fleet Vehicles: Not Just A Lot Of Hot Air", December 5, 2012, http://seekingalpha.com/article/1046211-u-s-natural-gas-fund-and-cng-fleet-vehicles-not-just-a-lot-of-hot-air

[171] AT&T. 2012. Transportation Initiatives, http://www.att.com/Common/about_us/files/csr_2012/transportation_initiatives.pdf

[172] Forbes. 2013. "Natural Gas Cars Not a Hit with Consumers Yet", March 7, 2013, http://www.forbes.com/sites/michaelkanellos/2013/03/07/natural-gas-cars-not-a-hit-with-consumers-yet/

[173] American Gas Association. 2013. How Does the Natural Gas Delivery System Work? https://www.aga.org/natural-gas/delivery/how-does-the-natural-gas-delivery-system-work-/

[174] United States Department of Agriculture. 2007. An Analysis of Energy Production Costs from Anaerobic Digestion Systems on U.S. Livestock Production Facilities. 2007. Natural Resources Conservation Service. U.S. Department of Agriculture. https://directives.sc.egov.usda.gov/OpenNonWebContent.aspx?content=22533.wba

without considering ancillary (e.g., storage) costs.[175] Jalalzadeh-Azar indicated that clustering sources of biogas (e.g., from multiple dairy farms) may be imperative To achieve necessary economies of scale of the upgrading system and make biomethane competitive with natural gas. CALSTART reached the same conclusion and found that the dominant cost for small facilities was upgrading the biogas to renewable natural gas; upgrading could cost up to $7/gigajoule.[176]

Princeton Energy Resources International prepared a report for the CEC that examined bioenergy production from digesters at California dairies. The report employed cash flow financial analysis for several scenarios, including production of biomathane for on-site power generation and pipeline quality gas. The study modeled cost of producing pipeline gas for 9 California dairy farms, which use either covered lagoon or plug-flow digester. The estimated costs range from $12 to $45/gigajoule (2007$), depending on the size of the farm and the distance from production site to natural gas transmission line. These estimates are higher compared to those estimated by Jalalzadeh-Azar in part because of the varying assumptions (e.g., return on investment, debt to equity ratio, transmission line pressure requirement) used by the analyses.[175]

Municipal solid waste landfills produce significant quantities of landfill gas, which typically has a methane content of about 40 to 55 percent with the balance being primarily carbon dioxide. If landfill gas is not utilized, it is incinerated in a flare. Landfill gas can be utilized as a substitute for natural gas and can be directly injected into natural gas pipelines. A study prepared by SCS Engineers for the CEC estimated the costs of producing renewable natural gas from landfill gas to be between $1.6 -$2.1/gigajoule (unit converted from mcf in original study).[177] However, the study did not specify the year associated with the dollar values.

There are several biomethane facilities using animal manure and other types of organic waste as feedstock in Sweden, Switzerland, Denmark, and the Netherlands. Based on costs data available from selected Swedish facilities, the costs estimated for biomathane (including upgrading) for three hypothetical dairy AD and biogas to biomethane plants are between $8.3/gigajoule and $11.6/gigajoule.[178] However, it should be noted that the size of the farms as well as costs could be quite different between European plants and U.S. plants, which could lead to difference in costs.

[175] Jalalzadeh-Azar, A. 2010. A Technoeconomic Analysis of Biomathane Production from Biogas and Pipeline Delivery. NREL/PR-5600-49629. http://www.nrel.gov/docs/fy11osti/49629.pdf.

[176] Calstart. 2010. Economic Assessment of Biogas and Biomethane Production from Manure. March 2010. White paper prepared by Patrick Chen et al.

[177] California Energy Commission. 2002. Economic and Financial Aspects of Landfill Gas to Energy Project Development in California. April 2002. 500-02-020F. Prepared by SCS Engineers.

[178] Krich, K., Augenstein, D., Batmale, J., Benemann., J., Rutledge., B., Salour., D. Biomethane from Dairy Waste. 2005. A Sourcebook for the Production and Use of Renewable Natural Gas in California. Prepared for Western United Dairymen. 2005.

Discussion

Natural gas has received renewed interest in recent years fueled primarily by new assessments of the U.S. reserves which are now able to "supply over 100 years of demand at today's consumption rates".[179] Just a decade ago, these estimates were very low, and predictions were that the United States would be importing this energy source by now. Another factor driving the interest in natural gas as a transportation fuel is the relatively low price. As of April 2013, the national average price of CNG was $2.10 per GGE (gasoline gallon equivalent), compared to $3.59/gallon for gasoline and $3.99 per GGE for diesel.[180] In its most recent annual energy outlook, U.S. EIA predicts that energy from natural gas will remain far less expensive than energy from oil through 2040: natural gas prices nearly double in the *Annual Energy Outlook 2013* Reference case, from $3.98 per million Btu in 2011 to $7.83 in 2040 (2011 dollars), and oil prices increase by about 50 percent, to $28.05 per million Btu in 2040.[181] U.S. EIA also predicts that natural gas will be the fastest-growing fuel in the transportation sector, with an average annual growth rate of 11.9 percent. Recent announcements on natural gas vehicle expansion made by companies such as UPS, FedEx, Waste Management and AT&T are indicators of the growing interest. Moreover, the Royal Dutch Shell announced in 2012 that it plans to invest heavily in LNG.[182]

If the natural gas use for transportation increases in the United States it may also pave the way to expansion of RNG as an alternative fuel. This trend is seen in the state of California. In addition to expanding its natural gas distribution network and fleet vehicles, the state is also focusing on promoting the production and use of biogas/RNG. This is evident from recent state legislative activities which include the new Bioenergy Action Plan and several laws relevant to biogas production from organic waste. The BioCycle Magazine[183] summarizes these activities below:

"The Brown Administration adopted the 2012 Bioenergy Action Plan, which includes 55 specific actions that state agencies must take to accelerate bioenergy development. The actions focus on increasing sustainable biomass production, streamlining and consolidating permitting requirements, increasing research and development, and incentivizing and monetizing the benefits of bioenergy. The 2012 Bioenergy Action Plan is available online

179 NPC. 2011. "Realizing the Potential of North America's Abundant Natural Gas and Oil Resources", National Petroleum Council. September 2011, https://www.npc.org/NARD-ExecSummVol.pdf

180 AFDC. 2013b. Alternative Fuel Price Report, Alternative Fuels Data Center, April 2013, http://www.afdc.energy.gov/uploads/publication/alternative_fuel_price_report_april_2013.pdf (b)

181 U.S. EIA. 2013b. Annual Energy Outlook 2013, May 2013, http://www.eia.gov/forecasts/aeo/pdf/0383(2013).pdf

182 Forbes. 2012. "All Roads Lead to Natural Gas Fueled Cars and Trucks", December 2012, http://www.forbes.com/sites/kensilverstein/2012/12/15/all-roads-lead-to-natural-gas-fueled-cars-and-trucks/

183 BioCycle Magazine. 2013. "Golden Opportunities in the Golden State", April 2013, https://www.biocycle.net/golden-opportunities-in-the-golden-state/

(https://resources.ca.gov/CNRALegacyFiles/docs/energy_and_climate_change/2012_Bioenergy_Action_Plan.pdf).

The California Legislature has also stepped up to promote bioenergy, passing three laws in 2012 that will help bioenergy development. SB 1122 (Rubio) requires California's utilities to purchase 250 megawatts (MW) of bioenergy from facilities that are 3 MW or smaller. Of the total, the bill requires that the utilities purchase 110 MW from urban organic waste, 90 MW from dairy and agricultural waste, and 50 MW from forest waste. AB 1900 (Gatto) requires new standards for pipeline injection of biomethane, and AB 2196 (Chesbro) clarifies the role of out-of-state biogas under California's Renewable Portfolio Standard. Together, the Gatto and Chesbro bills will enable much more biogas production and use in California."

CNG, due to its relatively low energy density, is primarily used in cars, transit busses, and smaller trucks, in other words, in urban environments with managed fueling. LNG, significantly more energy dense than CNG, is suitable for longer driving ranges and thus it is used in heavy-duty vehicles, typically vehicles that are classified as "Class 8" (above 33,000 pounds, gross vehicle weight). While the development of CNG engines is further along, there were only a few heavy-duty trucks that could run on LNG until recently. This situation is about to change. In April 2013, Cummins, a leading engine manufacturer, in a joint venture with Westport Innovations introduced a 12-liter LNG engine, which is the optimum size for heavy-duty 18-wheeler trucks. "Analysts believe that because it will have the size and power of a standard heavy-duty truck engine, it will be a game-changer. Truck manufacturers Freightliner, Kenworth, Peterbilt, Volvo, and Navistar all plan to take deliveries, with the new LNG rigs hitting the road as early as August.".[184] This breakthrough in truck fuel technology, a 50-cent-per-gallon federal tax credit to companies using LNG (scheduled to expire at the end of the year), and the Clean Energy's effort to build a network of LNG fueling stations on the U.S. Interstates to support long-haul trucks traveling across the country (called the America's Natural Gas Highway) are indicators of the push towards further development and use of LNG in the United States, which could present business opportunities for liquefied RNG as well.

General Motors Corp., Ford Motor Co., and Chrysler Corp. developed dedicated CNG and bi-fuel (gasoline-CNG) vehicles in recent years. These are primarily pickup trucks, vans or chassis models, which indicate that the majority of customers are commercial fleets, even though they are available to the general public.

Natural gas has not found acceptance among passenger car drivers in the United States which is evident from the fact that Honda is the only automaker currently that offers a CNG passenger car, the Civic NG model, and the sales are negligible. There are several reasons for the low popularity, some being the lack of refueling infrastructure, the large space that the CNG tank takes up in the car's trunk, and higher cost of vehicles relative to standard models. Until some breakthrough technology is developed such as new materials that could displace the existing gasoline tank or a new car design to better accommodate CNG tanks, it is likely that NG passenger cars will remain a niche market in the United States.

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[184] National Geographic. 2013. "Natural Gas Truck Stops", March 2013, http://news.nationalgeographic.com/news/energy/2013/03/130318-natural-gas-truck-stops/

NREL interviewed Dr. Michael Schuppenhauer, Chair of the American Biogas Council's research and development Advisory and President of Farmatic Inc., a San Francisco based company, to give his perspective on the market expansion opportunities and barriers to widespread commercialization and deployment of biogas/biomethane in California. "California has several features that predispose the state to lead the nation above all others in the adoption of biogas technologies", Dr. Schuppenhauer said. "These include:

- Top agricultural production state with significant organic waste feedstock from agro-food production such as fruit, vegetables, nuts (walnuts, almonds), meat and dairy products (whey)
- Dairy and chicken manure from 2 million cows and 10 million chicken in the Central Valley alone
- High energy cost in electricity and in vehicle fuel, both are highest in the contiguous 48 states
- Regulatory requirements that are favorable, such as AB 32 and AB 1122
- Regulatory requirements to achieve 70 percent diversion from landfills by 2020, which de facto can only be achieved by removing organic waste streams, which de facto can only be treated by using anaerobic digestion as the only option
- RPS requirement of 30 percent."

However, Dr. Schuppenhauer points out that "Despite best intentions from the administration, especially Gov. Jerry Brown and legislature, there are also several barriers that impede the roll out, some of which are general market issues:

- Up to eight different agencies are trying to regulate the biogas market, adding significant administrative burden with largely inconsistent and contradictory legal frameworks, mired in turf battles
- Interconnection costs are increasingly prohibitive, and given that the recipients are the utilities one may question the true motivation behind such high cost
- Gas feed-in regimes are inconsistent across the state, with each of the three utilities supporting a different standard
- CARB's low NO_x standard in the Central Valley[185] practically chokes all biogas-to-electricity efforts from dairy manure, sending off methane—-21 times more potent than CO_2— uninhibited into the atmosphere
- The CapEx in the US has been much higher than in Europe. This results in negative financial benefit, which in return leads to no investments. Cutting the CapEx in half to EU levels would make projects profitable and drive the industry. Bringing best practices

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[185] "The most recent San Joaquin Valley Air Quality District requirements limit NOx emissions to 9 - 11 ppm. Internal combustion (IC) engines are the most well-established and currently least expensive technology for generating electricity from biogas. However, IC engines generally can reliably achieve at best 50 ppm NOx emission concentrations" (Environmental Science Associates 2011).

developed in the leading biogas market to the US would help halve CapEx and double the methane yield per ton of organic total solids.

- Continued overall lack of equity for project development and debt financing capital places biogas in competition with other renewable and investment projects
- Excessive liquidated damage demands from project developers and contingencies added by engineering, procurement, and construction firms eliminate short term financial return potentials."

Renewable Hydrogen

Process Conversion Technologies for Renewable Hydrogen

Hydrogen is the most abundant element in the universe and one of the most abundant elements on Earth. However, on Earth it does not occur naturally in its pure H_2 form as the chemistry of the H atom favors bonding with other elements rather than with itself. Thus, there are many substances on Earth, which contain hydrogen. Three general categories of hydrogen containing substances are commercially used today for production of pure H_2: water, fossil fuels and biomass. In general, the majority of the pure hydrogen produced comes from water. For example, in water electrolysis, electricity is used to break the bond between oxygen and hydrogen. This results in two gas streams (H_2 and O_2) by the following reaction:

$2H_2O \text{ --> } 2H_2 + O_2$

In this case electric energy is used to break the H-O bonds in liquid water. The product hydrogen gas is subsequently dried to remove residual water and compressed to a desirable pressure. This process converts electric energy into chemical potential energy of hydrogen. As electricity is a relatively expensive form of energy, it is usually economically unfavorable to make hydrogen in this manner unless cheaper pathways of making hydrogen are unavailable or electricity is available at unusually low cost.

Another general method of making hydrogen is to leverage the fact that oxygen forms stronger bonds with carbon than with hydrogen. If steam is exposed to carbon at elevated temperature, oxygen-hydrogen bonds break and are replaced with oxygen-carbon bonds. This liberates the hydrogen from water. One example of the use of this reaction occurs in coal gasification. While it is not a renewable pathway, we use it here to demonstrate the principle. This general production method is called thermal gasification. The general equation of coal gasification is the following:

$2H_2O + C \text{ --> } CO_2 + 2H_2$

It is important to note that in this equation electricity is not required (other than to operate balance of plant components such as pumps and blowers). The majority of energy needed to produce hydrogen in this case comes from the chemical potential energy in the carbon-carbon bonds of coal.

Use of chemical energy to produce hydrogen is the prevalent pathway for hydrogen production today. However, instead of using coal as a source of chemical energy, natural gas is used. This pathway is called steam methane reforming. Similarly, to the overall formula for coal gasification, the overall steam methane reforming reaction is the following:

$CH_4 + 2H_2O \text{ --> } CO_2 + 4H_2$

This process is more easily accomplished than coal gasification due to the fact that natural gas is cheaper and is easier to handle and run through a reactor as a gas. Natural gas also contains significantly fewer impurities than coal, such as sulfur and heavy metals. More importantly the CH_4 in the natural gas contains hydrogen. Each carbon atom comes with four hydrogen atoms. In the process of reacting the carbon with oxygen, hydrogen is liberated not only from water but from the natural gas as well. This fact results in more hydrogen being produced for each carbon released. In net, stream methane reforming produces significantly less carbon-intensive than its cousin – coal gasification. Today carbon dioxide emissions from hydrogen production are vented into the atmosphere. This is the most economical thing to do from a business perspective as there are no monetary penalties to the business for emitting CO_2. However, given some additional capital expenditure, carbon capture and storage could be added to the reforming and gasification process to avoid release of fossil CO_2 into the air.

Yet another permutation of extracting hydrogen chemically is by the use of biomass fuels. The most abundant of these fuels are solids derived from woody biomass (wood chips), agricultural residue (such as corn stalks and hay), and carbon-containing municipal solid waste – Municipal solid waste (yard clippings, food residues). The common aspect of such feedstock is their hydrocarbon content. In the presence of steam at high temperature carbon from these fuels reacts with oxygen in the steam and liberates any hydrogen content of the bio-solids as well as the hydrogen in the reacted water. This process is called biomass gasification. Biomass gasification is of significant importance as it is largely carbon neutral. Carbon dioxide released in the production process came from the carbon in biomass. In turn this carbon came from carbon dioxide, which the plants absorbed from the atmosphere as they grew. This biological pathway forms a nearly complete carbon cycle. CO_2 from the air turns into plants, and then the carbon in the plants is used to make hydrogen and CO_2 is re-released into the air.

As we have highlighted, the use of biomass for hydrogen production is largely carbon neutral. It is worth taking this concept one step farther. Biomass gasification processes have exhaust streams with relatively concentrated CO_2. It is technically feasible for carbon capture and storage to be applied to this stream, with further concentration. Doing so would make hydrogen production a net carbon dioxide remover from the atmosphere. Carbon from the atmosphere turns into plants; plants' carbon is used to make hydrogen; carbon is placed under-ground. While this pathway is technically feasible, it is also more expensive due to the extra processing and sequestration steps. Biomass gasifiers have the potential of being the largest individual plants converting biomass into hydrogen – thus leveraging economies of scale. However, their scale is still relatively small compared to coal gasification or steam methane reformers.

The last renewable energy feedstock for hydrogen production to consider is bio-methane. This is a catch-all title for the methane produced by bacteria when they digest bio-degradable materials. This occurs when the digestion happens in anaerobic environments (in the absence of oxygen). For example, cattle manure is often kept in an enclosed container where bacteria can grow and produce methane. This container is called a digester and has the function of keeping air out of the digestion process. Additionally, it allows the collection of the product anaerobic digester gas. This same process is also found in wastewater treatment plants – where biological solids in the water are concentrated to form a sludge, which is in turn fed into an anaerobic digester. Anaerobic digester gas systems are typically small (definitely smaller than gasifiers). Overall, digestion works on a relatively small fraction of biomass matter – for example all cellulosic matter is indigestible in anaerobic digester gas and cannot be converted into gas. The biogas from anaerobic digester gas systems can be fed into steam methane reformers and converted into hydrogen. Carbon sequestration is theoretically also possible, but as anaerobic digester gas scales are even smaller than biomass gasification, the economies of scale are even more challenging.

The last near-term biofuel we consider is landfill gas. Modern landfills are encased with an impermeable liner underneath which prevents toxic liquids from contaminating urban water supplies. Additionally, landfills are covered with impermeable "cap", which reduces odors and toxic chemicals from contaminating the air. By such design, any bio-degradable materials which end up in a landfill are kept in an air-free environment, and naturally occurring bacteria break down nutrients to form methane-rich landfill gas. This gas is very similar to anaerobic digester gas but requires more intensive cleanup before being used in a steam methane reforming system.

Hydrogen Distribution and Delivery

Besides production of hydrogen, it is also important to consider how hydrogen could be distributed to dispensing locations. As the method of hydrogen distribution has a large impact on the production technology, it is essential to consider compression and liquefaction as part of this hydrogen production section. Four general pathways are prevalent today. Each one has strengths and applicability.

Gaseous Truck Delivery

Gaseous truck delivery is the most prevalent hydrogen distribution method from production to fueling stations in California today. This stems from the fact that majority of hydrogen is produced in the gas phase and transported in pipelines to refineries. A small fraction of hydrogen is distributed via truck and the quantity is often insufficient to justify liquefaction equipment. This type of delivery is adequate to supply small to medium size hydrogen fueling stations but may be impractical for supplying large commercial fueling stations. This technology allows leverage of current gaseous hydrogen production without the need for investment in liquefiers.

Liquid Truck Delivery

Liquid hydrogen production is not as common today as it caters to customers with intermittent needs for large quantities of hydrogen (for example, aerospace industry). Liquid hydrogen is generally more expensive to produce due to higher production energy use and liquefier capital. However, it enables cost savings in distribution and dispensing. Additionally, it enables delivery of hydrogen in sufficient quantities to operate very large dispensing stations which are envisioned in successful hydrogen adoption scenarios.

Pipeline Delivery

The vast majority of hydrogen today is used for industrial applications and refineries. Pipeline hydrogen distribution accounts for the vast majority of hydrogen delivered today as it is the most economical means of transporting large quantities of product. Hydrogen pipelines connect production facilities and refineries, and in some instances hydrogen pipelines are used for supplying extensive networks of neighboring industry consumers. While up-front capital investment is sizeable, this is potentially the optimal long-term solution for supplying hydrogen within urban settings. Pipelines allow for reduced station capital as less on-site storage is required. Also, pipelines reduce long-term distribution costs by trading capital expense for distribution truck fleets and drivers. This pathway is also the most energy efficient pathway for distributing hydrogen as minimal energy is consumed to transport the product. Pipelines reduce road use for delivery trucks, and also reduce central production cost. For example, pipeline distribution removes the need for fueling terminals, high pressure compression at central facilities or liquefiers.

Distributed Production and On-site Consumption

Production of hydrogen on-site has the benefit of reduced distribution costs. Production technologies used with this delivery pathway are small-scale steam methane reforming and electrolysis. In these cases, the cost of distribution of hydrogen is eliminated at the expense of increased distribution requirements for natural gas or electricity. Additionally, this method of delivery has a significant impact on dispensing cost as hydrogen production demands footprint in urban areas where land may be at premium if it is available at all. Distributed steam methane reforming systems in particular can require significant footprint when considered for large stations. Distributed steam methane reforming systems also do not reach economies of scale comparable to centralized systems and may run into air quality permitting obstacles. Lastly, this pathway may face maintenance challenges, as it introduces much higher station complexity (each steam methane reforming unit is truly a chemical plant). The other distributed hydrogen production method – electrolysis, also faces challenges. It relies on a relatively high-cost feedstock (electricity). Just as with steam methane reforming systems, it requires more footprint in urban settings and although it reduces hydrogen distribution, it increases electricity distribution requirements. A system delivering 1,000 kg/day may require an excess of 2 MW of electricity. This amount of hydrogen would support 1,800 vehicles assuming they have 60 mpg fuel efficiency, and each vehicle is driven 12,000 miles annually. While this may be challenging from grid distribution point of view, electrolyzers can also offer some benefits to the grid. If more renewable power is introduced on the grid, the need for ancillary services is increased. Due to electrolyzers' rapid response dynamics, they can offer up-regulation services and possible voltage control (by offering utilities the ability to reduce power demand in a dynamic manner). Such services can result in significant revenue streams for station owners – comparable to that of selling hydrogen. While with today's penetration rate of renewables, such systems may seem hardly economical, the benefits may be critical for the high-renewables grids of the future.

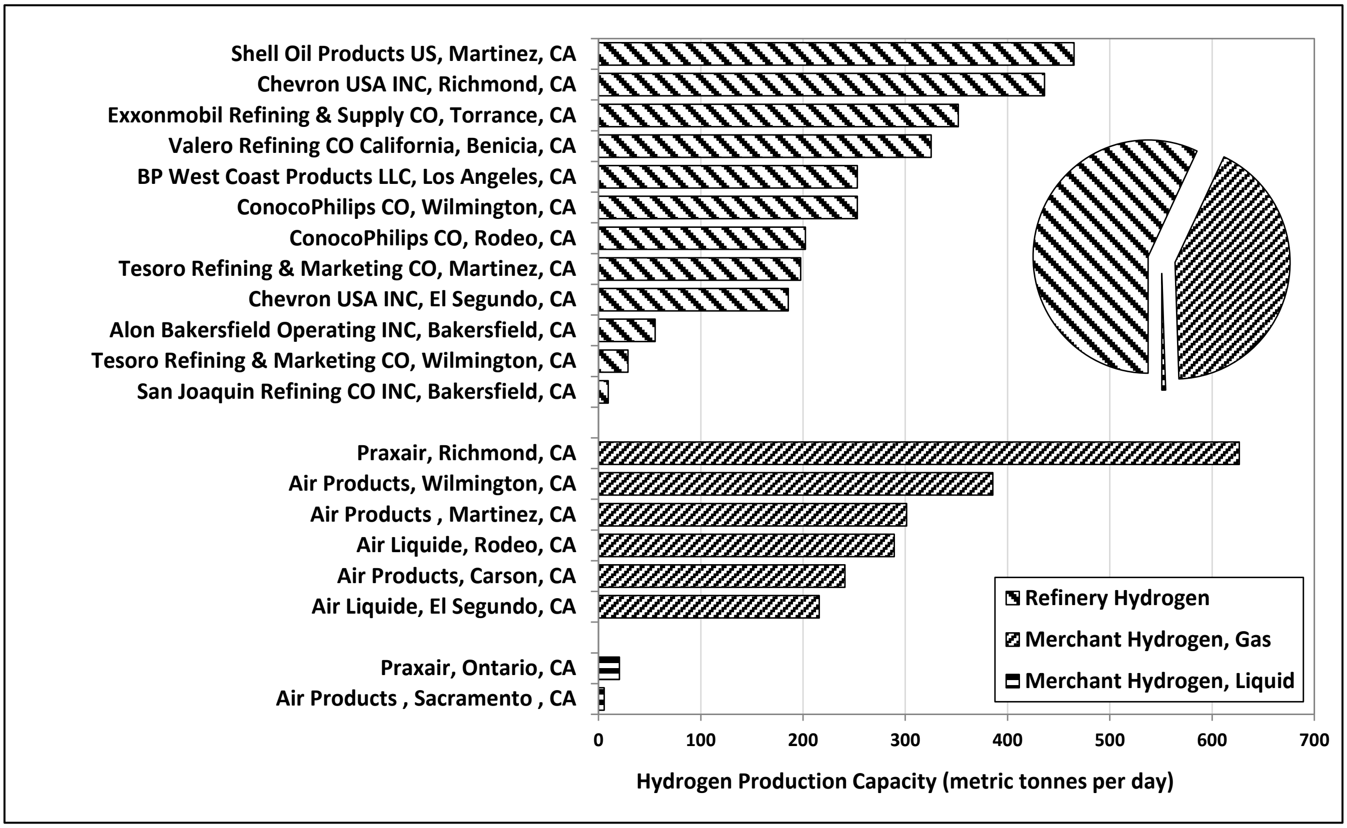
Production Facilities and Key Suppliers

Steam Methane Reforming Facilities

Steam methane reforming is the predominant production pathway for hydrogen in California (Figure 21). The top three largest producers of hydrogen in the United States are[186]:

- Airliquide
- Air Products and Chemicals, Inc.
- Praxair Technology, Inc.

Figure 21: Steam Methane Reformer Capacity in California by End Service and Product Phase



Source: NREL

These sources of hydrogen account for vast majority of production in California. In the central production merchant hydrogen, Air Products holds 45 percent of the market, Praxair 30 percent and Airliquide 25 percent (merchant hydrogen refers to all small-scale consumers of hydrogen, who cannot justify on-site production or use very small hydrogen production units). Smaller scale steam methane reformng production systems are also deployed in California, but a comprehensive survey of those systems is not publicly available.

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[186] DOE Hydrogen Analysis Resource Center. 2013. "Hydrogen Production." Accessed June 2013: http://hydrogen.pnl.gov/cocoon/morf/hydrogen/article/706

Biomass Gasification Facilities

There are a large number of commercial biomass gasification companies. However, with the exception of one plant in Japan (operated by Shin-Idemitsu Co.), all have focused on synthesis gas (syngas) production (a mixture of H_2, CO, CH_4 and other species). Syngas is typically used for production of high value products such as specialty chemicals, electricity, steam and heat, and can also be used in production of biofuels. No public information is available for gasification systems producing hydrogen as a final product. In the US, low cost of natural gas and large-scale steam methane reforming plants have made hydrogen production very economical. Although large biomass gasification plants rival the capacity and economies of scale of steam methane reforming systems, they have not found a foothold in the hydrogen market (mostly due to feedstock economics). However, hydrogen production via biomass gasification is very well understood, syngas to hydrogen requires engineering implementation rather than scientific breakthroughs.

Below is a short list of companies whose processes would be readily adaptable for hydrogen production:

- ANDRITZ Carbona
- Bioliq
- Enerkem
- Gas Technology Institute
- Rentech, Inc.
- REPOTEC
- ThermoChem Recovery International, Inc.

Electrolysis Plants

There are two commercially available technologies for electrolysis: alkaline and proton exchange membrane. Alkaline technology is historically the most deployed type of electrolyzer. NEL Hydrogen is the most experienced company in this technology. NEL Hydrogen has a long history in the technology and nearly a century of experience in potassium hydroxide electrolysis. They tailor their electrolyzers to industrial applications where multi-megawatt levels of electrolysis are employed. Today the industrial market is still dominated by NEL. Besides NEL, there are five more commercial manufacturers of mid- to large- scale electrolyzers:

- Angstrom Advanced Inc. (Alkaline)
- Giner Inc. (proton exchange membrane)
- Hydrogenics (Alkaline, PEM)
- ITM Power (proton exchange membrane)
- NEL Hydrogen (Alkaline)
- Proton On Site (proton exchange membrane)

Proton exchange membrane electrolyzers represent a relatively new technology for hydrogen production. Within the last decade their performance has advanced rapidly, and they are rapidly becoming competitive with alkaline systems. A comprehensive survey of proton exchange membrane and alkaline electrolyzer deployments is not available at this time.

Market Evaluation

Worldwide, two chemical processes dominate the demand for hydrogen. Crude oil refining is the first of those. It uses hydrogen for removal of sulfur in crude petroleum and also for hydrocracking of heavy crude. In hydrocracking, large hydrocarbon molecules are heated to high temperatures, which cause carbon-carbon bonds to break (crack). This is done at high pressures in the presence of hydrogen. As carbon-carbon bonds break, hydrogen reacts with each carbon to fill in for the broken bonds and thus form smaller and more useful hydrocarbon molecules. These lighter hydrocarbon molecules are separated by distillation into different fractions of petroleum products. This type of process yields transportation fuels such as gasoline, diesel, jet fuel, and bunker fuel (ship fuels). Some of the heavier petroleum fractions are used for asphalt and lighter fractions are used for plastics production and other specialty chemicals. The demand for hydrogen in California refineries accounts for approximately 56 percent of the total hydrogen production in the state. In California, approximately 2.8 million gallon of gasoline equivalents of hydrogen are consumed each day for refining purposes, and the demand has increased over time as heavier (less economic) crude petroleum is fed into refineries. To put this in perspective, this amount of hydrogen would be sufficient to power 5 million fuel cell vehicles assuming each drives 12,000 miles per year and has 60 miles per kg fuel efficiency. In relationship to the 28 million light duty vehicles on the road in CA in 2012[187], existing hydrogen production for refineries could propel 18 percent of the fleet.

Besides hydrogen for hydrocracking, refineries use hydrogen for removing sulfur from crude petroleum. This process separates sulfur species in the raw crude by forming H_2S. The trend for this process is for higher hydrogen use as well due to more stringent sulfur requirements in gasoline and diesel, as well as higher sulfur content in crude petroleum.

The second major use of hydrogen is for production of nitrogen fertilizers. Nitrogen is extracted from the air and then mixed with hydrogen. The two gasses are pressurized and exposed to a nickel-based catalyst at high temperatures. In this process (Haber-Bosch process), the nitrogen-nitrogen bond is broken, and ammonia is formed:

$$3H_2 + N_2 \rightarrow 2NH_3$$

Ammonia is an essential agricultural product. It can be directly land-applied by injection into the soil, or it can be further processed to a solid form – ammonium nitrate or urea. While California has very developed agricultural sector, our records show that no ammonia is produced in the state and thus no hydrogen production capacity is available through ammonia plants.

California has vibrant industries which use smaller quantities of hydrogen than would justify on-site production. Smaller consumers are served through merchant hydrogen production. This accounts for 2.1 million gallon of gasoline equivalents per day, which translates to 3.8

[187] Polk. 2012. Polk Vehicles in Operation 2012, POLK_VIO_DETAIL_2012

million vehicles worth of demand. Merchant hydrogen is used in a variety of applications such as metal processing, electronics manufacturing, plastics manufacturing and food production.

Discussion

While there are many pathways for production of renewable hydrogen, its current penetration in California is minimal. The driving factor for low penetration is the low cost and relative ease of converting natural gas to hydrogen. Analysis done by NREL[188], shows that hydrogen produced by steam methane reformers can be made for $1.88 per kg. This analysis was performed at a time when industrial natural gas was $6.09 per mmBTU[189] and had significant annual price increase. Since then, the price of industrial natural gas has dropped farther, and the latest industrial prices are close to $4.50 per mmBTU[189] (as of May 2013). Assuming that this price stayed constant for the life of a steam methane reforming plant, the projected levelized cost of hydrogen would be $1.17 per kg (before delivery and dispensing expenses). This price is difficult to compete with, based on financial considerations alone. According to hydrogen production modeling at NREL (H2A models), even if carbon capture and storage were added, steam methane reforming hydrogen is estimated to cost $1.56 per kg (down from $2.08 per kg estimated from higher cost natural gas feedstock). Carbon capture and sequestration costs and performance are outlined in detail in NREL's H2A model. In comparison, the cost of hydrogen from renewable pathways is shown in Table 21.[188]

Table 21: H2A Analysis Results for Hydrogen Production by Key Pathways

	Current Technology		Future Technology	
	Production cost of H2 $/kg	Feedstock cost	Production cost of H2 $/kg	Feedstock cost
Biomass gasification	$2.25	$83/metric tonne	$2.00	$69/metric tonne
Biogas SMR	$2.41	$12/mmBTU	$2.23	$12/mmBTU
Natural gas SMR	$1.88	$6.09/mmBTU	$1.95	$8.26/mmBTU
Central electrolysis	$4.14	¢5.7/kWh	$3.88	¢6.6/kWh
Distributed electrolysis	$4.17	¢5.7/kWh	$3.88	¢6.6/kWh

Costs are listed with a 2007 basis. Current technology assumes 2005 technology basis with full utilization and Nth plant cost assumption. Future technology assumes 2025 technology set.

Source: NREL

Note that for the above analysis feedstock costs are escalated according to Annual Energy Outlook projections. Biogas cost assumes directed biogas costs typically seen today. The analysis of costs above also reflects Nth plant capital cost as well as mature market equipment utilization. It is important to consider that in the case of distributed production, there is no additional cost of distribution of hydrogen, thus the distributed electrolysis cases above would have better economics than the central production cases.

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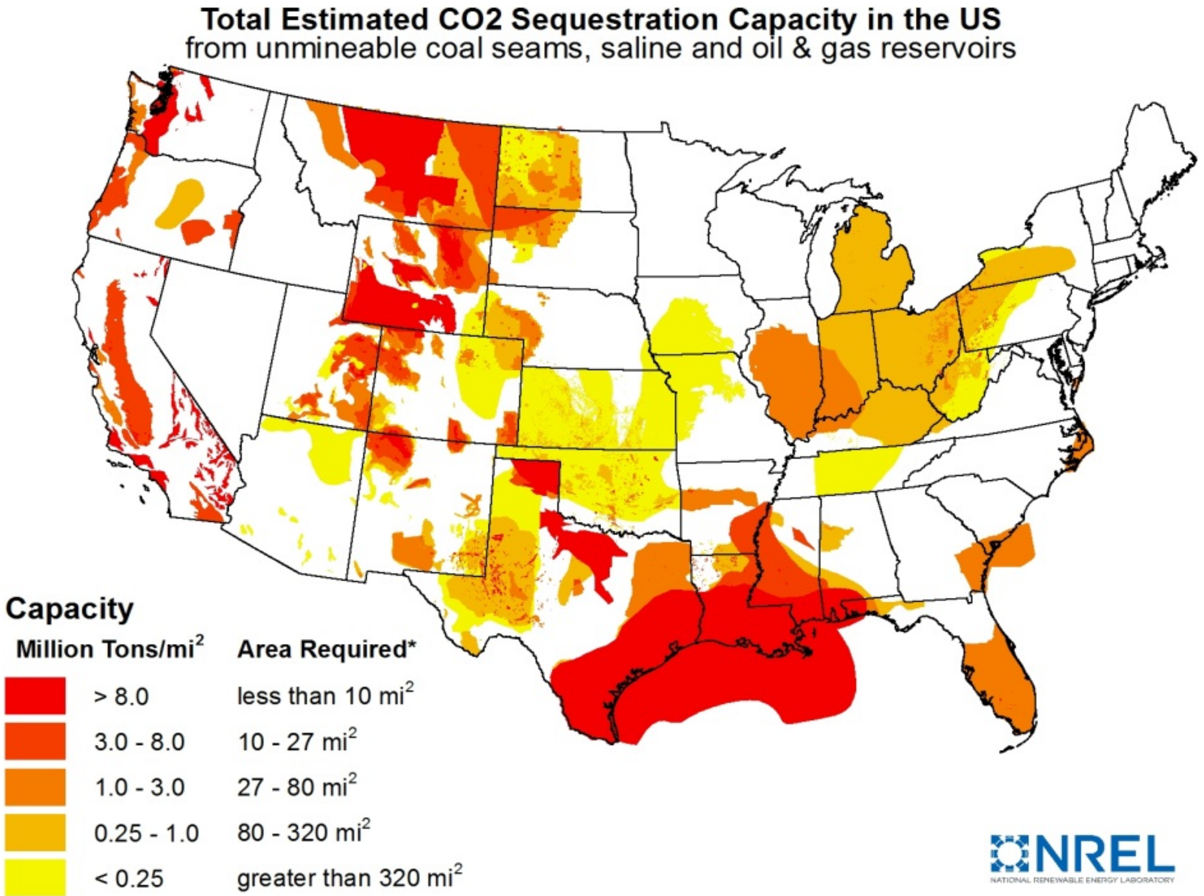
[188] U.S. DOE H2A Analysis. 2013. Accessed June 2013: http://www.hydrogen.energy.gov/h2a_analysis.html

[189] U.S. EIA. 2013a. Energy Information Administration. Accessed May 2013: http://www.eia.gov/

While the cost of natural gas is expected to remain competitive, the cost of electricity and biomass is not expected to drop. In the event of carbon taxes, steam methane reforming would still be the most economical option by employing carbon capture and storage. California has extensive geologic features that could be appropriate for carbon storage (see Figure 22). This pathway uses domestic natural gas resources while minimizing CO_2 emissions.[190]

Figure 22: Geographic Distribution of Geologic Sites in the United States, Suitable for Carbon Storage



Source: NREL

It is noteworthy that hydrogen production from biomass is the lowest-cost renewable production pathway. This result is contingent on the gasification plant being relatively large to capture economies of scale (consuming ~2,000 metric tonnes of bone-dry biomass per day or more). For such plant to be feasible, biomass harvesting in a region of approximately 30 miles radius (limit of economic transportability of biomass) must be dedicated for plant feedstock. Current trends in biomass utilization show market competition for the resource. Not a single biomass gasification plant in California (or the United States), produces hydrogen as a final product. Instead, they focus on higher value products such as biofuels and specialty chemicals. This could, however, change if transportation hydrogen demand were present and

[190] National Energy Technology Laboratory. 2008. NatCarb Atlas. https://www.netl.doe.gov/coal/carbon-storage/strategic-program-support/natcarb-atlas

the value of hydrogen production increased. At this time, it is, however, uncertain if central biomass gasification plants could realize economies of scale and realize competitive cost of hydrogen over natural gas steam methane reforming.

The electrolysis pathway for hydrogen production appears to be rather uneconomical. However, recent research and market analysis is highlighting new ways of employing the technology. The first is coined as "power to gas" and is currently under pilot development by E.ON (utility company in Germany).[191] This concept uses formerly curtailed renewable electricity to produce hydrogen. The gas is then injected into natural gas pipelines while issuing renewable energy credits. Hydrogen molecules are compatible with existing natural gas pipelines up to approximately twenty percent by volume. This concept allows generation of renewable natural gas credits which can then be purchased by distributed steam methane reformer operators. Owners of power to gas installations would have dynamic response capability which can provide ancillary services to the grid (stabilization of grid performance due to spikes in supply and demand). Ancillary services provide yet another revenue stream for such installation. Power-to-gas systems not only provide renewable gas credits and grid stabilization but also enable higher revenue streams for wind and solar farm operators. This improvement of renewable energy economics further allows higher penetration of renewables on the grid.

Technologies also exist which enable economic hydrogen extraction from transmission gas pipelines at city gates. Those are best accomplished at pressure-let down stations, where transmission pressure of hundreds of pounds per square inch (psi) is reduced to tens of psi before entering city distribution networks.[192]

A second electrolysis business model is currently emerging. This model is for distributed electrolysis at or near hydrogen fueling locations. This model increases electrolyzer functionality by not only offering hydrogen production, but also providing dynamic response capability to the electric grid (ancillary services). While this mode of operation is still in its early stages of evaluation, it is anticipated to greatly improve electrolyzer economics by realizing ancillary revenue streams. Increased dynamic performance of electrolyzer systems is pursued by most electrolyzer companies to capture such grid service revenues.

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[191] E.on. 2011. "Project profile Converting surplus energy to hydrogen", https://refman.energytransitionmodel.com/publications/1760

[192] Melaina, M. et al. 2013. "Blending Hydrogen into Natural Gas Pipeline Networks: A Review of Key Issues" National Renewable Energy Laboratory. http://www.nrel.gov/docs/fy13osti/51995.pdf

CHAPTER 5: Technology and Analysis Review

Technologies Achieving Market Viability without Need for Government Incentives

Drop-in biofuels generally receive government help in several forms including tax incentives, grants, or other government program support. Drop-in biofuels using cellulosic or algal feedstocks qualify for the second-generation biofuel production tax credit of $1.01 per gallon, authorized through January 1, 2014.[193] Drop-in biofuels plants producing renewable diesel qualify for a $1.00 or $0.50 per gallon credit when using virgin vegetable oil or waste oil/tallow respectively.[194] Renewable natural gas (RNG), also known as biogas, while little used in transportation, has generated RINs and is not provided with any significant government incentives. Starch-based ethanol is the only significant biofuel with significant market penetration and no government incentives.

Ethanol

Ethanol is the most significant alternative fuel consumed in the United States. As of 2012, it is blended into 96 percent of U.S. gasoline.[195] It has a long history of use but both production and use grew dramatically over the past decade. The dramatic rise in production and use are a result of a sustained period of favorable economics, federal regulation, and economic incentives.

The Energy Policy Act of 2005 established the nation's first renewable fuel standard (RFS) requiring 7.5 billion gallons of renewable fuel use by 2012. It did not require specific types of biofuels and was met by ethanol. The Energy Independence and Security Act of 2007 replaced and expanded the RFS with specific categories of biofuels with 36 billion gallons required by 2022. The conventional biofuels category is corn based ethanol which is capped at 15 billion gallons per year for corn-based ethanol to balance the demands for corn among feed, ethanol, food, and export markets.

While requirements for using biofuels ensures a market and encourages investment, these requirements were not the primary reason for significant growth in ethanol production capacity expansion and annual production. Besides 2012, the last many years have seen ethanol consumption and production outpace requirements of the RFS (Figure 27). Ethanol economics are complicated as corn is an agricultural commodity and ethanol prices are correlated to gasoline and oil prices. The combination of low corn and high oil prices in a period spanning 2005 to 2007 led to significant profits for ethanol plants allowing some plants to pay off ten-

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[193] Public Law 112-240 and 26 U.S. Code 40

[194] Public Law 112-240 and 26 U.S. Code 40A

[195] Renewable Fuels Association. 2013. California Ethanol Operating Capacity: Renewable Fuels Association. Ethanol Industry Outlooks. https://ethanolrfa.org/wp-content/uploads/2015/09/RFA-2013-Ethanol-Industry-Outlook1.pdf

year bank notes with just six months of profits. This period of sustained positive economic performance led to increased investment in the ethanol industry and rapid expansion of number of plants and total capacity. As of April 2013, there are 211 plants in 29 states with capacity of 14.8 billion gallons.[195] This is sufficient to meet the conventional biofuels requirement of the RFS as many plants are capable of producing above capacity. Ownership of ethanol plants is not consolidated, which is a rarity in manufacturing.

Incentives for biofuels began during fuel shortages in the late 1970s. Initially, the incentives were an exemption from the federal gasoline excise tax and an income tax credit for producers. In 2004, these were transformed into the Volumetric Ethanol Excise Tax Credit, paid to fuel blenders, not ethanol plants, to motivate blending of ethanol by petroleum companies. It was determined that a tax incentive was no longer necessary for the ethanol industry to remain viable and the VEETC expired at the end of 2011. In 2012, the ethanol industry contributed 70,000 direct jobs, $40.6 billion to GDP, and $28.9 billion in household income.[196]

Under certain market conditions, imported ethanol from Brazil has been cost competitive even with a $0.54 import tariff. The yield of ethanol from sugarcane grown in Brazil is superior to the yield of ethanol from corn in the United States. The import tariff was rescinded at the end of 2011; however, Brazil now imports ethanol from the United States due to high sugar prices favoring production for food markets rather than ethanol. Fluctuating market conditions for food products and transportation fuels over time will continue to impact trade of biofuels between nations.

Another motivation for the use of ethanol is its octane value. Oil refiners rely on the availability of ethanol to meet gasoline quality standards. This, in addition to the RFS, ensures a long-term market for ethanol.

After 16 years of annual production increases, there was a decline in 2012. A weak economy led to decreased demand for transportation fuels, and drought resulted in significant increases in corn prices. Additionally, the tax incentive ended, and the nation is up against the blend wall where the market for E10 is essentially met. More than 99 percent of ethanol is sold as an E10 blend. E15 was approved for use in model year 2001 and newer light-duty vehicles; sales began in late 2012 but it is available only at a few stations. E85 is available at more than 2,000 stations but still accounts for less than 1 percent of ethanol use. Ethanol exports in 2011 were 1.2 billion gallons and are estimated at 725 million gallons for 2012.[195]

Emerging Biofuel Technologies Not Currently Funded by the CEC

The CEC and the U.S. DOE have provided financial support, over the past two decades, for the creation of pilot and demonstration plants, refueling infrastructure, vehicle retrofits, and fleet development for the leading alternative fuels: ethanol, biodiesel, and compressed natural gas. This support has helped test and then scale up biological and thermochemical routes to key gasoline blending agents (ethanol) and diesel substitutes (biodiesel). The CEC and DOE have

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[196] Urbanchuk, J. 2013. "Contribution of the Ethanol Industry to The Economy of the United States". Cardno Entrix. January 31, 2013.

also funded some work on algae production to make fuels, waste stream gasification to renewable diesel, and waste fats/greases and oil conversion to biodiesel.

As the production capacity for making alcohols and biodiesel in both California and the rest of the United States has increased, concerns have arisen about the future compatibility of large amounts of these fuels with existing infrastructure, whether it is for transport, storage, refining, retail dispensing, or vehicle fleets. One option is to focus research and scale-up funds more on novel routes to convert biomass into hydrocarbon fuel precursors or hydrocarbon fuels, which are compatible with existing infrastructure and refinery unit operations. Some of the potential options that the CEC may want to consider in the future for possible seed or demonstration funding are spelled out in the sections that follow.

Syngas Fermentation to Hydrocarbons

Syngas fermentation is being developed by a variety of U.S. firms. A mixture of CO and H_2, generally produced by a biomass or coal gasifier, are fed to specialized micro-organisms, which convert these raw materials to fuels in a rapid fermentation process. Those furthest along, in terms of commercial scale up, are Ineos Bio, Coskata, and Lanzatech. Ineos Bio is building a demonstration plant in Indian River Florida, to produce eight million gallons/year of bioethanol from biomass-based waste streams. Coskata has built its Lighthouse demonstration facility in Madison, Pennsylvania to use syngas derived from biomass gasification to produce ethanol and is now raising funds to build a commercial unit using natural gas, rather than syngas, to provide the carbon and hydrogen used for the fermentation. Lanzatech, based in New Zealand, is building a first commercial plant in China to use off-gases (primarily CO) from steel mill operations to drive its fermentation to ethanol. It is also working on a biomass syngas process, at the pilot scale, to produce ethanol as well.

This same gas phase fermentation technology could be applied to make hydrocarbon precursors (such as alkanes) or even hydrocarbon fuels molecules. The genetic pathway modifications to the micro-organisms required to produce hydrocarbons rather than alcohols will be extensive, but some small-scale work has already been done to test out the concept. The advantage of this approach is that resulting blending agents or finished fuels will be compatible with existing infrastructure for transporting, storing and refining conventional fuels (diesel fuel, gasoline, jet fuel, and general aviation fuel).

Microbial Process for Transforming Natural Gas to Fuels

Recent research has indicated that methanotroph bacteria have the capability to transform methane directly into hydrocarbon fuels and chemicals. Additional genetic work is required to increase the efficiency and speed of these reactions. These organisms can be used in a variety of fashions to transform unwanted methane GHG emissions to fuels. At landfill sites, they can use the methane in landfill gas as food source. At remote natural gas locations, without connections to a gathering system, they can produce energy-dense hydrocarbon fuels or hydrocarbon precursors that can be transported to central locations for processing.

Aqueous Phase Reforming of Biomass Sugars and Acids to Hydrocarbons

Several university and private sector research groups have undertaken research on the catalytic transformation of biomass sugars, organic acids, and other molecules to hydrocarbon fuels in a relatively mild aqueous environment involving moderate pressures and temperature. Originally developed by the University of Wisconsin, this process can produce alkanes and, with further processing, specific chain length molecules for diesel fuel or jet fuel. Virent, Inc., is developing and scaling up this aqueous phase reforming technology (what they call BioForming), targeting the large-scale direct production of ASTM hydrocarbon fuels (particularly diesel fuel and jet fuel). They have a pilot plant located in Madison, Wisconsin. Virent has been working the National Advanced Biofuels Consortium to produce diesel fuel from lignocellulosic biomass and is currently working with the NREL to converting corn stover to jet fuel via novel pretreatment processes coupled with the BioForming upgrading steps. They have also produced quantities of ASTM standard jet fuel for various public agencies and private groups for engine testing purposes.

Microbial Processes for Converting Lignocellulosic Biomass to Hydrocarbons

Production of alcohols from simple sugars has been practiced for more than 5,000 years. Yeast and certain bacteria can produce ethanol from glucose and other monomeric sugars at high yields and titers. In the past two decades, genetically modified organisms have been created that can utilize not only glucose but also others sugars typically found in lignocellulosic biomass, such as xylose and arabinose. Yields of 75 gallons of ethanol/ton of biomass feedstock have been achieved, under DOE sponsorship, at the pilot scale. It has been proven by many researchers and a few startup companies that these same organisms (yeast and bacteria) can be genetically transformed to produce hydrocarbon fuel molecules instead of ethanol. The chief corporate example is Amyris, which has developed a micro-organism that produces Biofene, a long chain branched hydrocarbon known generically as farnasene. The extensive metabolic engineering required to convert sugars to hydrocarbons places a great burden on the micro-organism, so the yields are lower and the process slower than those more mature processes making cellulosic ethanol. Additional research and process intensification will be required to increase the yields and lower the costs to be cost-competitive with fossil fuels.

Higher Alcohols to Infrastructure Compatible Fuels

A number of research groups and start-up companies have focused on biological routes to producing iso-butanol or n-butanol. The higher energy density of butanol makes it attractive for gasoline blending or for operation in dedicated fuel vehicles. However, butanol can also serve as a feedstock for catalytic upgrading to hydrocarbon fuels, such as diesel fuel and jet fuel. These higher alcohol upgrading processes have been demonstrated at the bench-scale but have not been scaled up to pilot-scale or demonstration scale. In 2012, Cobalt Technologies announced that they were teaming with the Naval Air Warfare Center Weapons Division to produce a jet fuel from biobutanol at Albemarle's Baton Rouge, La., plant. Cobalt has recently won a DOE/EERE award to build a pilot plant system at NREL to convert sugars to biobutanol and then to upgrade it to military jet fuel catalytically.

Catalytic Pyrolysis to Produce Desired Fuel Molecules

Rapid pyrolysis can be used to transform a variety of lignocellulosic biomass to pyrolysis liquids. Traditionally, these resulting liquids are acidic, corrosive, unstable, and highly reactive, making them difficult to use as feedstocks for upgrading to either alcohols or hydrocarbons. However, it is possible to undertake catalytic transformations of the pyrolysis vapors, either inside the pyrolysis reactor or in a second vessel, to remove much of the oxygen, reduce the production of organic acids, and make the liquids when they are condensed much more compatible with traditional petrochemical and petroleum refining operations. KiOR, for example, uses a variant of Fluidized Catalytic Cracking technology to transform woody biomass into hydrocarbon molecules which can be upgraded to diesel fuel, gasoline and jet fuel. It has built one plant in Mississippi and has plans for additional commercial plants in the near future.

Transforming Algal Carbohydrates, as well as Lipids, to Fuels

A wide variety of researchers have focused on finding algal strains with high concentrations of lipids, extracting those lipids, and then transforming them into biodiesel or hydrocarbon fuels via a hydrotreating step. Even in the best of cases, 50 percent or more of the algal biomass (which is proteins and carbohydrates) is not used for making fuel. Recent research has shown that the algal biomass carbohydrates can be extracted and either fermented into fuels (typically ethanol) or can be thermochemically converted to fuels and chemicals. Research conducted by the Sustainable Algal Biofuels Consortium successfully investigated a number of pathways to fuels from the various components of algal biomass.

Ammonia as a Transportation Fuel

There have been a number of private and public sector initiatives to introduce new light-duty or fleet transportation fuels in the U.S. and elsewhere. Memorable examples in the past three decades are methanol and Dimethyl ether. Most of these efforts fail for two generic reasons:

- Getting industry agreement (generally through the ASTM process) on the standards and codes to cover all aspects of this new fuel, including production, transportation, storage, and retail dispensing; and
- The expense and difficulty of getting an engine/fuel combination tested and approved by the U.S. Environmental Protection Agency (generally around $20 million for each engine from each manufacturer) for meeting emissions standards.

Some of these problems go away if the proposed fuel is a chemical already in use for other purposes. Such is the case with anhydrous ammonia, one of the leading U.S. agricultural chemicals by dollar value. Current worldwide production of ammonia is approximately 190 million tons per year. It is used extensively in U.S. farm communities as a fertilizer. Production is large-scale, and it is transported and stored throughout the country. However, it is NOT produced or designed to be a transportation fuel. It has about 50 percent of the calorific value of diesel fuel. It has been discussed as a potential fuel by researchers for years and is currently promoted as a fuel by one small firm, GreenNH3. There is at least one example of a retrofitted truck running on an ammonia/gasoline mixture. There is no published literature on crash protection required to protect ammonia tanks onboard a truck or car.

The promoters of ammonia as a fuel point out, quite rightly, that the byproducts of ammonia combustion are nitrogen and water: $4 NH_3 + 3 O_2 \rightarrow 2 N_2 + 6 H_2O$. No greenhouse gases are produced. However, the process for making ammonia is highly energy intensive. Nitrogen must be extracted from the air, and then reacted hydrogen using a catalyst or over a promoted Fe catalyst under high pressure (100 standard atmospheres (10,000 kilopascal)) and temperature (450°C) to form anhydrous liquid ammonia.

Anhydrous ammonia is irritating and potentially toxic if vented into the air. Serious health effects start at concentrations as low at 100 parts per million. Eye exposure to concentrated gas or liquid can cause serious corneal burns or blindness. Exposure to high levels of anhydrous ammonia can cause death from a swollen throat or from chemical burns to the lungs.

Dimethyl Ether and Diethyl Ether

Dimethyl Ether or DME (CH_3OCH_3) is currently produced from natural gas or coal by gasifying the fossil fuel to first make methanol and then dehydrating the methanol to DME. For a renewable fuel, this process can also begin with gasification of biomass. DME is used as a cooking and industrial fuel, substituting for propane in liquefied petroleum gases in China and other parts of Asia. DME has been promoted as a diesel replacement fuel, due to its relatively high cetane number. DME is also a very clean-burning fuel, with very minimal levels of emissions of particulate matter, NO_x, and CO.

Diethyl Ether or simply ether -(C2H5)2O- is a highly flammable liquid. It is known primarily historically as a surgical anesthetic, although it is rarely used for that purpose today because of its flammability. It is also used as an industrial chemical solvent in the production of products such as cellulose acetate. Diethyl ether has a very high cetane number of 85-96 and is commonly used as an engine starting fluid for gasoline and diesel engines because of its high volatility and low flash point. Ether can be produced on an industrial scale by the acid ether synthesis. Ethanol is mixed with a strong acid, typically sulfuric acid, H2SO4, producing water, hydrogen, and diethyl ether. Diethyl ether is also produced as a byproduct of the process of converting ethylene to make ethanol. A 1997 review article concluded that Diethyl ether had potential as a renewable replacement fuel for compression ignition engines.[197] There has also some research in India on diethyl ether as an additive to biodiesel to help with cold weather starting. There has been recent patent activity on a diethyl ether/water mixture as a fuel for compression ignition engines.[198]

Drop-In Biofuels

Drop-in biofuels are hydrocarbons substantially similar and intended to be functionally equivalent to gasoline, diesel, and aviation fuel. They are designed to meet existing fuel quality standards (ASTM) for petroleum products. The term drop-in biofuels refers to the ability to drop the fuel into existing infrastructure and engines without impacts on performance or safety. The intent is to minimize infrastructure or engine compatibility issues which have impacted the ability to rapidly deploy biofuels like ethanol and biodiesel. Advanced biofuels such as biobutanol or cellulosic ethanol are not considered drop-in fuels; both are alcohol-based fuels, not hydrocarbons.

There are many methods to create a drop-in fuel. Researchers are exploring a variety of technology pathways. Feedstocks for drop-in fuels include crop residues, woody biomass, dedicated energy crops, and algae. Drop-in fuels are in a research and development phase with some pilot- and demonstration-scale plants operating and others under construction or

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[197] Bailey, B., Eberhardt, J., Goguen, S., and Erwin, J., "Diethyl Ether (DEE) as a Renewable Diesel Fuel," SAE Technical Paper 972978, 1997, doi:10.4271/972978

[198] Haldor Topsoe patent publication number EP2553238 A1, February 2013

planned. There is more focus on creating drop-in fuels to replace aviation fuel and diesel in medium- and heavy- duty applications as those vehicles are unlikely to be fueled by electricity.

The primary benefit of drop-in biofuels relative to other biofuels is compatibility with engine and infrastructure, and relative to petroleum-based fuels is increased domestic supply, and fewer criteria pollutants and greenhouse gas emissions. The most important of these is compatibility with infrastructure and existing engines in a wide array of applications. Compatibility will not be achieved without challenges. Fuel samples have been obtained and analyzed from various drop-in biofuel technology providers. While these samples meet current ASTM fuel quality specifications for gasoline or diesel, they also contain trace components or other minor impurities. Fuel quality standards for gasoline, diesel, and jet fuels do not consider some of the compounds found as they would not be expected from petroleum-based fuels. It is likely that engine manufacturers and pipeline companies would require testing to determine if there are any effects of trace components in drop-in biofuels on engines and infrastructure. This type of testing will ensure performance and safety will not be impacted. As an example, cellulosic ethanol meets the same fuel quality standards as corn-based ethanol, but vehicle manufacturers have expressed concerns about trace components found in cellulosic ethanol.

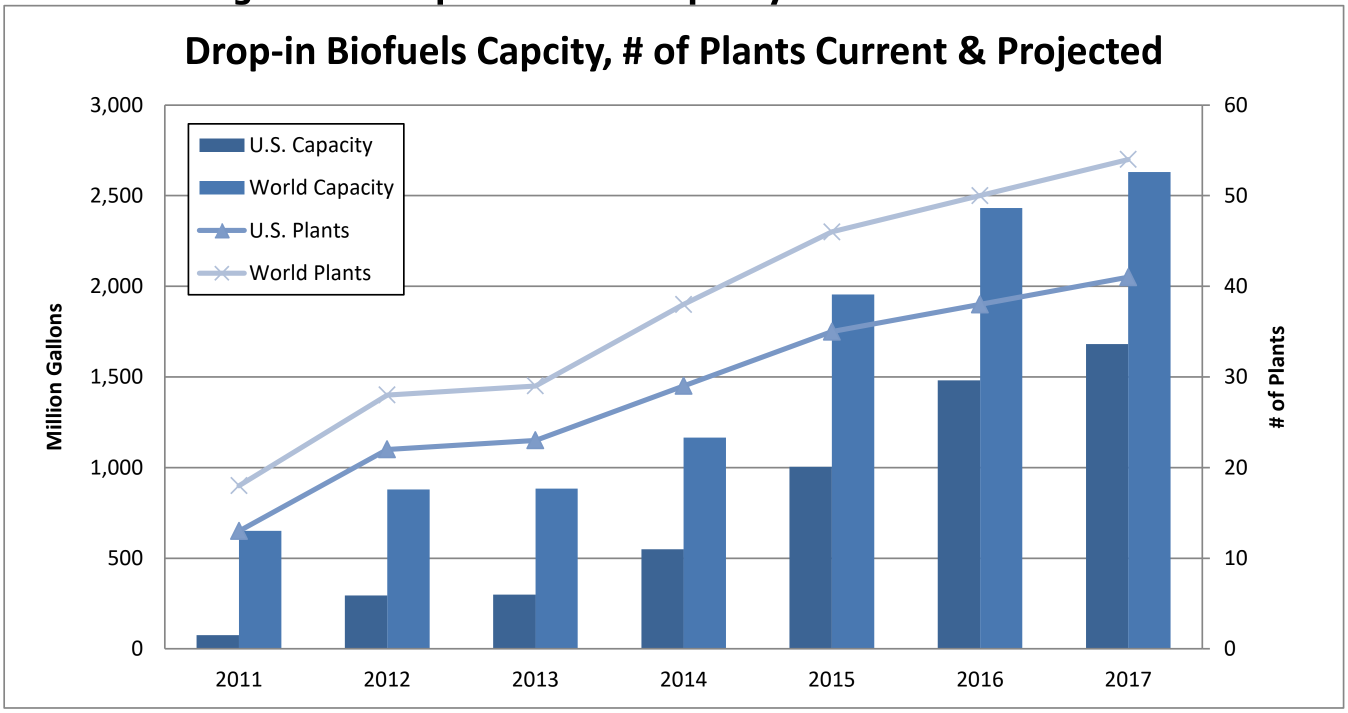
Elastomer materials such as seals and o-rings are common throughout fueling systems and refueling equipment. These materials can be impacted when exposed to a new fuel. The introduction of more ethanol into the marketplace as well as ultra-low sulfur diesel has resulted in fueling infrastructure manufacturers upgrading elastomer materials to polymers which perform well with a variety of fuels. These upgrades improve performance for other alternative fuels entering the marketplace. Manufacturers regularly test compatibility of their products with various fuel types to ensure performance. While drop-in fuels are expected to be used in existing infrastructure, manufacturers and regulators may want to see some testing of these fuels with elastomers and other materials to ensure compatibility. Underwriters Laboratories is an independent safety laboratory offering testing standards for fueling equipment. Several testing standards apply to tanks, pipes, and dispensing equipment. It is expected that drop-in fuels will be subject to the same Underwriters Laboratories testing standards as those applied to gasoline and diesel fuels. This allows equipment to meet all Occupational Safety & Health Administration regulations for dispensing equipment.

Most drop-in biofuels companies are in a research and development phase, with several pilot and demonstration scale plants operating. Three U.S. commercial scale drop-in biofuels plants started operations in 2012. Biofuels Digest projects less than one billion gallons of advanced biofuels in the U.S. by the end of 2014.[199] 2011 and 2012 data reflect plants operating while future years are projections based on various fuel companies plans (Figure 23). These data represent plants reporting production or planned production of drop-in renewable fuel, renewable diesel, and renewable gasoline only. It does not include other companies making renewable oils or bio-oil which are focused on producing higher value chemical products, not transportation fuels. The U.S. has more operational pilot and demonstration scale plants than any other nation, but the capacities are generally low with the exception of three commercial scale plants that began operations in 2012.[27] There is an early focus on producing renewable

[199] Malchanov, M. 2012. "Is the Renewable Fuels Standard Withering on a Vine?". Raymond James. July 30, 2012.

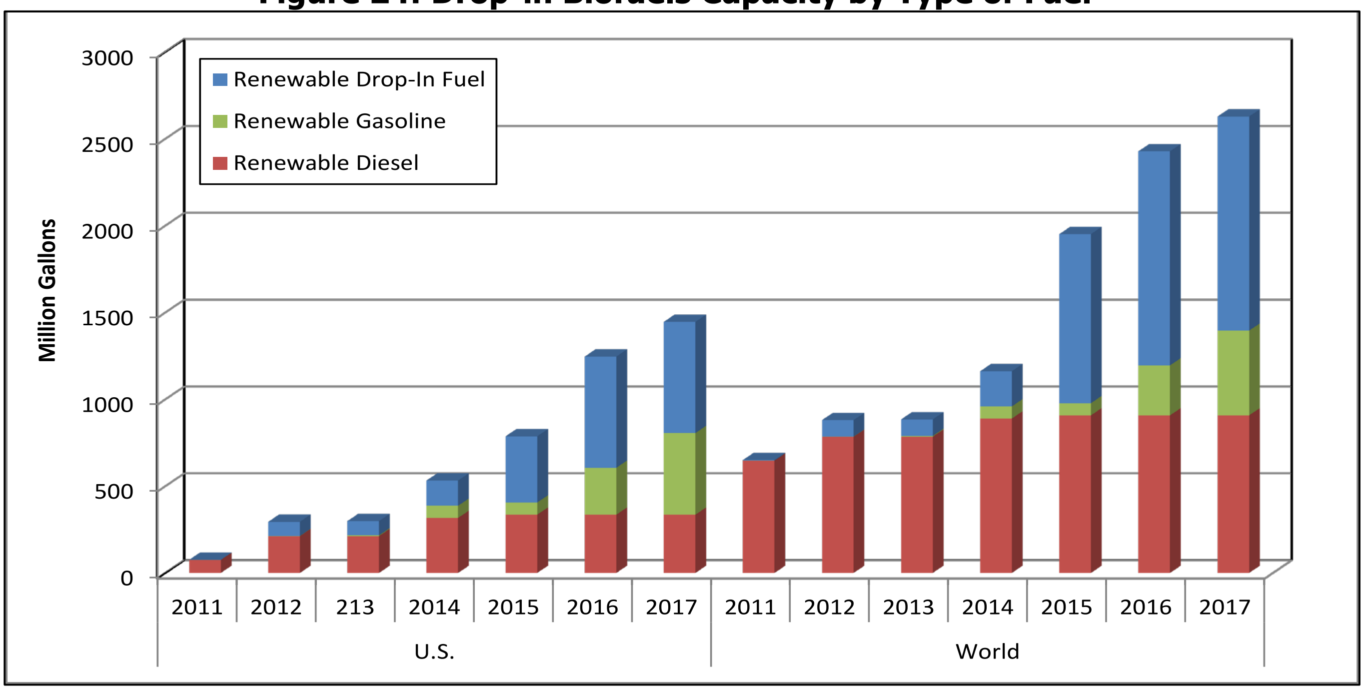
diesel. Future projects are generally listed as drop-in biofuels as companies are proving technology and may not be sure which type of fuel they will produce, and some may target the aviation fuels market (Figure 24).[27]

Figure 23: Drop-in Biofuels Capacity and Number of Plants



Source: Advanced Biofuels & Chemicals Project Database

Figure 24: Drop-in Biofuels Capacity by Type of Fuel

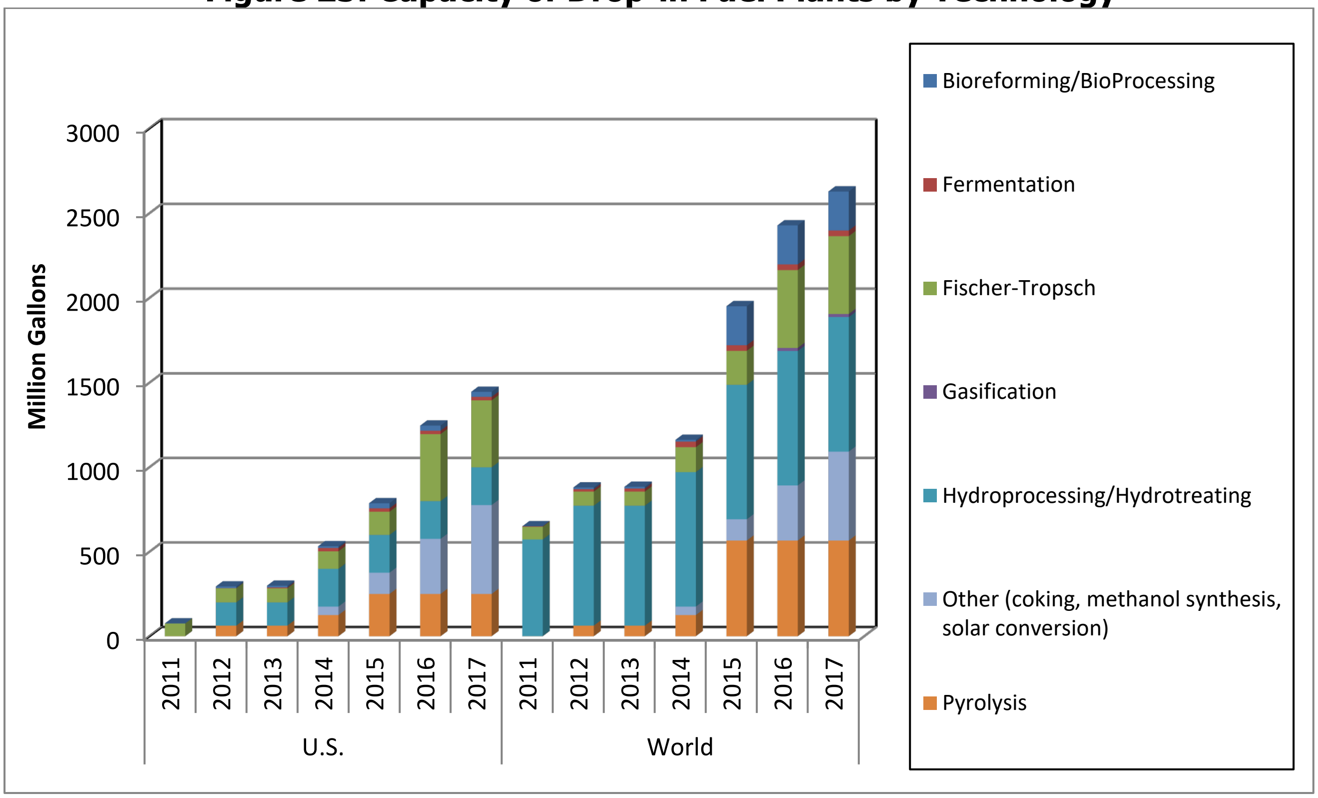


Source: Advanced Biofuels & Chemicals Project Database

The Bioenergy Deployment Consortium also maintains a list of existing and planned U.S. and select international pilot and demonstration plants. Bioenergy Deployment Consortium's list confirms the information available from Biofuels Digest. The Bioenergy Deployment Consortium list does not provide timelines for development or production but did suggest a few additional plants including an existing U.S. renewable diesel plant with 10,000 gallons of capacity and planned plants: 350,000 gallons of renewable gasoline; 28 million gallons of renewable diesel in Finland.

A myriad of technologies are being tested and demonstrated. Figure 25 illustrates that Fischer-Tropsch, hydroprocessing, and pyrolysis are the most common technology types in current years and projected forward. U.S. demonstration and commercial scale plants in 2012 were a fairly even mix of hydroprocessing, Fischer-Tropsch, and pyrolysis.[27] Outside of the U.S., Neste's hydroprocessing plants account for the majority of capacity at three plants in Europe and Asia.

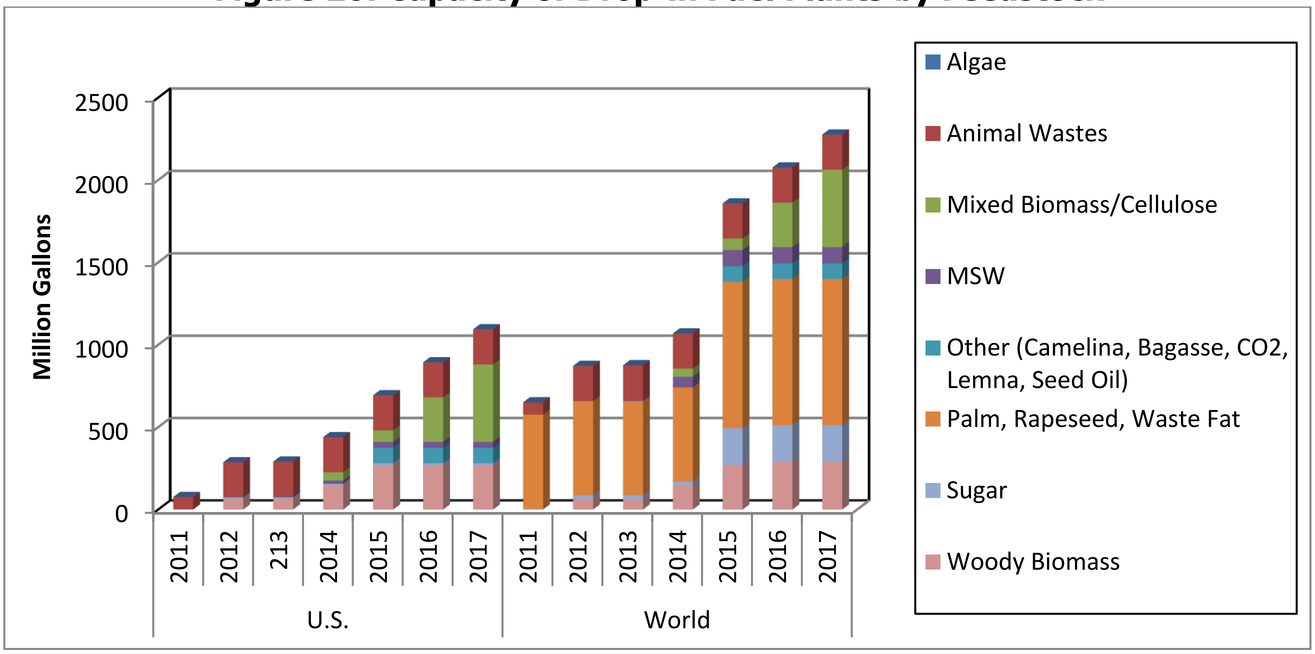
Figure 25: Capacity of Drop-in Fuel Plants by Technology



Source: Advanced Biofuels & Chemicals Project Database

Feedstocks at the initial U.S. pilot and demonstration scale plants are dominated by animal wastes and wood chips (Figure 26). All three large scale demonstration scale plants in the U.S. are located in the south. Two are using renderings left over from processing of livestock. Animal wastes are not considered a cellulosic feedstock and qualify as biomass-based diesel or other/undifferentiated advanced biofuels under the RFS. A third plant is using pyrolysis technology with wood chips located at the site of a former wood products plant. This plant was the first company and only company registered with U.S. EPA to generate cellulosic diesel renewable identification number (RINs) under the RFS. This fuel is being used in existing diesel infrastructure and vehicles. Palm and rapeseed oil are the primary feedstocks at three large commercial scale drop-in plants in Asia and Europe. These are unlikely feedstocks for U.S. drop-in fuel plants as palm oil does not meet the RFS criteria for GHG emission reductions and rapeseed (canola) is not a common feedstock due to availability and cost. Pilot and demonstration scale plants tend to prove technology with feedstocks that are already available rather than dedicated energy crops which are not yet available in sufficient quantities.

Figure 26: Capacity of Drop-in Fuel Plants by Feedstock



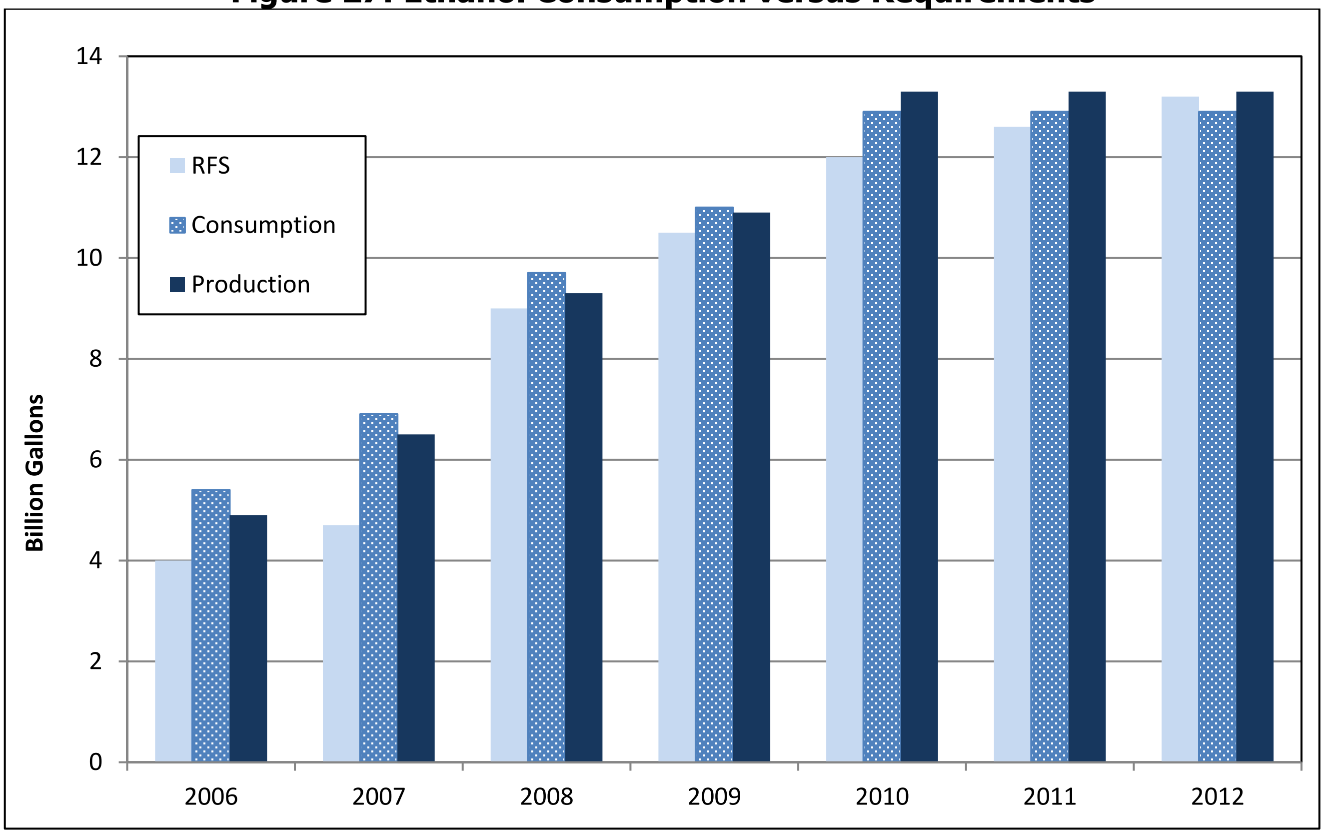
Source: Advanced Biofuels & Chemicals Project Database

Drop-in biofuels companies are working towards proving technology and financial constraints are often more challenging than technical hurdles. Generally, the commercialization for cellulosic ethanol is more advanced than for drop-in fuels. This is due to a funding focus on cellulosic ethanol over the past decade and investment of corn-based ethanol industry in second-generation ethanol. Funding with venture capital or public grants may be sufficient to demonstrate technology but cannot cover the costs for a commercial plant. Only two dedicated drop-in biofuels companies, KiOR and Amyris, have issued initial public offerings in recent years to raise capital. Other companies have made plans to but have found that not enough capital is available and are raising funds privately. Partnerships with larger companies can help move a project into commercial development. Some oil companies have partnered with or purchased drop-in biofuel technology. Loan guarantees from U.S. DOE or United States Department of Agriculture also help demonstration and commercial scale plants to obtain financing.

Building biofuels plants is capital intensive. Economies of scale eventually brought corn ethanol plant prices to the $2 per gallon annual output capacity range. An existing demonstration scale renewable diesel plant reports capital costs of $16 per gallon capacity.[81] Bioenergy Deployment Consortium reports projected costs for some advanced biofuels plants (mostly cellulosic ethanol) with an estimated average of $10 to $12 per gallon capacity range with some well above and a bit below this level. Until these plants are built, it is difficult to accurately predict the costs of scaling up novel technology.

The RFS created a mandated market for cellulosic biofuels and drop-in fuels (Figure 27). While drop-in fuels are more costly to produce, they are not expected to require modifications for use in existing engines and infrastructure. While the RFS is mandated, the U.S. EPA has the ability to adjust the requirements in each category annually. Only low volumes of cellulosic biofuels have been produced causing the U.S. EPA to reduce the RFS requirements for cellulosic fuels to 3.45 million in 2012. Fewer than 22,000 cellulosic RINs were generated in 2012 falling far short of the 3.45 million U.S. EPA requirement and the 500 million gallons in the Energy Independence and Security Act. The U.S. EPA allows obligated parties to buy cellulosic biofuel waiver credits to meet their RFS required volumes. This creates uncertainty in the marketplace for demand of drop-in biofuels. The price for these compliance credits are also established by U.S. EPA, which in effect establishes a price ceiling on the emerging market for RINs.

Figure 27: Ethanol Consumption versus Requirements



Source: NREL

Biodiesel

Biodiesel has only been commercially produced for a decade and is produced in significantly smaller quantities than ethanol. The biodiesel industry is not as homogenous as the ethanol industry, with greater variation in plant capacities (200,000 gallons to 100 million gallons per year), location of plants, and markets (transportation, home heating, generator, off-road). Recent biodiesel production and consumption is driven by the second iteration of the RFS which specifically requires its use. The period of 2007 through 2009 saw significant exports as producers were able to obtain higher prices in European markets. A change to European tax policy curtailed the export market.

A biodiesel tax credit of $1.00 or $0.50 per gallon (depending on feedstock) for producers or blenders was originally created under the American Jobs Creation Act of 2004. The biodiesel tax credit expired at the end of 2009 resulting in significantly lower production in 2010. RFS regulations allowed obligated parties to meet their biodiesel volume requirements with past year use. While production declined, it did not stop, which indicates that biodiesel will be produced without a tax credit to meet RFS. Many plants changed ownership and started using more than one feedstock during this time period. The tax credit was reinstated at the end of 2010 but expired at the end of 2011. Production in 2012 was strong without the incentive due to the RFS required volumes. The tax credit was once again reinstated at the end of 2012 retroactively covering fuels produced in 2013 and it is set to expire at the end of 2013. The biodiesel industry cannot count on a tax credit and has demonstrated that production continues without one.

RNG

In 2012, nearly 3 million RNG RINS were generated as advanced biofuels (D5 RIN category). The U.S. EPA reports 1.2 million generated in the first quarter of 2013. There are five RNG producers registered with U.S. EPA to generate biofuel RINS (Table 22). Due to confidentiality requirements, U.S. EPA does not provide data on the volumes of RINs generated by registered companies.

There are no federal incentives for RNG used in vehicles. A few states (CO, KS, MT, NC, ND, and WA) offer minimal incentives but none of the RINS are being generated in these states. It is possible that these five RNG-producing companies received some type of government aid in building facilities. RNG facilities use a variety of feedstocks, including methane produced at landfills, water treatment facilities, and from manure. In many cases, there are minimal, or no costs associated with collecting, delivering, or using the feedstock which differentiates it from many biofuels plants. In some instances, government regulations require the collection of methane leaving just a few additional steps for use in vehicles or electricity generation. RNG is generally used in medium or heavy-duty vehicles due to the availability of engines in this sector which can operate on biogas.

Table 22: Biogas RIN Companies

Company Name	Facility Name	City	State
AMP Americas LLC	Renewable Dairy Fuels	Fair Oaks	IN
Canton Renewables, LLC	Canton Renewables, LLC	Canton	MI
Dallas Clean Energy McCommas Bluff	Dallas Clean Energy McCommas Bluff	Dallas	TX
High Mountain Fuels, LLC	Altamont Liquefied Biogas Plant	Livermore	CA
Quasar Energy Group,LLC	Central Ohio BioEnergy, LLC	Columbus	OH
Quasar Energy Group,LLC	Zanesville Energy	Zanesville	OH

Source: NREL

Review of Life Cycle Analysis Literature on Biofuels

The transportation sector is the single largest source of GHG emissions, accounting for 38.3 percent of California's gross inventory in 2010.[200] The on-road category, which includes passenger vehicles and heavy-duty trucks, is the largest GHG contributor and constitutes about 92.2 percent of the total transportation sector emissions. State and national policies are in place to reduce GHG emissions from the transportation sector (see Chapter 2) through implementation of low carbon and renewable fuel requirements. Such low carbon fuel policies measure the carbon intensity of transportation fuels on a life cycle basis and require GHG reductions in the life cycle carbon intensity of transportation fuels compared to the incumbent petroleum fuels (often estimated in terms of CO_2 equivalent (eq.) per energy unit of fuel). To understand the potential benefits of GHG savings through displacing petroleum fuels with various biofuels, this subsection reviews literature estimates of life cycle GHG emissions for biofuels currently produced at large commercial scale (corn ethanol and biodiesel, in particular) and for selected advanced biofuels (including cellulosic ethanol, cellulosic diesel and gasoline, renewable diesel, renewable natural gas, and hydrogen from renewable electricity) and compares them with fossil fuel-derived incumbent fuels.

Over the last decade, many life cycle studies of biofuels have been completed. The majority considered starch, sugar, and oil seed-derived (often referred to as "first generation") fuels such as ethanol derived from corn and biodiesel from soybean or rapeseed in North American or European settings, respectively. Fewer studies have considered biofuels produced from lignocellulosic biomass or other renewable feedstock such as algae, in large part because these feedstock-to-fuel "pathways" are not yet at a commercial scale and reliable data are therefore limited in availability. This situation may change in the near future as commercial plants are expected to begin operation within the next few years.

Our review also suggests that the majority of life cycle studies applied so called "attributional life cycle analysis (LCA)" to evaluate individual biofuel pathways, which do not consider market-mediated effects resulting from the production of a given biofuel. Consequential LCA is more appropriate for estimating "net" GHG impacts from implementation of a policy or decision. However, consequential LCA studies are sparse partly because this approach requires modeling of economy-wide effects, which are often more difficult to quantify and more uncertain compared to direct biofuel supply-chain related activities such as crop farming, transportation, and fuel production. The first section below summarizes life cycle GHG emissions research for two first generation biofuels: corn ethanol and biodiesel. The second section summarizes emissions research for second generation biofuels: renewable diesel, cellulosic ethanol, other cellulosic biofuels, electricity, and renewable natural gas. We report life cycle emissions on the basis of 1 MJ of fuel produced and used, as per the convention of California's Low Carbon Fuel Standard (LCFS). However, it should be noted that this unit ignores the differences in power train efficiency. For example, 1 MJ of average California electricity is more carbon intensive than 1 MJ of gasoline, yet a light-duty battery electric vehicle emits significantly less carbon per km or mile driven than a comparable gasoline

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[200] ARB. 2013b. California Greenhouse Gas Emissions from 2000 to 2010 – Trends by Emissions and Other Indicators. March 2013. California Air Resources Board. https://ww3.arb.ca.gov/cc/inventory/pubs/reports/2000_2011/ghg_inventory_trends_00-11_2013-10-02.pdf

internal combustion engine vehicle does due to the higher inherent efficiency of electric drive trains.[201] To address this issue, ARB has adopted the energy economy ratio, which is defined as the number of miles driven per unit energy consumed for a fuel of interest to the miles driven per unit energy for a reference fuel (e.g., gasoline), to account for the differences in vehicle powertrain efficiencies.

Life-cycle GHG Emissions for First-generation Biofuels

Ethanol

With continued increase in corn ethanol production in the United States over the last decade, many studies characterized the GHG emissions of this pathway. The wide range in reported values is the result of differences in the vintage of the data used to evaluate the ethanol conversion technology and the agricultural practices of corn production, both of which evolved substantially during the rapid growth phase of the industry. Methodological differences in LCAs (e.g., attributional vs. consequential LCA, treatment of coproduct credit, and selection of system boundaries) also caused the reported values to vary widely.

The environmental performance of corn ethanol has been improving steadily due mainly to increased corn yield and ethanol yield, better agricultural management practices (e.g., switch to less intensive tillage) and adoption of advanced technologies that consume less process energy, such as cold starch fermentation and replacement of molecular sieve and rectifier units with high-efficiency membranes.

Meanwhile, concerns have been raised about the magnitude of change in land use and land cover caused by increasing demand for corn as a biofuel feedstock. Land use and land cover change could trigger release of carbon stored in soil and vegetation, depending on prior land use and type of land cover. Biofuel-induced land use or land cover change could occur either directly, when land is diverted from other uses to growing biofuel feedstock, or indirectly, if expanding biofuel feedstock production causes land-use change elsewhere through market-mediated effects.[202] While there is no consensus on the most appropriate approach to quantifying GHG emissions from biofuel-induced land use change (Warner et al. 2013), the LCFS and the RFS2 consider emissions from land use and land cover change in their estimates of life cycle GHG emissions for corn ethanol. In contrast, virtually all life cycle studies or models prior to 2008, when Searchinger published the watershed study on emissions through biofuel-induced land use change, report only emissions directly associated with the supply chain of corn production without considering market-mediated effects.[203]

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[201] University of California. 2007. A Low-Carbon Fuel Standard for California. Part 1: Technical Analysis. May 29, 2007.

[202] National Research Council. 2011. Renewable Fuel Standard: Potential Economic and Environmental Effects of U.S. Biofuel Policy.

[203] Searchinger, T., Heimlich, R., Houghton, R.A., Dong, F., Elobeid, A., Fabiosa, J., Tokgoz,S., Hayes, D., and Yu, T. 2008. Use of U.S. Croplands for Biofuels Increases Greenhouse Gases Through Emissions from Land-Use Change. February 2008. Science 29 Vol. 319 no. 5867 pp. 1238-1240

Life cycle GHG emissions for average corn ethanol (including emissions from land use change) estimated in recently published literature span a wide range from 69 to 177 g CO_2 eq/MJ.[204] The life cycle GHG emissions estimated by ARB are between 73 and 121 g CO_2 eq/MJ (including land use change), which fall into the wide range indicated by published studies. The major drivers of the variations in GHG estimates include, but are not limited to, the type of process energy (coal vs. natural gas vs. biomass), the technologies used in the conversion process (dry mill vs. wet mill, corn oil fractionation), the fraction of coproduct (mainly distillers grain solubles) that is dried, the magnitude of GHG emissions from land use change, the assumed emission factors for N_2O from nitrogen fertilizer application, and approaches to dealing with credits from coproducts. All these estimates are based on attributional LCAs with emissions from land use change as an add-on value modeled by different approaches.

On the other hand, U.S. EPA applied consequential LCA to estimate GHG emissions for biofuels for three specified years (2012, 2017 and 2022). U.S. EPA's consequential LCA took into consideration GHG emissions emitted, directly and indirectly, as a consequence of changes in demand for the product.[205] U.S. EPA defined reference case (without RFS2) and control case (with production of RFS2 biofuel of interest at mandated level) scenarios to quantify the difference in GHG emissions between these cases, and then assigned emissions differences between the two cases to the fuel investigated. The mean life cycle GHG emissions for 2022 U.S. average natural gas-fired dry mill corn ethanol are estimated at 73 g CO_2 eq/MJ (about 21 percent lower than baseline 2005 gasoline with a carbon intensity of 93 g CO_2 eq/MJ), with a range between 48 and 111 g CO_2 eq/MJ, depending on the estimated magnitude of land use change emissions. Corn ethanol produced from coal-fired dry mills or wet mills can hardly meet the 20 percent GHG reduction threshold (compared to baseline gasoline) with only few exceptions where the mills adopt cold starch fermentation, membrane separation, corn oil fractionation, and produce only wet distillers grain solubles. In contrast, all corn ethanol produced from biomass-fired dry or wet mills can satisfy the 20 percent reduction criterion regardless of whether the mills adopt advanced technologies (e.g., fractionation, cold starch fermentation) or whether the distillers grain solubles is sold wet or dry.[205] U.S. EPA's consequential LCA does not account for other potentially important market-mediated effects

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[204] Wang, M., Huo, H., Arora, S. 2011. Methods of dealing with co-products of biofuels in life-cycle analysis and consequent results within the U.S. context. 2011. Energy Policy. 39. 5726–5736.

Wang, M., Han, J., Dunn, J., Cai, H., and Elgowainy, A. 2012. "Well-to-wheels Energy Use and Greenhouse Gas Emissions of Ethanol from Corn, Sugarcane and Cellulosic Biomass for US Use." Environmental Research Letters. 2012. Volume 7. http://dx.doi.org/10.1088/1748-9326/7/4/045905.

Mullins, K., Griffin, M., and Matthews, S. 2011. Policy Implications of Uncertainty in Modeled Life-Cycle Greenhouse Gas Emissions of Biofuels. Environmental Science and Technology, 2011, 45 (1), pp 132–138.

Taheripour, F., and Tyner, W.E. "Induced Land Use Emissions due to First- and Second-Generation Biofuels and Uncertainty in Land Use Emission Factors." 2013. Economics Research International. Volume 2013, Article ID 315787. http://dx.doi.org/10.1155/2013/315787.

[205] U.S. EPA. 2010. "EPA Regulatory Announcement, U.S. EPA Finalizes Regulations for the National Renewable Fuel Standard Program for 2010 and Beyond." EPA-420-F-10-007, Washington, D.C.: U.S. Environmental Protection Agency

such as the so-called "rebound effects" caused by likely change in global gasoline price due to increased use of biofuels, which could lead to lower demand for gasoline.

ARB also estimated life cycle GHG emissions for ethanol produced from Midwest sorghum. The estimated emissions range from 56 to 66 g CO_2 eq/MJ (without land use change), depending on whether the coproduct is dried. ARB indicated that emissions from land use change will be estimated separately and will be added to the direct emissions once the modeling work is completed.

Biodiesel

While ethanol is currently produced primarily from corn in the United States (accounting for about 96 percent of ethanol production capacity in 2011), biodiesel is produced from a wider range of feedstocks including soybeans (accounting for more than 50 percent of biodiesel production in 2011), recycled cooking oil, animal fats, and corn oil (a byproduct from corn ethanol production, which is extracted from distillers grain solubles before drying). A key advantage of using "waste" as feedstocks is that it does not incur undesirable land use change. As a result, waste-derived biodiesel has much lower life cycle GHG emissions compared to biodiesel derived from crops, which compete with food for agricultural land. The most recent lookup table for biodiesel (updated by ARB in December 2012) clearly shows that the life cycle GHG emissions of biodiesel produced from used cooking oil and corn oil (extracted from distillers grain solubles) range from 4 to 19 g CO_2 eq/MJ, whereas those of biodiesel from Midwestern soybean are estimated at 83 g CO_2/MJ when land use change is included. ARB assigned a mean indirect land use change effect of 62 g CO_2/MJ to soybean biodiesel, which is more than double that assigned to corn ethanol (30 g CO2/MJ), in large part because 1) soybean has much lower yield compared to corn (on a per unit of land basis), and 2) the conversion yield of biodiesel from soybean is lower than that of ethanol from corn. On average, 1 acre of corn can produce about 34 gigajoules (about 32 MMBtu) of ethanol while 1 acre of soybean can produce only 7.5 gigajoule (about 7.1 MMBtu) of biodiesel.

In U.S. EPA's consequential LCA, soybean biodiesel is estimated to have life cycle GHG emissions of 40 g CO_2 eq/MJ in 2022 (including the mean estimate of emissions from land use change). The much lower estimate (compared to ARB's one) is partially because the U.S. EPA projects a large amount of soil carbon sequestration from biodiesel production in 2022, assuming that more farmers will adopt no-till practice by that time. A recent study by United States Department of Agriculture argues that allocating 100 percent land use change emissions to soybean biodiesel is erroneous as the study shows there is a statistically significant positive correlation between soybean oil and soybean meal prices.[206] Therefore, the study concludes that the price of soybean meal is also a strong driver of land use change caused by increasing soybean demand. By partitioning land use change between soybean biodiesel and soybean meal, the life cycle GHG emissions of soybean biodiesel are estimated at about 22 g CO_2 eq/MJ. Even when compared to these much lower estimates, biodiesel

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[206] Pradhan, A., Shrestha, D.S. Van Gerpen, J., McAloon, A., Yee, W. Haas, M., Duffiend, J.A. 2012. Reassessment of Life Cycle Greenhouse Gas Emissions for Soybean Biodiesel. Transactions of the ASABE. Vol 55(6) 2257-2264. 2012 American Society of Agricultural and Biological Engineers ISSN 2151-0032.

derived from waste cooking oil still has an advantage; U.S. EPA projects the life cycle emissions of waste oil-derived biodiesel at about 14 g CO_2 eq/MJ.

U.S. EPA also estimated life cycle GHG emissions for biodiesel derived from canola oil to be about 45 g CO_2 eq/MJ, comparable to soybean biodiesel due in part to a similar estimate of emissions from land use change. U.S. EPA recently identified an additional biodiesel pathway that uses camelina oil as a feedstock.[207] U.S. EPA indicates that camelina biodiesel will have lower GHG emissions than soybean biodiesel because camelina (a new feedstock) is expected to be grown as a rotation crop on land that would otherwise remain fallow, for example, in the semi-arid regions of the Northern Great Plains, where dryland wheat farmers currently leave acres fallow once every three to four years to allow additional moisture and nutrients to accumulate. Therefore, U.S. EPA believes that production of camelina for biofuels will not result in either direct or indirect land use change in the near term.

Life-cycle GHG Emissions for Second-generation Biofuels

Renewable Diesel

Renewable diesel refers to petroleum diesel-like fuels derived from biomass that are chemically not esters and are thus distinct from biodiesel. Hydrogenation-derived renewable diesel, also known as green diesel, is the product of fats or vegetable oils—alone or blended with petroleum—refined by a hydrotreating process. In general, renewable diesel can be produced from the same feedstocks used for biodiesel. Several variations of renewable diesel conversion processes exist, which require slightly different inputs (for example, some processes use steam while others do not) and produce different slates of coproducts (including protein products, propane fuel mix, fuel gas, naphtha).

Similar to biodiesel, the type of feedstock used to produce renewable diesel appears to play a significant role in determining the carbon intensity of the fuel. ARB's LCAs show that renewable diesel produced from tallow has much lower life cycle GHG emissions than that from Midwestern soybean (20-39 g CO_2 eq/MJ for the former vs. 82 g CO_2 eq/MJ for the latter). The GHG emissions for these two renewable biodiesel pathways, modeled on a hydrogenation process developed by UOP (a Honeywell company), would be very similar if land use change induced by increasing demand for soybean had not been included. Even when land use change is included, ARB's LCA results suggest that renewable diesel from soybean still achieves a 16 percent GHG reduction compared to the reference petroleum diesel.

Because of the difference in the slate and amount of coproducts from each unique renewable conversion process, the approach used to deal with coproduct credit in the LCA plays a considerable role in the estimated magnitude of GHG emissions. Two major approaches to co-product accounting are the displacement method and the allocation approach. In the displacement method (also called system expansion method), the products that are displaced by the coproducts from biofuel production are determined and the energy use and emissions of producing the otherwise substituted products are estimated. The estimated emissions and energy use of the displaced products are subtracted from the total emissions from the biofuel

[207] U.S. EPA. 2013d. Regulation of Fuels and Fuel Additives: Identification of Additional Qualifying Renewable Fuel Pathways Under the Renewable Fuel Standard Program. Federal Register/Vol. 78, No.43. March 5, 2013.

production cycle. In the allocation approach, the energy use and emission burdens from biofuel production are allocated among all products based on their mass, or energy or economic values.

Huo conducted an attributional LCA of a SuperCetane renewable conversion pathway that produces a large number of coproducts.[208] The conversion pathway, assumed to replace carbon intensive petroleum diesel fuel, has a much larger GHG reduction (130 percent vs. 64 percent) when using a displacement method compared to a market value- or energy-based allocation. The authors further noted the allocation approach was more often used in the literature because of limited data on the products and the quantities that will be displaced by the coproducts. Nevertheless, the allocation approach has its own limitations, including that the fluctuation of prices of both primary products and coproducts could impact the results. Similarly, Fan et al. applied different approaches (displacement approach and energy and market value allocation) to account for coproduct credits from producing renewable diesel from pennycress (a member of the mustard family) grown in the Midwest as a winter crop without affecting food production. Fan et al. indicated that the life cycle GHG emissions of pennycress-derived renewable diesel (using the UOP process) range from 13 to 41 g CO_2 eq/MJ, depending on how coproduct credits are calculated.[209]

Cellulosic Ethanol

A large number of LCAs has examined the GHG emissions of several cellulosic ethanol pathways, in part because detailed techno-economic analyses for these pathways are available and provide the needed data (e.g., material and energy inputs and outputs) for LCAs. Several potential technologies, consisting of different pretreatment methods and hydrolysis and fermentation orientations, have been investigated for converting lignocellulose to ethanol.[205] While results have varied, the studies generally agree that lignocellulosic ethanol can reduce GHG emissions across the life cycle in comparison to petroleum gasoline and corn ethanol.[210]

EPA's consequential LCA suggests that ethanol derived from switchgrass via biochemical conversion can reduce GHG emissions by 102 percent to 117 percent (with life cycle emissions of -2 to -16 g CO_2 eq/MJ) (95 percentile interval) compared to 2005 baseline gasoline, including switchgrass-induced land use change.[205] The estimated large reductions are primarily because of an emission credit from excess electricity that is assumed to be sold to the grid to displace U.S. average electricity mix. Estimated life cycle GHG emissions of ethanol derived from switchgrass via thermochemical conversion are higher than those of ethanol via biochemical conversion simply because the former conversion process is not expected to generate excess electricity. Despite no credit assigned to switchgrass ethanol via

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[208] Huo, H., Wang, M., Bloyd, C., Putsche, V. 2009. Life Cycle Assessment of Energy Use and Greenhouse Gas Emissions of Soybean-derived Biodiesel and Renewable Fuels. Environmental Science and Technology. 2009. 43, 750-756.

[209] Fan, J., Shonnard, D. R., Kalnes, T., Johnsen, P.B., Rao, S. 2013. A Life Cycle Assessment of Pennycress (Thlaspi Arvense L.) – Derived Jet Fuel and Diesel. Biomass and Bioenergy. 2013. Article in Press.

[210] Spatari, S., Zhang, Y., MacLean, H.L. 2005. Life Cycle Assessment of Switchgrass and Corn Stover – Derived Ethanol Fueled Automobiles. Environmental Science and Technology, 39, 9750-9758.

thermochemical conversion, on average this pathway is estimated to reduce GHG emissions by 72 percent (with a range between 64 percent and 79 percent) compared to 2005 baseline gasoline. Corn stover-derived ethanol is projected to achieve higher reductions because corn stover dose not result in land use change; U.S. EPA's results show that emissions of ethanol derived from corn stover via biochemical or thermochemical conversion are about 20 percent lower than those of the respective switchgrass-derived ethanol. Although U.S. EPA did not provide numerical values for cellulosic ethanol derived from energy cane, it concluded in its recent analysis that ethanol derived from energy cane via biochemical or thermochemical conversion will qualify as cellulosic biofuel under the RFS2 (i.e., with GHG reduction of at least 60 percent compared to 2005 baseline gasoline).[207]

ARB performed an attributional LCA for ethanol derived from farmed trees (such as poplar) and forest waste via biochemical and thermochemical conversion processes, respectively. The GHG emissions of ethanol derived from farmed trees via biochemical conversion (20.4 g CO_2 eq/MJ) are slightly lower than those of ethanol derived from forest waste via thermochemical conversion (22.2 g CO_2 eq/MJ) mainly because thermochemical conversion is not assumed to generate excess electricity. ARB assigned a land use change emission of 18 g CO_2/MJ to farmed tree-derived ethanol but indicated that this estimate should be considered preliminary. Results could vary considerably for these lignocellullosic biofuels if and when they develop self-sustaining markets, depending on the type of feedstock used, conversion process, approach to deal with coproducts, whether or not land use change is considered, and key assumptions made (e.g., feedstock yield, N_2O emission from N fertilizer).

Other Cellulosic Biofuels

Life cycle studies on other, non-ethanol, cellulosic biofuel pathways are limited in large part because of the scarcity of data available in the public domain concerning the detailed design of the conversion process. Most of the technologies are still under development and the uncertainty about the performance of the conversion technologies is high.

Producing renewable gasoline and diesel from cellulosic feedstocks using fast pyrolysis followed by upgrading (e.g., hydroprocessing) is one of the most studied pathways (other than the biochemical and thermochemical pathways discussed above) as the technology is deemed promising by researchers.[211] For example, Hsu (2012) examined the life cycle GHG emissions of producing gasoline and diesel based on a fast pyrolysis process designed by Pacific Northwest National Laboratory[79] for a mature (n^{th}) commercial-scale plant. That study reported GHG emissions of 39 g CO_2/MJ for both gasoline and diesel when forest residue is used as the feedstock, electricity is purchased from the grid, and hydrogen is produced from natural gas for hydroprocessing. Hsu's estimated emissions for diesel and gasoline via fast pyrolysis are higher than ARB's estimated emissions for ethanol produced from the same feedstock via thermochemical conversion partially because the process requires hydrogen for bio-oil upgrading, which is assumed to be produced from a fossil fuel (natural gas).[212]

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[211] Venderbosch, R.H.; W. Prins. 2010. Fast pyrolysis technology development. Biofuel Bioproducts & Biorefining, 4 (2010), pp. 178–208.

[212] Hsu. D. 2012. Life cycle assessment of gasoline and diesel produced via fast pyrolysis and hydroprocessing. Biomass and Bioenergy. Volume 45, October 2012, Pages 41–47.

Iribarren et al. (2012) studied a similar conversion process using short-rotation poplar as feedstock and reported life cycle GHG emissions of 24 g CO_2 eq/MJ of biofuel (43 percent gasoline and 57 percent diesel by mass) without taking into account GHG emissions from land use change.[213]

In its recent LCA analysis, U.S. EPA examined life cycle GHG emissions for renewable gasoline and diesel produced from corn stover via catalytic pyrolysis followed by upgrading and estimated the GHG emissions at 30 g CO_2 eq/MJ of biofuel (no estimate is given specifically to diesel or gasoline) by 2022.[207] The modeled process is slightly different from that modeled by Hsu and Iribrren et al. as U.S. EPA assumes that a small amount of surplus electricity coproduced can be exported to the grid. U.S. EPA's analysis also looked at life cycle GHG emissions of cellulosic renewable gasoline produced from corn stover using two other conversion technologies: 1) biochemical fermentation with upgrading to renewable gasoline via carboxylic (based on confidential business information as indicated by U.S. EPA), and 2) direct biochemical fermentation through the use of microorganisms to convert sugars from cellulose. The former pathway is estimated to have GHG emissions of 32 g CO_2 eq/MJ of renewable gasoline while the latter has a much lower GHG emission of -27 g CO_2 eq/MJ of renewable gasoline. This is attributable to a large amount of surplus electricity assumed to be exported to the grid, similar to the corn stover ethanol conversion process discussed above. U.S. EPA further concluded that even without accounting for excess electricity, the routes analyzed will meet the 60 percent GHG reduction criterion specified in RFS2; the estimated GHG reduction (without electricity credit) for catalytic pyrolysis, biochemical fermentation via carboxylic, and direct biochemical fermentation is 65 percent, 62 percent and 93 percent, respectively, compared to 2005 baseline petroleum fuels.

In addition to these pathways, U.S. EPA also evaluated the Fischer-Tropsch (F-T) diesel pathway (which involves gasifying biomass into syngas and then converting the syngas into a hydrocarbon mix further refined into finished biofuel products). In its impact analysis[205], U.S. EPA estimated life cycle GHG emissions of F-T diesel at 28 and 9 g CO_2 eq/MJ of F-T diesel, respectively, using switchgrass and corn stover as the feedstock. The switchgrass estimate includes land use change (no land use change for corn stover). In its 2013 analysis, U.S. EPA emphasized that these estimates should be considered conservative because no excess electricity production is assumed for this conversion process.[207] Furthermore, U.S. EPA concluded that a process for producing primarily renewable gasoline rather than diesel from a gasification route should not result in significantly worse GHG impacts than the F-T diesel route.[207] These estimates are comparable to results from other studies. For example, Stratton et al. (2011)[214] indicated that life cycle GHG emissions of F-T diesel made from switchgrass has a baseline emission of 18 g CO_2/MJ excluding potential soil carbon change and induced

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[213] Iribarren, D., Peters, J.F., Dufour, J. 2012. Life Cycle Assessment of Transportation Fuels from Biomass Pyrolysis. Fuel 97 (2012) 812–821.

[214] Stratton, R.W., Wong, H, M., Hileman, J.I. 2011. Quantifying Variability in Life Cycle Greenhouse Gas Inventories of Alternative Middle Distillate Transportation Fuels. Environmental Science and Technology. 2011, 45, 4637-4644.

emissions from land use change.[215] Similar results are reported in Iribarren et al. (2013) for F-T diesel produced from syngas derived from wood chips.[216]

A few studies have examined other novel conversion technologies. One such study is Maleche (2012), which looked at Gas Technology Institute's integrated hydropyrolysis and hydroconversion process converting cellulosic biomass to hydrocarbon liquid transportation fuels in the range of gasoline and diesel. The estimated life cycle GHG emissions of biofuel (a mixture of diesel and gasoline) produced from this process are approximately 7 and 4 g CO_2 eq/MJ, respectively, using corn stover and forest residue as the feedstock.

Electricity

The RFS2 targets only biofuels and does not consider the potential contribution of electricity, hydrogen, and natural gas toward reducing the carbon intensity of transportation fuels. In contrast, under California's LCFS electricity is an eligible option as a low-carbon transportation fuel used in plug-in vehicles. ARB's LCA estimated GHG emissions for two electricity scenarios, one based on the 2005 resource mix of electricity consumed in California (including imported electricity used in California) and the other one based on the marginal electricity mix (assumed to be natural gas combusted in combined cycle combustion turbines, and renewables) (ARB 2009). The 2005 resource mix of electricity is composed of 43.1 percent gas, 17.9 percent hydro, 14.8 percent nuclear, 15.4 percent coal, and 8.8 percent other renewables (e.g., geothermal, wind and solar). The estimated GHG emissions are 124 and 105 g CO_2 eq/MJ, respectively, for electricity produced from the 2005 resource mix and the assumed marginal electricity mix.

The life cycle GHG emissions of electricity depend primarily on the type of energy used. Studies (e.g., SRREN 2012) find that electricity generated from renewable sources, as well as nuclear, in general has much lower life cycle emissions compared to that associated with fossil fuels. The median life cycle GHG emissions range from 1 to 13 g CO_2 eq/MJ for electricity from renewables and nuclear and from 130 to 278 g CO_2 eq/MJ for electricity from fossil fuels.

For passenger cars, the assigned energy economy ratio for gasoline is 1.0 while the energy economy ratio of electricity used in a battery electric or plug-in hybrid electric vehicle is 3.4 in the LCFS.[22] Using an energy economy ratio of 3.4 for electricity makes electricity from all resources favorable compared to gasoline (on a basis of 1 km or mile travelled), assuming the median values of GHG emissions discussed above (130 to 278 g CO_2 eq/MJ). The estimated emissions of electric vehicles using California 2005 average electricity and California marginal electricity are 63 percent to 68 percent lower than those of gasoline vehicles (per unit distance) based on the following formula: adjusted emissions on a unit of distance driven = carbon intensity of electricity/energy economy ratio of battery or plug-in electric vehicle.

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[215] Stratton, R.W., Wong, H, M., Hileman, J.I. 2011. Quantifying Variability in Life Cycle Greenhouse Gas Inventories of Alternative Middle Distillate Transportation Fuels. Environmental Science and Technology. 2011, 45, 4637-4644.

[216] Iribarren ,D., Susmozas, A., and Dufour, J. 2013. Life-cycle Assessment of Fischere Tropsch Products from Biosyngas. Renewable Energy 59 (2013) 229 -236.

Hydrogen
The RFS2 does not include hydrogen in its overall program while the LCFS considers it an option to lower the carbon intensity of transportation fuels. The pathways analyzed by ARB include 1) compressed hydrogen from central reforming of natural gas (with or without liquefaction and re-gasification steps), 2) liquid hydrogen from central reforming of natural gas, 3) compressed hydrogen from on-site reforming of natural gas, and 4) compressed hydrogen from on-site reforming with (partial) renewable feedstocks.

Using North American natural gas as the feedstock, hydrogen is estimated to have life cycle GHG emissions ranging from 98 to 142 g CO_2 eq/MJ in ARB's LCAs. Compressed hydrogen produced with two-thirds of the feedstock from North American natural gas and one-third from landfill gas (from California) has lower emissions (estimated at 76 g CO_2 eq/MJ) due to the use of renewable landfill gas, which has low life cycle GHG emissions thanks to the emission credit given to the avoided flare gas otherwise emitted if the landfill gas were not recovered.

For passenger cars, the energy economy ratio of hydrogen used in a fuel cell vehicle is 2.5 as specified in the LCFS. Based on an energy economy ratio of 2.5 and ARB's emission estimates of several hydrogen production pathways (discussed above), passenger vehicles fueled with hydrogen reduce GHG emissions by between 42 percent and 69 percent compared to gasoline-fueled vehicles per unit distance.

Similar to biofuels, the feedstock used to produce hydrogen plays a major role in determining the carbon intensity of the fuel. Spath and Mann examined the production of hydrogen via wind electricity and electrolysis (in which water is separated into hydrogen and oxygen using electricity) and reported life cycle GHG emissions of 8 g CO_2 eq/MJ of hydrogen (based on low heating values).[217] Hydrogen can also be produced from biomass (e.g., via gasification) and nuclear (e.g., via high temperature electrolysis) with life cycle GHG emissions comparable to those from wind/electrolysis.[218]

Renewable Natural Gas
The LCFS includes several renewable natural gas pathways, which are considered low carbon gasoline and diesel substitutes, including 1) compressed natural gas (CNG) produced from landfill gas (cleaned up to pipeline quality NG and compressed in California), 2) LNG produced from dairy digester biogas (generated via anaerobic digestion of livestock manure), 3) CNG produced from dairy digester biogas, 4) LNG produced from landfill gas, and 5) biomethane from high solids anaerobic digestion of organic (food and green) wastes.

Using the same feedstock (e.g., landfill gas or biogas from anaerobic digestion), LNG has higher life cycle GHG emissions simply because additional energy from electricity is needed during liquefaction. For example, the estimated emissions of CNG produced from landfill gas are about 11 g CO_2 eq/MJ while those of LNG from the same gas are between 16 and 26 g CO_2 eq/MJ, depending on the efficiency of liquefaction (the lower bound corresponds to 90

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[217] Spath, P., and Mann, M. 2004. Life Cycle Assessment of Renewable Hydrogen Production via Wind/Electrolysis. 2004. NREL/MP-560-35404. National Renewable Energy Laboratory.

[218] IPHE. 2011. Renewable Hydrogen Report. 2011. International Partnership for Hydrogen and Fuel Cells in the Economy.

percent efficiency and the upper bound 80 percent efficiency). CNG and LNG produced from biogas generated from livestock manure via anaerobic digestion have slightly higher GHG emissions than the respective CNG and LNG from landfill gas (by about 2 g CO_2 eq/MJ). In all cases, renewable natural gas produced from landfill gas or livestock manure-derived biogas reduces GHG emissions by between 71 percent and 88 percent compared to petroleum fuels.

A recent LCA conducted by ARB indicated that GHG emissions for the production of biomethane from high solids anaerobic digestion of organic wastes are much lower (-15 g CO_2 eq/MJ).[219] Although the breakdown of organic matter in an anaerobic digestion vessel (used in the high solids anaerobic digestion process) is similar to the decomposition of that material in a landfill, nearly all of methane and CO_2 generated in the vessel can be captured. On the other hand, about 25 percent of the methane generated in a landfill escapes to the atmosphere as fugitive emissions. Therefore, a much larger credit for avoided emissions is assigned to this high solids anaerobic digestion conversion process, leading to the lower estimate of GHG emissions compared to natural gas produced from landfill gas and livestock manure-derived biogas.

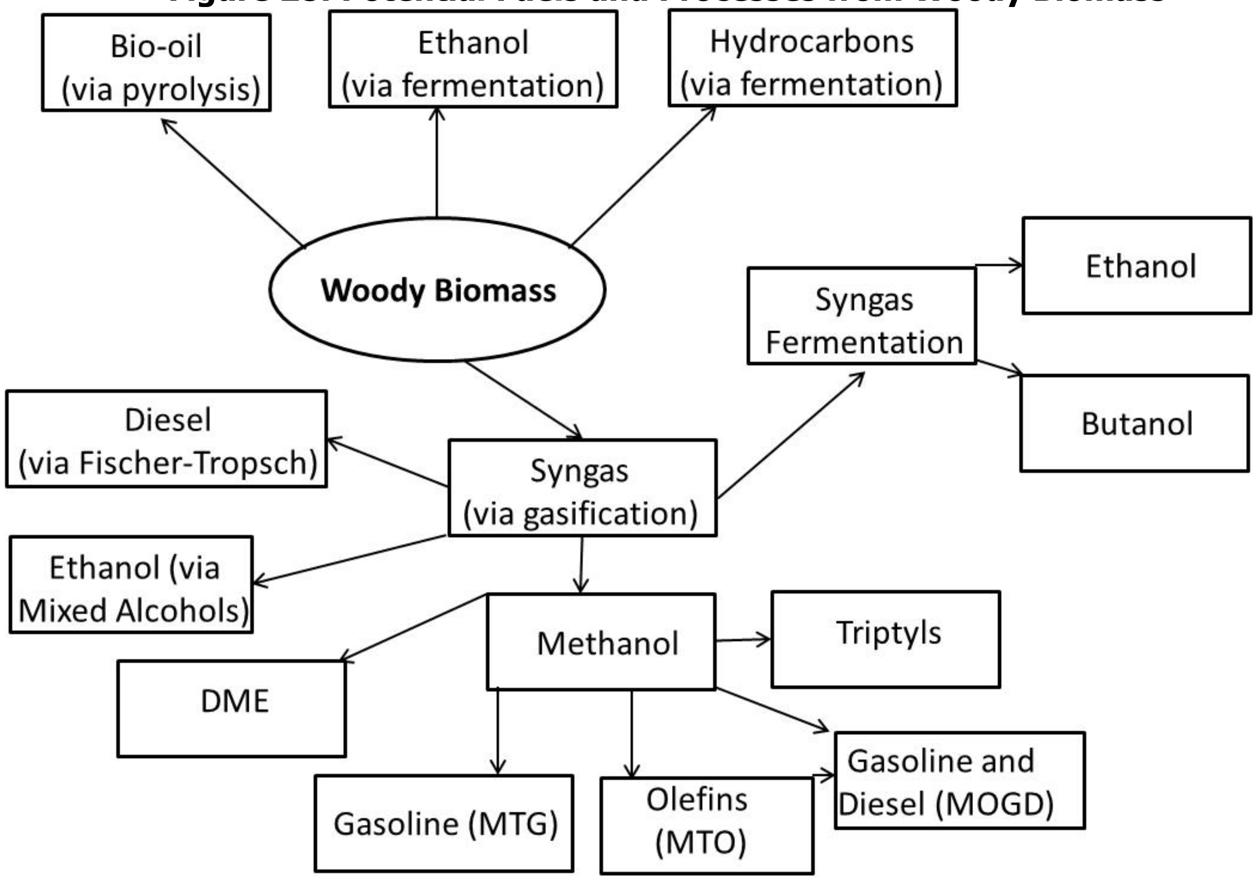
Lower-moisture feedstocks such as agricultural residues can be used for thermal gasification to produce bio-syngas, which can be methanated and cleaned to produce renewable natural gas. While thermal gasification of coal is a mature technology, technologies for producing renewable natural gas from biomass are still under development with some demonstration facilities in Europe.[155] No literature was located that specifically examined life cycle GHG emissions of renewable natural gas produced from cellulosic biomass.

[219] ARB. 2012. Low Carbon Fuel Standard Regulation, Final Regulation Order. California Air Resources Board. https://ww3.arb.ca.gov/regact/2011/lcfs2011/frooalapp.pdf

CHAPTER 6: Woody Biomass

Woody biomass can be used as a feedstock for a variety of processes that produce fuels. These processes range from pyrolysis to fermentation, and the greatest variety of fuels from woody biomass stems from biomass gasification to produce synthesis gas, also called synthetic gas or syngas. The syngas can then be converted to a wide range of fuels through a variety of processes. The plethora of fuels process options is demonstrated in Figure 28.

Figure 28: Potential Fuels and Processes from Woody Biomass



Source: NREL

As we evaluate the variety of fuels which can be produced from woody biomass, there are many important distinguishing characteristics about each fuel and process.[69] Information is given on each of the fuels in Table 23.[220]

[220] Hofstra University. 2013. "The Geography of Transport Systems." https://transportgeography.org/wp-content/uploads/GTS_Third_Edition.pdf

Table 23: Characteristics of Fuels which can be produced from Woody Biomass

Fuel[221]	Production Processes	Specific Energy (MJ/kg)	Chemical/ Molecular Formula	Physical State at STP
Methane	Gasification	56	CH_4	Gas
Hydrogen	Gasification	142	H_2	Gas
Ethanol	• Gasification • Fermentation • Syngas Fermentation	25	CH_3CH_2OH	Liquid
Methanol	Gasification	21	CH_3OH	Liquid
Dimethyl ether (DME)[72]	• Gasification	28	C_2H_6O	Gas
Gasoline	• Gasification • Fermentation • Pyrolysis (with upgrading)	46	Hydrocarbons in the C_4-C_{12} range	Liquid
Diesel	• Gasification • Fermentation • Pyrolysis (with upgrading)	46	Hydrocarbons in the C_8-C_{25} range	Liquid
Bio-oil	Pyrolysis	18		Viscous Liquid

Source: NREL

Chapter 4 provides detailed descriptions of the individual fuels that can be produced from woody biomass.

Conversion Technologies

Woody biomass can be converted to a variety of fuels by means of an absolute plethora of technology options including pyrolysis, catalytic fast pyrolysis (ex-situ and in-situ), biochemical conversions, and gasification to liquid fuels. These processes may produce a fuel directly or may produce a feedstock or blendstock for subsequent conversions to fuels.

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221 AFDC. 2013h. "Fuel Properties Comparison." 2/27/2013. http://www.afdc.energy.gov/fuels/fuel_comparison_chart.pdf.

Biomass Gasification

Though there is a wide array of fuel conversion technologies that start with woody biomass, the basic building block for many of them is production of synthesis gas from gasification. Figure 29 demonstrates the processes that begin with gasification of woody biomass.

Gasification converts biomass-based or fossil-based materials into CO, H_2 and CO_2. This is achieved by reacting the feedstock at high temperatures with a controlled amount of oxygen and/or steam, without combustion. This syngas can be converted to a variety of fuels, including: biomethane, methanol, ethanol, dimethyl ether (DME), gasoline, and diesel. The composition of the produced gas is dependent on the gasifier technology (updraft, downdraft, fluidized bed, thermal gasification) and whether air or oxygen or neither is used in the process.[222] For more information, on the various gasifier designs, see Craig and Mann (1996).[223] VTT presented the liquid fuel cases from gasification utilizing a pressurized fluidized-bed steam/O_2.[121] A low-pressure indirectly-heated circulating fluidized bed gasifier, based on the Battelle Columbus Laboratory gasifier, is considered. The conditions of this gasifier are approximately 25 pounds per square inch absolute (psia) and 1,600°F (870°C) and the exiting syngas has the gas composition shown in Table 24.[69]

[222] Murphy, Jerry D., James Browne, Eoin Allen, and Cathal Gallagher. 2013. "The Resource of Biomethane, Produced via Biological, Thermal and Electrical Routes, as a Transport Biofuel." Renewable Energy 55 (July): 474–479. doi:10.1016/j.renene.2013.01.012.

[223] Craig, Kevin R., and Margaret K. Mann. 1996. "Cost and Performance Analysis of Biomass-Based Integrated Gasification Combined-Cycle (BIGCC) Power Systems". NREL/TP-430-21657. NREL.

Table 24: Gasifier Conditions and Outlet Gas Composition

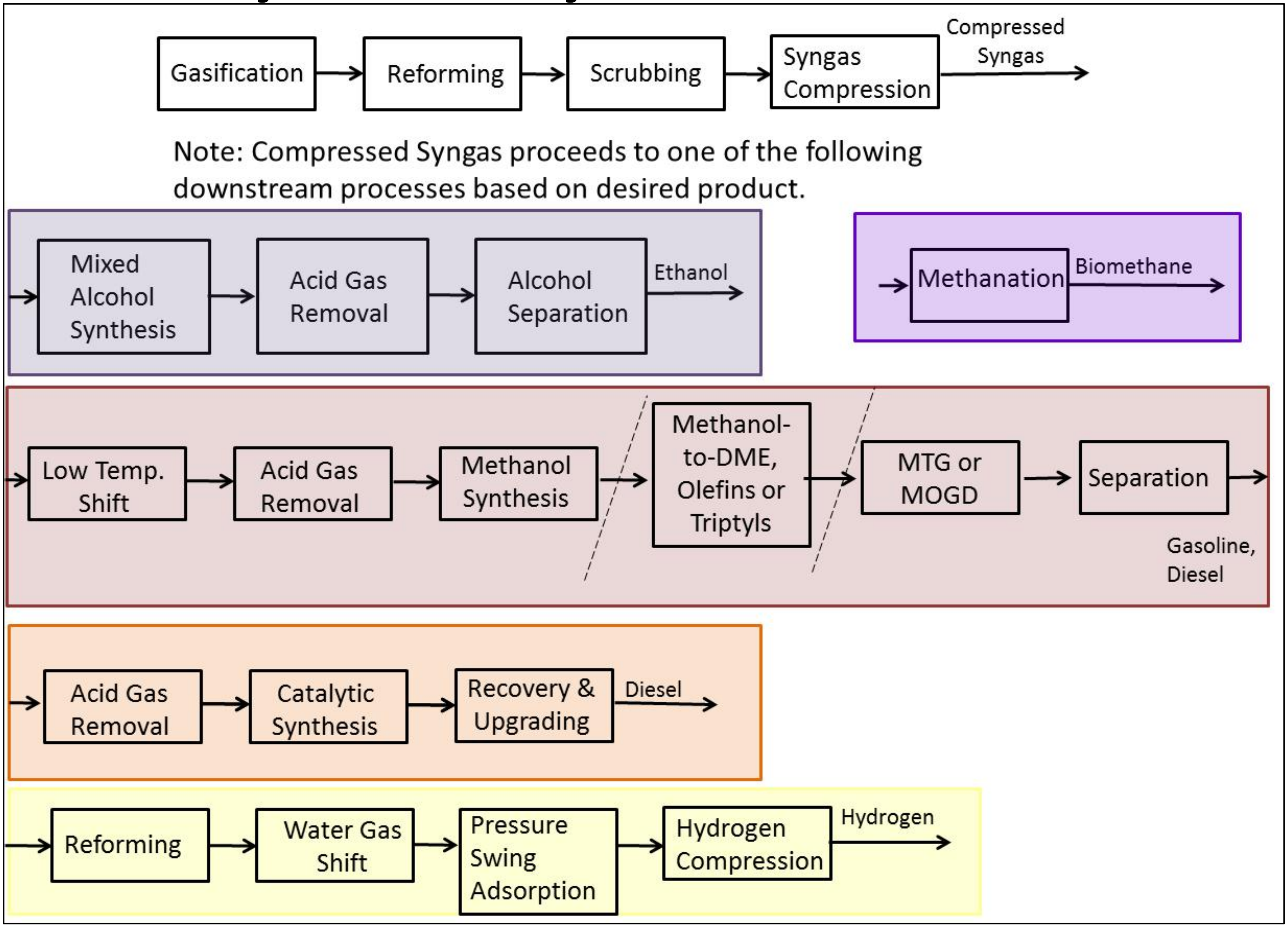
Gasifier Variable	**Value**	
Temperature	1,622ºF (883ºC)	
Pressure	21.4 psia (1.5 bar)	
Gasifier Outlet Gas Composition	**mol% (wet)**	**mol% (dry)**
H_2	13.9	24.7
CO_2	7.1	12.6
CO	23.7	42.0
H_2O	43.6	--
CH_4	8.6	15.2
C_2H_2	0.2	0.4
C_2H_4	2.4	4.2
C_2H_6	0.1	0.2
C_6H_6	0.07	0.1
Tar ($C_{10}H_8$)	0.1	0.2
NH_3	0.2	0.3
H_2S	0.04	0.1
H_2:CO molar ratio	0.59	
Stoichiometric Ratio*	1.047	
Gasifier Efficiency**	75.3% high heating value basis 74.9% lower heating value basis	

***Stoichiometric Ratio = Air to Fuel Ratio (the fuel for the gasifier is the woody biomass)**

****Gasifier Efficiency = Energy exiting gasifier divided by energy entering gasifier**

Source: NREL

Figure 29: Process Flow Diagrams for Gasification to Fuels Processes



Source: NREL

As shown in the process flow diagram, Figure 29, dry woody biomass feedstock enters the gasifier. Subsequent to the gasifier, the syngas is cleaned and conditioned to be synthesized. The tars and hydrocarbons in the syngas are reformed to additional CO and H_2 in a tar reformer. Particulates are removed via quench, cooled by liquids. From this point there are different back-end processes depending on the desired product.

Ethanol

Subsequent to the quench the syngas is compressed to 2,000-3,000 psia. It then enters the mixed alcohol synthesis reactor where it contacts a metal-sulfide catalyst. This is followed by an acid gas removal system. The product gas is subsequently cooled, and the alcohols condensed. The liquid alcohols are then de-gassed, dried, and separated into three streams: methanol, ethanol and mixed higher-molecular weight alcohols. The methanol stream is recycled back to the inlet of the alcohol synthesis reactor. The ethanol and mixed alcohol streams are cooled and sent to product storage.[67]

An alternative approach to ethanol synthesis is syngas fermentation. In this case, the syngas is produced via gasification, cleaned and conditioned. It is subsequently immersed in a fermentation broth. The microbes within the broth convert the CO and H_2 to ethanol or butanol.

Methanol

For methanol, a low temperature shift (water gas shift reaction) is utilized to increase the amount of hydrogen in the syngas to achieve a H_2:CO ratio of approximately 2.1 from approximately 1.6. If catalytic steam reforming is implemented, a water gas shift is not required. This is followed by an acid gas removal system. The syngas proceeds to the methanol synthesis reactor where it meets a copper/zinc oxide/alumina catalyst. Conversion to methanol is approximately 99 percent. It is then degassed and dehydrated.[224]

DME

Production of DME is achieved by utilizing a gamma-alumina or aluminosillicate dehydration catalyst to dewater the methanol. Typically, methanol is produced first, and subsequent dewatering occurs in a separate step. However, a relatively new option exists to mix the methanol and dehydration catalysts in a single reactor to achieve DME from syngas in a single step.[121]

Gasoline

The process for gasoline builds off of the gasification and subsequent methanol processes. The methanol is reacted over a catalyst in either a fixed or fluidized bed reactor at 360-415°C and 2.77 bar. Mobil utilizes a ZSM-5 zeolite catalyst. Subsequently the gasoline is separated in a sequence of distillation columns, similar to a typical gasoline refinery finishing section.[69]

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[224] Tarud, J., and S. Phillips. 2011. "Technoeconomic Comparison of Biofuels: Ethanol, Methanol, and Gasoline from Gasification of Woody Residues" presented at the 2011 ACS National Meeting and Exposition, September 28, Denver, Colorado. http://www.nrel.gov/docs/fy12osti/52636.pdf.

Variations of this process have been developed by Haldor Topsoe,[225] Primus Green[226] and Pacific Northwest National Laboratory. The Methanol-to-Gasoline process was run commercially for several years in New Zealand during the 1980s and 1990s.[66] The feedstock for the plant was natural gas. It was subsequently converted to a methanol plant when no longer able to compete with low fossil-based gasoline prices.

Diesel

For the FT process, the cleaned syngas first proceeds through acid gas removal. It is then catalytically converted in a fixed bed reactor with a cobalt based catalyst. The reactor conditions can be 200°C and 30 bar. Condensable products are recovered from the reactor effluent. Most of the hydrocarbons are recovered by condensation via cooling water. C_5 and higher are recovered, while C_1-C_4 products are recycled back to the synthesis reactor to improve yields.[121]

Olefins

Methanol can also be utilized to produce light olefins, which are intermediates in the Methanol-to-Gasoline reaction. This process is known as Methanol-to-Olefins. A Methanol-to-Olefins demonstration plant was operated by Mobil in Wesseling Germany in the 1980s. Union Carbide also developed a process to convert methanol to olefins employing a silicoaluminophosphate catalyst.[227]

The Methanol-to-Olefins process can be combined with the Mobil Olefins-to-Gasoline/Diesel process. Mobil Olefins-to-Gasoline/Diesel is a process for production of olefins from methanol. The Mobil Olefins-to-Gasoline/Diesel product distribution is determined by thermodynamic, kinetic, and shape-selective restrictions. A large-scale Mobil Olefins-to-Gasoline/Diesel test was run in a Mobil refinery in 1981 utilizing a zeolite catalyst, and with a natural gas feedstock.[227]

Triptyls (2,2,3-Trimethylbutyls)

The methanol to triptyls (triptane and triptene) is a similar process to the MTG process. Methanol serves as an intermediate and is subsequently converted to a gasoline blendstock. The process yields are weighted towards branched C7 molecules, suitable for a gasoline blendstock. A β-zeolite catalyst is utilized.

Biomethane

In recent years, the primary research focus has been on converting the syngas produced in the gasifier to ethanol or other fuels. For conversion to ethanol, synthesis gas rich in CO and H_2 is desired. Methane, the primarily component in natural gas, is undesirable and is reformed

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[225] Haldor Topsoe. 2013. "Gasoline - TIGAS." Accessed May 17. https://www.topsoe.com/processes/gasoline-synthesis/tigas

[226] Primus Green Energy. 2013. "STG+ Technology." Accessed May 6. https://www.primusge.com/technology/overview-of-primus-stg-technology/

[227] Keil, Frerich J. 1999. "Methanol-to-hydrocarbons: Process Technology." Microporous and Mesoporous Materials 29 (1–2) (June): 49–66. doi:10.1016/S1387-1811(98)00320-5.

to CO and H_2. Process parameters have been studied to increase the amounts of CO and H_2 in syngas. This includes reforming of methane to CO and H_2. In contrast, if the target product is renewable natural gas or biomethane, methane is desired and thus a different type of reforming would be recommended. The process to produce biomethane includes gasification of the woody residues, syngas cleanup with subsequent methanation.

Methanation Reaction

$CO_{(g)} + 3H_{2\,(g)} \rightarrow CH_{4(g)} + H_2O_{(v)}$

Hydrogen

Cleaned and compressed synthesis gas proceeds to reforming and water-gas shift. The high temperature shift and low temperature shift reactors convert the majority of the CO when reacted with H_2O into CO_2 and H_2 through the water-gas shift reaction. For purification, a pressure swing adsorption unit is used to separate the hydrogen from the other components in the shifted gas stream, mainly CO_2, CO, CH_4, and other hydrocarbons. Finally, the hydrogen is compressed to 1,015 psia.[228]

Water-Gas Shift Reaction

$CO_{(g)} + H_2O_{(v)} \rightarrow CO_{2(g)} + H_{2(g)}$

Hydrothermal Liquefaction

Hydrothermal liquefaction (liquification) includes submersing the biomass in supercritical water for 15 minutes (at 400°C and high pressure) where it is broken down into a bio-oil. Subsequently the bio-oil can be hydrogenated or thermally upgraded to obtain gasoline fuels with existing refinery technology.[86] A flow diagram of the hydrothermal liquefaction process is shown in Figure 33. Feedstocks for hydrothermal liquefaction include whole algae, a variety of waste streams, and cellulosic feedstocks. A newer area of research for hydrothermal liquefaction is refining the oil produced to gasoline. Companies to note in this area are: New Oil, Enertech Environmental, Biodiesel BV (Netherlands).

Pyrolysis

Pyrolysis produces bio-oil, a mixture of naptha-range products (gasoline blend stock) and diesel-range products (diesel blend stock), from woody biomass. Pyrolysis processes are now widely used for charcoal production.[229] Pyrolysis liquid yield is improved when biomass feedstock is heated rapidly and the vapors are condensed at a rapid rate, called fast pyrolysis.[229] Figure 30 demonstrates pyrolysis yields as a function of residence time. The increase in yield has led most pyrolysis research to the area of fast pyrolysis. Fast pyrolysis is performed under a range of reactor temperatures and short residence times to maximize the liquid hydrocarbon yield. Conventional non-catalyzed fast pyrolysis is already

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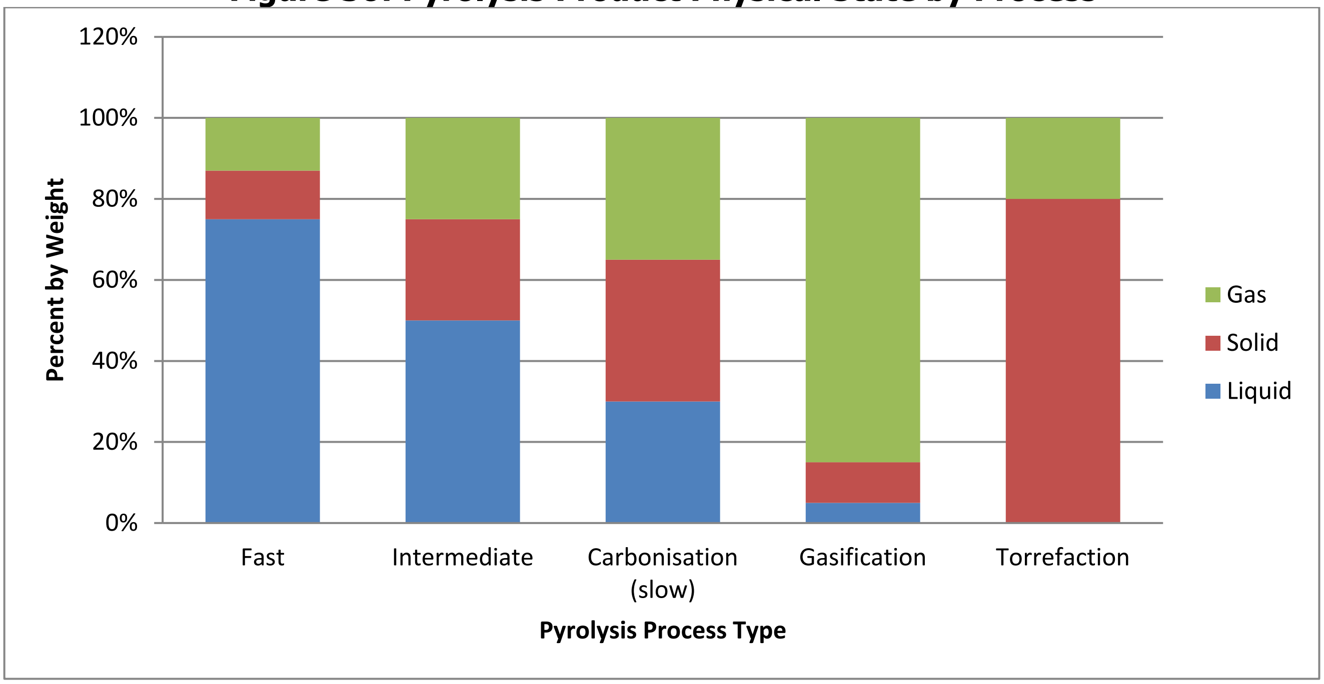
[228] Spath, P., A. Aden, T. Eggeman, M. Ringer, B. Wallace, and J. Jechura. 2005. "Biomass to Hydrogen Production Detailed Design and Economics Utilizing the Battelle Columbus Laboratory Indirectly-Heated Gasifier". NREL/TP-510-37408. http://www.nrel.gov/docs/fy05osti/37408.pdf.

[229] Mohan, Dinesh, Charles U. Pittman, Jr., and Philip H. Steele. 2006. "Pyrolysis of Wood/Biomass for Bio-oil: A Critical Review." Energy & Fuels (20): 848–889.

commercialized.[230] Catalytic vapor phase upgrading can reduce costs associated with upgrading the product bio-oil from conventional fast pyrolysis to a hydrocarbon by producing a lower-oxygen-content intermediate with lower associated water. Catalytic vapor phase upgrading can be added after the pyrolysis reactor (Ex-Situ Catalytic Fast Pyrolysis) or in the pyrolysis reactor (In-Situ Catalytic Fast Pyrolysis) in order to produce a lower-oxygen-content intermediate with lower water content, thus reducing bio-oil upgrading costs.[80] Figure 31 demonstrates the pyrolysis processes described above.[114]

Figure 30: Pyrolysis Product Physical State by Process



Source: NREL

A variation of pyrolysis is integrated hydropyrolysis with hydroconversion.[231]

The lignocellulosic feedstock enters a pressurized fluid-bed hydropyrolysis reactor where it is converted to gas and liquid in the presence of hydrogen. The vapor from this stage is directed to a hydroconversion unit which removes oxygen, and thus produces deoxygenated gasoline and diesel products.[82]

An alternative type of pyrolysis is torrefaction. Torrefaction combined with densification produces an energy-dense fuel carrier with the following characteristics: higher energy density, better grindability, and better hydrophobic properties. Torrefaction is a mild form of pyrolysis; its temperatures typically range from 250° to 300°C.[232]

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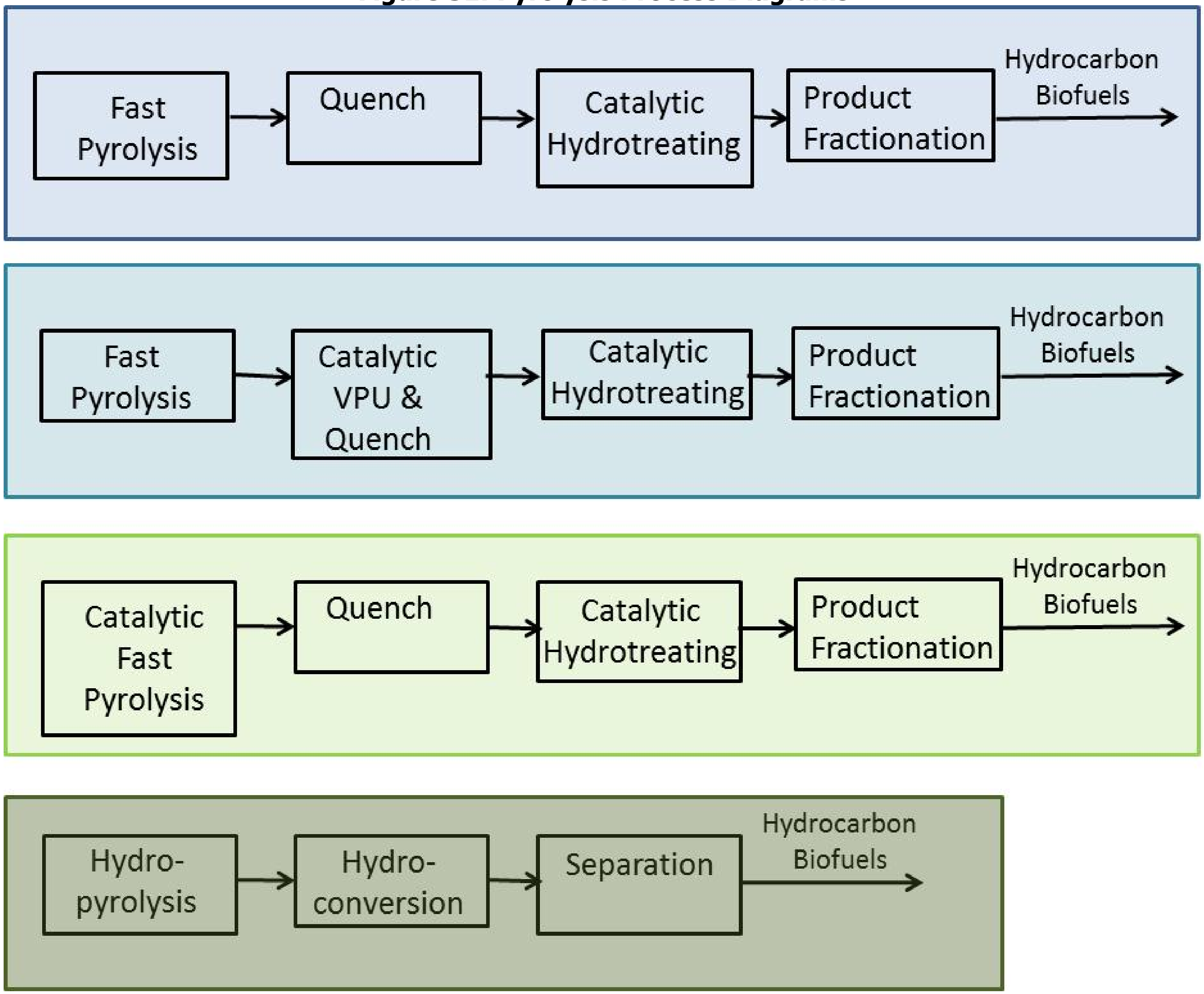
230 Envergent. 2013. "About Us." Accessed May 6. http://www.envergenttech.com/about.php.

231 Bridgwater, A.V. 2012. "Review of Fast Pyrolysis of Biomass and Product Upgrading." Biomass and Bioenergy 38 (March): 68–94. doi:10.1016/j.biombioe.2011.01.048.

232 Andritz. 2013. "Torrefaction of Biomass." Accessed August 2013, https://pdf.directindustry.com/pdf/andritz-ag/torrefaction-biomass/34052-529429.html.

Figure 31: Pyrolysis Process Diagrams



Source: NREL

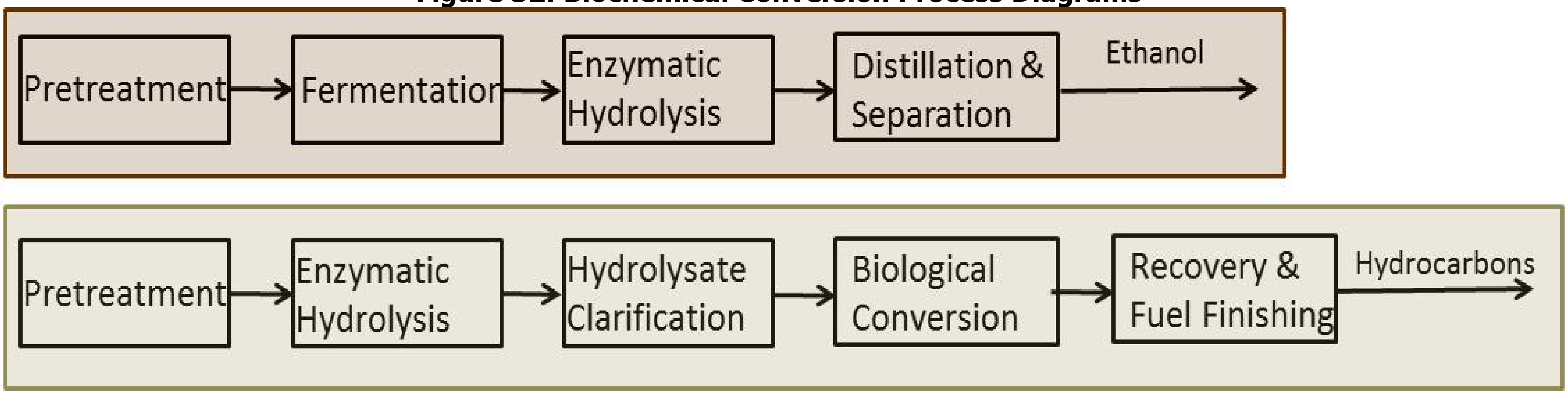
Biochemical Conversion

The biochemical route to biofuels is a possible biofuels route that can utilize woody biomass. The high acetate content in most woody biomass can be a strong inhibitor to the fermentation process and thus woody biomass has not typically been a high interest feedstock for this process. However, recent advancements in de-acetylation processes have renewed interest in biochemical conversion of woody biomass.

The biochemical processes of converting woody biomass to ethanol or hydrocarbons are similar to the biochemical conversion of corn stover to ethanol or hydrocarbons. However, the yields are currently lower than that for corn stover and different pretreatment is required. For a feedstock of woody biomass, steam explosion or auto hydrolysis are effective pretreatment strategies.[233] As shown in Figure 32, this is followed by fermentation, enzymatic hydrolysis, and separation for the production of ethanol. For production of hydrocarbons, pretreatment is followed by enzymatic hydrolysis with subsequent hydrolysate clarification to remove remaining insoluble solids, primarily lignin. This is a variation from biochemical ethanol production where lignin is removed after sugar fermentation. Biological conversion for hydrocarbon production is likely to proceed via aerobic respiration, compared to anaerobic fermentation for ethanol. The final steps include recovery/purification and fuel finishing.[65] In order to produce hydrocarbons, microorganisms are genetically engineered for targeted fuel components or co-products.

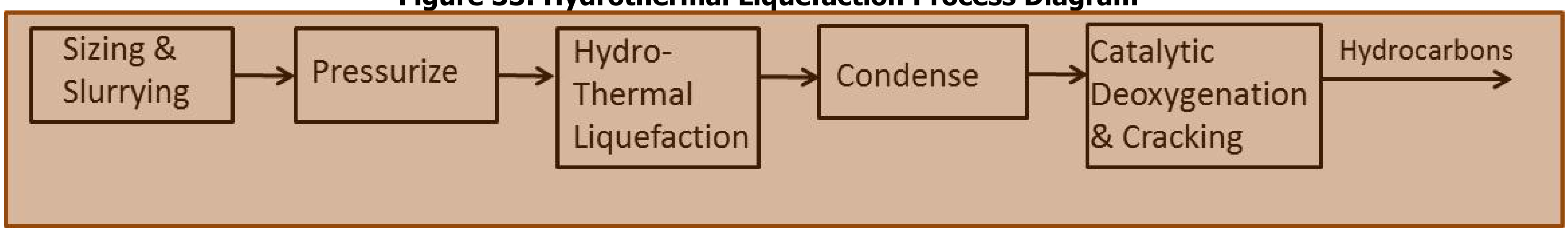
[233] Duff, Sheldon J. B., and William D. Murray. 1996. "Bioconversion of Forest Products Industry Waste Cellulosics to Fuel Ethanol: A Review." Bioresource Technology (55): 1–33.

Figure 32: Biochemical Conversion Process Diagrams



Source: NREL

Figure 33: Hydrothermal Liquefaction Process Diagram



Source: NREL

Modeled Cost Production Data

Cost data based on engineering economic models is available for some of the processes described above. However, modeled production costs are inherently dependent upon many assumptions in the model. Key factors include plant size, feedstock moisture level and cost, first-of-a-kind vs. n^{th} plant, required return on investment, value from co-products, stream factor (percentage of time on-stream) and others.

Cost information for gasification of woody biomass to ethanol, methanol, and gasoline was compared in the 2011 ACS presentation.[224] This report included the following economic assumptions: n^{th} plant, $2007, 30-year plant life, 10 percent internal rate of return, 40 percent equity of total plant investment, and 8 percent loan rate on remaining 60 percent debt. The reported plant gate prices are listed in Table 25.

Table 25: Plant Gate Prices

	($/MMBtu)	($/gal)	($/gge)
Methanol	18.42	1.20	2.23
Ethanol[67]	24.10	2.05	3.11
Gasoline	22.66	2.72	2.72

Source: NREL

Hydrogen from biomass gasification was analyzed at NREL in 2011.[234] The hydrogen production costs were found to be $2.80/kg for an n^{th} plant (2,000 dry short tons per day) and $5.40/kg for a first plant (500 dry short tons per day).

The work presented thus far was completed by NREL. Other techno-economic analysis information for conversion of woody biomass to fuels has been completed at the Pacific Northwest National Laboratory.[235] Pacific Northwest National Laboratory reported the following minimum selling prices for biofuels from woody biomass (as shown in Table 26).[236]

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[234] Ruth, Mark. 2011. "Hydrogen Production Cost Estimate Using Biomass Gasification". NREL. http://www.nrel.gov/docs/fy12osti/51726.pdf.

[235] Jones, SB, and JL Male. 2012. "Production of Gasoline and Diesel from Biomass via Fast Pyrolysis, Hydrotreating and Hydrocracking: 2011 State of Technology and Projections to 2017". PNNL-22133. PNNL. http://www.pnnl.gov/main/publications/external/technical_reports/PNNL-22133.pdf.

[236] Jones, SB, and Y Zhu. 2009. "Techno-economic Analysis for the Conversion of Lignocellulosic Biomass to Gasoline via the Methanol-to-Gasoline (MTG) Process". PNNL-18481. PNNL. http://www.pnl.gov/main/publications/external/technical_reports/PNNL-18481.pdf.

Table 26: Minimum Fuel Selling Prices from Pacific Northwest National Laboratory

Process	SOT Minimum Selling Price ($/gal)	2017 Projected Minimum Selling Price ($/gal)
Fast Pyrolysis → Gasoline	5.12	2.32
Fast Pyrolysis → Diesel	5.19	2.32
Gasification → Gasoline	3.20	

Source: NREL

Economic assumptions from Jones and Zhu[236] include the following: $2008, 90 percent stream factor, 20-year plant life, and 10 percent return on investment.

In addition to the numbers given above, the report 'Techno-economic analysis for the conversion of biomass-derived syngas to fuels and chemicals' adjusts various techno-economic analyses to match NREL economic assumptions then compares results. Table 27 contains the plant gate price averages and ranges reported in 2012. As a reference point,

Table 28 demonstrates current market value for the aforementioned products.

Table 27: Plant Gate Price Survey of Existing Literature

Process	n^{th} Plant Gate Prices			Pioneer Plant Gate Prices		
	Average	Lower Probability Limit	Upper Probability Limit	Average	Lower Probability Limit	Upper Probability Limit
Ethanol via Mixed Alcohols, $/gge ($/MMBtu)	3.77 (30.16)	2.35	5.19	7.18 (56.64)	4.99	9.37
Ethanol via Syngas Fermentation, $/gge ($/MMBtu)	3.53 (28.24)	2.83	4.23	5.94 (47.52)	4.38	7.51
Fischer-Tropsch Liquids, $/gge ($/MMBtu)	2.51 (20.08)	1.76	3.27	4.66 (37.28)	3.44	5.88
Gasoline, $/gge ($/MMBtu)	2.70 (21.60)	2.00	3.40	4.54 (36.32)	3.67	5.42
DME, $/gal ($/MMBtu)	1.15 (9.06)	0.92	1.39	2.25 (17.72)	1.67	2.83
Methanol, $/gal ($/MMBtu)	0.94 (16.42)	0.72	1.17	1.61 (28.15)	1.26	1.95

Process	n^{th} Plant Gate Prices			Pioneer Plant Gate Prices		
	Average	**Lower Probability Limit**	**Upper Probability Limit**	**Average**	**Lower Probability Limit**	**Upper Probability Limit**
Synthetic Natural Gas, $/ Thousand standard cubic feet ($/MMBtu)	14.98 (14.98)	12.66	17.30	25.67 (25.67)	24.05	27.28
Hydrogen, $/ Thousand standard cubic feet ($/MMBtu)	5.43 (18.72)	3.49	7.36	10.41 (35.90)	7.55	13.27

Source: NREL

Table 28: Fuel Market Prices

Fuel	Market Price	Market Price (Energy Basis) $/MMBtu
Gasoline[237]	$3.65/gallon	29.20
Diesel[237]	$3.87/gallon	28.25
Natural Gas[238]	$7.82/ Thousand standard cubic feet	7.82
Hydrogen[239]	$3.68/gge	29.44
Methanol[240]	$1.48/gallon	25.96
Ethanol[241]	$2.51/gallon*	29.88

***Wholesale price**

Source: NREL

Industrial Participation

As varied as the processes to convert woody biomass is the collection of companies involved in producing biofuels from woody biomass. Below is a description of those companies from the Biofuels Digest Advanced Biofuel Company Database[27]:

The format below is as follows: **Company** (Planned Capacity, Year Expecting to be Producing at this Capacity)

BlueFire Renewables (19 MGPY, 2014) – BlueFire Renewables utilizes acid hydrolysis to produce sugars and ethanol from a variety of feedstocks, including woody biomass and Municipal solid waste. Their 200lb/day demonstration facility is located in Anaheim, CA. BlueFire has begun construction for their 1st commercial in Fulton, MS, which is set to produce 19MGPY in 2014.

Clearfuels (38 MGPY, 2015) – Colorado based, Clearfuels, utilizes Fischer-Tropsch and steam reforming to produce renewable diesel from wood waste. Their first commercial plant is set for

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[237] EIA. 2013h. "Gasoline and Diesel Fuel Update." Petroleum and Other Liquids. June 3. http://www.eia.gov/petroleum/gasdiesel/.

[238] EIA. 2013j. "Natural Gas Summary." Natural Gas. http://www.eia.gov/dnav/ng/ng_sum_lsum_dcu_nus_m.htm.

[239] Dillich, Sara, Todd Ramsden, and Marc Melaina. 2012. "Hydrogen Production Cost Using Low-Cost Natural Gas". DOE Hydrogen and Fuel Cells Program Record 12024. U.S. Department of Energy. http://www.hydrogen.energy.gov/pdfs/12024_h2_production_cost_natural_gas.pdf.

[240] Argus. 2012. "Methanol Prices." Petrochemical Portal. December. https://www.argusmedia.com/en/petrochemicals/argus-methanol-services.

[241] EIA. 2013e. "Daily Prices." Today in Energy. June 10. http://www.eia.gov/todayinenergy/prices.cfm.

20 MGPY in 2014 in Tennessee with a second commercial plant set to produce 18 MGPY in 2015 in Hawaii.

CORE BioFuel (18 MGPY, 2017) – Canada's CORE BioFuel produces renewable gasoline from gasification and catalytic reactors with a feedstock of wood waste.

Coskata (181 MGPY, 2017) – Coskata's technology includes fermentation of syngas (from gasification) or natural gas to produce ethanol, and other fuels and chemicals. They plan to produce 181 MGPY by 2017 based on three plants: the first to produce 17 MGPY ethanol in 2014, the second to produce 34 MGPY in 2016, and a third to produce 130 MGPY in 2017. However, the feedstock listed for all three of their commercial plants is listed as natural gas, not woody biomass. Coskata was selected for the United States Department of Agriculture advanced biofuel loan guarantee program.

Flambeau River Biofuels (6 MGPY, 2015) – Wisconsin's Flambeau River Biofuels plans to produce ethanol from wood waste via enzymatic hydrolysis.

Front Range Energy (3 MGPY, 2013) – Colorado-based Front Range Energy, traditionally a corn (starch)-based ethanol producer, has set a 2013 goal for 7 percent (~3 MGPY) of their ethanol to be produced from wood utilizing Sweetwater Energy's technology. This would reduce their corn usage by 1.2 million bushels.[242]

Haldor Topsoe – In 2013, Haldor Topsoe plans to integrate Carbona Gasification with their own Topsoe Integrated Gasoline Synthesis technology to produce renewable gasoline at the GTI pilot facility.[128]

INEOS New Planet BioEnergy (8 MGPY, 2012) – INEOSBio was one of the recipients of the United States Department of Agriculture advanced biofuels loan guarantees for a process to produce 8 MGPY cellulosic ethanol along with a gross electricity production of 6 MW. They utilize a variety of feedstock, one of which is wood waste. Construction of the facility was completed in June 2012.

KiOR (250 MGPY, 2015) – By 2015, KiOR plans to have four commercial plants operating in the southeastern United States, each producing 62.5 MGPY of renewable drop-in fuel from pyrolysis of wood chips. The first commercial plant, located in Mississippi, is already producing renewable diesel. In March 2013, KiOR shipped their first cellulosic diesel products.[243] The secon commercial plant is also located in Mississippi and set for 2014, with the third and fourth commercial plants, located in Georgia and Texas, set for production in 2015.

Lignol – Canada-based Lignol is working to produce ethanol from wood waste via enzymatic hydrolysis. They are currently at the pilot scale.

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[242] Biofuels Digest. 2013a. "Front Range to Produce 7% of Ethanol from Wood in 2014", February 13. http://www.biofuelsdigest.com/bdigest/2013/02/13/front-range-to-produce-7-of-ethanol-from-wood-in-2014/.

[243] Biofuels Digest. 2013b. "KiOR Shipping Cellulosic Biofuels; Releases Q1 Results", May 10. http://www.biofuelsdigest.com/bdigest/2013/05/10/kior-shipping-cellulosic-biofuels-releases-q1-results/.

Mascoma (40 MGPY, 2014) – New York-based Mascoma is utilizing consolidated bioprocessing to produce ethanol from hardwood. In their Michigan plant they plan to produce 20 MGPY in 2013 with an increase to 40 MGPY in 2014.

Oxford Catalysts – Austrian Oxford Catalysts utilizes Fischer-Tropsch to produce renewable diesel from wood chips. They are at pilot scale.

Renewable Energy Institute International (0.35 MGPY in 2012) – Renewable Energy Institute International is investigating production of renewable drop-in fuels by gasification of biomass.

Renmatix (26 MGPY, 2015) – Pennsylvania (formerly Georgia) based Renmatix plans to produce 26 MGPY of cellulosic sugars by 2015 by hydrolysis of wood waste. The cellulosic sugars can then be converted to biofuels or biochemicals. Renmatix was named one of top 10 most innovative companies by Fast Company magazine.[244]

Rentech ClearFuels (259 MGPY, 2016) – Rentech predicts production of 259 MGPY by 2016 utilizing Fischer-Tropsch technology to produce renewable drop-in fuels.

Sweetwater Energy – New York based Sweetwater Energy produces concentrated fermentable sugars from a variety of cellulosic feedstocks including woody biomass. The sugars are suitable for use in today's biorefineries.[245] They have signed deals with Front Range Energy ($100M), ACE Ethanol ($100M), and Naturally Scientific ($250M) to provide cellulosic sugars for biofuels and biochemical.[246]

UPM (32 MGPY, 2014) – Finland-based UPM is focusing on wood-based biodiesel production with their Lappeenranta biorefinery. This biorefinery, which is scheduled for completion in 2014, is built to produce 100,000 metric tonnes annually of renewable advanced diesel (~ 32 MGPY).[247] UPM has partnered with VTT and VV-Auto Group to begin testing their renewable diesel in Volkswagen Golf automobiles.[248]

Woodland Biofuels – Canada-based Woodland Biofuels utilizes enzymatic hydrolysis of wood waste to produce ethanol. They are currently at pilot scale.

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[244] Fast Company. 2013. "The World's Top 10 Most Innovative Companies in Energy." 2013. Fast Company. Accessed May 30. http://www.fastcompany.com/most-innovative-companies/2013/industry/energy.

[245] Sweetwater Energy. 2013b. "The Sweetwater Process." Technology. Accessed May 13. https://www.sweetwater.us/process/

[246] Sweetwater Energy. 2013a. "News." Accessed May 13. http://www.sweetwater.us/news.

[247] UPM. 2013. "Hydrotreated Biofuels." Biofuels. Accessed May 13. http://www.upm.com/EN/PRODUCTS/Biofuels/Hydrotreated-biofuels/Pages/default.aspx.

[248] Biofuels Digest. 2013c. "Short Takes in Biofuels for April 29: UPM, Volkwagen, Renewable Diesel", April 29. http://www.biofuelsdigest.com/bdigest/2013/04/29/short-takes-in-biofuels-for-april-29-upm-volkswagen-renewable-diesel/.

ZeaChem (25 MGPY, 2014) – Oregon's ZeaChem is currently at the demonstration scale for production of ethanol utilizing a combination of gasification and fermentation of poplar woods.

Key Research Areas

Many key research areas for the processes described above were highlighted in recent reports from the National Advanced Biofuels Consortium, including:

Pyrolysis

- Characterization of final fuel products is important to determine if it is of sufficient quality to use as a blendstock.[249]
- The understanding of wastewater treatment for the pyrolysis processes needs to be improved in the following areas: impact of organic compounds, toxicity of trace compounds, and minimization of carbon loss to wastewater.[249]
- Ex-Situ Catalytic Fast Pyrolysis – Improve vapor phase upgrading reactor and process in order to retain the maximum amount of carbon in the liquid while removing highly reactive oxygen species.[114]
- In-Situ Catalytic Fast Pyrolysis – As most of literature has focused on various forms of the ex-situ Catalytic Fast Pyrolysis process, the concept of combining pyrolysis with upgrading in a single vessel needs to be studied and optimized.[80]

Biochemical Conversion of Sugars to Hydrocarbons

- Pretreatment and enzymatic hydrolysis processes for sugar production are important areas for additional improvement through research and development.[65]

Syngas Upgrading to Hydrocarbons

- Alternatives and improvements to the methane-to-gasoline process face the challenge of developing catalysts with increased selectivity to molecules with carbon chains in the gasoline and diesel range, while minimizing unwanted side products, including light gases and coke.[115]
- Additional research and development is investigating alternative intermediates, other than methanol, to get to hydrocarbons. Alternative intermediates such as mixed oxygenates, mixed olefins, or mixed alcohols could improve yields and economics.[115]
- Research and development could help consolidate process configuration, such as through development of catalysts that can directly convert syngas to gasoline- or diesel-range products.[115]

Discussion

Current technology options have given a plethora of fuel options starting with a feedstock of woody biomass. When comparing fuel options several distinguishing factors between the fuels

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[249] Biddy, Mary, Abhijit Dutta, Susanne Jones, and Aye Meyer. 2013b. "In-Situ Catalytic Fast Pyrolysis Technology Pathway." NREL and PNNL, March 2013. http://www.nrel.gov/docs/fy13osti/58056.pdf; Biddy, Mary, Abhijit Dutta, Susanne Jones, and Aye Meyer. 2013. Ex-Situ Catalytic Fast Pyrolysis Technology Pathway. NREL and PNNL, March 2013. http://www.nrel.gov/docs/fy13osti/58050.pdf.

can help determine the best option for the specific need. These factors include infrastructure and vehicle compatibility, energy content, safety characteristics, process conversion technology and efficiency. A measuring factor of conversion efficiency is the yield measured as the energy content of the fuel per dry tonne feedstock. Table 6 includes a comparison of yields. As discussed in Chapter 3, California has approximately 16 million tons of woody biomass. Column 4 of Table 29 shows the potential barrels of ethanol equivalent that these resources could be converted to.

Table 29: Yields of Biofuels Technologies and California Production Potential

	Gallons Gasoline Equivalent Product/Dry Ton Woody Biomass[250]	Gigajoule/Dry Ton Woody Biomass[250]	Annual Potential California Production (Mgge)	Revised Annual Potential California Production (Mgge)*
Feed – Wood	---	16.9		
Methanol	74.4	9.3	1,190.7	870.7
DME	68.6	8.5	1,097.3	802.4
Fischer-Tropsch Liquids (Diesel/Jet Fuel Substitute)	49.6	6.2	793.8	580.5
Thermochemical Ethanol	59.1	7.4	945.6	691.4
Biochemical Ethanol**	57.6	7.2	922.2	674.4
Methanol-to-Gasoline	54.7	6.8	875.5	640.2
Pyrolytic Fuel-Oil	83.2	10.4	1,330.8	973.2

***Not counting resources currently used for electricity generation (11.7 million dry tons)**

****A decrease in yields is expected for a feedstock of woody biomass**

Source: NREL

We interviewed Richard Bain, Principal Researcher at NREL on important challenges for California in large-scale production of biofuels from woody biomass. Bain feels the consequences of extraction of woody biomass feedstock from its current applications are an important consideration. In California, the primary utilization of woody biomass is for electricity

[250] Augustine, Chad, Richard Bain, Jamie Chapman, Paul Denholm, Easan Drury, Douglas G. Hall, Eric Lantz, et al. 2012. "Renewable Electricity Futures Study Volume 2: Renewable Electricity Generation and Storage Technologies". NREL. http://www.nrel.gov/docs/fy12osti/52409-2.pdf.

generation. In California 4.3 million short tons of woody biomass were consumed in order to produce 3.6 million MWh electricity in 2012.[238] By U.S. EIA's definition the woody biomass feedstock includes wood and wood waste, such as paper pellets, railroad ties, utility poles, wood chips, bark and wood waste solids. Table 29 shows California potential fuel production not accounting for the feedstock currently utilized for electricity consumption.

GLOSSARY

AMERICAN SOCIETY FOR TESTING AND MATERIALS (ASTM)—An international standards organization that develops and publishes voluntary consensus technical standards for a wide range of materials, products, systems, and services.

AMMONIA (NH3)—A pungent colorless gaseous compound of nitrogen and hydrogen that is very soluble in water and can easily be condensed into a liquid by cold and pressure. Ammonia reacts with NOx to form ammonium nitrate -- a major PM2.5 component in the western United States.

ANAEROBIC DIGESTION (AD)—The process through which bacteria break down organic matter—such as manure—without oxygen. As the bacteria "work," they generate biogas. The biogas that is generated is made mostly of methane, the primary component of natural gas. The non-methane components of the biogas are removed so the methane can be used as an energy source.[251]

BONE DRY TON (BDT)—Two thousand pounds of woody material at 0 percent moisture content.

BRITISH THERMAL UNIT (Btu)—The standard measure of heat energy. It takes one Btu to raise the temperature of one pound of water by one degree Fahrenheit at sea level. MMBtu stands for one million Btu.

CALIFORNIA AIR RESOURCES BOARD (CARB)— The state's lead air quality agency consisting of an 11-member board appointed by the Governor, and just over thousand employees. CARB is responsible for attainment and maintenance of the state and federal air quality standards, California climate change programs, and is fully responsible for motor vehicle pollution control. It oversees county and regional air pollution management programs.

CALIFORNIA ENERGY COMMISSION (CEC)—The state agency established by the Warren-Alquist State Energy Resources Conservation and Development Act in 1974 (Public Resources Code, Sections 25000 et seq.) responsible for energy policy. The CEC's five major areas of responsibilities are:

1. Forecasting future statewide energy needs.
2. Licensing power plants sufficient to meet those needs.
3. Promoting energy conservation and efficiency measures.
4. Developing renewable and alternative energy resources, including providing assistance to develop clean transportation fuels.
5. Planning for and directing state response to energy emergencies.

Funding for the CEC's activities comes from the Energy Resources Program Account, Federal Petroleum Violation Escrow Account, and other sources.

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[251] Anaerobic Digestion- U.S. EPA https://www.epa.gov/agstar/how-does-anaerobic-digestion-work#:~:text=Anaerobic%20digestion%20is%20a%20process,primary%20component%20of%20natural%20gas

CARBON DIOXIDE (CO_2)—A colorless, odorless, nonpoisonous gas that is a normal part of the air. Carbon dioxide is exhaled by humans and animals and is absorbed by green growing things and by the sea. CO_2 is the greenhouse gas whose concentration is being most affected directly by human activities. CO_2 also serves as the reference to compare all other greenhouse gases (see carbon dioxide equivalent).

COMPRESSED NATURAL GAS (CNG)—Natural gas that has been compressed under high pressure, typically between 2,000 and 3,600 pounds per square inch, held in a container. The gas expands when released for use as a fuel.

CUBIC FOOT (CF)—The most common unit of measurement of natural gas volume. It equals the amount of gas required to fill a volume of one cubic foot under stated conditions of temperature, pressure and water vapor. One cubic foot of natural gas has an energy content of approximately 1,000 Btus. One hundred cubic feet equals one therm ($100\ ft^3 = 1$ therm).

DIMETHYL ETHER (DME)—Dimethyl ether is a synthetically produced alternative to diesel for use in specially designed compression ignition diesel engines. Under normal atmospheric conditions, DME is a colorless gas. It is used extensively in the chemical industry and as an aerosol propellant. Dimethyl ether requires about 75 pounds per square inch of pressure to be in liquid form. Because of this, DME's handling requirements are similar to those of propane—both must be kept in pressurized storage tanks at an ambient temperature.[252]

E85—E85 motor fuel is defined as an alternative fuel that is a blend of ethanol and hydrocarbon, of which the ethanol portion is 75-85% denatured fuel ethanol by volume and complies with the most current American Society of Testing and Measurements specification D5798.

UNITED STATES ENERGY INFORMATION ADMINISTRATION (U.S. EIA)—An independent agency within the U.S. Department of Energy that develops surveys, collects energy data, and does analytical and modeling analyses of energy issues. The Agency must satisfy the requests of Congress, other elements within the Department of Energy, Federal Energy Regulatory Commission, the Executive Branch, its own independent needs, and assist the general public, or other interest groups, without taking a policy position.

GASOLINE GALLON EQUIVALENT (GGE)—The amount of alternative fuel it takes to equal the energy content of one liquid gallon of gasoline. GGE allows consumers to compare the energy content of competing fuels against a commonly known fuel—gasoline. GGE also compares gasoline to fuels sold as a gas (natural gas, propane, and hydrogen) and electricity.

GREENHOUSE GAS (GHG)—Any gas that absorbs infrared radiation in the atmosphere. Greenhouse gases include water vapor, carbon dioxide (CO_2), methane (CH_4), nitrous oxide (NO_x), halogenated fluorocarbons (HCFCs), ozone (O_3), per fluorinated carbons (PFCs), and hydrofluorocarbons (HFCs).

HYDROGEN (H_2)—A colorless, odorless, highly flammable gas, the chemical element of atomic number 1.

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[252] DME Definition- U.S. DOE https://afdc.energy.gov/fuels/emerging_dme.html

HYDROGEN SULFIDE (H_2S)—A highly flammable, explosive gas. H_2S burns and produces other toxic vapors and gases, such as sulfur dioxide.

KILOGRAM (kg)—The base unit of mass in the International System of Units that is equal to the mass of a prototype agreed upon by international convention and that is nearly equal to the mass of 1,000 cubic centimeters of water at the temperature of its maximum density.

LIFECYCLE ANALYSIS (LCA)—A tool that can be used to evaluate the potential environmental impacts of a product, material, process, or activity. An LCA is a comprehensive method for assessing a range of environmental impacts across the full life cycle of a product system, from materials acquisition to manufacturing, use, and final disposition.

LIQUEFIED NATURAL GAS (LNG)—Natural gas that has been condensed to a liquid, typically by cryogenically cooling the gas to minus 260 degrees Fahrenheit (below zero).

LOW CARBON FUEL STANDARD (LCFS)—A set of standards designed to encourage the use of cleaner low-carbon fuels in California, encourage the production of those fuels, and therefore reduce greenhouse gas emissions. The LCFS standards are expressed in terms of the carbon intensity of gasoline and diesel fuel and their respective substitutes. The LCFS is a key part of a comprehensive set of programs in California that aim cut greenhouse gas emissions and other smog-forming and toxic air pollutants by improving vehicle technology, reducing fuel consumption, and increasing transportation mobility options.

MEGAJOULE (MJ)—A joule is a unit of work or energy equal to the amount of work done when the point of application of force of one newton is displaced one meter in the direction of the force. It takes 1,055 joules to equal a British thermal unit. It takes about one million joules to make a pot of coffee. A megajoule itself totals one million joules.

MEGAWATT (MW)–A unit of energy equal to one-million watts

METHANE (CH_4)—A light hydrocarbon that is the main component of natural gas and marsh gas. It is the product of the anaerobic decomposition of organic matter and enteric fermentation in animals, and is one of the greenhouse gases.

METRIC TON (MT)—A unit of mass equal to 1,000 kilograms.

NATIONAL RENEWABLE ENERGY LABORATORY (NREL)—The United States' primary laboratory for renewable energy and energy efficiency research and development. NREL is the only Federal laboratory dedicated to the research, development, commercialization, and deployment of renewable energy and energy efficiency technologies. Located in Golden, Colorado.

NATURAL GAS VEHICLE (NGV)—An alternative fuel vehicle that uses compressed natural gas (CNG) or liquefied natural gas (LNG).

NITROGEN (N, N_2)—An essential element of life and a part of all plant and animal proteins. Nitrogen is commercially recovered from the air as ammonia, which is produced by combining nitrogen in the atmosphere with hydrogen from natural gas.[91]

NITROGEN OXIDES (OXIDES OF NITROGEN, NO_x)—A general term pertaining to compounds of nitric oxide (NO), nitrogen dioxide (NO_2), and other oxides of nitrogen. Nitrogen oxides are typically created during combustion processes and are major contributors to smog formation and acid deposition. NO2 is a criteria air pollutant and may result in numerous adverse health effects.

POUNDS PER SQUARE INCH ABSOLUTE (PSIA)—Used to make it clear that the pressure is relative to a vacuum rather than the ambient atmospheric pressure.[96]

RENEWABLE FUEL STANDARD (RFS)– National policy that requires a certain volume of renewable fuel to replace or reduce the quantity of petroleum-based transportation fuel, heating oil or jet fuel.[253]

RENEWABLE IDENTIFICATION NUMBER (RIN)—The credits used for compliance, and the "currency" of the Renewable Fuel Standard program.[254]

RENEWABLE NATURAL GAS (RNG)—Or biomethane, is a pipeline-quality gas that is fully interchangeable with conventional gas and thus can be used in natural gas vehicles. RNG is essentially biogas (the gaseous product of the decomposition of organic matter) that has been processed to purity standards. Like conventional natural gas, RNG can be used as a transportation fuel in the form of compressed natural gas (CNG) or liquefied natural gas (LNG).

STANDARD CUBIC FEET PER MINUTE (SCFM)—The molar flow rate of a gas corrected to standardized conditions of temperature and pressure, thus representing a fixed number of moles of gas regardless of composition and actual flow conditions.

UNITED STATES ENERGY INFORMATION ADMINISTRATION (U.S. EIA)—An independent agency within the U.S. Department of Energy that develops surveys, collects energy data, and does analytical and modeling analyses of energy issues. The Agency must satisfy the requests of Congress, other elements within the Department of Energy, Federal Energy Regulatory Commission, the Executive Branch, its own independent needs, and assist the general public, or other interest groups, without taking a policy position.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY (U.S. EPA)—A federal agency created in 1970 to permit coordinated governmental action for protection of the environment by systematic abatement and control of pollution through integration or research, monitoring, standards setting, and enforcement activities.

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[253] Renewable Fuel Standards Program U.S. EPA (https://www.epa.gov/renewable-fuel-standard-program/overview-renewable-fuel-standard)

[254] Renewable Identification Number- U.S. EPA https://www.epa.gov/renewable-fuel-standard-program/renewable-identification-numbers-rins-under-renewable-fuel-standard

Appendix A: Biofuels Companies

There are approximately 165 active advanced biofuels companies, including 91 biodiesel companies already in commercial production and 74 companies working to produce other types of advanced biofuels.[255] In addition, there are about 80 companies contributing to the supply chain by providing feedstock, technology, and infrastructure.

Several biofuels companies have received federal and public funding, totaling approximately $1.77 billion since 2008. Table A-1 shows the federal loan and grant sums by agency.

Table A-1: Federal Loan and Grants by Agency

Agency	Million Dollars
U.S. DOE	730
United States Department of Agriculture	967
Other Agencies*	73

*Including CEC, Federal Aviation Agency and others

Source: NRE

[255] Solecki, Mary, Anisa Dougherty, and Bob Epstein. 2012. "Advanced Biofuel Market Report 2012". San Francisco, CA: Environmental Entrepreneurs. https://e2.org/wp-content/uploads/2016/01/E2AdvancedBiofuelMarketReport2012.pdf