Western Governors' Association

Transportation Fuels for the Future

Biofuels: Part I

WGA Biofuels Team
Ethanol, Biobutanol and Biomethane
January 8, 2008
Final Report

The following report is based on the contributions of the individuals and organizations listed below. The Team members were chosen for their breadth of knowledge and industry or policy experience. The group was assembled with the goal of having a wide scope of interests including industry, academia and environmental analysis. The group also worked towards consensus viewpoints on the critical issues impacting the development of Biofuels. This consensus model helped to achieve a balanced perspective on the challenges and potential solutions to further commercial development of this alternative transportation fuel.

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EXECUTIVE SUMMARY

Biofuels offer substantial benefits to Western states and the country in reducing our dependence on imported oil. They also offer potential for improved environmental protection and economic growth. Biofuels include but are not limited to ethanol and ethanol blend fuels; biobutanol; biodiesel, renewable diesel, and diesel blends; and biomethane and biomethane blends. Biodiesel and renewable diesel are addressed in a separate report.

Starch-based biofuels are produced from agricultural products, primarily corn. With commercialization of cellulosic ethanol an option in the future, the potential feedstock sources can be expanded to include agricultural residues, dedicated energy crops, and forest resources. Biomethane can be produced today from municipal waste.

The processing technology for starch-based ethanol has been proven effective and industry continues to reduce operating costs and resource requirements. Cellulosic ethanol and biobutanol have not reached economically viable commercialization. However, significant public and private sector investments make these technologies promising in the three- to ten-year timeframe.

A number of challenges exist for expanding biofuel production and consumption in the West. First, the U.S. is approaching the maximum threshold for use of starch-based feedstocks, beyond which there likely will be impacts to U.S. and foreign food supplies. Second, technologies for cellulosic ethanol and biobutanol are not commercially ready. Third, agricultural unknowns and risks exist for producing feedstocks for cellulosic ethanol. Production will need to address not only technical and financial considerations, but also environmental impacts to the global climate, water, and land use. In the West, where water is such a significant issue, water availability for feedstock production and biofuel processing becomes a critical consideration.

While these challenges are significant, they can be addressed through coordinated research, demonstration, and deployment actions carried out within states, regionally, and nationally.

KEY RECOMMENDATIONS

Research, Demonstration and Technology Transfer

- Advocate for full funding of the Department of Energy's research and demonstration activities, including its genomic work aimed at achieving dramatic changes in how ethanol and other biofuels are produced.
- Advocate for full funding of USDA's Biomass Research and Development Program at its authorized level. Funding to allow this program's complementary focus on feedstock collection and other agricultural issues is essential, or it will become a weak link in the national effort to move toward cellulosic-derived fuels and other biofuels.
- Complement Federally sponsored research with state efforts in delivering appropriate feedstock production and residue removal**.** Potential resource inventories need to be expanded and evaluated in terms of agricultural science.
- Structured federal incentives in a manner that provides additional per-gallon amounts for cellulosic biofuels, based on the energy efficiency of the production process (including feedstock production), environmental impacts including water and land use, and the resulting carbon emissions.

Cellulosic and Other Biofuels Feedstock Supply

- Provide government assistance to implement short- and medium-term burden sharing for producers. This can be done, at least in part, through a competitive program to pay farmers (or farm cooperatives or communities) to plant bioenergy crops. Also, consideration can be given to gross receipt tax elimination.
- Expand technical assistance from the Natural Resources Conservation Service and the cooperative extension services.
- Make funds available to cost-share purchases of new bioenergy harvesting machinery.
- Establish a low-carbon renewable fuels loan guarantee program.

Increasing the Demand for Biofuels

- Expand immediately the RFS, commensurate with market capacity, to create a floor under current and planned production achievements.
- Determine market infrastructure needs for distributing biofuels and expand the market capacity to maximize current and projected future consumption patterns.
- Consider the monetization of the cellulosic ethanol trading credit contained in the current RFS.
- Promote procurement of flex-fuel vehicles in the federal, state, and municipal governments, as well as other renewable fuels, and ensure the availability of E85 and other renewable fuels' fueling facilities as long as the net result is reduced fossil fuel consumption.
- Federal and state agencies help establish income streams with long-term cellulosic ethanol supply contracts for federal and state purchases.
- Support research into the compatibility of emerging biofuels, such as biobutanol, with vehicles and distribution infrastructure.

- Consider state adoption of a low-carbon fuel standard similar to that adopted by California, which is 10-percent reduction in the carbon intensity of transportation fuels by 2020.[1]

Innovative Approaches Renewable Fuels Infrastructure

- Adopt a new city-to-region approach to solve the infrastructure challenge by funding a high-profile competition providing funds to three metropolitan areas.
- Encourage the DOE to fund a high-profile competition providing funds to three metropolitan areas.
- Establish goals in states for increasing E85 infrastructure and support those goals with tax incentives.
- Adopt incentives for retailers to sell E85.
- Establish grants for renewable fuel infrastructure corridors in the West that serve all of the renewable and advanced biofuels.

Funding Alternative Fuel Actions

- Consider a $ .01/gallon "sustainable energy transition fee" to invest in alternative fuels.

[1] A Low-Carbon Fuel Standard for California Part I – Technical Analysis, Final Report, University of California

Introduction

"The fuel of the future is going to come from apples, weeds, sawdust--almost anything" Henry Ford told the New York Times.[2] Indeed, the fuel used in Ford's cars was ethyl alcohol-ethanol.

There is widespread recognition of the challenges facing the nation in the transportation sector. There is also a growing understanding of the role that biofuels can play when paired with greater fuel efficiency and use of a greater range of fuels. Creating a vision of how Western states can contribute to expanded production and use of biofuels in a way that ensures economic and environmental benefits is essential to the future of our states and the nation.

For this report, "biofuels" include but are not limited to ethanol and ethanol blend fuels; biobutanol; biodiesel, renewable diesel, and diesel blends; and biomethane or biomethane blends.[3] Biodiesel and renewable diesel are addressed in a separate report.

The benefits of biofuels are tremendous, particularly as we look for opportunities to diversify feedstocks and technologies in ways that result in less water use and fewer energy inputs in the production of fuel. Moreover, the economic potential of producing our own renewable transportation fuel, rather than importing it, grows each year in terms of both the investment dollars that remain in our states and the diminished impact of future oil supply disruptions on the lives of our citizens.

The West can deliver substantially greater quantities of biofuels in the coming decade. Biofuel production and use in the West offer great opportunities, and we should move aggressively to take advantage of them. However, we must move forward with the understanding that no energy source is without trade-offs and no single energy solution will alleviate the national security and economic circumstances facing us because of our dependency on imported oil. The biofuels answer to this challenge will likely be found in an approach that relies on regional work to elevate priority state and federal policies. These crucial policies will need to be supported by coordinated research, demonstration, and deployment actions carried out with our federal and industry partners.

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[2] (Bill Kovarik, "Henry Ford, Charles Kettering and the Fuel of the Future," *Automotive History Review, Spring 1998, No. 32, pp. 7-27, www.radford.edu/~wkovarik/papers/fuel.html.*

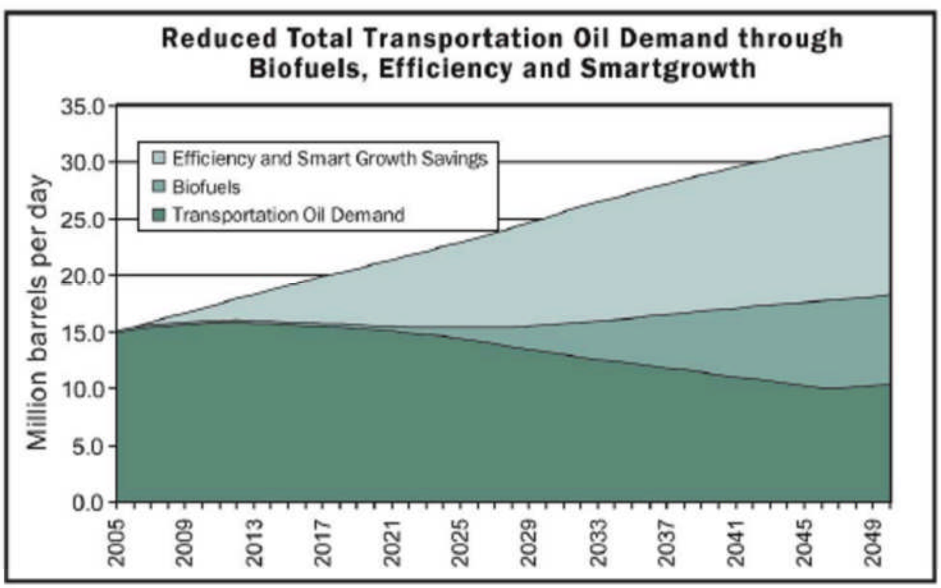
[3] *The following definitions comport with the definitions of 'biofuels' in The* Renewable Fuels, Consumer Protection, and Energy Efficiency Act of 2007, *HR 6, as Amended by the Senate. `Conventional biofuel' means ethanol derived from cornstarch. `Advanced biofuel' means fuel derived from renewable biomass other than corn starch and includes cellulosic biomass ethanol; ethanol derived from sugar or starch other than corn starch, waste material, including crop residue, other vegetative waste material, animal waste, and food waste and yard waste; other diesel-equivalent fuel derived from renewable biomass, including vegetable oil and animal fat; biogas (including landfill gas and sewage waste treatment gas) produced through the conversion of organic matter from renewable biomass; butanol or other alcohols produced through the conversion of organic matter from renewable biomass; or other fuel derived from cellulosic biomass.*

Potential

Starch-based ethanol is typically made by fermenting the sugar components of grains, such as corn and grain sorghum. In 2006, production of starch-based ethanol reached nearly 5.02 billion gallons, with corn used as the primary feedstock. Starch-based ethanol is a market commodity supplied as a 10 percent blend of ethanol in gasoline or as E85, a mixture of 85 percent ethanol and 15 percent gasoline. Ethanol can also be produced from cellulosic materials. Cellulose is the main component of a plant cell wall and is the most common organic compound on earth. Cellulosic materials include wood and wood products, such as paper and cardboard; crops grown for energy use; agricultural residues, such as rice straw and corn stover; animal wastes, such as manures; and sewage from water treatment plants. These resources are distributed throughout the country in rural areas, thus provide an opportunity to diversify the U.S. energy production network while providing economic benefits to rural communities.

A recent report by the U.S. Departments of Energy and Agriculture found that land resources in the U.S. are capable of producing a sustainable supply of 1.3 billion tons per year of biomass, which would be sufficient to displace 30 percent or more of the country's present transportation fuel consumption. This 30 percent reduction in consumption is equivalent to 60 billion gallons of ethanol, on a BTU- equivalent basis with gasoline.

The following graph illustrates the role biofuels could play in reducing our oil use and demand.[4]



Source: *Bringing Biofuels to the Pump*, NRDC, July 2005

[4] *Bringing Biofuels to the Pump*, NRDC, July 2005, p. 2

While ethanol is currently the biofuel option receiving the most attention, it is important to recognize that it is not the only biofuel. Biobutanol, biodiesel and renewable diesel, and methanol from gasification are some examples of other biofuels. However, the state of development of these fuels does not approach the current level of ethanol development and production from corn. Ultimately, the market will select which biofuels will be produced and consumed, based on the technology, feedstocks, environmental, economic, and other goals. For now, it will take a focus on deploying all types of biofuels to make an appreciable difference in reducing the nation's dependence on imported petroleum fuels.

Supply Sources

Major Western Feedstocks

Agricultural Resources
Agricultural Crops (e.g., corn)
Agricultural Residues (e.g., orchard trimmings, straw)
Energy Crops (e.g., perennial grasses, perennial woody crops)
Animal Wastes (e.g., manure, biogas)
Food Processing Residues (e.g., hulls, shells)

Forest Resources
Logging residues from conventional harvest
Excess biomass (e.g., fuel treatments)
Mill residues

Municipal Waste
Solid waste organic material
Biogas from wastewater treatment
Sludge from wastewater treatment

Western feedstock opportunities for biomass conversion include agricultural crops; agricultural residues; non-food crops, such as sorghum and switch grass; other crops that can be grown for oil value, with the remaining cellulosic structure further processed into alcohol; manures from animal feedlots; forest and wood residues; municipal solid waste (MSW); and municipal sewage.

To have the nation significantly reduce its current and projected future gasoline requirements, feedstocks and/or conversion processes will have to expand beyond today's primarily starch-based ethanol. Many analysts consider the use of cellulosic materials the most promising path for long term sustainability, volume production and CO_2 reduction. WGA states have an excellent opportunity in the production of ethanol from cellulosic materials, and it is highly unlikely that the nation can meet the ambitious goals referred to in this report without the contributions of the West. Appendix I discussed biomass resources in the WGA region.

Agriculture Resources

Today's ethanol is primarily corn-based. The WGA states of Nebraska, Kansas, and South Dakota are national leaders in the production of starch-based ethanol, and in 2006 produced 1.3 billion gallons of the 5.02 billion gallons produced nationwide.[5,6] There is limited corn ethanol production in the other WGA states and, because of their need for irrigation, this is unlikely to change in the future. Studies indicate that the current sustainable production of corn for fuel in the U.S. may be no more than 15 billion gallons per year at most, and perhaps only 12-14 billion gallons .[7] Beyond that amount, the nation's food supply would be significantly impacted in the near term. This will change over time as the yield per acre of corn continues its multi-decade trend upward with evolving farming practices and seed

[5] http://www.ethanolproducer.com/article.jsp?article_id=2818
[6] http://www.ethanolmarket.com/PressReleaseEthanolMarket010107.html
[7] http://www.gao.gov/highlights/d07713high.pdf

genomics. New corn strains include varieties designed to yield more drought tolerance, more bushels per acre, and more ethanol per bushel.

The Federal *Billion Ton Report*[8] addresses the potential availability of biomass feedstock projected to approximately 2050. The report focuses on the primary resources of forest- and agriculture-derived biomass. These are the resources that are considered to have the greatest potential to supply large, sustainable quantities of biomass. The Sun Grant Initiative to establish Regional Feedstock Networks is examining how much of the Billion Ton estimate can be contributed by each region.[9] Additionally, the Natural Resources Defense Council's report, *Growing Energy: How Biofuels Can Help End America's Oil Dependence,* estimates that American farmers "could produce the equivalent of nearly 7.9 million barrels of oil per day by 2050." That amount is equal to more than 50 percent of our current total oil use in the transportation sector and more than three times as much as we import from the Persian Gulf alone."[10]

Potential Western agricultural crops include rice, wheat, corn, barley, sorghum, oat grain crops and sugar beets. While these are currently in food production, a shift to energy crops is possible. In some cases, being able to shift into energy markets can provide greater stability in farm prices.[11] In California, if these crops were shifted to ethanol production, it is estimated that they could supply approximately 360 million gallons of ethanol.[12] This dramatic a shift is unlikely, however; any shift will depend on market product value.

Perennial plants (trees and grasses) have high potential as dedicated energy crops. In some areas of the West, a variety of crops may be possible if there is a long growing season and high-quality soil.

It is unlikely that short-rotation woody crops, such as willow and poplar, will be available by 2015. Although the *Billion Ton Report* projects short-rotation woody crops to increase to 5 million acres with 25 percent of the woody crop for bioenergy, recent studies do not support this because analysts expect a higher value for these products. Rather, they suggest that the most likely scenario in the West is for short-rotation woody crops to supplement bioenergy feedstocks as a byproduct of pulpwood production.[13]

Appendix A shows feedstock potential in the West. All of these potential feedstocks need further investigation, including field trials. (See Recommendations, Cellulosic Biomass Supply, for a discussion of needed research.)

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[8] *Billion Ton Report*, DOE and USDA, April 2005

[9] The WGA states are covered by 3 Sun Grant Regions: North Central lead by South Dakota State University, Central lead by Oklahoma State University, and Western, lead by Oregon State University.

[10] *Growing Energy: How Biofuels Can Help End America's Oil Dependence,* by Nathanel Greene, NRDC, December 2004, pp. v-v11, www.nrdc.org/air/energy/biofules/contents.asp.

[11] *A Low-Carbon Fuel Standard for California, Part1: Technical Analysis, May 2007,* p. 83

[12] ibid

[13] Ince, Moiseyev. "Forestry implications of Agricultural SRWC in the US. In: Forest Policy for Private Forestry", Ch. 17. pp. 180-188

Agricultural and Municipal Waste Biogas Resources

The West is also rich in agricultural biogas feedstock from large dairy operations and farm wastes. Decomposing biological matter naturally gives off methane gas during the process of decomposition. This resulting methane biogas can be purified, and often liquefied, for easy use and transport to end-users typically as liquefied natural gas (LNG) or compressed natural gas (CNG) vehicle fuel. Landfills and wastewater treatment plants are plentiful in the West, particularly near large concentrated populations. All of these sources produce biogas either inherent in the process (as in landfills) or with the help of anaerobic digesters (as in wastewater treatment facilities). Washington, Oregon, and California flare the equivalent of one million gallons ofLNG at landfills every day.

Forest Resources

Once cellulosic ethanol processes become commercial, ethanol feedstocks will include lignocellulosic materials from forests. The main categories are:[14]

- Unused logging slash: Wood debris left after a timber harvest, including branches, chunks, bark, and stumps. Traditionally, logging slash has been left in the forest or piled and burned.
- Primary mill residues: Unmerchantable biomass generated by sawmills.
- Forest fuel treatment biomass: Biomass removed from forestland to mitigate fire hazard.

Forest fuel treatment biomass is a particularly strategic source of biomass in Western states. Major challenges include access to forest fuels, transportation costs, and processing. The U.S. Forest Service has estimated 23 million acres of timberland in 12 Western states are at high risk for stand-replacement fire. Thinning this acreage to reduce fire hazards could provide 318 million dry tons of wood, of which 7.2 million tons would be available for feedstock. (This estimate excludes higher value products. See the WGA Biomass Report for a discussion of the methodology. [15])

Siting of Facilities

Inventories of biomass resources for the West and analysis of feedstock locations compared to resource quantities and relevant transportation factors are underway. (Note: the USDA WGA Bioenergy Strategic Assessment project will provide a good start on this necessary analysis. The findings will be available in Fall, 2007.) The transportation factor is a primary determinant of the economic viability of a project, as cellulosic ethanol facilities require large amounts of

[14] *Biomass Task Force Report*, Clean and Diversified Energy Initiative, WGA, January 2006, p. 37
[15] Ibid

biomass feedstocks to be delivered on a daily basis. Often, feedstocks are located in rural areas and may be widely dispersed, but access to good roads or rail connections may be limited. The cost of securing the necessary amounts of wood waste or agricultural feedstocks may be prohibitively high due to transportation costs.

On the other hand, certain kinds of feedstocks, most notably municipal solid waste (MSW), may offer highly favorable economics. A conversion facility can be co-located with a landfill, and cellulosic materials separated from the waste stream. Feedstock transportation is eliminated by this approach. The ethanol resulting from the operation can be utilized by the local community, thus minimizing transportation of the finished product. The economics of MSW conversion can benefit significantly by capturing some, if not all, of the tipping fee, which is usually paid to the landfill authority for trash disposal.

Landfills and wastewater treatment plants are also ideal locations for biomethane production facilities to provide liquid natural gas or compressed natural gas as vehicle fuel for local fleets. Creating fuel as close to the end-user as possible—called "distributed fuel" production—promotes system-wide efficiencies, significantly reducing transportation costs, fuel loss, and additional pollution associated with transporting fuel long distances. Good examples of this distributed fuel model include trash haulers that deliver to landfills powered by the fuel they create and urban transit fleets that are converted from diesel to clean-burning LNG, which is made from the local landfill or wastewater treatment plant.

Anaerobic digestion of manure to biogas represents a mature technology to reduce both waste and fugitive emissions of methane by capturing the biogas for electricity generation, combined heat and power (CHP), or biomethane, which can be used as a vehicle fuel for local fleets.

Sustainable Feedstock Development

Some feedstock sources are more sustainable than others. Using forest residues does not require additional or alternative land use. Some amount of woody material removed in forest thinning operations should remain in the forest to supply animal habitat, reduce soil erosion, and maintain soil fertility. However, the West could provide significant amounts of woody materials from trees destroyed by bark beetles. This "beetle kills" need to be removed from the region's forests to reduce the risk and severity of wildfires. Wood waste, such as sawdust from a milling operation, may qualify as a highly appropriate feedstock, if no better use for it is offered. Animal manures can be used to some extent as fertilizing materials, but speedy removal of manures and conversion to biomethane vehicle fuel, syngas, and/or ethanol is necessary to avoid potential environmental problems. The West abounds with large dairy and cattle feedlot operations that are constantly producing waste materials, offering a sustainable supply of manure-based cellulosic material, the timely conversion of which should render multiple environmental and economic benefits.

Municipal solid waste and wastewater treatment biogas should qualify as an eminently sustainable feedstock, because they are produced in large quantities on a daily basis. The transportation factors involved are minimal, as is the amount of fossil fuel that might be used in moving and processing the MSW. In many instances, a slipstream of the biogas can be used to power the purification and liquefaction plants. Discussion should be encouraged as to which materials recovered from the waste stream would render better or higher use if recycled as products other than fuel. These materials should then be removed from the waste stream, leaving only those materials that would otherwise be landfilled.

Growing crops for ethanol can require large acreages converted to industrial agriculture. Potential impacts that need to be addressed include native plant and animal habitats, loss of valuable carbon sinks by removing native trees, and possible addition of large amounts of fertilizers and pesticides that can affect groundwater and public health. Removal of excessive amounts of biomass residue from soils can aversely affect soil health and fertility.

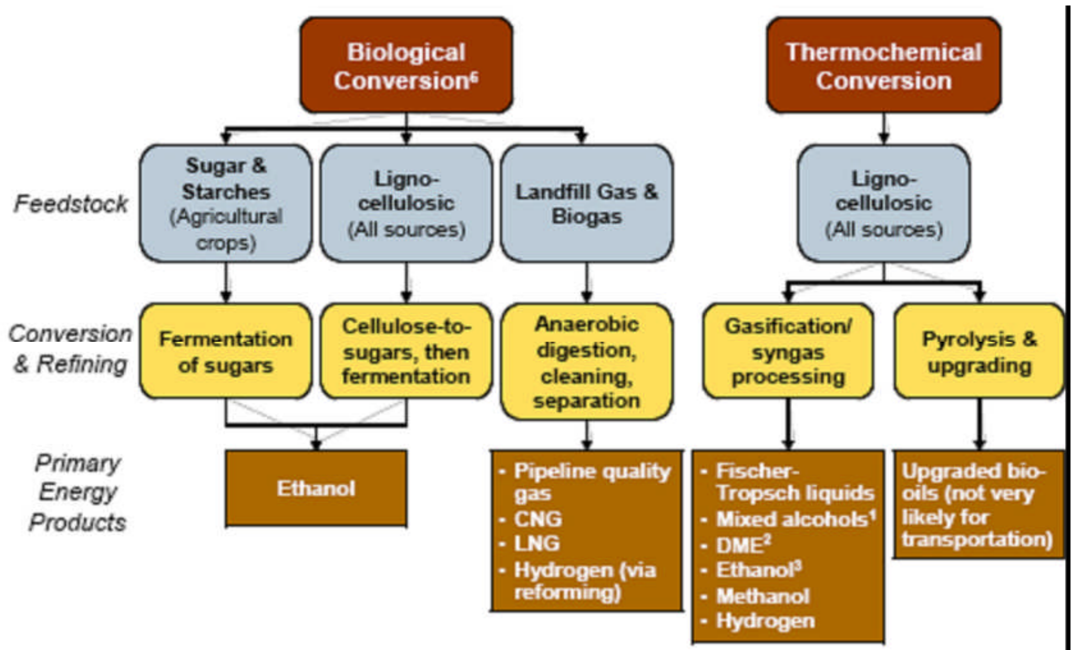
Technology

Cellulosic ethanol can be produced by biochemical or thermochemical conversion. In biochemical conversion, the feedstock is pretreated to prepare the cellulosic material for enzymatic digestion or acid hydrolysis. A typical pretreatment process uses steam and chemicals to disrupt the biomass surface and expose the cellulose to the cellulase enzymes. The cellulase enzymes break down the cellulose into sugars. A fermentation stage then converts the sugars to ethanol using microbes. The ethanol is then separated from the mix of ethanol, water, microbes, and residue and purified through distillation. Enzyme companies have led successful research projects with the U.S. Department of Energy to reduce costs and increase the efficiency of operations. The combined process of pretreated biomass and the enzymatic hydrolysis of biomass is one of the highest capital costs for the bioethanol process. While critical strides have been achieved in reducing the cost of enzymes, other hurdles remain, including feedstock cost, advances in bioprocessing technology, and developing robust microorganisms to ferment these biomass sugars.

Thermochemical conversion is often referred to as gasification. With this process, fibrous or mixed feedstocks are heated in a constrained-oxygen or anaerobic (without oxygen) environment to yield a mixture of carbon monoxide (CO) and hydrogen (H_2) gases and char. This resulting mixture of gases is called “syngas.” The syngas can be processed using a high-pressure catalytic technology to produce a variety of alcohols, such as ethanol, butanol, and methanol or converted to distillates in the Fischer Tropsch process. A key advantage of the gasification technology is its ability to utilize a wide range of carbon and hydrocarbon feedstocks, either alone or in combination. Much research and development has taken place

over the past several years by private companies, universities, and the National Renewable Energy Laboratory (NREL) to advance this technology, but no commercial systems have yet been built and successfully operated in the U.S.

The following schematic is a summary of biofuel conversion pathways:[16]



To produce LNG from biogas, it must be compressed, purified, and cooled. The conversion of landfill gas, which has significant impurities in the feedstock and requires a robust purification and liquefaction system, can include pre-purification, bulk purification, liquefaction and post-purification, and refrigeration.

Numerous U.S. companies are working to develop cost-effective biochemical and thermo-chemical conversion of biomass to ethanol, as well as several other biofuel production methods like production of biomethane from waste. Most are confronting the common problem of limited sources of investment capital comfortable with high-risk levels. This severely restricts the developer's ability to develop, refine, and market the technology. Appendix B describes representative conversion technologies.

Likely Technology Progression

Thermochemical gasification systems are usually rated by the amount of feedstock they consume each day. A minimum commercial size might be approximately 550 dry tons per day

[16] *Recommendations for a Bioenergy Action Plan for California, February 2006*, p. 17

(estimate for Fischer Tropsch gasification process.) A 550 ton-per-day gasifier could produce about 10 million gallons of Fischer Tropsch liquids (i.e., middle distillates and naptha) annually, when mated with the appropriate back-end catalytic processor. A Fischer Tropsch facility of this size could cost about $250 million. In comparison, a "large" enzymatic cellulosic ethanol facility may produce about 60 million gallons per year and may cost $200 million or more. Such a facility is anticipated for the 2015 timeframe. This contrasts with a current state-of-the-art corn ethanol facility rated at 100 million gallons per year, which could cost approximately $150-$200 million. The high capital cost for cellulosic ethanol facilities presents a challenge to reduce costs and become increasingly competitive. However, the feedstock cost helps to lower the overall operating costs to make cellulosic ethanol facilities more competitive with corn ethanol. For a more detailed discussion, see Appendix C Conversion Technology Model Calculators.[17]

As commercial cellulosic ethanol production facilities take their place in the commercial market, it is likely that larger units will be built, but the output from such facilities will depend on the amount of locally available feedstocks. A possible deployment scenario is a cellulosic industry that involves hundreds or thousands of distributed small facilities, rather than a more limited number of large centralized facilities. Such a future, however, will depend on the cost-effectiveness of small units.

Likewise, while the LNG and CNG fleets in the West are currently fueled from larger baseload liquefaction plants, of which more will be built, the distributed fuel model would look to utilize the numerous sources of waste and stranded methane to fuel local fleets. This will require the rapid deployment small, distributed purification and liquefaction facilities. Economies of production can be achieved by factory production of modular units. Once commercially proven in the West, this technological model will have applications throughout the U.S. and beyond.

Markets

Ethanol is fully compatible with any appropriately designed vehicle or product with a spark ignition internal combustion engine. Ethanol-gasoline blends containing up to 10 percent ethanol by volume are widely compatible with existing vehicles and products; blends containing up to 85 percent ethanol by volume can be used with flexible fuel vehicles, which are designed and certified for such use. In theory, ethanol could displace up to 85% of gasoline use in the U.S. if the refueling infrastructure, appropriately designed vehicles and products replace existing vehicles and products and sufficient feedstock and ethanol production capacity were to exist.   For the U.S. market, major automakers already produce about 30 models of flexible fuel vehicles (FFV), which can operate on E85; automakers produced about 700,000 FFVs in 2006, and almost five million FFVs are in the nation's fleet of 240 million vehicles

[17] Analysis prepared by Antares Group Inc. as part of USDA/DOE Bioenergy Grant for the Strategic Development of Bioenergy in the Western States.

today. Expanding the supporting infrastructure beyond the limited number of outlets would greatly help increase ethanol consumption.
In 2006, corn-based ethanol facilities in the U.S. had the potential to generate about 5.02 billion gallons annually, and new capacity is under construction that would add another 6 to 12 billion gallons. Twelve to fourteen billion gallons is pushing the limit of U.S. corn-based ethanol capacity. Additional increase will need to come from cellulosic sources. Current ethanol output is nearly sufficient to supply the 10 percent or E10 blend that is common in many cities and some states. If the U.S. market for ethanol is to be expanded, car manufacturers will need to offer consumers a wider and better choice of E85 flex-fuel vehicles. Also, the state and federal governments will need to provide financial incentives for refueling stations to install far more E85 pumps, because E85 requires different dispensing equipment. Currently, less than 1,500 exist, compared to approximately 180,000 service stations.

Because the present ethanol industry is founded on starch-based feedstocks, most ethanol production takes place in the Midwestern “grain belt.” However, as discussed above, the West has abundant cellulosic feedstocks and large fuel markets. It may be that cellulosic ethanol made in the West would complement or expand starch-based ethanol transported by rail from the Midwest. A flourishing Western cellulosic ethanol industry would be driven in part by the huge ethanol market of the West (especially California), which consumes over 589 million gallons of ethanol each year, much of which must travel by rail from the Midwest.[18]

Given general projections of 25 to 30 percent of present gasoline demand (140 billion gallons) that could be displaced by all domestic sources of ethanol, the market is then approximately 62 billion gallons of denatured ethanol per year. This leaves a shortfall of approximately 46 billion gallons that would need to be filled by cellulosic production facilities. This amount could represent an annual revenue stream of $115 billion per year at a wholesale price of $2.50 per gallon. The West could capture a major share of the ethanol market given a price-competitive cellulosic ethanol product.

The West also has strong market potential for biomethane. Currently, the market in the West for LNG or CNG is centered on fleet use, largely in Southern California and the Southwest due to the region’s air pollution issues and the clean-burning qualities of natural gas fuel. LNG sales in this region are about 180,000 gallons per day and are limited by fuel supply constraints, fueling infrastructure needs, and diesel vehicle conversions. As initial investment hurdles such as gas cleaning and compression are overcome, low feedstock costs of waste and stranded biogas, combined with reduced fuel transport costs based on the distributed fuel model of serving local fleets with locally produced fuel, will make for an attractive price of fuel compared to the rising cost of diesel. The demand for clean-burning biomethane is

[18] http://www.fhwa.dot.gov/policy/ohim/hs03/htm/mf33e.htm (2003 estimate)

growing in sectors such as ports and other areas of high pollution, and the market for sustainable and renewable sources of LNG is growing as citizens strive to reduce their carbon footprints. As more sources of local biomethane become available they can be mixed with current supplies of LNG/CNG to produce mixtures of “green fuel.”

Advantages and Disadvantages

Advantages

Biofuels can be produced from domestic renewable feedstock sources, can provide American farmers and other producers with a dependable revenue stream, are non-toxic and biodegradable, have lower air emissions than gasoline when burned as fuel, can reduce greenhouse gas emissions, and keep investment and purchasing dollars in the country for the benefit of the U.S. economy. Cellulosic ethanol and biomethane production also hold the promise of addressing an assortment of environmental problems, while producing a high-quality fuel. Distributed production of these fuels also helps move the U.S. toward energy independence and increased energy security.

Since ethanol production facilities are also small refineries, the ethanol that leaves the facility needs no further processing other than the appropriate blending with petroleum fuels. Likewise, the distributed fuel model for localized production of biomethane from waste relies on small biorefineries. A decentralized energy production and refining network can be more secure and distribute economic benefits of production more equitably than one that is highly centralized.

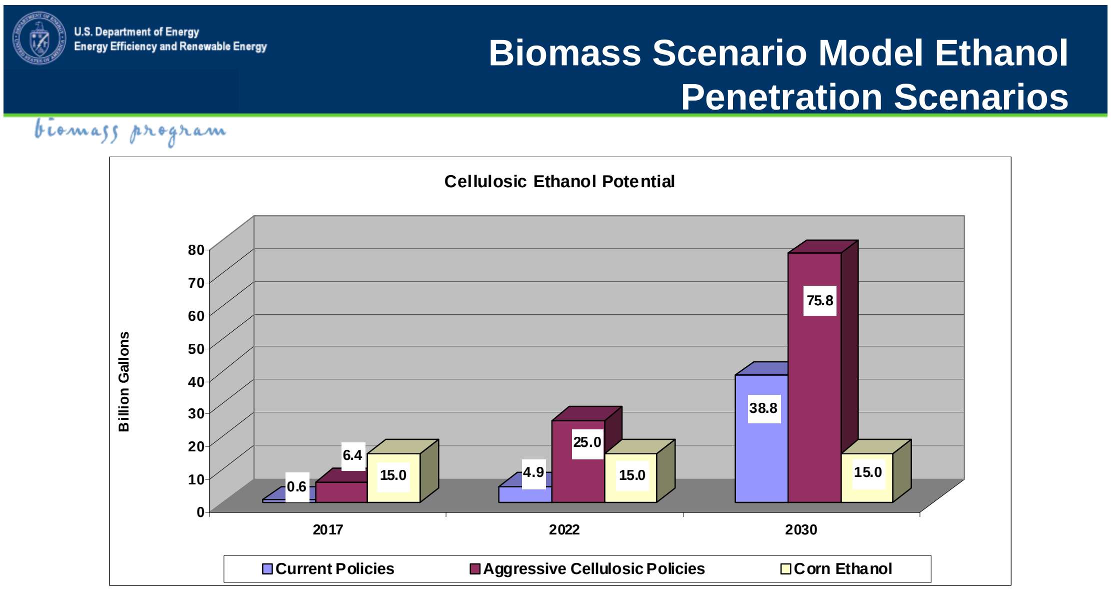
Disadvantages

Ethanol faces several disadvantages. It has a lower energy content compared to gasoline and higher blend levels of ethanol (e.g., greater than 10%) are not compatible with existing non-flex fuel vehicles, dispensers, and pipeline infrastructure. Starch-based ethanol faces limits on the amount that can be produced from corn without impacting food crop production and costs. Ethanol from cellulosic feedstocks is not likely to impact food crop production. The greatest disadvantage of cellulosic ethanol is that there currently is no commercial-scale production, although the technologies appear encouraging for the future, with some analysts estimating availability within three years.

Biobutanol is a promising product, because early research suggests it may be compatible with existing infrastructure and products: vehicles, dispensing equipment and pipeline distribution. Biobutanol has not been demonstrated to be economically viable at the commercial scale. However, significant private sector resources are being applied in an effort to achieve economic and environmental viability.

Oil and Gasoline Displaced

The plan called for in President Bush's 2007 State of the Union address would increase the supply of renewable and alternative fuels by setting a mandatory fuels standard, requiring 35 billion gallons of renewable and alternative fuels by 2017. This is nearly five times the 2012 target under current law. The DOE has established what it considers a realistic goal of 60 billion gallons by 2030. Ethanol thus represents a 20% reduction in gasoline demand by 2030.



Cellulosic ethanol's contribution will be minimal for the 2017 target…

…, Cellulosic ethanol's contribution will be the primary source in reaching and exceeding 60 billion gallons by 2030

The graph above[19] shows the timeline for the projection for corn and cellulosic ethanol production using the current policies and under aggressive cellulosic ethanol policies.

Synergies with Other Fuels

[19] NREL Biomass Program

Given that just about all transportation vehicles currently operate on liquid fuels, out of necessity, these fuels will continue to power our vehicles for the near term. Most experts limit the contribution of biofuels to 25 to 30 percent of current gasoline fuel demand. However, a new generation of vehicles is under development that will be capable of using non-liquid fuels, such as hydrogen or electricity. Ethanol can be used to make hydrogen for use in fuel-cell vehicles. Indeed, a gasifier generates syngas, of which hydrogen is a main component. Thus the same cellulosic facilities could be optimized for hydrogen production should it become a more valuable product than ethanol.

Likewise, plug-in biofuel-powered hybrid vehicles could further reduce our use of gasoline. If the backup engine is an E85 flex-fuel internal combustion engine that runs 25 percent of the time, it would supply 25 percent of the vehicle's fuel, and electricity would supply the remaining 75 percent. If biofuels can supply 25 percent of the current demand for fuel, then we have sufficient biomass to displace 100 percent of the petroleum used by the engine (85 percent in the case of E85), as long as electricity displaces the remaining petroleum portion.

Although algae is generally thought of as a biodiesel feedstock for its lipid content, the cellulosic material that remains following lipid extraction can be further processed to make ethanol. Algae is ideally suited as a Western biofuel feedstock, because large-scale algae farms require level, abundant open land, water (saline water can be used), sunshine and CO_2—all of which are plentiful in the West. (A more detailed discussion of algae is in the Biodiesel and Renewable Diesel Report.)

Synergies also exist between transportation fuel production and energy produced from other waste materials. These forms of energy are produced from communities' waste materials and include biogas, combined heat and power, and electricity. Turning local wastes into renewable energy would help reduce the amount of imported energy, produce jobs, and generate revenue. By combining waste inputs from a given community, more options for energy production can be achieved than simply focusing on one biofuel product or feedstock.

Barriers and Challenges

While many barriers and impediments have already been mentioned, this section summarizes the major challenges of key technologies in moving toward biofuel replacements for gasoline.

Technological Challenges

- There are many limitations to starch-based ethanol. As discussed above, producing more than 12-14 billion gallons a year would require an unacceptable use of cropland and would impact food supply, including food for cattle.
- While cellulosic ethanol offers improved energy use and lower CO2 emissions when compared to corn-based ethanol, the necessary technology has not been demonstrated at a commercial scale. This applies not only to agricultural-based feedstocks, but also to forest waste and municipal waste sources. Likewise, biobutanol offers advantages over ethanol, but it is not commercially viable today.
- Flex fuel vehicle technology holds much promise as a sensible and convenient means to transition from imported oil to domestically produced ethanol. U.S. carmakers have manufactured almost six million FFVs and have expressed a continued commitment to the technology. However, to fully harness the potential of E85, it needs to be as attractive as possible to consumers. Some ways to do this include: optimizing engines for the 105 octane content of E85, adopting policies to help E85 become more cost-competitive with gasoline, and increasing the availability of a more diverse range of FFVs. Notably lacking in the FFV lineup are fuel-efficient 4-cylinder vehicles.

Agricultural Challenges

- While corn production is extensive in the eastern part of the WGA region, it generally requires more irrigation in other parts of the West. Additional research and field trials are needed on alternative sugar and starch feedstocks, and this research needs to address land, soil, and water requirements. Likewise, additional information is needed on the sustainability of removing agricultural residues from croplands. New equipment may be necessary as well as considerations to year-round supply of feedstocks.
- Feedstock storage has associated issues, including fire risks and feasible storage duration and methods under the diverse conditions across the West.
- Larger-scale conversion systems will require larger-scale feedstock handling and delivery. As the quantity of feedstocks to be processed increases, there will be significantly increased truck traffic with impacts on local transportation systems. Alternatives such as increased rail use will have to be considered. There needs to be more research and development on the entire feedstock supply infrastructure.
- Use of crops for biomass feedstocks can affect global commodities, the "fuel versus food" issue. The displacement of food crops by fuel crops can cause economic impacts and land use changes elsewhere. For example, using more corn for ethanol in the U.S. and reducing corn exports can have impacts on importing nations.[20]

Infrastructure Challenges

[20] Turner, B.T, Plevin, R.J., O'Hare, M, Farrell, A. E., *Creating Markets for Green Biofuels*, 2007, p. 9

- Today ethanol is transported by truck and rail. However, when large-scale volumes (10-15 billion gallons/year) are produced, it will likely create bottlenecks in both the transportation system and the availability of transport vehicles. Dedicated ethanol pipelines and expanded rail are among the alternatives that need to be considered, and the planning should begin immediately for the widespread availability of E85 for use in flex fuel vehicles.
- Infrastructure and public awareness to support E85 is limited. There are less than 1,500 E85 stations in the U.S. currently, compared to 180,000 gas stations. Even when E85 fueling stations are available, many consumers may not realize they are driving a vehicle that can use E85.
- Some major service station brands prohibit the use of non-branded E85 fuel under their canopies. This is slowly changing, but major service station brands need to eliminate this prohibition.
- If a service station desires to add E85 to its fuel offerings, sufficient physical space for an additional dispenser and tank may not be available. A new canopy may need to be added, increasing the cost of biofuel conversion.

Financing/Economic Challenges

- While financing has been available for corn-based ethanol production in the recent past, obtaining venture capital for cellulosic ethanol has been challenging, especially for the stage between R&D and commercialization, the so-called "valley of death." This has been particularly problematic for gasification technologies.
- DOE has funded large-scale, "commercial-ready" projects through its Office of Biomass Programs, however government funding support for small- and medium-scale projects has been limited.

Regulatory Challenges

- Underwriters Laboratories (UL) has issued an outline of investigation for fueling equipment, which allows manufacturers to determine whether they will meet the UL guidelines. It is expected that there will be certified equipment available by June 2008.
- Permitting requirements for biofuels-conversion facilities are complex and lengthy.
- New blends of ethanol or new biofuels will have to meet various requirements for production and use promulgated by the U.S. Environmental Protection Agency (EPA) and/or by the states. The EPA has the authority to regulate biofuels for vehicle certification, fuel quality and registration, and biorefinery permitting. This challenge is also a benefit, however, because it will ensure new fuels are compatible with vehicles and will not increase emissions. This will enable manufacturer and market confidence in the new fuel. Interagency cooperation and advanced notification on new biofuels, biofuel applications, and biorefinery permitting will allow for timely deployment of biofuels.

Life Cycle Environmental and Societal Impacts

Life Cycle Assessments (LCA) are used to measure impacts of transportation fuels. The factors of greatest interest in the West are the total emissions of greenhouse gases and energy consumption tied to a particular fuel. (Note: Specific geographic areas may have additional concerns.) The analysis of a transportation fuel cycle, also known as a fuel cycle, is often reported in two distinct phases: well-to-tank (WTT) and tank-to-wheels (TTW). The well-to-tank phase includes resource extraction, feedstock production, refining, blending, transportation, and distribution. The tank-to-wheels phase includes refueling, along with consumption and evaporation of the fuel. The complete fuel cycle analysis is referred to as a well-to-wheels (WTW) analysis.

The following chart is the well-to-wheels LCA framework for biofuel technology from feedstock production, feedstock transportation, fuel production, fuel transport and blending, and vehicle operation.[21]

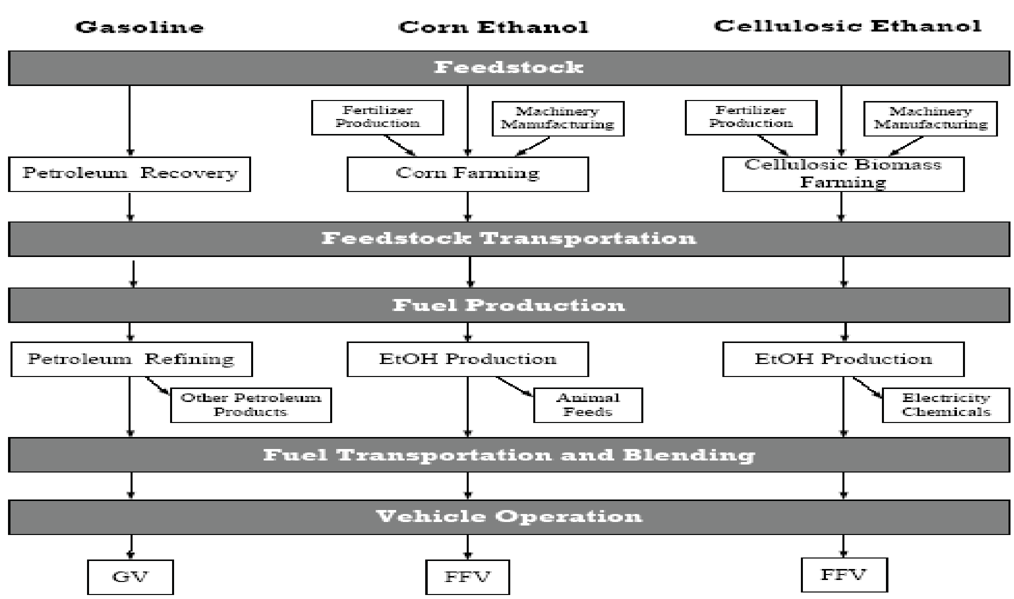
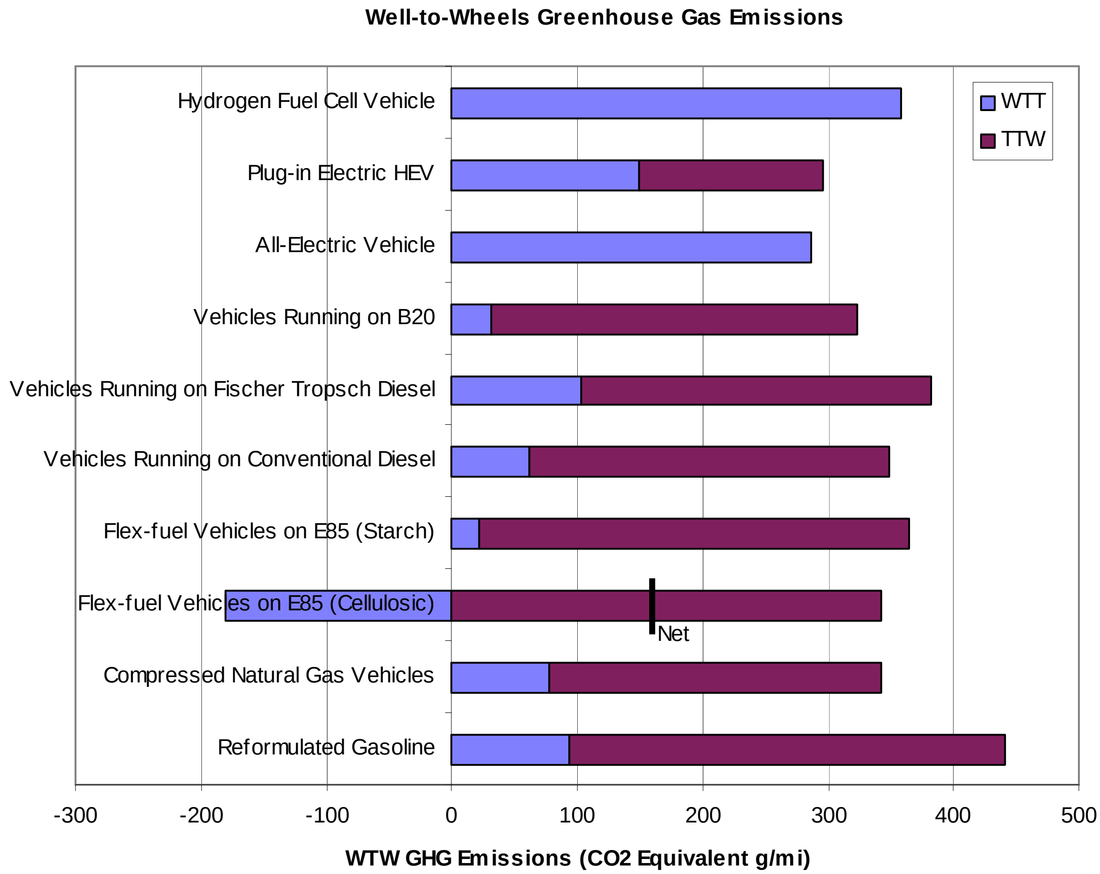


FIGURE 1 Schematic Representation of Well-to-Wheels Analysis System Boundaries for Biofuels and Petroleum Gasoline

GREET (*G*reenhouse gases, *R*egulated *E*missions, and *E*nergy use in *T*ransportation), is a model developed by the Argonne National Laboratories that simulates life-cycle energy use and emissions for various transportation fuels and vehicle technologies. Members of WGA's Transportation Fuels Teams are using GREET as the primary means of modeling side-by-side comparisons of energy efficiency and emissions analysis, although other variables are available in the model. The GREET model is the most publicly available and widely cited

[21] Wu, et. al., Fuel-Cycle Assessment of Selected Bioethanol Production Pathways in the U.S., ANL/ESD/06-7, Argonne National Laboratory. 2006

research tool for analysis of transportation fuel emissions and energy usage. However, there is no expert consensus on the best analytic tool, and Appendix D has an extended discussion on the assumptions and limitations of this model.



The graph above[22] serves as a visual description of total well-to-wheels GHG emissions from one of many potential alternative fuel pathways The axis bars represent the total fossil use of fuel pathways over the life cycle as measured in BTUs per mile. The energy usage is broken down into energy used during the well-to-tank and tank-to-wheels portion of the life cycle. In this instance, specific fuel pathways have been chosen such as compressed natural gas, conventional diesel, and E85 from corn feedstock. GREET has calculated the well-to-wheels green house gas emissions in CO2 equivalent grams per mile. While recent studies in Northern Europe have shown significant well-to-wheels emission reductions of biomethane over diesel and other fuels, a GREET assessment is needed as part of the evaluation process of this fuel option.

[22] Results from a default run of the GREET Model, Argonne National Laboratory

Well-To-Wheels Fossil Energy Use

It requires a significant amount of energy to produce finished fuels, whether they are made from petroleum or from renewable resources. An important metric for assessing the sustainability or renewable nature of a fuel produced from renewable resources is the net energy balance (NEB). This is obtained from a life cycle analysis that sums all of the fossil energy inputs used to produce the fuel and compares that to the amount of energy available in the final fuel product. Several LCAs have been completed for biofuels utilizing corn grain, corn stover, and forest residues as feedstocks. These studies address supply of the feedstock and associated environmental impacts. Most studies account for energy used in crop production agriculture (planting, harvesting, fertilizer production, etc.); transportation of the feedstock; conversion to a biofuel; and other associated energy inputs.

The NEB is usually expressed as the fossil energy ratio (FER):

$$\textbf{Fossil Energy Ratio (FER)} = \frac{\textbf{Energy Delivered to Customer}}{\textbf{Fossil Energy Used}}$$

Overall, the LCA studies that have been conducted find biofuels' FER to be significantly greater than 1, indicating that production of biofuel is a truly renewable and sustainable activity from an energy standpoint. Removal of crop and forest residues does impact soil and water quality, and the LCA studies recommend that local and regional analyses need to be completed to assess the various types of feedstock that can be used in making biofuels. The table below lists the results of the GREET analyses.

Feedstock	BTU Fossil Energy	FER
Gasoline	1.22	0.82
Corn grain	0.76	1.32
Wood residue	0.16	6.25
Corn stover	0.09	11.11*

*Value depends upon assumptions, including amount of fossil energy used to grow the corn crop and how this is allocated to corn grain and corn stover.

The corn grain LCA primarily addressed the energy balance of converting grain to ethanol using current cropland production data and conversion technology.[23]

Processing energy for ethanol comes principally from natural gas, but approximately 20 percent comes from coal.[24] Depending on how much fossil fuel is used in the production of ethanol, combusting a gallon of ethanol can result in a significant reduction in CO_2, compared to combusting a gallon of gasoline. Ethanol production from coal-fired ethanol facilities exceeds net greenhouse gas emissions (GHG) from gasoline, but ethanol production using natural gas yields a small reduction in GHG emissions. Direct use of wet distiller grains further avoids emissions from dryers, although emissions can contribute to volatile

[23] Shapouri, et al., *The Energy Balance of Corn Ethanol, USDA*, 2002

[24] EPA 2007 in *A Low Carbon Fuel Standard for California*, p. 80

organic compounds. Ethanol production using energy from biomass, such as crop residues, biogas and landfill gas, reduces GHG further.

Cellulosic ethanol production LCAs have focused on corn stover as the feedstock because of its large availability across the U.S. These studies have addressed the energy balance of converting cellulose to a fuel and the additional environmental impacts due to the removal of the stover from agriculture lands. They highlight the importance of local and regional modeling studies addressing sustainability of the soil resource in relation to soil-carbon and soil-erosion impacts.[25]   Studies on impacts to soil and water quality have been limited and require further work to address changes in nutrient cycling and associated impacts to water supplies.[26] The use of herbaceous energy crops (grasses) and forest residues continues to be studied using LCA tools. Local and state governments could be impacted due to changes in the types of crops being grown, new crops and associated land values.

GREET does not address environmental impacts associated with land and water resources. Therefore, additional tools are required to assess the overall sustainability of the feedstock production system.

Water Considerations in Biofuel Development

Water is used in growing feedstocks and in biorefining. In growing corn, irrigation may or may not be used. For example, Nebraska uses an average of seven inches per acre, while Minnesota uses none.[27] As research is done on cellulosic agricultural feedstocks, water requirements will be a critical element.

Measuring water in biorefining is simpler than in feedstock production. Approximately four to six gallons of water are used to process one gallon of corn ethanol in a dry mill process, and wet mill processing typically uses about five times more water than dry mill. Estimates vary in starch-ethanol facilities, and incentivizing best practices can help avoid excessive use.[28]

Land Use Considerations in Biofuel Development

The move toward biofuel crops will cause changes in the spatial allocation of land uses within the landscape.   Projecting what these land use changes will be and understanding their consequences—economic, social and environmental—within the landscape should be a component of future energy policy.   These factors include the local and regional changes in infrastructure, inputs, prices, tax base, employment, water use, water and air quality, and wildlife habitat.   The positioning of biofuel processing facilities will change land use throughout the landscape and affect each of these factors. Facility locations and economic incentives that maximize positive changes in these factors will produce sustainable local and regional biofuel industries.

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[25] Sheehan, et al. 2004, "Energy and Environmental Aspects of Using Corn Stover for Fuel Ethanol," J. of Industrial Ecology 7(3-4), p. 117-146.

[26] Kim and Dale, *Life Cycle Assessment of Various Cropping Systems Utilized for Producing Biofuels: Bioethanol and Biodiesel.* Biomass and Bioenergy 29, 2005, p. 426-439.

[27] *Creating Markets for Green Biofuels*, op cit, p. 51

[28] Ibid p. 51

Recommendations

Even as the ethanol industry produces historic amounts of biofuels and national attention focuses on the construction of first-of-a-kind cellulosic demonstration facilities, it is increasingly clear that decisive leadership is needed at the federal and state levels to expand production in ways that deliver this renewable fuel to consumers at lower prices, more efficiently, and in greater quantities. The following recommendations are a set of state, regional, and federal policies that would work together to meet the aggressive goals under consideration.

The necessary policy framework to take biofuels from an important but modest blend component of gasoline to a fuel source that replaces substantial quantities of transportation fuel produced in all regions of the nation would require the following actions:

1. Sustained expansion and improved alignment of research, demonstration and technology transfer efforts in the federal, state, and private spheres;
2. Innovations and support for cellulosic ethanol and other biofuel feedstock supply;
3. Steady increases in the demand floor for biofuels commensurate with the numbers of compatible vehicles; and
4. Innovative approaches to catalyzing the development of infrastructure for higher blend ethanol fuels and other biofuels.

Following is a list of elements that have emerged in many federal and state legislative initiatives over the past several years. However, an integrated strategy that ties these together in a coordinated fashion and considers the importance of collaboration across state and federal efforts has not emerged. Of equal importance is working together in a more cohesive fashion to achieve the paramount national goal of reduced dependency on imported oil.

Research, Demonstration and Technology Transfer

Technological breakthroughs and incremental process improvements are the bedrock of expanding production of ethanol and biofuels and, in particular, delivering the promise of cellulosic ethanol. Without sustained investments in the well-planned research and incentive authorizations of the Energy Policy Act of 2005, the U.S. may not lead the way in creating the biofuel technologies and processes of the future. Ensuring that we expedite delivery of needed technological breakthroughs requires vastly improving the coordination of federal resources and efforts with private and state efforts. The following are recommendations to help achieve the needed breakthroughs and improvements.

<u>National</u>

- Advocate for full funding of the Department of Energy's biomass research and demonstration activities, including its genomic work aimed at achieving dramatic changes in how ethanol and other biofuels are produced. These programs are delivering results and should be provided a consistent level of funding to achieve the research goals and objectives established by Congress. Congress should also work to reduce the level of earmarks under this program to ensure coordinated, ongoing, and planned research and demonstration activities can be carried out over the next five years.

- Advocate for full funding of USDA's biomass research and development program at its authorized level. Funding to allow this program's complementary focus on feedstock collection and other agricultural issues is essential, or it will become a weak link in the national effort to move toward cellulosic-derived fuels and other biofuels. Substantially greater leadership and resources are needed so the USDA's unique expertise in the areas of plant biology, soil quality, and biomass collection can be used.

- Structure federal incentives in a manner that provides additional per gallon amounts for cellulosic ethanol, based on the energy efficiency of the production process, including feedstock production; environmental impacts including water and land use; and the resulting carbon emissions. This system should be designed in a manner that encourages innovation by rewarding the development and use of feedstocks and processes with superior lifecycle environmental, energy and emissions profiles.

<u>State</u>

- Complement federally funded research with state research, development, and demonstrations in delivering appropriate feedstock production and residue removal. Potential resource inventories need to be expanded and evaluated in terms of agricultural science.

- States need to actively partner with local companies in alternative energy projects, pursue federal funding where applicable, and use the full gamut financial incentives to encourage growth of the industry.

Cellulosic and Other Biofuels Feedstock Supply

A study undertaken by University of Tennessee[29] looked at the economic, environmental, and agricultural impacts of increasing levels of ethanol production and use. The results of the study show that further expansion of production (10 billion gallons in 2010, 30 billion gallons in 2020, and 60 billion gallons in 2030) is well within the capability of the industry and farmers under conservative grain-yield improvement assumptions and market entry of modest amounts of cellulosic-derived ethanol production by 2012.

Steps are needed to actualize this potential supply of cellulosic feedstocks. Currently there is no functioning market for perennial bioenergy. There are uncertainties about the conditions under which these and other crops can even grow in the West. The following recommendations will support and encourage the transition to cellulosic feedstocks[30]:

- Provide government assistance to implement short- and medium-term burden sharing for producers. This can be done, at least in part, through a competitive program to pay farmers (or farm cooperatives or communities) to plant bioenergy crops on working lands. Consideration can also be given to gross receipt tax elimination.
- Expand technical assistance from the Natural Resources Conservation Service and the cooperative extension services.
- Consider making funds available to cost-share purchases of new bioenergy harvesting machinery.
- Establish a low-carbon renewable fuels loan guarantee program. The Governors Ethanol Coalition recommends that this be an expansion of the USDA loan guarantees and that it be competitive and performance-based.
- Re-evaluate the USDA risk management program and adjust, as necessary, to meet the needs of evolving bioenergy crops.
- Consider establishing a regional ethanol reserve to maintain an assured supply.

Increasing the Demand for Biofuels

The passage of the Renewable Fuel Standard (RFS) in 2005, along with the phase-out of methyl tertiarybutyl ether (MTBE), drove a surge of ethanol production expansion. This means that in or before 2008, actual use of ethanol will surpass the nation's RFS goal of using 7.5 billion gallons of ethanol a year by 2012. The ethanol industry now produces than 5 billion gallons annually, with an additional 6-12 billion gallons of production under construction or planned to come online over the next 24 months. This rapid progress means the nation can achieve far greater reductions in oil imports than envisioned in the Energy Policy Act of 2005.

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[29] http://www.energyfuturecoalition.org/pubs/UTReport.pdf
[30] *2007 Farm Bill Recommendations*, Governors Ethanol Coalition, April 2007

Specific actions to increase demand for biofuels include:

National

- Support implementation of the expanded RFS. The accelerated expansion of an advanced biofuels RFS will only be effective when linked to the recommended research and demonstration policies and the related incentive measures envisioned in the Energy Policy Act of 2005.
- Determine market infrastructure needs for distributing biofuels and expand the market capacity to maximize current and projected future consumption patterns.
- Consider the monetization of the cellulosic ethanol trading credit contained in the current RFS.
- Because government fleets are in a position to be movers for alternative fuels, the federal government should promote procurement of flex-fuel vehicles, as well as renewable fuels, and ensure the availability of E85 and other renewable fuels fueling facilities.
- Federal agencies can help establish income streams with long-term cellulosic ethanol supply contracts for federal and state purchases.

State

- States and municipalities should promote procurement of flex-fuel vehicles, as well as renewable fuels, and ensure the availability of E85 and other renewable fuels fueling facilities.
- State agencies can help establish income streams with long-term cellulosic ethanol supply contracts for federal and state purchases.
- States should consider adoption of a low-carbon fuel standard similar to that adopted by California, which is 10-percent reduction in the carbon intensity of transportation fuels by 2020.[31]
- States should consider modifying their highway taxes to address the lower BTU content of E85.

Innovative Approaches to Renewable Fuels Infrastructure

National

- Adopt a city-to-region approach to solve the infrastructure challenge by funding a high-profile competition providing funds to three metropolitan areas. The strategic distribution of E85 in several major metropolitan markets leading to region-wide availability, combined with a greater number of flexible fuel vehicles, is a relatively rapid and cost-effective means of building sustained consumer support and consumption of ethanol.
- Encourage the DOE to fund a high-profile competition providing funds to three metropolitan areas. (note: the GEC suggests $10 million.) Collaborative teams would compete for the one-time, cost-shared awards with selection criteria that address the potential for long-term market transformation, economic sustainability, market impact and evidence of a local commitment. This concentrated effort would maximize private, state and local investments in marketing and infrastructure and would provide evidence of the

[31] *A Low Carbon Fuel Standard for California,* op cit

potential of a flexible-fuel system. Moreover, the approach would offer “lessons learned,” allowing state and private efforts of a similar nature to occur in other areas of the nation.

State

- Establish goals for increasing E85 infrastructure, such as Colorado’s target of 50 E85 stations by the end of 2007 and for supporting those goals with tax incentives.
- Adopt incentives for retailers to sell E85.

Regional

- Establish grants for renewable fuel infrastructure corridors in the West that serve all of the renewable and advanced biofuels. One such corridor could be the I-5 corridor from Mexico to Canada. Others include I-15, I-25, and I-35, as well as key east-west corridors such as I-10, I-70, I-80, and I-90.

Funding Alternative Fuel Actions

- Consider a $.01/gallon “sustainable energy transition fee” to invest in alternative fuels.

Demonstration Recommendations

The following suggestions include new ideas and models for states to consider.

- Fund a select number of demonstration projects designed to prove the commercial readiness of lignocellulosic biofuels, including those derived from municipal wastes.
- Establish demonstration projects to streamline collection, transport, and storage of cellulosic crop residue.
- Extend E85 infrastructure using the Colorado model below.

> The **Colorado Biofuels Coalition** is comprised of Colorado organizations, businesses, government agencies, environmental groups, and others involved in the production, distribution, promotion, and use of biofuels. The Coalition provides funding assistance as well as outreach to increase consumer and retailer interest. It has successfully researched and recommended E85 geographic locations and has developed an interim solution to certification of tank and pump equipment while Underwriters Laboratories completes their review. As a result of the Colorado Energy Office leadership and the Coalition’s work, Colorado has successfully dispersed alternative fuel infrastructure in less than two years, anticipating more than fifty stations to be installed by the end of 2007.

APPENDIX A

Biomass Resource Assessment and Supply Analysis for the WGA Region - Report prepared by Antares Group, Inc. as part of USDA/DOE Bioenergy Grant for the Strategic Development of Bioenergy in the Western States[32]

Background

Resource assessment and supply analyses are important factors in determining energy inputs and outputs, environmental impacts, and most importantly, the economic feasibility of biomass-related production and utilization scenarios. Quantitative assessment and cost of delivery associated with each individual and applicable biomass resource within a set distance of a conversion facility is critical to optimizing and maximizing the energy returns, environmental enhancement, and economic feasibility.

The objectives of this assessment were to:

1) provide estimates of quantities of various biomass resources throughout the WGA region on a county or city basis for use as feedstocks for liquid fuel (transportation) production,
2) use these estimated quantities to generate potential supply curves,
3) calculate the effect of biomass and crop production on water use and carbon dioxide emissions, and
4) provide quantities and supply curve data for an integrated GIS analysis.

Biomass resources considered in this project included:

- Agricultural crop residues
  - corn stover
  - small-grain straws (wheat, barley, oats)
- Animal fats and waste greases (beef tallow, yellow grease)
- Forest biomass resources
- Energy crops (short-rotation woody crops (SRWC) and herbaceous)
- Orchard and vineyard trimmings (apples, almonds, grapes, etc.)
- Biosolids

[32] Richard Nelson *(*Kansas State University*)*, Skog *(*USDA Forest Service, Forest Products Laboratory, and Rummer (USDA Forest Service, Southern Research Station)

- Grain and oilseeds (corn, soy, and canola)

The impact bioenergy crop production (grain and stover/straw) has on water use and carbon dioxide emissions due to irrigation and emissions of CO_2 from crop planting/establishment, field maintenance, and harvesting was also examined.

Agricultural Crop Residues

Agricultural crop residues are lignocellulosic biomass that remains in the field after the harvest of agricultural crops. The most common residues include stalks and leaves from corn (stover) and straw from wheat, barley, oats, and rye production. Agricultural crop residues play an important role in maintaining/improving soil productivity, protecting the soil surface from water and wind erosion, and helping to maintain nutrient levels. While agricultural crop residue quantities produced are substantial, only a percentage of them can potentially be collected for bioenergy use primarily due to their effect on soil productivity and especially soil erosion. The amount of soil erosion agricultural cropland experiences is a function of many factors: crop rotation, field management practices (tillage), timing of field management operations, physical characteristics of the soil type (soil erodibility), field topology (% slope), localized climate (rainfall, wind, temperature, solar radiation, etc.), and the amount of residue (cover) left on the field from harvest until the next crop planting. Recent analyses demonstrated that under certain conditions, agricultural residue removal can potentially occur without exceeding tolerable soil loss limits[33,34].

A quantitative and economic assessment of corn stover and spring and winter wheat straws on a county-level basis were covered in a previous WGA-sponsored project[35]. An assessment of the amounts and development of county-level supply curves for straw derived

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[33] Nelson, R.G. 2002. "Resource Assessment and Removal Analysis for Corn Stover and Wheat Straw in the Eastern and Midwestern United States – Rainfall and Wind Erosion Methodology." *Biomass & Bioenergy*. Volume 22 pp. 349-363.
[34] Nelson, R.G., Marie E. Walsh, John J. Sheehan, and Robin L. Graham. 2003. "Methodology to Estimate Removable Quantities of Agricultural Residues for Bioenergy and Bioproduct Use." *Applied Biochemistry and Biotechnology* 113 pp. 0013-0026.
[35] Western Governors' Association. 2006. *Clean and Diversified Energy Initiative*. Biomass Task Force Report. http://www.westgov.org/wga/initiatives/cdeac/Biomass-supply.pdf

from other applicable cereal grains such as barley, oats, and rye was performed in this project since they also possess potential as feedstocks for biofuel production.

State-level supply curves expressed in terms of total dry tons available at the field edge at a given price over different price levels ranging from $12.50 to $50.00 per dry ton) for each state in the WGA region were derived. These values were estimated utilizing National Agricultural Statistics Service (NASS) corn, spring and winter wheat, barley, oats, and rye production (yield and acreage planted) data for 2000-2003 and employing a procedure developed by Nelson that estimates crop residue retention levels after harvest subject to up to three different field management (tillage) scenarios (conventional tillage, CT; conservation/reduced tillage, RT; and/or no-till, NT) such that rainfall and/or wind erosion rates did not exceed NRCS soil-specific tolerable soil loss limits[2].

In general, the amount of field crop residue available for bioenergy use in the WGA region, especially from barley, oats, and rye, is small which can be attributed to the following three reasons:

1) production of barley, oats, and rye is relatively minor due to a number of factors such as climate and markets, therefore significant quantities of residue (on the order of providing feedstock to 25-100 million gallon per year biofuels production facilities) will not be generated,

2) supply for the WGA region is based primarily on the wind erosion equation (WEQ) which was not specifically developed to analyze residue removal and in utilizing residue retention or removal with WEQ, several broad-reaching agronomic assumptions had to be made which may have undercounted true residue availability, and

3) residue removal is heavily dependent upon field management (tillage) practices and the tillage "mix" in the 2000-2003 time period in the WGA region is heavily skewed toward conventional (one or more passes of disking and field cultivation) which, due to the large residue burial rates (>50%) associated with disking and heavy field cultivation, leaves little or no residue available for removal.

In select counties, and possibly areas within a county, there are probably "pockets" (small areas) not subject to the county-level "average" tillage mixes as supplied by the Conservation Tillage Information Center, climate conditions, soil erosion, etc. that could potentially produce enough residue for alternative end uses[36]. Also, these numbers do not directly account for any carbon losses or concerns with soil moisture. Appendix ACR provides state-level quantities of each specific agricultural crop residue available for removal at each of five price increments. Supply curves were generated using accepted engineering and economic parameters for machinery that might typically be used to harvest and/or field process, bale, and transport the corn stover or small-grain straw to the field edge. Table 1 presents the economic data used as a function of the amount of both corn stover and small-grain straw that would be harvested at various dry tons per acre increments..

Table1. Edge-of-field costs for corn stover and small-grain straw.

Yield	Edge-of-Field Cost	
(dt/ac)	Corn	Small-grain
0.1	$350.26	$243.99
0.5	$83.31	$58.65
1.0	$50.95	$35.48
1.5	$41.84	$28.68
2.0	$35.24	$28.28
2.5	$32.92	$25.15
3.0	$34.85	$25.45
4.0	$33.45	$22.20
5.0	$33.50	$20.25

Supply Curves for Corn Stover and Small-grain Straws

County-level supply curves based on residue retention rates by individual soil type within a county, cropping rotation, and county-level yields were generated for corn stover and small-grain straws these were aggregated into state-level supply curves. Figures 1 through 4 present state-level supply curves for corn stover and straw from winter wheat,

[36] http://www.ctic.purdue.edu/

barley, and oats in the WGA region based on the soil erosion and residue retention methodology described earlier.

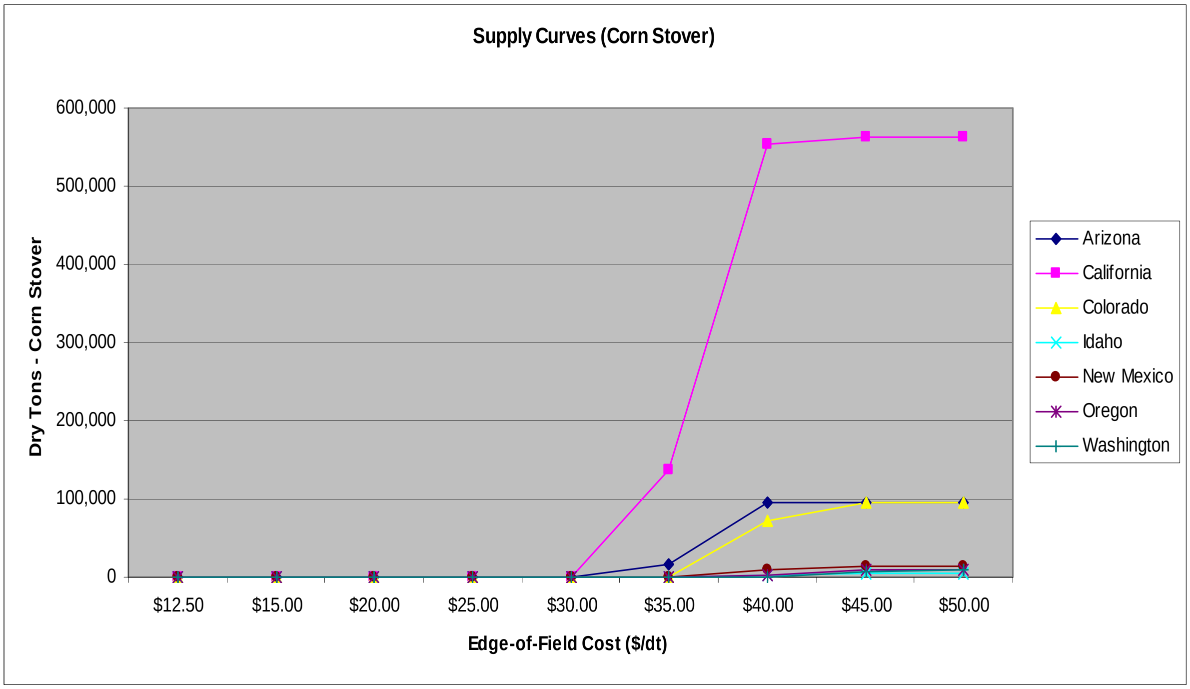

Figure 1. Supply Curves for Corn Stover in the Western Governors' Association Region.

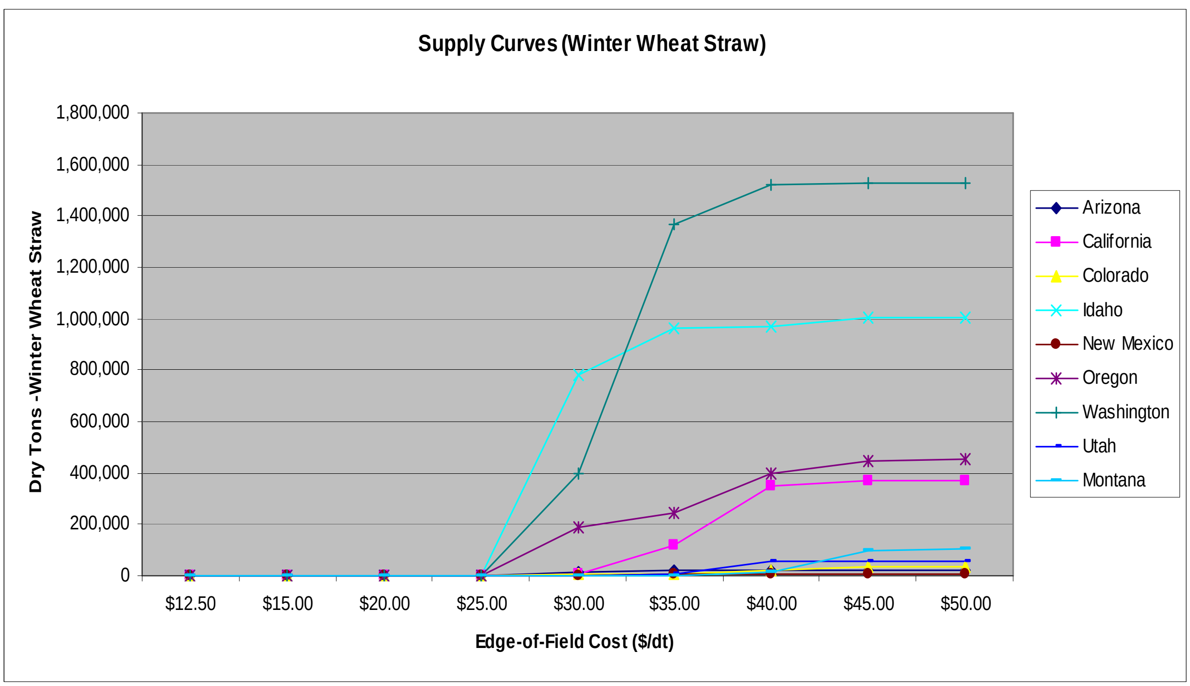

Figure 2. Supply Curves for Winter Wheat Straw in the Western Governors' Association Region.

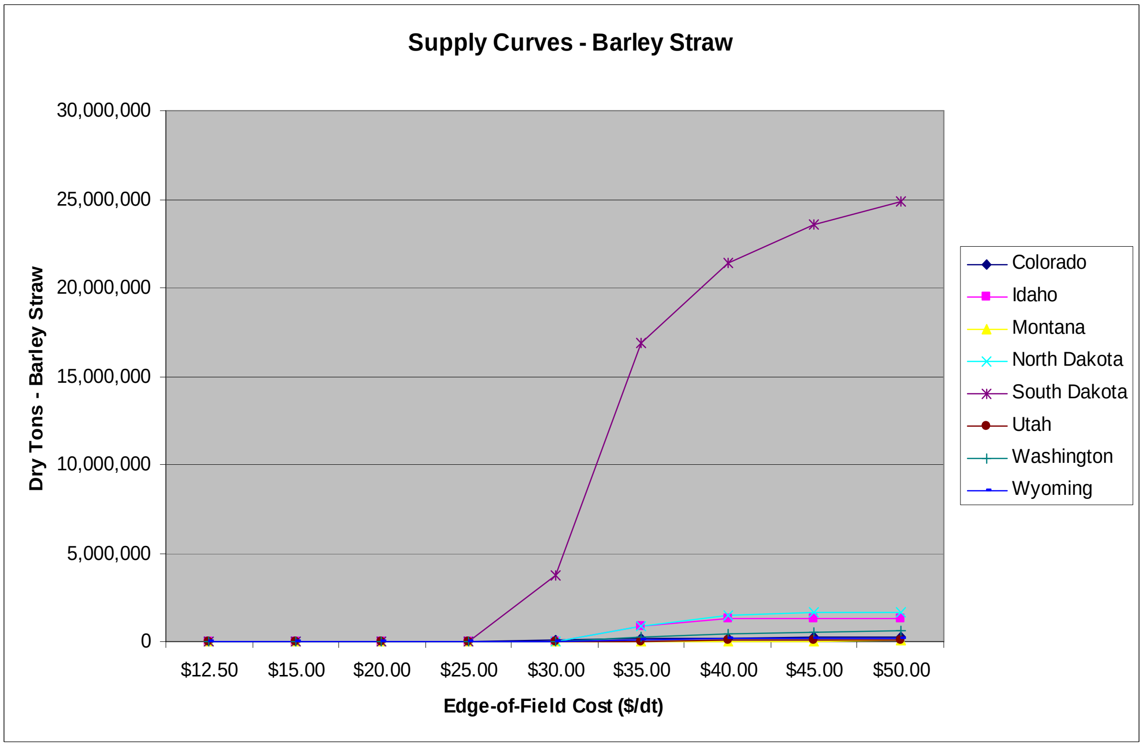

Figure 3. Supply Curves for Barley Straw in the Western Governors' Association Region.

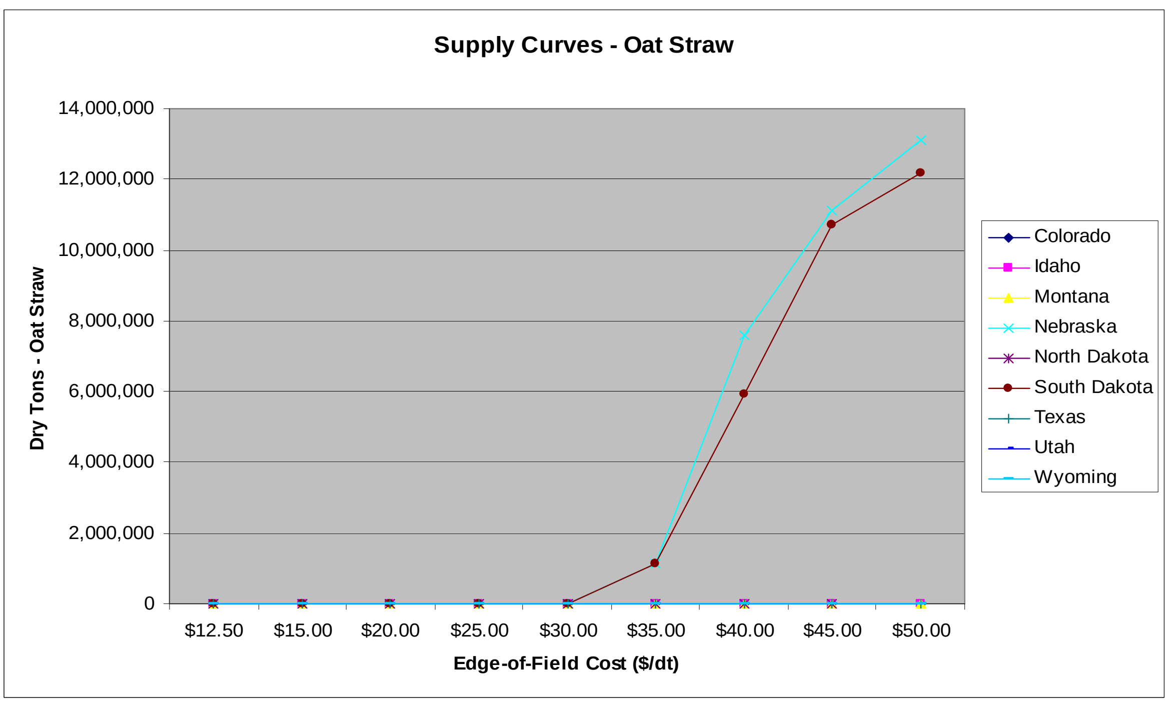

Figure 4. Supply Curves for Oat Straw in the Western Governors' Association Region.

Water Use in Agricultural Crop Production

Within the Western Governors' Association region a fair amount of corn, soybeans, wheat, barley, and oats are irrigated. Existing USDA-related databases were utilized to obtain state-wide values for the amount of water consumed per ton of grain and residue produced in each WGA state[37]. Water was allocated between the grain and stover/straw portions of each crop on a mass basis using standard straw (residue)-to-grain ratios which are 1.0, 1.7, 1.3, 1.0, and 2.0 for corn, winter wheat, spring wheat, barley, and oats respectively. Table 2 lists average, state-wide allocations of water between the grain and residue portions for each of the five crops. These values were applied to the supply (on a per ton basis) of corn stover and small-grain straws in each WGA state where applicable.

Carbon Dioxide (CO_2) Emissions from Crop Production and Allocation to Residues

For all five crops previously examined, carbon dioxide is released through the use of electricity, natural gas, diesel, and/or LP-gas required to pump water for irrigation. The quantity of carbon dioxide generated depends upon 1) water requirements (acre-feet/acre) of each particular crop, 2) type of energy source used and the percentage of that energy source within a state, and 3) depth to water. State-wide average amounts of water, pumping depth, operating pressure, and the number of irrigated acres within each state allocated to electricity, natural gas, and diesel and LP-gas along with accepted state-level CO_2 emission factors for each energy source were combined to estimate a 'composite' CO_2 emissions (tons per tons of grain and residue)[4]. Table 3 provides estimates of CO_2 emissions per ton of crop produced due to energy from electricity, natural gas, diesel, and LP-gas inputs for irrigation for each crop allocated by their individual grain and residue production.

Estimates of CO_2 Emissions from Corn Stover and Small-grain Straw Harvesting

Removal of corn stover and wheat straw from the field and baling these residues for transport to a conversion facility also requires energy in the form of expended diesel fuel and CO_2 is produced from these expenditures. Typical operations used in the harvest of corn stover and small-grain straw include flail shredding, baling, and transporting the baled residue to the field edge. Emissions of CO_2 resulting from these operations for average

[37] http://www.nass.usda.gov/census/census02/fris/fris03.htm

Table 2. Average statewide water consumption (gallons per acre) values for corn, soybeans, winter wheat, barley, and oats and their associated residues.

State	Corn		Soybeans		Winter Wheat		Barley		Oats	
	gallons/acre grain/oilseed	gallons/acre stover/straw	gallons/acre grain/oilseed	gallons/acre stover/straw	gallons/acre grain/oilseed	gallons/acre stover/straw	gallons/acre grain/oilseed	gallons/acre stover/straw	gallons/acre grain/oilseed	gallons/acre stover/straw
Alaska										
Arizona	499,447	499,447			400,484	680,823	294,031	441,047		
California	155,858	155,858			271,503	461,556	222,113	333,170	97,741	195,482
Colorado	273,822	273,822	82,103		126,071	214,321	189,374	284,060	108,601	217,203
Hawaii									0	0
Idaho	407,652	407,652			195,000	331,500	169,418	254,127	217,203	434,405
Kansas	226,789	226,789	64,509		106,729	181,439	52,129	78,193	43,441	86,881
Montana	471,854	471,854			134,809	229,175	143,354	215,031	152,042	304,084
Nebraska	196,539	196,539	58,645		110,474	187,805			108,601	217,203
Nevada					226,604	385,226			0	0
New Mexico					241,128	409,918			0	0
North Dakota	144,590	144,590	41,051		90,099	153,168	92,789	139,183	119,461	238,923
Oklahoma	244,353	244,353	56,149		120,668	205,136	26,064	39,096	54,301	108,601
Oregon	400,900	400,900	0		170,752	290,278	168,263	252,395	141,182	282,364
South Dakota	145,749	145,749	45,850		65,819	111,892			130,322	260,643
Texas	252,412	252,412	51,228		118,255	201,033			86,881	173,762
Utah	534,203	534,203			223,871	380,581	236,831	355,247	206,343	412,685
Washington	320,633	320,633			208,900	355,130	211,773	317,659	130,322	260,643
Wyoming	159,715	159,715			110,612	188,041	257,577	386,365		

Table 3. Average CO_2 emissions due to irrigation per ton of crop produced for corn, soybeans, winter wheat, barley, and oats and their associated residues.

	Corn		Soybeans		Winter Wheat		Barley		Oats	
	CO_2 from irrigation allocated to grain	CO_2 from irrigation allocated to straw	CO_2 from irrigation allocated to soybean oil	CO_2 from irrigation allocated to straw	CO_2 from irrigation allocated to grain	CO_2 from irrigation allocated to straw	CO_2 from irrigation allocated to grain	CO_2 from irrigation allocated to straw	CO_2 from irrigation allocated to grain	CO_2 from irrigation allocated to straw
Alaska										
Arizona	6,754	6,754			3,055	5,194	2,076	3,114		
California	1,871	1,871			692	1,177	533	799	7,338	14,676
Colorado	2,785	2,785	256.3	n/a	569	967	1,345	2,018	18,171	36,341
Hawaii										
Idaho					0	0				
Kansas	2,402	2,402	212.6	n/a	392	667	251	377	4,277	8,553
Montana	2,420	2,420			409	695	504	756	21,905	43,811
Nebraska	1,903	1,903	180.8	n/a	359	611			29,448	58,896
Nevada					1,735	2,950				
New Mexico					1,122	1,907				
North Dakota	1,178	1,178	93.9	n/a	419	712	447	671	2,530	5,059
Oklahoma	2,417	2,417	168.5	n/a	370	629	126	190	5,613	11,225
Oregon	759	759			185	314	153	230	5,651	11,302
South Dakota	973	973	76.4	n/a	192	326			1,674	3,349
Texas	3,368	3,368	131.1	n/a	445	756			25,069	50,139
Utah	5,534	5,534			1,538	2,614	1,530	2,295	114,025	228,049
Washington	817	817			313	533	131	196	8,033	16,066
Wyoming	2,017	2,017			787	1,339	2,460	3,690		

quantities of residue removed in the WGA region is approximately 0.03 tons CO_2 per acre. These emissions were applied to the supply curves for all corn stover and small-grain straw across the WGA region.

N_2O Emissions from Agriculture

N_2O is a potent greenhouse gas with a global warming potential of nearly 300 times that of CO_2. Agriculture accounts for approximately 70% of the anthropogenic emissions of N_2O mostly due to microbial processes associated with gasses emitted through denitrification/nitrification, which can be enhanced through use of nitrogen fertilizers. The rate of N_2O emissions from agricultural operations is a function of many factors including soil type, fertilizer type, and cropping rotation. While recognized in this report, it was beyond the scope of this project to attempt to quantify N_2O emissions for the agricultural crops and/or practices used to generate bioenergy resources across the WGA region.

Criteria Pollutant Emissions Allocation to Biomass Feedstock Production

Calculations were made concerning the amount of select criteria pollutants (CO, PM, SO_2, NO_X) emitted due to use of diesel fuel in agricultural field operations (planting, field maintenance, harvesting) and use of both diesel fuel and electricity in irrigation operations per ton of crop or residue produced. In all cases, these values were considered negligible (< .01% of one ton per ton of crop or residue produced) and therefore were not included in the environmental analysis.

Animal Fats and Waste Greases

Animal Fats (Beef Tallow)

Tallow is a by-product of our meat production and processing system and two types of tallow are generated through the slaughter of beef cattle. These are edible and inedible and each has distinct characteristics and price structure. Edible and inedible tallow are potential biodiesel feedstocks that, due to their highly centralized generation in slaughter/processing facilities, may have energy, environmental, and economic advantages that could be exploited.

Most tallow (edible and inedible) in the United States is currently generated by the meat packing industry. Inedible tallow is most often used as a supplement for animal feed (majority of market share), followed by use in fatty acids, soap, lubricants, and other uses while edible tallow is primarily used as a cooking or baking product. Statistics derived from two independent sources[38, 39] show an average generation of tallow, of about 1.6 billion pounds in the Western Governors' Association area from approximately 50 separate locations in Arizona, California, Colorado, Kansas, Nebraska, Texas, Utah, and Washington. Prices for edible and inedible tallow at various locations throughout the US were obtained from a national source[40] for a period of two years (July 2005 through June 2007) and these were used in conjunction with the resource data in each state and county location to derive 'psuedo' supply curves for producing biodiesel at each geographic location. Table 4 presents average quantitative data on beef tallow generation by state within the WGA region.

Yellow Grease

Waste grease feedstocks (e.g. restaurant greases) are a secondary, but very accessible and pertinent source of biodiesel feedstocks. Estimates of this resource were made based on methodology developed by Wiltsee (1998)[41] using urban population statistics. Wiltsee estimated an average yellow grease generation of nine (9) pounds yellow grease/capita. These figures may change by 2015 due to a variety of factors such as an increased focus on health, especially heart-related matters, and waste disposal regulations, but due to a lack of better data, they were employed in this analysis.

All WGA population centers with greater than 100,000 persons as measured by the 2000 census (latest data available) were included in this analysis. Population expansions were estimated for each WGA city for 2015 using data for state population increases derived from data provided by the US Census Bureau[42]. Within the WGA region, over 50 million gallons per year (MGY) of yellow grease-based biodiesel could potentially be produced in 126 urban centers with individual city plant capacities ranged from 0.14 to

[38] Livestock Marketing Information Center. Lakewood, CO.
[39] Steve Kay. Cattle Buyers Weekly. Petaluma, CA.
[40] http://www.thejacobsen.com/
[41] http://www.biodiesel.org/resources/reportsdatabase/reports/gen/19981001_gen-107.pdf
[42] http://www.census.gov/compendia/statab/population.html

Table 4. Average annual tallow generation (pounds) and estimated tallow-based biodiesel.

State	Edible and Inedible Tallow Generation (pounds)	Estimated Gallons of Tallow-based Biodiesel
Alaska	0	0
Arizona	30,618,358	4,082,448
California	94,151,452	12,553,527
Colorado	120,483,240	16,064,432
Hawaii	0	0
Idaho	0	0
Kansas	449,477,499	59,930,333
Montana	0	0
Nebraska	0	0
Nevada	445,879,842	59,450,646
New Mexico	0	0
North Dakota	0	0
Oklahoma	0	0
Oregon	0	0
South Dakota	8,802,778	1,173,704
Texas	416,103,489	55,480,465
Utah	36,129,663	4,817,288
Washington	65,217,103	8,695,614
Wyoming	0	0
WGA Region	1,666,863,424	222,248,457

greater than 12 MGY. Brown grease was not considered as a serious source due to its high FFA content, which would add to pre-processing costs. Table 5 presents data on estimated yellow grease quantities for each WGA state with a projected 2015 population of 100,000 persons or greater.

Table 5. Estimated yellow grease generation and associated biodiesel production.

State	Yellow Grease (million pounds) - 2015	Potential Biodiesel Production (MGY)	State	Yellow Grease (million pounds) - 2015	Potential Biodiesel Production (MGY)
Alaska	0	0.0	New Mexico	5	0.6
Arizona	42	5.5	North Dakota	19	2.6
California	167	22.2	Oklahoma	9	1.1
Colorado	18	2.5	Oregon	8	1.1
Hawaii	0	0.0	South Dakota	1	0.2
Idaho	2	0.3	Texas	97	12.9
Kansas	7	1.0	Utah	4	0.6
Montana	0	0.0	Washington	13	1.7
Nebraska	0	0.0	Wyoming	0	0.0
Nevada	6	0.8	WGA Region	397.8	53.0

Forest Biomass Resources

Sustainability

Estimates of forest biomass supply were developed for several sources by first identifying sustainability principles to guide their use. Specific guidelines are noted for each source discussed. In general terms sustainability means today's management actions will not degrade the ecological functioning of a natural system[43]. In the context of biomass removal from forests, the question of sustainability requires consideration of a wide range of issues, including: nutrient cycling and soil productivity, maintenance of biodiversity, water quality, and wildlife habitat. These factors, and resulting constraints on forest operations to address concerns, are generally very site-specific. Soil productivity in certain soil types, for example, may be more sensitive to micro-nutrient levels and thus require retention of some level of woody residue. Wildlife habitat requirements may stipulate retention of snags or maintenance of coarse woody debris.

Sustainability is explicitly addressed in this analysis through several assumptions. On Federal lands, vegetation management projects are implemented within the framework of

[43] Helms, J.A., ed. The Dictionary of Forestry. Society of American Foresters, Bethesda, MD. 210 p. (1998).

environmental analyses and regulations that ensure consideration of ecological effects and sustainability. While less restricted, treatments on private lands are also constrained through various environmental laws and regulations[44]. The potential forest biomass supply that is modeled here is a secondary output of other management objectives. We consider biomass that would be available from forest health treatments, fire hazard reduction work, or treatment of activity fuels after logging where questions of sustainability are addressed in the larger management plan.

The present assessment also assumes ecological considerations and practical limitations would have the effect of reducing the amount of biomass available for removal and utilization. The process used models silvicultural treatments and estimates total available biomass. The total available biomass is then further reduced to reflect material left on site to meet ecological constraints or is otherwise impractical to remove. The reduced amount is the net biomass available for removal. For example a previous study[45] with limited environmental screens estimated 345 million oven dry tons (odt) of biomass may be available from fire hazard reduction thinning whereas with our additional screens – for our Base Case – we estimate 114 million odt tons are currently available. For each estimate it is assumed these amounts would be harvested over a period of years.

As a final gross check on sustainability, the net annual growth in western forest types was calculated from Forest Inventory and Analysis (FIA) plot data and compared to the estimated biomass removal volumes. While growth, mortality and removal are not holistic measures of ecological integrity, they provide a benchmark of management intensity and impact. For 2002 the total net annual growth of growing stock on timberland in western states was about 97 million odt per year and of this 43 million odt were removed[46]. Growing stock growth does not include growth in tops and branches or in non growing stock trees. Our Base Case would use about 13 million odt of biomass per year, which is an amount less

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[44] Ellefson, P.V., Chen, A.S., Moulton, R.T. "State forest practice regulatory programs: an approach to implementing ecosystem management on private forest lands in the United States." Environmental Forestry 21(3):421-432. (1997).

[45] USFS. 2003. A strategic assessment of forest biomass and fuel reduction treatments in western states. http://www.fs.fed.us/research/infocenter.html

[46] Smith, W. Brad; Miles, Patrick D.; Vissage, John S.; Pugh, Scott A. 2003. Forest Resources of the United States, 2002. Gen. Tech. Rep. NC-241. St. Paul, MN: USDA Forest Service, North Central Research Station. 137 p. See Table 36 – Net growth for ND, SD, all intermountain states, OR, WA, CA is (6.5 billion cu. ft. x 30 lbs/ cf / 2000 lbs/ton =) 97.5 million od tons. Removal of growing stock in 2002 was 2.9 billion cf (= 43 million od tons).

than 25% of currently unremoved net growth of growing stock (13/ (97-43) = 0.24). The estimated fraction would be less if we included, in the denominator, the growth of tops of growing stock trees and growth of non-growing stock trees.

The key effort is to recognize that forest practice laws and guidelines[47] will place ecological constraints on the impacts biomass removal can have. Our adjustments to attempt to reflect these guidelines are very gross and further evaluations will be needed to determine availability in local areas. We don't know the "real" numbers for availability, but we guess that public lands would allow less removal than private lands. For a County Commissioner looking at this report, and if they knew that there were no endangered species in their county and no water quality issues or sensitive soils, the estimates of available biomass from this report would be overly conservative. Similarly, if they were in a county with the only remnant population of an endangered species, the estimates may not be conservative enough.

Biomass sources

The forest biomass sources used for this report are very similar for those used for the Western Governors Association CDEAC report[48]. In general terms the forest biomass sources for the current report are:

1) Thinning of timberland with high fire hazard,
2) Logging residue left behind after anticipated logging operations for conventional products,
3) Treatment of Pinyon Juniper woodland,
4) General thinning of private timberland,
5) Precommercial thinning on National Forest land in western OR and WA, and
6) Unused mill residue.

Biomass supply estimates were made for each county in selected Western States. We make a Base Case supply estimates for each source and for some sources we make a High

[47] Ellefson, P.V., Chen, A.S., Moulton, R.T. "State forest practice regulatory programs: an approach to implementing ecosystem management on private forest lands in the United States." *Environmental Forestry* 21(3):421-432. (1997).
[48] Western Governors Association. 2006. Forest fuel treatment & thinning biomass – Timberland. In: 2006 Biomass Taskforce Report: Clean and diversified energy initiative – Biomass Task Force Report - Supply Addendum. Denver, CO. p 11-12ff. http://www.westgov.org/wga/initiatives/cdeac/Biomass-supply.pdf

Case estimate to cover a range of uncertainty about supply from the source. Supply estimates include amounts available at roadside in each county for each of several successively higher costs.

Base Case and High Case estimates of total potential annual supply by source are shown in Table 6. Base Case and High Case estimates of potential annual supply by state and roadside cost are shown in Tables 7 and 8, and in Figures 5 and 6.

Thinning of timberland with high fire hazard

Thinning of timberland with high fire hazard contributes to forest sustainability by reducing the risk of uncharacteristically severe fire. By conducting a thinning the intent is to move toward a natural fire regime pattern with natural recurrence of less severe fire. Supply was estimated by simulating thinnings on federal and non federal land using the FTE 3.0 model[49] and Forest Service FIA plot data[50]. It is assumed that timberland with current high fire hazard will be thinned over a period of years with either 1) an uneven aged thinning (where some trees of all size classes may be taken) or 2) an even aged thinning where trees where small diameter trees are taken first followed by successively larger trees until the hazard reduction target is met. A series of screens were applied to identify about 23 million federal and non federal acres that would receive simulated treatment (see CDEAC Exhibit 1-1). One screen excluded from treatment is those forest types where stand replacement fire is the norm (lodge pole pine and spruce-fir). An additional screen excluded treatment of wet climate counties in western Oregon and Washington (see separate source below). These areas were excluded because such treatments would not be consistent with our ecological objectives. These screening steps are the same as those used for the WGA CDEAC report.

For federal lands it is assumed even aged and uneven aged treatments are used equally but for non federal land it is assumed only uneven aged treatments are used. The WGA CDEAC report assumed all eligible timberland was treated equally by each type of treatment. The change was made to reflect the likelihood that nonfederal land would seek higher value and profit by using uneven aged treatments on all treated land.

[49] Miles, Patrick D. Aug-04-2005. Fuel Treatment Evaluator web-application version 3.0. St. Paul, MN: U.S. Department of Agriculture, Forest Service, North Central Research Station. [Available only on internet: http://www.ncrs2.fs.fed.us/4801/fiadb/fte_test/fte_testwc.asp]
[50] See http://fia.fs.fed.us/tools-data/

For this source and sources C, D, and E in table 6 it was assumed biomass volumes identified would be harvested over a period of years. Over this period of harvest, tree growth and mortality will continue and – depending on these growth and mortality rates – additional material would be available for harvest beyond the estimated harvest period. For the Base Case, for sources A and E, we chose a harvest period of 22 years. This time period was previously chosen for the CDEAC study, and used here, so fire hazard reduction treatments (Source A) would be done on about 500,000 acres per year. For Sources C and D we chose a harvest period of 30 years to match the harvest period used in the DOE/USDA "Billion ton supply" report[51] for thinning treatments.

For the Source A Base Case it is assumed that tops and branches of all trees and main stem of trees up to seven inches diameter at breast height (dbh) are supplied for biofuels and for the High Case trees removed up to nine inches are also supplied for biofuels. Main stem of larger trees not used for biofuels are assumed to be used to make lumber or other higher value products. The cost to remove tops and branches to roadside was assumed to be covered by the cost of removing the whole tree. At roadside there is an assumed $8/dry ton chipping cost. The cost for removing the main stem of trees supplied for biofuels was estimated using the FRCS model[52] for wood removals from each FIA forest plot. It was assumed stumpage cost would be $2/odt on private land and $0 on public land. Using this data wood biomass supply curves were estimated for each county in 12 Western States[53].

Logging residue left behind after anticipated logging operations for conventional products

Wood harvested and left on the ground at harvesting sites (or land clearing sites) may be taken to a certain degree subject to limits including (but not limited to) the need to maintain nutrients on site and to retain habitat. For the Base Case supply estimate we use the allowable removal fractions from the DOE/USDA "Billion-ton-supply" report – 65% for logging residue is available for biofuels from harvest sites and 50% from land clearing sites.

[51] Perlack, R.D. et al. 2005 Biomass as feedstock for a bioenergy and bioproducts industry: the technical feasibility of a billion ton supply. Oak Ridge National Laboratory, Oak Ridge, TN 60 p. http://feedstockreview.ornl.gov/pdf/billion_ton_vision.pdf

[52] Biesecker, R.L.; Fight, R.D. 2006. My fuel treatment planner: a user guide. Gen. Tech. Rep. PNW-GTR-663. Portland, OR: U.S. Department of Agriculture, Forest Service, Pacific Northwest Research Station. 31 p. http://www.fs.fed.us/pnw/data/myftp/myftp_home.htm

[53] Arizona, California, Colorado, Idaho, Montana, Nevada, New Mexico, Oregon, South Dakota, Utah, Washington, and Wyoming

The High Case is the same as the Base Case for this source as only a Base Case exists for this source. Data on logging residue and land clearing is from the Forest Service 2002 RPA Timber Product Output data base[54]. To estimate the roadside cost we assume that whole tree removal will be used (where not already used) to bring out tops and branches to roadside. The cost for removing tops and branches to roadside will be covered by the cost of removing the main stem material. That is, the only cost to provide the wood at roadside will be to chip for $8/odt. It is assumed stumpage cost would be $2/odt on private land and $0 on public land. It is recognized logging residues come from current logging operations that provide sawlogs, pulpwood, posts and poles. It is assumed if thinning to reduce fire hazard expands and general thinning on private land expands (including biomass for fuels) then the extent of traditional operations will decrease along with associated logging residue. Given the uncertainty about the degree of displacement - we decrease logging residue use for fuels by one-quarter unit for each unit increase in biomass for fuels coming from new thinnings.

Treatment of Pinyon Juniper woodland

Pinyon-Juniper is a category of woodland (forest which produces less than 20 cu. ft. per acre per year). Pinyon Juniper forest type has expanded extensively beyond its historic range and our ecological objective in treating this area over time is to bring the extent of this forest type closer to its historic range. For the Base Case supply estimate we use allowable removal fractions from the DOE/USDA "Billion-ton-supply" report (table A-6) – 45.9% of wood on these public Pinyon-Juniper lands is available for biofuels and 61.2% of wood on private Pinyon-Juniper lands is available. This study excludes wood supply from other woodland categories in the west because we could not cite an ecological reason for such treatment.

For the Base Case we estimate 1/30 of the total volume would be supplied each year. (as assumed in the billion ton supply report). We made a general estimate that the average cost of harvest would be $60/odt and roadside chipping would cost $12.60/odt for a total of $72.60/odt. It was assumed stumpage cost would be $2/odt on private land and $0 on public land. For the High Case we assume that the treatments would occur over 20 years and costs would be subsidized at $20/odt.

[54] See http://ncrs2.fs.fed.us/4801/fiadb/rpa_tpo/wc_rpa_tpo.ASP

Note that Figure 5 shows that large quantities of biomass from Pinyon-Juniper land become available in several states when price reaches $72.60. This is because we have a single price estimate for removing this biomass. In reality the supply would increase more gradually over a range of prices we estimate would be centered on a price of $72.60.

General thinning of private timberland

It is presumed that as demand and prices for biomass for fuels increases there will be an increase in operations to harvest both woody biomass and sawlogs/pulpwood in combined operations on private land. Some private land is excluded from this source because it is already treated under the fire hazard reduction thinnings noted above. This source estimates supply from private land acres that have sufficient stocking to warrant thinning but have lower fire hazard. For the Base Case supply estimate we simulated an unevenaged thinning on private land FIA timberland plots that were not treated by a fire hazard thinning procedure (source A). The estimation procedure is the same used to estimate biomass from thinning U.S. timberland for the Billion ton supply report (stands with density greater than 30% of maximum stand density index are thinned back to 30%). Since the thinnings may be heavier than appropriate for lodgepole pine and spruce-fir forest types - they are subject to wind throw if thinned too heavily - we did not treat those forest types. A lighter thinning could have been developed and applied as was done in wildland urban interface areas for the CDEAC report and Source A above.

The Base Case supply is assumed to be provided in equal annual amounts over 30 years. The supply costs were estimated in the same way as for the fire hazard reduction thinnings (source A). For the High Case, trees removed up to nine inches are also supplied for biofuels and the annual supply is assumed to be provided in equal amounts over 20 years. It is assumed stumpage cost would be $2/odt.

Precommercial thinning on National Forest land in western counties in OR and WA

We did not simulate fire hazard reduction thinnings on National Forest[55] timberland in counties west of the Cascade Mountains in Oregon and Washington where the thinning

[55] With additional data, estimates could be made for other federal forest land (BLM) in these OR and WA counties.

objective would not be focused on reducing fire hazard but on maintaining appropriate stocking and habitat conditions. Instead, for source E, we simulated a precommercial thinning of FIA plots to remove trees five to nine inches dbh in stands up to 40 years old. For the Base Case it is assumed that 1/22 of this volume could be harvested each year (the same as for source A). The cost to harvest and move wood to roadside was estimated for each treated FIA plot using the FRCS model. It is assumed stumpage cost on National Forest land is $0/odt. The High Case supply is the same as the Base Case.

Unused mill residue

Forest Service surveys of wood products mills (e.g. lumber, plywood, pulp) periodically estimate amounts of coarse and fine wood and bark residue generated by county and how much goes for various uses (e.g. fuel, fiber input for pulp or panels). Source F is the estimate of mill residue that goes unused. We assume this entire unused amount is available to make biofuels. The amount supplied is the same for the Base Case and High Case. It is assumed the cost at the mill is $0/odt.

Table 6 – Current potential annual wood biomass supply from selected western states (million oven-dry tons)

Source	Source	Base Case	High Case	WGA CDEAC	BTSR
A	Fire hazard thinning on timberland	5.2	7.5	7.2	
B	Logging residue	4.7	4.1	5.3	5.3
C	Treatment of Pinyon Juniper woodland	7.6	11.5		
D	General thin on private timberland	2.7	4.3		
E	Pre-commercial thin on National Forest in western counties of Oregon and Washington	0.3	0.3		
F	Mill residue	0.2	0.2	0.3	0.3
	TOTAL	20.7	27.9		
	Thinning to reduce fire hazard on timberland				10.8
	Thinning on other forest land			9.2	9.2
	TOTAL			22.0	25.6
BTSR = Perlack et al. 2005. Biomass as feedstock for a bioenergy and bioproducts industry: The technical feasibility of a billion-ton annual supply					

Table 7 - Base Case cumulative forest biomass supply (oven dry tons per year) by state and roadside cost.

State	Roadside cost in dollars per oven dry ton						
	$10	$20	$30	$40	$50	$75	$100
Arizona	53,313	154,025	222,599	225,198	228,874	2,092,106	2,094,275
California	1,271,547	3,366,681	3,966,745	4,046,998	4,104,845	4,263,956	4,268,243
Colorado	82,812	193,561	279,369	324,313	341,516	1,542,596	1,552,011
Idaho	778,692	1,005,643	1,478,387	1,592,434	1,669,077	1,803,476	1,824,399
Kansas	8,720	8,720	8,720	8,720	8,720	8,720	8,720
Montana	628,548	1,053,812	1,554,616	1,694,996	1,768,144	1,850,486	1,882,451
Nebraska	4,971	4,971	4,971	4,971	4,971	4,971	4,971
Nevada	4,799	7,043	7,122	7,195	7,195	1,370,524	1,370,524
New Mexico	68,897	135,084	299,745	326,263	352,722	1,675,499	1,680,423
North Dakota	265	265	265	265	265	265	265
Oregon	924,418	1,628,936	1,712,498	1,764,367	1,824,752	1,850,106	1,851,089
South Dakota	95,407	98,503	112,224	112,224	112,224	112,224	112,224
Texas	3,022	3,022	3,022	3,022	3,022	3,022	3,022
Utah	32,670	48,437	101,966	118,102	128,534	1,776,062	1,787,916
Washington	916,029	1,437,920	1,657,948	1,757,994	1,803,262	1,820,173	1,826,722
Wyoming	81,784	123,925	185,505	204,620	211,075	298,320	301,136
Total	4,955,893	9,270,549	11,595,702	12,191,683	12,569,199	20,472,506	20,568,392

Table 8 - High Case cumulative forest biomass supply (oven dry tons per year) by state and roadside cost.

	Roadside cost in dollars per oven dry ton						
	$10	$20	$30	$40	$50	$75	$100
Arizona	96,705	250,019	345,982	368,714	373,112	3,166,477	3,173,163
California	2,168,806	4,102,790	4,665,927	4,830,207	4,869,050	5,129,086	5,154,233
Colorado	102,932	246,115	379,128	436,494	468,969	2,267,626	2,290,743
Idaho	809,109	1,166,217	1,914,282	2,062,528	2,175,302	2,401,380	2,465,831
Kansas	8,720	8,720	8,720	8,720	8,720	8,720	8,720
Montana	652,215	1,216,020	2,027,512	2,387,698	2,474,417	2,628,944	2,676,008
Nebraska	4,971	4,971	4,971	4,971	4,971	4,971	4,971
Nevada	4,697	4,697	4,770	4,843	6,808	2,051,801	2,051,807
New Mexico	82,152	169,769	405,814	472,724	514,633	2,495,484	2,504,444
North Dakota	265	265	265	265	265	265	265
Oregon	1,451,328	1,778,410	1,875,010	1,958,933	2,057,311	2,097,133	2,100,369
South Dakota	95,407	106,298	129,042	129,042	129,042	129,042	129,042
Texas	3,022	3,022	3,022	3,022	3,022	3,022	3,022
Utah	35,852	53,571	141,958	171,528	192,325	2,678,423	2,691,756
Washington	1,144,729	1,624,495	1,855,034	2,052,241	2,120,472	2,175,068	2,188,618
Wyoming	81,340	150,630	263,255	281,884	294,622	429,622	432,318
Total	6,742,251	10,886,012	14,024,691	15,173,815	15,693,041	27,667,065	27,875,310

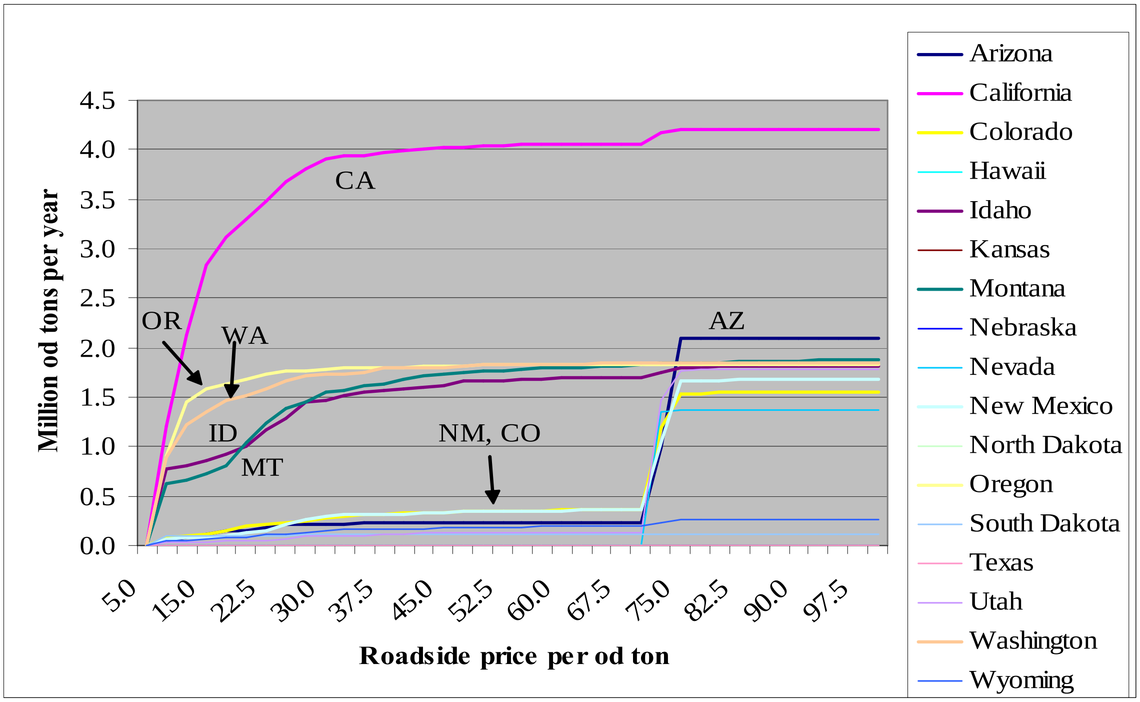

Figure 5 – Base Case forest biomass supply by state.

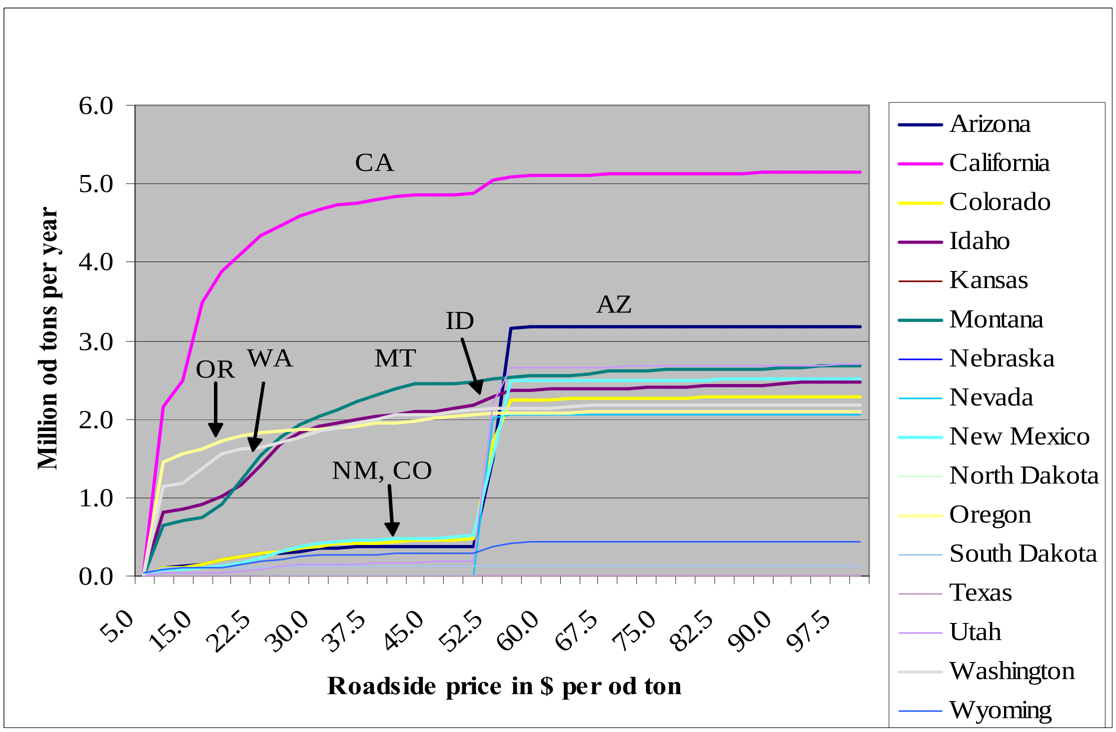

Figure 6 – High Case forest biomass supply by state.

Estimates of CO_2 Emissions from Forest Thinnings

Carbon dioxide is also released from the combustion of diesel fuel used to remove forest thinnings. Average numbers indicate roughly 2 gallons of diesel consumed per thousand cubic feet which translates into approximately 1.2 gallons per oven dry ton and nearly 27 pounds of CO_2 emissions per oven dry ton of thinnings[56, 57].

Dedicated Energy Crops

Dedicated energy crops such as short-rotation woody crops (poplar, willow) and herbaceous energy crops (switchgrass, big bluestem) have been touted as a means of providing significant quantities of bioenergy feedstock both for electricity and liquid fuels due primarily to their high mass per unit area production. In addition, there appear to be environmental benefits such as enhanced carbon sequestration and water quality benefits associated with dedicated energy crops, although these have not been confirmed on a large-scale or over extended periods of time. Because both feedstocks are "agriculturally-based" they must also compete on an economic (opportunity cost) and land availability basis with current pulp and paper, commodity crops, or hay production as well as compete with the price of the energy resource(s) they would displace.

Short Rotation Woody Crops in the WGA Region

Short-rotation woody crops produced for energy would directly compete with the pulp and paper industry and recent research has shown paper and paperboard production/ consumption will increase approximately 80% within the next 40 years due to increased economic and population growth as well as an expectation that virgin wood fiber demand will also increase[58]. This report also indicated for areas within the WGA region SRWC did not show any significant development between the present and 2025. The literature suggests the total cost of biomass from SRWC in the West would be high due to a number of factors

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[56] Johnson, Leonard R., Bruce Lippke, John D. Marshall, and Jeffrey Comnick. 2005. *Life-Cycle Impacts of Forest Resource Activities in the Pacific Northwest and Southeast United States*. Wood and Fiber Science, 37 Corrim Special Issue. pp. 30-46

[57] Robert B. Rummer. USDA Forest Service, Auburn, AL. Personal communication.

[58] Alig, Ralph J., Darius M. Adams, Bruce A. McCarl, Peter J. Ince. 2000. Economic potential for SRWC on agricultural land for pulp fiber production in the United States. Forest Products Journal 50(5): 67-74.

such as land rent and plantation costs as well as harvest and transport costs. In order to impact bioenergy in 2015 these woody plants would already need to be planted because they are not ready for harvest for 7-9 years. The role of short rotation woody crops may be an important part of the feedstock supply of the future in areas where there is adequate short term productivity to justify investments. Therefore, based on these factors, a resource assessment and supply analysis concerning potential quantities of dedicated woody crops for the WGA region was not conducted.

Herbaceous Energy Crops in the WGA Region

In general, due to high production volumes (bushels per acre) and current and forecasted prices for the four main commodity crops of corn, soybeans, grain sorghum, and wheat, and potentially other oilseeds, herbaceous energy crops will probably not be able to compete on a net-return basis on cropland designated as land capability classes I and II (prime farmland) unless changes are made to 1) the federal commodity crop payment structure, 2) economic allowances are adjusted for the production of dedicated energy crops, and/or 3) an environmental "monetization" of the bioenergy crop production occurs. In some cases crop productivity and hence its relative economics might be less than bioenergy production costs, but these may occur on lands (land capability classes III-VIII) potentially unsuitable for establishment, maintenance, and harvesting of each type of energy crop due to characteristics of individual soil types and field topology (slope). In addition, concerns exist over the availability of large-scale amounts of land required to produce and supply feedstock within close proximity to the electric generating or liquid fuel production facilities. For a 50 million gallon per year bioethanol production facility, approximately 200,000 acres (17 square miles) would be required at an average annual yield of three dry tons per acre per year.

There are many examples of "test plots" with different varieties of herbaceous energy crops at different geographic locations throughout the United States, mostly at USDA agricultural experiment stations and universities, but most of these are small-scale (less than 40 acres), confined to a single climatic zone, and production usually occurs on one or two soil types. Extrapolation of this data to an area as large and geographically diverse as the WGA region using data from small-scale plots would produce inconsistent results. In

addition, no large-scale computer modeling effort has been performed within the western region concerning herbaceous energy crop production across different climate regimes and soils that could be used to help generate supply curves.

An estimate of quantities (dry tons per acre) of herbaceous crops that could potentially be produced within the WGA region was obtained from a USDA database which contained production statistics (dry tons per acre) for native grass species produced on individual soil types within each county in the WGA region[59]. The database was populated by NRCS rangeland experts over many years and reflects possible production levels of a large number of herbaceous species under "non-managed" conditions (e.g., no fertilizer and/or chemical applications or optimal field preparation that could potentially increase production).

The WGA region is diverse from a geographic and climatic standpoint with large variations in precipitation, soil type and field topography, and elevation. Consultation with a number of USDA-related personnel with expertise in rangeland grass production revealed that inadequate and inconsistent production could possibly occur at elevations of greater than 4,500 feet, field slopes greater than 15% which relates to proper field preparation, establishment, harvesting, and crop transport to the field edge, and most importantly, in areas where average annual precipitation was less than 20 inches. The precipitation value of 20 inches was deemed the most important factor of the three considered.

Figure 7 provides precipitation data for the United States and details the geographic areas in the WGA region, which would not meet the 20 inches per year criteria. Even in some areas within the region that have an average annual precipitation of 20 inches or greater, these area fall in mountainous areas such as in Wyoming, northern Idaho, and Colorado. The states of South Dakota, Nebraska, Kansas, Oklahoma, Texas, Washington, Oregon, and California were examined in this project. Soil data for Washington state was deemed incomplete and therefore was not use for this analysis.

The database used was sorted by the three criteria listed above as well as only examining soil types classified as cropland, rangeland, and grassland designated as land capability class III-VIII. Table 9 provides an example of the type of data used to help estimate potential levels of herbaceous energy crop production in each county of each of the

[59] http://websoilsurvey.nrcs.usda.gov/app/

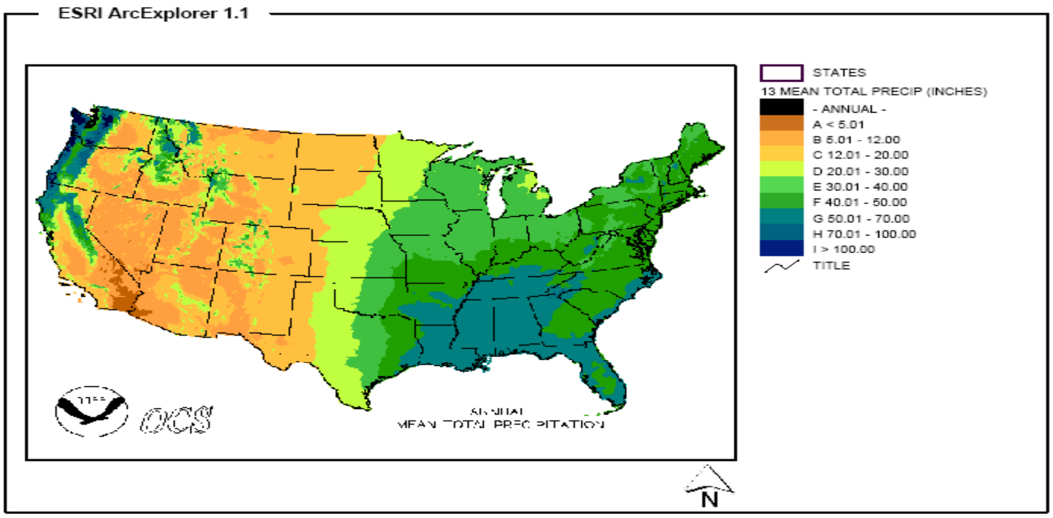

Figure 7. Average annual precipitation (inches per year).

Table 9. Example production, field topology, and climatic data from USDA database on native grass species for Allen county, Kansas.

Soil Type	**acres**	**% slope**	**average annual precipitation (in)**	**elevation (ft)**	**production (dry tons)**
Osage silty clay, occasionally flooded	3,803	1	40.3	771	3.13
Verdigris silt loam, channeled	14,974	1	39.9	771	3.50
Bates loam, 3 to 7 percent slopes	5,645	6	39.9	1,082	2.38
Bates loam, 3 to 7 percent slopes, eroded	1,118	5	39.9	1,082	2.38
Bates-Collins complex, 3 to 15 percent slopes	94	6	41.9	1,082	2.38
Collins complex, 3 to 15 percent slopes	3	9	40.0	899	1.50

eight WGA states examined. From this individual soil type production data, county-level supply curves were generated using economic and engineering parameters similar to those utilized for corn stover and small-grain baling and harvest.

Appendix HEC provides estimates of possible state-level supplies (annual dry tons) derived from the county-level data for native grass species on select soil types throughout the WGA region. No allowance is made in this analysis to compare the production of grass or

herbaceous species on individual soil types and land capability classes with current agricultural practices.

Soil Carbon Sequestration with Herbaceous Energy Crop Production

Energy crops such as switchgrass and big bluestem have deep root systems which potentially offer more favorable conditions for sequestering carbon, however the magnitude of sequestration (tons C per acre per year) is dependent upon 1) net primary production, 2) climatic conditions, 3) soil type and its physical and chemical properties, 4) previous management/use of the land base upon which the energy crops will be produced, and 5) field maintenance practices associated with their use as an alternate energy source.

Several studies indicate the range of variability in magnitude that can exist in sequestering carbon through energy crop production. Liebeg et al examined soil organic carbon (SOC) across the Great Plains on numerous soil types and depths and determined that significant differences exist in SOC rates with depth, with more sequestered at greater depths[60]. Conant et al. reviewed studies of managed grasslands throughout the world and found rates of soil organic carbon (SOC) varied from 0.05 to 1.36 tons ac^{-1} yr^{-1} with an average of 0.24 tons ac^{-1} yr^{-1} and recent publication suggests an annual SOC sequestration rate of 0.49 tons ac^{-1} yr^{-1} [61, 62]. The latter rate was derived from small-scale test plots, which have not been duplicated to any real degree on a large-scale.

The Chicago Climate Exchange (CCX) has posted prices ($ per metric ton of carbon) for carbon sequestered for a variety of different land management scenarios including herbaceous energy crop production[63]. In addition prices for sequestered carbon are offered in futures contracts and these are approximately $4 per metric ton ($3.64 per ton) for 2010 vintage, which relates to approximately $3.33 using an inflation rate of 3%. Using the $3.33 target price per ton of carbon sequestered and a sequestration rate of 0.24 tons ac-1 yr-1 yields an annual gross payment of around $0.80 per acre. This presents a conservative

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[60] Liebig, M. A., Johnson, H. A., Hanson, J. D., and Frank, A. B. 2005. Soil carbon under switchgrass stands and cultivated cropland. Biomass Bioenergy 28: 347-354.
[61] Conant, R. T., Paustian, K., and Elliott, E. T. 2001. Grassland management and conversion into grassland: effects on soil carbon. Ecol. Appl. 11: 343-355.
[62] Sartori, Fabio, Lal, Rattan, Ebinger, Michael H. and Parrish, David J. (2006) 'Potential Soil Carbon Sequestration and CO2 Offset by Dedicated Energy Crops in the USA', Critical Reviews in Plant Sciences, 25:5, 441 - 472
[63] http://www.chicagoclimatex.com/

estimate of sequestration potential and the price offered for the carbon is low due to no better determination of sequestration rates. For the herbaceous energy crop market to be viable, finer resolutions of those variables that affect sequestration would be required.

Orchard and vineyard prunings

Residues (trimmings, dead wood, etc.) are generated from the growth and cultivation of crops produced in the WGA region in orchards and vineyards. Production statistics (acreages and yields) and the average annual quantity of residue by each crop for each crop listed in table 10 were obtained from the 2002 Census of Agriculture and data from an analysis performed in California by Jenkins et al.[64, 65]. Only quantitative data is presented as supply curves were not generated due to a lack of engineering data concerning residue pick-up and transport to the field edge. There would be a cost associated with the removal and transport of these orchard and vineyard prunings to an end-use facility, but presently this has not been defined. Average annual residue amounts (dry tons per year) on a state-level basis for each orchard and vineyard crop analyzed is presented in Appendix O&V.

Table 10. Estimated total dry tons per acre per year from orchard and vineyard prunings.

All Citrus	0.65	Dates	0.39	Limes	1.30	Pecans	1.04
Almonds	0.85	Figs	1.43	Nectarines	1.04	Persimmons	1.04
Apples	1.43	Grapes	1.30	Olives	0.98	Pistachios	0.65
Apricots	1.30	Hazelnuts	0.65	Oranges	1.95	Plums & Prunes	0.98
Avocados	0.98	Kiwifruit	1.30	Peaches	1.30	Pomegranates	1.04
Cherries	0.26	Lemons	1.30	Pears	1.50	Walnuts	0.65

Wastewater treatment plant sludge and biosolids

Biosolids are the nutrient-rich organic portion that results from treatment of sewage in wastewater facilities. After treatment the biosolids can be recycled and applied as fertilizer

64 http://www.agcensus.usda.gov
65 Jenkins, B.M. (ed.). 2005. Biomass resources in California: preliminary 2005 Assessment, PIER Collaborative Report, California Energy Commission Contract 500-01-016, Sacramento, CA, (http://faculty.engineering.ucdavis.edu/jenkins/CBC/UpdateFiles/ResourceUpdate.html)

to improve and maintain productive soils and stimulate plant growth. Most generated biosolids are land applied and used as fertilizer supplements.

Values (tonnages) for biosolids generation (dry basis) at the county level were available for all states within the WGA region and were estimated by using a combination of parameters comprising the expected future design flow, expressed in million gallons per day (MGD), an average national biosolids generation rate of approximately 206 dry tons of material per MGD capacity, and an expected conversion rate of 80%[34]. No cost data exist in which to build supply curves as they depend upon transportation, bioenergy conversion facility size, and type of technology. An allowance was made for facilities under 0.3 MGD as they were felt to not have the necessary infrastructure to allow the capture of treated waste for energy purposes. This figure was arrived at in discussions with US EPA and state POTW regulators. Table 11 provides state-level data concerning the totals amount of biosolids that would possibly be generated in 2015.

Table 11. Projections of total biosolids (tons) for each WGA region state in 2015.

Alaska	13,159	New Mexico	22,088
Arizona	124,449	North Dakota	31,324
California	912,000	Oklahoma	287
Colorado	95,366	Oregon	184,571
Hawaii	32,014	South Dakota	12,125
Idaho	32,685	Texas	550,966
Kansas	118,736	Utah	98,742
Montana	33,400	Washington	168,059
Nebraska	7,419	Wyoming	21,346
Nevada	36,600	WGA Region	2,495,336

Future Commodity Crop Assessment

Currently, a majority of the ethanol in the United States is produced from corn with grain sorghum as another feedstock. Biodiesel produced in this country is derived mainly from soybeans, with the remainder coming from canola, animal fats (beef tallow), and yellow grease. Potential acreages, prices, and production of corn, soybeans, and canola that might

potentially occur in all WGA region counties in 2015 was estimated using 2006/2007 crop year planted acres and yield data for corn, soybeans, and canola from USDA's National Agricultural Statistics Service and projections of acreages and yields provided by the Food and Agricultural Policy Research Institute (FAPRI) [66, 67]. Similar statistics exist from the USDA's Baseline Agricultural analysis[68]. Both sets of data could be used to develop estimates of national supply curves, but they would be at an extremely aggregated resolution and really only 'valid' for a single year due to potential changes in export potential, agriculture and energy legislation, and recently, alternative fuel demand. County-level supply curves for individual grain crops are also subject to these factors, but especially local grain/oilseed prices, which are not accurately known. Therefore, due to these reasons, supply curves were not developed .

For each crop, FAPRI and the Baseline Analysis provides annual estimates of potential select commodity crop yields and acreages planted for the crop years of 2007/2008 through 2015/2016. Projected production (total bushels or pounds) forecasts for each WGA county in which corn, soybeans, and/or canola were produced were estimated by multiplying the percentage change in yield and planted acres on a national basis for each of the three crops between the 2006/2007 crop year and the average of the 2014/2015 and 2015/2016 crop years. The crop years of 2014/2015 and 2015/2016 were used instead of one single year as decisions concerning 2015 plantings could possibly be made in an earlier year. Yield and acreage projections were 14.5% and 13.6% for corn; -4.2% and 7.9% for soybeans; and 14.9% and 10.6% for canola and these were applied to 2006/2007 crop year statistics. It is noted that projections of agricultural commodities such as these are tenuous at best as agriculture, energy, and/or environmental legislation, market forces, and the world petroleum situation concerning supply and demand could very quickly render these numbers obsolete and therefore these projections should be evaluated and used with this in mind.

[66] http://www.nass.usda.gov/
[67] http://www.fapri.iastate.edu/outlook2007/
[68] http://usda.mannlib.cornell.edu/MannUsda/viewStaticPage.do?url=http://usda.mannlib.cornell.edu/usda/ers/94005/./2007/

Appendix ACR

Supply of Corn Stover at Five Different Price Levels for each WGA State (dry tons)

	$30.00	$35.00	$40.00	$45.00	$50.00
Alaska	0	0	0	0	0
Arizona	0	16,921	95,528	95,528	95,528
California	0	136,097	553,349	562,665	562,665
Colorado	0	0	71,885	95,040	95,040
Hawaii	0	0	0	0	0
Idaho	0	0	1,329	3,675	3,887
Kansas	0	0	0	0	0
Montana	0	0	0	0	0
Nebraska	0	0	0	0	0
Nevada	0	0	0	0	0
New Mexico	0	0	8,525	14,275	14,275
North Dakota	0	0	0	0	0
Oklahoma	0	0	0	0	0
Oregon	0	0	2,899	8,458	8,458
South Dakota	0	0	0	0	0
Texas	0	0	0	0	0
Utah	0	0	93	93	93
Washington	0	0	0	6,493	8,228
Wyoming	0	0	0	0	0

Supply of Winter Wheat Straw at Five Different Price Levels for each WGA State (dry tons)

	$30.00	$35.00	$40.00	$45.00	$50.00
Alaska					
Arizona	14,920	19,728	19,728	19,728	19,728
California	3,853	115,907	350,752	368,029	368,096
Colorado	6,392	6,392	22,459	34,118	34,118
Hawaii					
Idaho	783,324	964,661	970,752	1,003,304	1,003,428
Kansas	0	0	0	0	0
Montana	0	2,692	13,182	95,342	105,148
Nebraska	0	0	0	0	0
Nevada					
New Mexico	0	7,976	7,976	9,974	9,974
North Dakota	0	0	0	0	0
Oklahoma	0	0	0	0	0
Oregon	185,274	241,120	399,520	443,357	453,012
South Dakota	0	0	0	0	0
Texas	0	0	0	0	0
Utah	2,452	5,051	59,222	59,222	59,222
Washington	397,708	1,365,289	1,520,602	1,525,669	1,525,669
Wyoming	0	0	0	287	287

Supply of Spring Wheat Straw at Five Different Price Levels for each WGA State (dry tons)

	$30.00	$35.00	$40.00	$45.00	$50.00
Alaska					
Arizona	0	0	0	0	0
California	0	0	0	0	0
Colorado	0	3,702	4,275	4,275	4,275
Hawaii					
Idaho	0	246,063	336,605	352,787	352,787
Kansas	0	0	0	0	0
Montana	0	0	7,468	8,381	8,460
Nebraska	0	0	0	0	0
Nevada					
New Mexico	0	0	0	0	0
North Dakota	0	0	0	0	0
Oklahoma	0	0	0	0	0
Oregon	0	6,099	18,534	20,355	20,355
South Dakota	0	0	0	0	0
Texas	0	0	0	0	0
Utah	0	0	703	3,568	3,568
Washington	0	0	70,641	143,346	189,890
Wyoming	0	0	0	0	0

Supply of Barley, Oat, and Rye Straw for each WGA State (dry tons)

Barley

	$30.00	$35.00	$40.00	$45.00	$50.00
Colorado	76,609	197,957	210,992	219,736	219,823
Idaho	0	878,628	1,280,994	1,331,533	1,334,041
Montana	0	0	14,676	37,520	50,198
North Dakota	0	827,536	1,490,767	1,652,599	1,688,360
South Dakota	3,739,743	16,836,202	21,395,032	23,605,937	24,869,290
Utah	0	35,791	77,992	87,774	87,776
Washington	0	231,369	400,859	560,564	592,785
Wyoming	0	107,805	153,499	160,754	161,230

Oats

	$30.00	$35.00	$40.00	$45.00	$50.00
Colorado	0	0	319	1,211	1,733
Idaho	0	0	4,701	11,654	13,774
Montana	0	0	329	1,385	1,945
Nebraska	0	1,139,547	7,583,988	11,114,067	13,117,601
North Dakota	0	0	107	2,698	8,491
South Dakota	0	1,143,760	5,918,381	10,719,788	12,174,202
Texas	0	709	3,881	8,069	14,757
Utah	0	4	1,309	2,694	3,140
Wyoming	0	0	0	0	0

Rye

	$30.00	$35.00	$40.00	$45.00	$50.00
North Dakota	0	0	0	0	0
South Dakota	0	0	0	186,764	303,026

APPENDIX HEC

SUPPLY CURVES

Estimated Supply Curves (dry tons) for Native Gras Species in the WGA Region Based on Soil Type Characteristics, Annual Precipitation, Field Topology, and Elevation

	$10.00	$20.00	$30.00	$40.00	$50.00	$60.00	$70.00
North Dakota	0	0	5,793	20,011	20,608	20,608	20,608
South Dakota	0	2,071	103,224	201,236	224,753	229,177	231,472
Nebraska	0	796	1,664,488	4,973,956	5,977,629	5,987,291	5,997,665
Kansas	0	294,124	6,527,817	12,662,734	13,972,989	14,006,186	14,012,453
Oklahoma	0	107,630	2,210,595	2,876,251	3,783,402	4,004,190	4,073,062
Texas	0	111,746	13,278,807	20,643,588	24,529,912	24,817,909	25,146,188
Oregon	0	0	0	0	0	0	0
California	0	0	254	6,591	39,786	39,814	40,032

APPENDIX O&V
Average Annual Generation of Orchard and Vineyard Prunings (Dry Tons)

	AZ	CA	CO	ID	KS	MT	NM	OR	UT	WA
Apples	176	22,700	2,658	4,061	273	435	2,385	8,747	2,191	216,017
Dates	340	3,300	0	0	0	0	0	0	0	0
Grapefruit	1,004	incl. in Oranges	0	0	0	0	0	0	0	0
Grapes	1,503	1,416,900	562	844	55	25	226	14,182	21	73,269
Hazelnuts	0	no data	0	0	0	0	0	20,413	0	80
Lemons	0	incl. in Oranges	0	0	0	0	0	0	0	0
Nectarines	0	incl. in Oranges	0	0	0	0	0	0	0	0
Oranges	10,953	183,700	0	0	0	0	0	0	0	0
Peaches	105	124,000	2,304	928	36	1	153	932	1,646	3,596
Pears	39	15,300	380	239	5	4	85	47,342	109	70,078
Pecans	5,742	2,300	0	0	3,009	0	31,963	0	148	0
Pistachios	1,285	117,800	0	0	0	0	380	0	0	0
Plums and Prunes	8	91,000	21	480	1	5	21	1,853	4	683
Sweet Cherries	0	18,400	0	0	0	0	0	0	0	0
Tangelos	4,388	incl. in Oranges	0	0	0	0	0	0	0	0
Tangerines	1,022	incl. in Oranges	0	0	0	0	0	0	0	0
Walnuts	0	170,100	0	0	0	0	0	1,095	1	29

Summary Page - Costs & Yield Data, Grain Ethanol Production

Inputs

Feedstock Type	**Grain**
Economic Lifetime of Plant (Years)	25
Weighted Cost of Capital	10%

Current Conversion Technology

	Dry Mill	Wet Mill	
Applicable Feedstocks	Corn, Sorghum	Corn	
Applicable Size Range (MGY) (1)	5 - 100	50 - 300	
Feedstock Input (ton/yr)	1,000,000	1,000,000	For typical feedstock with about 15% MC
Yield Ethanol (MGY) (2)	100.0	89.3	
Conversion Efficiency (HHV) (3)	64%	57%	
Consumables and By-Products (4)			
DDG Yield (ton/yr)	335,000	--	
Corn Gluten Feed Yield (ton/yr)	--	203,571	
Corn Gluten Meal Yield (ton/yr)	--	53,571	
Corn Oil Yield (ton/yr)	--	28,571	
CO2 Stream (ton/yr) (5)	312,500	279,018	
Water Consumption (1000 gal/yr) (6)	470,000	2,182,143	
Ethanol Production Costs			See table below for details
Fixed O&M ($/yr)	$ 16,670,172	$ 18,541,454	
Variable O&M ($/yr)	$ 33,264,482	$ 34,105,281	
Co-product credit ($/yr)	$ (34,337,500)	$ (46,526,786)	
Annual Operating Cost ($/yr)	***$ 15,597,154***	***$ 6,119,950***	
Total Capital Investment ($) (7)	***$ 167,152,364***	***$ 197,036,083***	
Fixed Charge Rate	12.3%	12.3%	
Non-Feedstock Production Cost ($/gal)	**$ 0.36**	**$ 0.34**	*Ethanol production cost*

1) Based on typical sizes for wet and dry mills reported in Gallagher et al. 2005. Dry mill facilities have typically been 5 - 30 MGY, but current expansions are 40 - 100 MGY

2) A conversion value of 2.8 gallons per bushel of corn (100 gal/ton) is used for dry mills, based on data from Shapouri & Gallagher 2005 for new facilities. The same study also reports averages for existing dry mill plants of 2.7 gal/bu for small facilities (>40 MGY), and 2.6 gal/ton for large facilities (40 - 100 MGY). In comparison, McAloon et al. 2000 uses a conversion of 2.71 gal/ton for dry mills. Wet mill facilities have slightly lower conversion to ethanol, around 2.5 gal/bu (89.3 gal/ton) (Butzen and Hobbs 2002). Note that the USDA standard weight for a bushel of corn is 56 lb.

3) Calculated using a typical ethanol heating value 84,000 Btu/gal, and corn heating value of 369,410 Btu/bushel (6,600 Btu/lb) for product with 15% moisture.

4) Dry mill facilities generate distiller's grains as a by-product. This analysis assumes all distiller's grains are converted to DDG. For comparison, Shapouri & Gallagher 2005 showed that 70% of distiller's grains were converted to DDG in the ethanol plants surveyed. It is estimated that dry mill facilities produce 6.7 lb DDG per gallon of ethanol produced (at 10% moisture content) (McAloon et al. 2000). Wet mills generate several by-products, including corn gluten feed, corn gluten meal, and corn oil. The yields of these products from 1 bushel of corn are 11.4 lb, 3 lb, and 1.6 lb, respectively (Butzen and Hobbs 2002).

5) CO2 production from fermentation is estimated to be 17.5 lb per bushel of corn for dry mill facilities, based on data from Antares 2005a and McAloon et al. 2000. No data available for wet mill CO2 production. The CO2 production for wet mills is based on the same value, but scaled by the ethanol conversion rate.

6) Average water requirement for dry mills is 4.7 gallons per gallon of ethanol (Shapouri & Gallagher 2005). Based on data from Shapouri & Gallagher 2002, wet mills use 5.2 times as much water as dry mills.

7) Capital cost data for dry mill based on relationship derived from Gallagher et al. 2005. Minimum capital cost ($/gal) occurs at 65 MGY, after that the cost increases with capacity. The effective scaling factor for facilities under 65 MGY is 0.84. Wet mill capital costs are based on data from Whims 2002, using a scaling factor of 0.6. The capital for a wet mill facility is higher than for a dry mill facility, due to additional process equipment requirements.

O&M Costs (1)	Dry Mill	Wet Mill
Co-product (2)		
DDGS	$ 34,337,500	$ -

Corn Gluten Feed	$ -	$ 10,178,571
Corn Gluten Meal	$ -	$ 18,348,214
Corn Oil	$ -	$ 18,000,000
Total Co-product value ($/yr)	***$ 34,337,500***	***$ 46,526,786***
Variable O&M		
Consumables ($/yr) (3)	$ 12,351,082	$ 16,812,140
Utilities ($/yr) (4)	$ 20,913,400	$ 17,293,141
Total Variable O&M ($/yr)	***$ 33,264,482***	***$ 34,105,281***
Fixed O&M		
Annual Labor Cost ($/yr) (5)	$ 6,036,623	$ 8,738,190
Other Fixed O&M ($/yr) (6)	$ 10,633,549	$ 9,803,264
Total Fixed O&M ($/yr)	***$ 16,670,172***	***$ 18,541,454***
Sources	*USDA 2007, Shapouri & Gallagher 2005, McAloon et al. 2000*	*USDA 2007, Shapouri et al. 2002, Shapouri & Gallagher 2005*

1) All costs reported in 2006 US$, converted using CEPCI where necessary.

2) Average wholesale co-product values from USDA 2007. DDG range $90/ton to $115/ton, similar to data from McAloon et al. 2000 and Shapouri & Gallagher 2005. The current values for corn gluten feed ($40-60/ton), corn gluten meal ($335-350/ton), and corn oil is ($0.31-0.32/lb) from USDA are similar to those reported in Shapouri & Gallagher 2005 for 2003.

3) Consumables include enzymes, yeast, chemicals, and denaturant. The cost for small dry mills is $0.13/gal and for large dry mills the cost is $0.12/gal (Shapouri & Gallagher 2005). The cost of consumables for wet mils is $0.19/gal (Shapouri et al. 2002).

4) Utilities include electricity, fuels, water and waste management. The cost for small dry mills is $0.27/gal and for large dry mills the cost is $0.19/gal (Shapouri & Gallagher 2005). Average electricity use was 1.19 kWh/gallon of ethanol and the average heat use 34,800 Btu per gallon of ethanol. The cost of electricity for dry mills has been increased to 5.7 ¢/kWh, based on the average 2005 costs for the industrial sector (EIA 2006). New dry mill facilities have minimal wastewater discharge. Total utility costs for wet mills are $0.19/gal (Shapouri et al. 2002). Wet mill energy usage is lower than dry mills as they typically employ cogeneration of steam and electricity.

5) Annual labor costs for dry mills are $0.077/gal for small facilities and $0.060/gal for large facilities (Shapouri & Gallagher 2005). Labor costs for wet mills are estimated to be $0.096/gal (Shapouri et al. 2002). No scaling included for the wet mill costs as the data represents various size facilities.

6) Other fixed costs include maintenance, administrative costs, and other costs. For dry mills, other fixed costs are equivalent to $0.090/gal for small facilities and $0.106/gal for large facilities (Shapouri & Gallagher 2005). For wet mills other fixed costs is $0.108/gal (Shapouri et al. 2002).

Summary Page - Costs & Yield Data, Current Biodiesel (FAME) - Example #1

Inputs

Feedstock Type	**Virgin Oil**
Economic Lifetime of Plant (Years)	25
Weighted Cost of Capital	10%

Base catalyzed transesterification is used for virgin feedstocks, and acid catalyzed transesterification is used for waste greases.

	Current	
Applicable Feedstocks	virgin oil, animal fat, waste grease	
Applicable Size Range (MGY)	1 - 80	
Feedstock Input (ton/yr)	200,000	
Yield Biodiesel (ton/yr)	189,777	
Yield Biodiesel (MGY)	51.6	
Conversion Efficiency (HHV) (1)	92%	
Consumables and By-Products		
Crude Glycerin Yield (ton/yr) (2)	20,656	
Water Consumption (1000 gal/yr) (3)	1,546	
Biodiesel Production Costs		
Fixed O&M ($/yr)	$ 2,827,884	
Variable O&M ($/yr)	$ 10,517,023	
Co-product credit ($/yr) (4)	$ (2,065,600)	
Annual Operating Cost ($/yr)	***$ 11,279,307***	
Total Capital Investment ($) (5)	***$ 30,393,982***	
Fixed Charge Rate	12%	
Non-Feedstock Production Cost ($/gal)	**$ 0.29**	*Biodiesel production cost*

1) Calculated using a heating value of oil feedstocks of 16,500 Btu/lb, and a typical biodiesel heating value of 117,000 Btu/gal.

2) Based on average glycerin production from Bender 1999 and Haas et all. 2006 for virgin feedstocks (0.8 lb/gal). Note that waste oils may produce slighly higher glycerin yields, but this has not been included in the analysis.

3) Scaled based on data from Haas et al 2006. Annual water use is 0.25 lb water per gallon biodiesel produced.

4) Current market prices for glycerin from biodiesel plants is about $0.05/lb, based on Nilles (Sept. 2006) and personal communication with Leland Tong (National Biodiesel Board contributor).

5) Capital cost data for virgin oil feedstock from Haas et al. 2006. Waste grease (acid catalyzed) facility equipment cost from Zhang et al. 2003b, with added cost for storage facilities from Haas et al. 2006. Multiplier from Haas et al. 2006 was used to calculate TCI. A scalling factor of 0.6 is used for all facilities. This value was verified using data from Bender 1999.

O&M Costs (1)	
Variable O&M (2)	
Consumables ($/yr) (3)	$ 8,348,143
Utilities ($/yr)	$ 2,168,880
Total Variable O&M ($/yr)	***$ 10,517,023***
Fixed O&M	
Annual Labor Cost ($/yr) (4)	$ 2,189,611
Other Fixed O&M ($/yr) (5)	$ 638,274
Total Fixed O&M ($/yr)	***$ 2,827,884***

1) All costs reported in 2006 US$. Where necessary, cost have been converted using CEPCI. Data source used for O&M costs for virgin feedstocks is Haas et al. 2006. Waste grease facility data also from Zhang et al. 2003b.

2) Consumables include methanol, sodium methoxide, hydrochloric acid, sodium hydroxide, and water. Utilities include natural gas, WWT and waste disposal, and electricity.

3) Data from Haas et al. 2006 used for virgin feedstocks. Waste grease cost based on Haas et al. 2006 data, but adjusted to incorporate increased quantity of methanol and different catalyst using data from Zhang et al 2003.

4) Based on data for a virgin oil facility from Haas et. al 2006, but increased operator salary to $20/hr from $12.5/hr, based on Antares experience. Values in the literature suggest that acid catalyzed facilities have higher labor requirements, so Antares estimated there would be 1 additional operator per shift (for a 10 MGY facility). For comparison, the base catalyzed facility had 2 operators per shift. Labor cost includes scaling by facility size (based on available data from pyrolysis oil production facilities.)

5) Other fixed O&M costs (including taxes, insurance, and supplies) are 2.1% of capital cost.

Feedstock (1)	Yield range (gal/ton)	Average Yield (gal/ton)	*Sources*
Virgin Oil (2)	246.4-270.0	258.2	*Haas et. al 2006, Sheehan et al. 1998, Zhang et al. 2003a, Canakci and van Gerpen 2001*
Animal Fats	266.3	266.3	*Bender 1999*
Yellow Grease (3)	234.9 - 263.2	249.1	*Zhang et al. 2003a, Canakci and van Gerpen 2001*

1) All data based on feedstocks with negligible water content.

2) Based on data for degummed soybean oil. High end of the yield range from Haas et al 2006, which assumes a negligible free fatty acid content in the feedstock.

3) Conversion yield for waste greases based on acid catalyzed reaction. For comparison, the transesterification reaction for virgin feedstocks use base catalysts.

Summary Page - Costs & Yield Data, Current Biodiesel (FAME) - Example #2

Inputs

Feedstock Type	**Yellow Grease**
Economic Lifetime of Plant (Years)	25
Weighted Cost of Capital	10%

Base catalyzed transesterification is used for virgin feedstocks, and acid catalyzed transesterification is used for waste greases.

	Current	
Applicable Feedstocks	virgin oil, animal fat, waste grease	
Applicable Size Range (MGY)	1 - 80	
Feedstock Input (ton/yr)	200,000	
Yield Biodiesel (ton/yr)	183,052	
Yield Biodiesel (MGY)	49.8	
Conversion Efficiency (HHV) (1)	88%	
Consumables and By-Products		
Crude Glycerin Yield (ton/yr) (2)	19,924	
Water Consumption (1000 gal/yr) (3)	1,491	
Biodiesel Production Costs		
Fixed O&M ($/yr)	$ 3,670,077	
Variable O&M ($/yr)	$ 26,399,300	
Co-product credit ($/yr) (4)	$ (1,992,400)	
Annual Operating Cost ($/yr)	***$ 28,076,977***	
Total Capital Investment ($) (5)	***$ 47,259,808***	
Fixed Charge Rate	12%	
Non-Feedstock Production Cost ($/gal)	**$ 0.68**	*Biodiesel production cost*

1) Calculated using a heating value of oil feedstocks of 16,500 Btu/lb, and a typical biodiesel heating value of 117,000 Btu/gal.

2) Based on average glycerin production from Bender 1999 and Haas et all. 2006 for virgin feedstocks (0.8 lb/gal). Note that waste oils may produce slighly higher glycerin yields, but this has not been included in the analysis.

3) Scaled based on data from Haas et al 2006. Annual water use is 0.25 lb water per gallon biodiesel produced.

4) Current market prices for glycerin from biodiesel plants is about $0.05/lb, based on Nilles (Sept. 2006) and personal communication with Leland Tong (National Biodiesel Board contributor).

5) Capital cost data for virigin oil feedstock from Haas et al. 2006. Waste grease (acid catalyzed) facility equipment cost from Zhang et al. 2003b, with added cost for storage facilities from Haas et al. 2006. Multiplier from Haas et al. 2006 was used to calculate TCI. A scalling factor of 0.6 is used for all facilities. This value was verified using data from Bender 1999.

O&M Costs (1)	
Variable O&M (2)	
Consumables ($/yr) (3)	$ 9,962,000
Utilities ($/yr)	$ 16,437,300
Total Variable O&M ($/yr)	***$ 26,399,300***
Fixed O&M	
Annual Labor Cost ($/yr) (4)	$ 2,677,621
Other Fixed O&M ($/yr) (5)	$ 992,456
Total Fixed O&M ($/yr)	***$ 3,670,077***

1) All costs reported in 2006 US$. Where necessary, cost have been converted using CEPCI. Data source used for O&M costs for virgin feedstocks is Haas et al. 2006. Waste grease facility data also from Zhang et al. 2003b.

2) Consumables include methanol, sodium methoxide, hydrochloric acid, sodium hydroxide, and water. Utilities include natural gas, WWT and waste disposal, and electricity.

3) Data from Haas et al. 2006 used for virgin feedstocks. Waste grease cost based on Haas et al. 2006 data, but adjusted to incorporate increased quantity of methanol and different catalyst using data from Zhang et al 2003.

4) Based on data for a virgin oil facility from Haas et. al 2006, but increased operator salary to $20/hr from $12.5/hr, based on Antares experience. Values in the literature suggest that acid catalyzed facilities have higher labor requirements, so Antares estimated there would be 1 additional operator per shift (for a 10 MGY facility). For comparison, the base catalyzed facility had 2 operators per shift. Labor cost includes scaling by facility size (based on available data from pyrolysis oil production facilities.)

5) Other fixed O&M costs (including taxes, insurance, and supplies) are 2.1% of capital cost.

Feedstock (1)	Yield range (gal/ton)	Average Yield (gal/ton)	*Sources*
Virgin Oil (2)	246.4-270.0	258.2	*Haas et. al 2006, Sheehan et al. 1998, Zhang et al. 2003a, Canakci and van Gerpen 2001*
Animal Fats	266.3	266.3	*Bender 1999*
Yellow Grease (3)	234.9 - 263.2	249.1	*Zhang et al. 2003a, Canakci and van Gerpen 2001*

1) All data based on feedstocks with negligible water content.

2) Based on data for degummed soybean oil. High end of the yield range from Haas et al 2006, which assumes a negligible free fatty acid content in the feedstock.

3) Conversion yield for waste greases based on acid catalyzed reaction. For comparison, the transesterification reaction for virgin feedstocks use base catalysts.

Summary Page - Costs & Yield Data, Lignocellulosic Ethanol Production - Example #1

Inputs

Feedstock Type	**Poplar**
Economic Lifetime of Plant (Years)	25
Weighted Cost of Capital	10%

	Short Term (2010)	Mid Term (2015-2020)	Long Term (2025+)
Applicable Feedstocks	clean herbaceous feedstocks (agricultural residues and grasses) and de-barked wood chips		
Applicable Size Range (MGY)	25 - 60	60 - 150	60 - 300
Feedstock Input (dry ton/yr)	500,000	700,000	1,000,000
Feedstock Input (MMBtu/yr)	9,000,000	12,600,000	18,000,000
Yield - Dilute Acid (gal/dry ton)	76.9	85.9	91.9
Yield - Advanced Tech (gal/dry ton)	--	81.2	98.6
Conversion efficiency (HHV)	36%	40%	43%
Ethanol Production (MGY)	**38.4**	**60**	**92**
Pretreatment Technology	Dilute Acid	Dilute Acid	Dilute Acid
Capital Cost ($/gallon)	7.13	3.39	2.33
Consumables and By-Products			
CO2 Stream (ton/yr) (1)	121,800	190,400	291,000
Water Consumption (1000 gal/yr) (2)	267,100	373,900	534,200
Net Electricity Production (kWh/gal) (3)	2.62	2.01	0.00
Ethanol Production Costs			
Fixed O&M ($/yr) (3)	$ 10,421,977	$ 7,145,931	$ 8,119,959
Fixed O&M ($/gal/yr)	$ 0.27	$ 0.12	$ 0.09
Variable O&M ($/gal/yr) (3)	$ 0.25	$ 0.18	$ 0.14
Electricity Value ($/gal/yr) (4)	$ (0.15)	$ (0.11)	$ -
Net Electricity Value ($/yr) - credit	$ 5,732,921	$ 6,885,555	$ -
Annual Operating Cost ($/yr)	***$ 14,119,838***	***$ 10,817,761***	***$ 20,781,591***
Total Capital Cost ($) (5)	***$ 274,189,133***	***$ 203,437,293***	***$ 213,924,081***
Fixed Charge Rate	12.3%	12.3%	12.3%
Annual Capital Payment ($/gal/yr)	$ 0.87	$ 0.42	$ 0.29
Non-Feedstock Production Cost ($/gal)	**$ 1.24**	**$ 0.60**	**$ 0.51**

Ethanol Production Cost

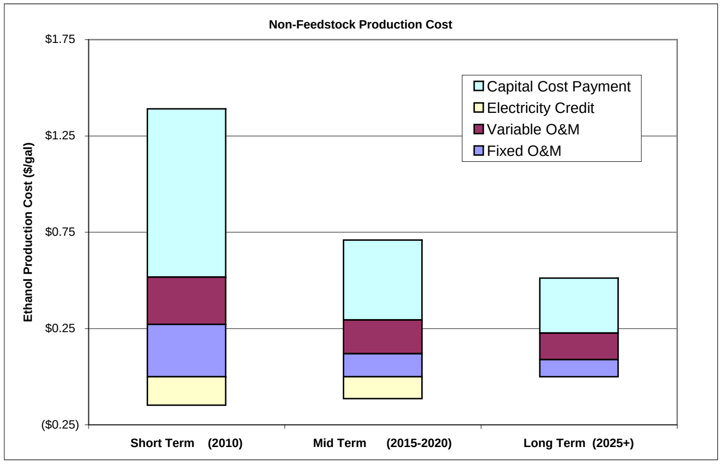
1) Estimated by assuming that the amount of CO2 produced is approximately 96% of the weight of ethanol produced, since the theoretical max yield is 51% ethanol and 49% CO2 (by weight) from sugars.

2) Calculated based on the annual feedstock input, using data from Wooley et al. (1999) for near-term dilute acid process. Potential changes in water consumption for different time periods or for different pretreatment processes are not included in this analysis.

3) Short term value is average of values reported in the literature - see table below for details.

4) Based on average electricity price for industrial consumers in 2005, from EIA (2006).

5) Total capital cost is based on the average TCI values from the literature (shown in the table below), scaled by facility size within a particular size range using a scaling factor of 0.8.



Plant Capacity (MGY)	Total Capital Investment ($/gallon) (1) Short Term	Mid Term	Long Term	Pretreatment Technology	
25 - 60	$ 7.05	--	--	*Dilute Acid*	*average size 40.7 MGY*
60 - 100	--	$ 3.31	$ 2.35	*Dilute Acid*	*mid term average size 67.7 MGY, long term 88 MGY*
> 100 (2)	--	$ 4.61	$ 3.45	*Steam Explosion, LHW*	*mid term size 130 MGY, long term 311 MGY*

1) Based on average of results from Hamelinck et al. 2005, Wooley et al. 1999, Aden et al. 2002, and McAloon et al. 2000. BIGCC case and best of industry are excluded from capital cost estimates, as they are not representative of an average facility.
2) Trend suggests that large ethanol facilities (>100 MGY) have higher capital costs than medium facilities, similar to dry mill corn ethanol plants (Gallagher et al. 2005). However, the larger facilities are based on advanced pretreatment technologies (steam explosion and LHW for mid and long term), while the small and medium plants (<100 MGY) are based on dilute acid pretreatment. Ethanol production costs will vary by technology.

Conversion (% of theoretical) (1)					
	Short Term	*Mid Term*		*Long Term*	
Pretreatment Technology	*Dilute Acid*	*Dilute Acid*	*Steam Explosion*	*Dilute Acid*	*LHW*
Saacharification					
Hemicellulose	83%	85%	55%	85%	93%
Cellulose	75%	85%	93%	90%	98%
Fermentation					
Xylose & other sugars (2)	86%	90%	85%	95%	94%
Glucose (2)	93%	94%	93%	95%	94%
Source	*Hamelinck et al. 2005, Wooley et al. 1999*	*Wooley et al. 1999*	*Hamelinck et al. 2005*	*Wooley et al. 1999*	*Hamelinck et al. 2005*

1) Average conversion estimates based on poplar feedstock and the reported pretreatment technologies. The advanced technologies for mid and long term pretreatments may not be suitable for all feedstocks.

2) Cellulose is converted to glucose during saccharification, while hemicellulose is converted to xylose and other sugars

Feedstock Composition				Yield	Actual Yield (gal/ton) (2)								
Feedstock	**Hemicellulose (wt%)**	**Cellulose (wt%)**	**Lignin (wt%)**	**Theoretical Yield (1) (gal/dry ton)**	**Short Term (Dilute Acid)**	**Comparative Values (3)**	**Mid Term (Dilute Acid)**	**Mid Term (Steam Explosion)**	**Comparative Values (3)**	**Long Term (Dilute Acid)**	**Long Term (LHW)**	**Comparative Values (3)**	**HHV (Btu/lb) (4)**
Agricultural Resources													
Corn Stover (5)	23.23%	36.20%	18.50%	107.6	72.6	68.5	80.6	77.3	90.6	86.0	82.0		8,185
Wheat Straw (5)	23.20%	33.47%	17.28%	98.8	69.3		76.8	73.6		82.0	77.9		8,500
Bagasse (5)	25.79%	40.37%	23.90%	116.2	80.8		89.7	85.9		95.8	91.0		8,500
Grass Resources													
Switchgrass (6)	25.19%	31.98%	18.13%	99.7	70.0		77.4	74.4		82.6	78.7		8,400
Woody Resources													
Hybrid poplar (6)	18.55%	44.70%	26.44%	109.9	76.9	73.0	85.9	81.2	86.9	91.9	98.6	107.4	9,000
Black locust (6)	17.66%	41.61%	26.70%	103.0	72.1		80.4	75.9		86.1	92.4		9,000
Eucalyptus (6)	13.07%	49.50%	27.71%	108.6	75.8		85.0	83.8		91.1	97.8		9,000
Pine (6)	21.90%	44.55%	27.67%	115.1	80.9		90.2	83.7		96.4	103.5		9,130

1) Yield values from EERE's Theoretical Ethanol Yield Calculator (http://www1.eere.energy.gov/biomass/ethanol_yield_calculator.html), based on sugar content

2) Actual yields calculated based on average conversion values for all feedstocks in short term, and wood for all terms. Agricultural and grass feedstock yields for advanced mid and long term pretreatment technologies based on average increase of wood feedstock yields from short to mid term (4.4% of theoretical), as the conversion technology information does not apply to these materials, but other comparable advanced technologies may apply.

3) Comparative values based on average values from published research, only available for select feedstocks. Includes various pretreatment technologies.

4) Higher Heating Value (HHV) given for dry feedstocks. Data from (Energy Research Centre of the Netherlands, n.d.).

5) Biochemical composition data from U.S. DOE Biomass Feedstock Composition and Property Database, adjusted to 100% mass closure

6) Biochemical composition data from Hamelinck et al. 2005

O&M Costs (1)	**Short Term**			**Mid Term**		**Long Term (2)**	
Ethanol Production (MGY)	24	45	52.2	67.2	130	87.5	311
Pretreatment		dilute acid		dilute acid	steam explosion	dilute acid	LHW
Fixed O&M (3) (million$/yr)	$ 11.35	$ 10.61	$ 9.30	$ 7.99	$ 23.00	$ 7.73	$ 30.56
Fixed O&M ($/gal/yr)	$ 0.48	$ 0.24	$ 0.18	$ 0.12	$ 0.18	$ 0.09	$ 0.10
Variable O&M (4) ($/gal/yr)	$ 0.27	$ 0.24	$ 0.23	$ 0.18	$ 0.21	$ 0.14	$ 0.09
Total ($/gal/yr)	$ 0.74	$ 0.47	$ 0.41	$ 0.29	$ 0.39	$ 0.23	$ 0.19
Co-Products (5)							
Net Electricity Production (kWh/gal)	2.92	3.16	1.76	2.01	6.33	0.00	2.11
Source	*McAloon et al. 2000*	*Hamelinck et al. 2005*	*Wooley et al. 1999*	*Wooley et al. 1999*	*Hamelinck et al. 2005*	*Wooley et al. 1999*	*Hamelinck et al. 2005*

1) All costs reported in 2006$, converted using CEPCI where needed. All sources use poplar feedstock except McAloon et. al, which uses corn stover.

2) Long term Variable O&M estimated based on decreased cellulase costs from mid term, equivalent to $0.12/gal/yr

3) Fixed O&M includes labor, maintenance supplies, insurance and property taxes

4) Variable O&M includes raw materials (sulfuric acid & lime for dilute acid, cellulase or ammonia & CSL for cellulase production, other chemicals) and solids disposal (i.e. ash and gypsum).

5) Net electricity production based on heat and power production with partially dried solid residuals (lignin, cell mass) and unfermented sugars (dried to a syrup), fired in a boiler. Note that the net electricity production for the steam explosion pretreatment is much higher than other pretreatment, as this method has lower steam requirements. Furthermore, cellulase is not made on site in the steam explosion case, which means a larger quantity of non-fermented sugars and residuals are available for power generation.

Summary Page - Costs & Yield Data, Lignocellulosic Ethanol Production - Example #2

Inputs

Feedstock Type	**Switchgrass**
Economic Lifetime of Plant (Years)	25
Weighted Cost of Capital	10%

	Short Term (2010)	Mid Term (2015-2020)	Long Term (2025+)
Applicable Feedstocks	clean herbaceous feedstocks (agricultural residues and grasses) and de-barked wood chips		
Applicable Size Range (MGY)	25 - 60	60 - 150	60 - 300
Feedstock Input (dry ton/yr)	500,000	800,000	1,000,000
Feedstock Input (MMBtu/yr)	8,400,000	13,440,000	16,800,000
Yield - Dilute Acid (gal/dry ton)	70.0	77.4	82.6
Yield - Advanced Tech (gal/dry ton)	--	74.4	78.7
Conversion efficiency (HHV)	35%	39%	41%
Ethanol Production (MGY)	**35.0**	**62**	**83**
Pretreatment Technology	Dilute Acid	Dilute Acid	Dilute Acid
Capital Cost ($/gallon)	7.27	3.36	2.38
Consumables and By-Products			
CO_2 Stream (ton/yr) (1)	110,800	196,200	261,700
Water Consumption (1000 gal/yr) (2)	267,100	427,300	534,200
Net Electricity Production (kWh/gal) (3)	2.62	2.01	0.00
Ethanol Production Costs			
Fixed O&M ($/yr) (3)	$ 10,421,977	$ 7,365,473	$ 7,302,905
Fixed O&M ($/gal/yr)	$ 0.30	$ 0.12	$ 0.09
Variable O&M ($/gal/yr) (3)	$ 0.25	$ 0.18	$ 0.14
Electricity Value ($/gal/yr) (4)	$ (0.15)	$ (0.11)	$ -
Net Electricity Value ($/yr) - credit	$ 5,216,976	$ 7,097,098	$ -
Annual Operating Cost ($/yr)	***$ 13,787,042***	***$ 11,150,111***	***$ 18,690,486***
Total Capital Cost ($) (5)	***$ 254,263,820***	***$ 208,422,229***	***$ 196,522,873***
Fixed Charge Rate	12.3%	12.3%	12.3%
Annual Capital Payment ($/gal/yr)	$ 0.89	$ 0.41	$ 0.29
Non-Feedstock Production Cost ($/gal)	**$ 1.29**	**$ 0.59**	**$ 0.52**

Ethanol Production Cost

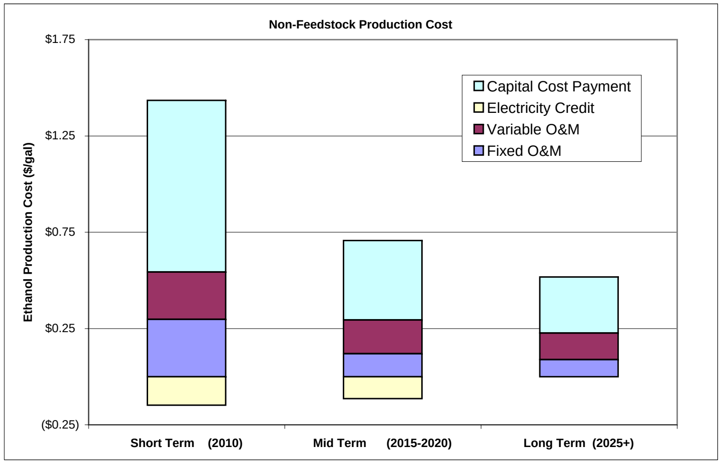
1) Estimated by assuming that the amount of CO2 produced is approximately 96% of the weight of ethanol produced, since the theoretical max yield is 51% ethanol and 49% CO2 (by weight) from sugars.

2) Calculated based on the annual feedstock input, using data from Wooley et al. (1999) for near-term dilute acid process. Potential changes in water consumption for different time periods or for different pretreatment processes are not included in this analysis.

3) Short term value is average of values reported in the literature - see table below for details.

4) Based on average electricity price for industrial consumers in 2005, from EIA (2006).

5) Total capital cost is based on the average TCI values from the literature (shown in the table below), scaled by facility size within a particular size range using a scaling factor of 0.8.



Plant Capacity (MGY)	Total Capital Investment ($/gallon) (1) Short Term	Mid Term	Long Term	Pretreatment Technology	
25 - 60	$ 7.05	--	--	*Dilute Acid*	*average size 40.7 MGY*
60 - 100	--	$ 3.31	$ 2.35	*Dilute Acid*	*mid term average size 67.7 MGY, long term 88 MGY*
> 100 (2)	--	$ 4.61	$ 3.45	*Steam Explosion, LHW*	*mid term size 130 MGY, long term 311 MGY*

1) Based on average of results from Hamelinck et al. 2005, Wooley et al. 1999, Aden et al. 2002, and McAloon et al. 2000. BIGCC case and best of industry are excluded from capital cost estimates, as they are not representative of an average facility.
2) Trend suggests that large ethanol facilities (>100 MGY) have higher capital costs than medium facilities, similar to dry mill corn ethanol plants (Gallagher et al. 2005). However, the larger facilities are based on advanced pretreatment technologies (steam explosion and LHW for mid and long term), while the small and medium plants (<100 MGY) are based on dilute acid pretreatment. Ethanol production costs will vary by technology.

Conversion (% of theoretical) (1)					
	Short Term	*Mid Term*		*Long Term*	
Pretreatment Technology	*Dilute Acid*	*Dilute Acid*	*Steam Explosion*	*Dilute Acid*	*LHW*
Saacharification					
Hemicellulose	83%	85%	55%	85%	93%
Cellulose	75%	85%	93%	90%	98%
Fermentation					
Xylose & other sugars (2)	86%	90%	85%	95%	94%
Glucose (2)	93%	94%	93%	95%	94%
Source	*Hamelinck et al. 2005, Wooley et al. 1999*	*Wooley et al. 1999*	*Hamelinck et al. 2005*	*Wooley et al. 1999*	*Hamelinck et al. 2005*

1) Average conversion estimates based on poplar feedstock and the reported pretreatment technologies. The advanced technologies for mid and long term pretreatments may not be suitable for all feedstocks.

2) Cellulose is converted to glucose during saccharification, while hemicellulose is converted to xylose and other sugars

	Feedstock Composition			Yield	*Actual Yield (gal/ton) (2)*								
Feedstock	**Hemicellulose (wt%)**	**Cellulose (wt%)**	**Lignin (wt%)**	**Theoretical Yield (1) (gal/dry ton)**	**Short Term (Dilute Acid)**	**Comparative Values (3)**	**Mid Term (Dilute Acid)**	**Mid Term (Steam Explosion)**	**Comparative Values (3)**	**Long Term (Dilute Acid)**	**Long Term (LHW)**	**Comparative Values (3)**	**HHV (Btu/lb) (4)**
Agricultural Resources													
Corn Stover (5)	23.23%	36.20%	18.50%	107.6	72.6	68.5	80.6	77.3	90.6	86.0	82.0		8,185
Wheat Straw (5)	23.20%	33.47%	17.28%	98.8	69.3		76.8	73.6		82.0	77.9		8,500
Bagasse (5)	25.79%	40.37%	23.90%	116.2	80.8		89.7	85.9		95.8	91.0		8,500
Grass Resources													
Switchgrass (6)	25.19%	31.98%	18.13%	99.7	70.0		77.4	74.4		82.6	78.7		8,400
Woody Resources													
Hybrid poplar (6)	18.55%	44.70%	26.44%	109.9	76.9	73.0	85.9	81.2	86.9	91.9	98.6	107.4	9,000
Black locust (6)	17.66%	41.61%	26.70%	103.0	72.1		80.4	75.9		86.1	92.4		9,000
Eucalyptus (6)	13.07%	49.50%	27.71%	108.6	75.8		85.0	83.8		91.1	97.8		9,000
Pine (6)	21.90%	44.55%	27.67%	115.1	80.9		90.2	83.7		96.4	103.5		9,130

1) Yield values from EERE's Theoretical Ethanol Yield Calculator (http://www1.eere.energy.gov/biomass/ethanol_yield_calculator.html), based on sugar content

2) Actual yields calculated based on average conversion values for all feedstocks in short term, and wood for all terms. Agricultural and grass feedstock yields for advanced mid and long term pretreatment technologies based on average increase of wood feedstock yields from short to mid term (4.4% of theoretical), as the conversion technology information does not apply to these materials, but other comparable advanced technologies may apply.

3) Comparative values based on average values from published research, only available for select feedstocks. Includes various pretreatment technologies.

4) Higher Heating Value (HHV) given for dry feedstocks. Data from (Energy Research Centre of the Netherlands, n.d.).

5) Biochemical composition data from U.S. DOE Biomass Feedstock Composition and Property Database, adjusted to 100% mass closure

6) Biochemical composition data from Hamelinck et al. 2005

O&M Costs (1)	**Short Term**			**Mid Term**		**Long Term (2)**	
Ethanol Production (MGY)	24	45	52.2	67.2	130	87.5	311
Pretreatment		dilute acid		dilute acid	steam explosion	dilute acid	LHW
Fixed O&M (3) (million$/yr)	$ 11.35	$ 10.61	$ 9.30	$ 7.99	$ 23.00	$ 7.73	$ 30.56
Fixed O&M ($/gal/yr)	$ 0.48	$ 0.24	$ 0.18	$ 0.12	$ 0.18	$ 0.09	$ 0.10
Variable O&M (4) ($/gal/yr)	$ 0.27	$ 0.24	$ 0.23	$ 0.18	$ 0.21	$ 0.14	$ 0.09
Total ($/gal/yr)	$ 0.74	$ 0.47	$ 0.41	$ 0.29	$ 0.39	$ 0.23	$ 0.19
Co-Products (5)							
Net Electricity Production (kWh/gal)	2.92	3.16	1.76	2.01	6.33	0.00	2.11
Source	*McAloon et al. 2000*	*Hamelinck et al. 2005*	*Wooley et al. 1999*	*Wooley et al. 1999*	*Hamelinck et al. 2005*	*Wooley et al. 1999*	*Hamelinck et al. 2005*

1) All costs reported in 2006$, converted using CEPCI where needed. All sources use poplar feedstock except McAloon et. al, which uses corn stover.

2) Long term Variable O&M estimated based on decreased cellulase costs from mid term, equivalent to $0.12/gal/yr

3) Fixed O&M includes labor, maintenance supplies, insurance and property taxes

4) Variable O&M includes raw materials (sulfuric acid & lime for dilute acid, cellulase or ammonia & CSL for cellulase production, other chemicals) and solids disposal (i.e. ash and gypsum).

5) Net electricity production based on heat and power production with partially dried solid residuals (lignin, cell mass) and unfermented sugars (dried to a syrup), fired in a boiler. Note that the net electricity production for the steam explosion pretreatment is much higher than other pretreatment, as this method has lower steam requirements. Furthermore, cellulase is not made on site in the steam explosion case, which means a larger quantity of non-fermented sugars and residuals are available for power generation.

Summary Page - Costs & Yield Data, Lignocellulosic Ethanol Production - Example #3

Inputs

Feedstock Type	**Poplar**
Economic Lifetime of Plant (Years)	25
Weighted Cost of Capital	10%

	Short Term (2010)	Mid Term (2015-2020)	Long Term (2025+)
Applicable Feedstocks	clean herbaceous feedstocks (agricultural residues and grasses) and de-barked wood chips		
Applicable Size Range (MGY)	25 - 60	60 - 150	60 - 300
Feedstock Input (dry ton/yr)	500,000	1,200,000	1,500,000
Feedstock Input (MMBtu/yr)	9,000,000	21,600,000	27,000,000
Yield - Dilute Acid (gal/dry ton)	76.9	85.9	91.9
Yield - Advanced Tech (gal/dry ton)	--	81.2	98.6
Conversion efficiency (HHV)	36%	38%	46%
Ethanol Production (MGY)	**38.4**	**97**	**148**
Pretreatment Technology	Dilute Acid	Steam Explosion	LHW
Capital Cost ($/gallon)	7.13	3.07	4.01
Consumables and By-Products			
CO_2 Stream (ton/yr) (1)	121,800	308,700	468,500
Water Consumption (1000 gal/yr) (2)	267,100	641,000	801,300
Net Electricity Production (kWh/gal) (3)	2.62	6.33	2.11
Ethanol Production Costs			
Fixed O&M ($/yr) (3)	$ 10,421,977	$ 17,239,654	$ 14,531,960
Fixed O&M ($/gal/yr)	$ 0.27	$ 0.18	$ 0.10
Variable O&M ($/gal/yr) (3)	$ 0.25	$ 0.21	$ 0.09
Electricity Value ($/gal/yr) (4)	$ (0.15)	$ (0.36)	$ (0.12)
Net Electricity Value ($/yr) - credit	$ 5,732,921	$ 35,138,837	$ 17,777,448
Annual Operating Cost ($/yr)	***$ 14,119,838***	***$ 2,848,478***	***$ 10,499,859***
Total Capital Cost ($) (5)	***$ 274,189,133***	***$ 299,420,939***	***$ 592,685,668***
Fixed Charge Rate	12.3%	12.3%	12.3%
Annual Capital Payment ($/gal/yr)	$ 0.87	$ 0.38	$ 0.49
Non-Feedstock Production Cost ($/gal)	**$ 1.24**	**$ 0.41**	**$ 0.56**

Ethanol Production Cost

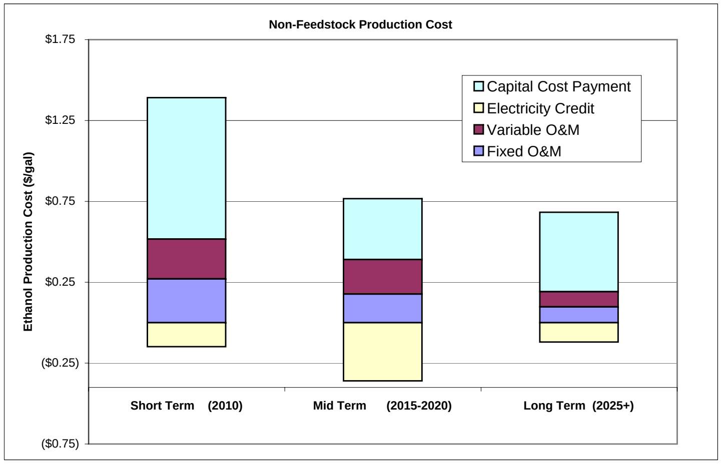
1) Estimated by assuming that the amount of CO2 produced is approximately 96% of the weight of ethanol produced, since the theoretical max yield is 51% ethanol and 49% CO2 (by weight) from sugars.

2) Calculated based on the annual feedstock input, using data from Wooley et al. (1999) for near-term dilute acid process. Potential changes in water consumption for different time periods or for different pretreatment processes are not included in this analysis.

3) Short term value is average of values reported in the literature - see table below for details.

4) Based on average electricity price for industrial consumers in 2005, from EIA (2006).

5) Total capital cost is based on the average TCI values from the literature (shown in the table below), scaled by facility size within a particular size range using a scaling factor of 0.8.



Plant Capacity (MGY)	Total Capital Investment ($/gallon) (1) Short Term	Mid Term	Long Term	Pretreatment Technology	
25 - 60	$ 7.05	--	--	*Dilute Acid*	*average size 40.7 MGY*
60 - 100	--	$ 3.31	$ 2.35	*Dilute Acid*	*mid term average size 67.7 MGY, long term 88 MGY*
> 100 (2)	--	$ 4.61	$ 3.45	*Steam Explosion, LHW*	*mid term size 130 MGY, long term 311 MGY*

1) Based on average of results from Hamelinck et al. 2005, Wooley et al. 1999, Aden et al. 2002, and McAloon et al. 2000. BIGCC case and best of industry are excluded from capital cost estimates, as they are not representative of an average facility.
2) Trend suggests that large ethanol facilities (>100 MGY) have higher capital costs than medium facilities, similar to dry mill corn ethanol plants (Gallagher et al. 2005). However, the larger facilities are based on advanced pretreatment technologies (steam explosion and LHW for mid and long term), while the small and medium plants (<100 MGY) are based on dilute acid pretreatment. Ethanol production costs will vary by technology.

Conversion (% of theoretical) (1)					
	Short Term	*Mid Term*		*Long Term*	
Pretreatment Technology	*Dilute Acid*	*Dilute Acid*	*Steam Explosion*	*Dilute Acid*	*LHW*
Saacharification					
Hemicellulose	83%	85%	55%	85%	93%
Cellulose	75%	85%	93%	90%	98%
Fermentation					
Xylose & other sugars (2)	86%	90%	85%	95%	94%
Glucose (2)	93%	94%	93%	95%	94%
Source	*Hamelinck et al. 2005, Wooley et al. 1999*	*Wooley et al. 1999*	*Hamelinck et al. 2005*	*Wooley et al. 1999*	*Hamelinck et al. 2005*

1) Average conversion estimates based on poplar feedstock and the reported pretreatment technologies. The advanced technologies for mid and long term pretreatments may not be suitable for all feedstocks.

2) Cellulose is converted to glucose during saccharification, while hemicellulose is converted to xylose and other sugars

Feedstock Composition				Yield	*Actual Yield (gal/ton) (2)*								
Feedstock	**Hemicellulose (wt%)**	**Cellulose (wt%)**	**Lignin (wt%)**	**Theoretical Yield (1) (gal/dry ton)**	**Short Term (Dilute Acid)**	**Comparative Values (3)**	**Mid Term (Dilute Acid)**	**Mid Term (Steam Explosion)**	**Comparative Values (3)**	**Long Term (Dilute Acid)**	**Long Term (LHW)**	**Comparative Values (3)**	**HHV (Btu/lb) (4)**
Agricultural Resources													
Corn Stover (5)	23.23%	36.20%	18.50%	107.6	72.6	68.5	80.6	77.3	90.6	86.0	82.0		8,185
Wheat Straw (5)	23.20%	33.47%	17.28%	98.8	69.3		76.8	73.6		82.0	77.9		8,500
Bagasse (5)	25.79%	40.37%	23.90%	116.2	80.8		89.7	85.9		95.8	91.0		8,500
Grass Resources													
Switchgrass (6)	25.19%	31.98%	18.13%	99.7	70.0		77.4	74.4		82.6	78.7		8,400
Woody Resources													
Hybrid poplar (6)	18.55%	44.70%	26.44%	109.9	76.9	73.0	85.9	81.2	86.9	91.9	98.6	107.4	9,000
Black locust (6)	17.66%	41.61%	26.70%	103.0	72.1		80.4	75.9		86.1	92.4		9,000
Eucalyptus (6)	13.07%	49.50%	27.71%	108.6	75.8		85.0	83.8		91.1	97.8		9,000
Pine (6)	21.90%	44.55%	27.67%	115.1	80.9		90.2	83.7		96.4	103.5		9,130

1) Yield values from EERE's Theoretical Ethanol Yield Calculator (http://www1.eere.energy.gov/biomass/ethanol_yield_calculator.html), based on sugar content

2) Actual yields calculated based on average conversion values for all feedstocks in short term, and wood for all terms. Agricultural and grass feedstock yields for advanced mid and long term pretreatment technologies based on average increase of wood feedstock yields from short to mid term (4.4% of theoretical), as the conversion technology information does not apply to these materials, but other comparable advanced technologies may apply.

3) Comparative values based on average values from published research, only available for select feedstocks. Includes various pretreatment technologies.

4) Higher Heating Value (HHV) given for dry feedstocks. Data from (Energy Research Centre of the Netherlands, n.d.).

5) Biochemical composition data from U.S. DOE Biomass Feedstock Composition and Property Database, adjusted to 100% mass closure

6) Biochemical composition data from Hamelinck et al. 2005

O&M Costs (1)	**Short Term**			**Mid Term**		**Long Term (2)**	
Ethanol Production (MGY)	24	45	52.2	67.2	130	87.5	311
Pretreatment		dilute acid		dilute acid	steam explosion	dilute acid	LHW
Fixed O&M (3) (million$/yr)	$ 11.35	$ 10.61	$ 9.30	$ 7.99	$ 23.00	$ 7.73	$ 30.56
Fixed O&M ($/gal/yr)	$ 0.48	$ 0.24	$ 0.18	$ 0.12	$ 0.18	$ 0.09	$ 0.10
Variable O&M (4) ($/gal/yr)	$ 0.27	$ 0.24	$ 0.23	$ 0.18	$ 0.21	$ 0.14	$ 0.09
Total ($/gal/yr)	$ 0.74	$ 0.47	$ 0.41	$ 0.29	$ 0.39	$ 0.23	$ 0.19
Co-Products (5)							
Net Electricity Production (kWh/gal)	2.92	3.16	1.76	2.01	6.33	0.00	2.11
Source	*McAloon et al. 2000*	*Hamelinck et al. 2005*	*Wooley et al. 1999*	*Wooley et al. 1999*	*Hamelinck et al. 2005*	*Wooley et al. 1999*	*Hamelinck et al. 2005*

1) All costs reported in 2006$, converted using CEPCI where needed. All sources use poplar feedstock except McAloon et. al, which uses corn stover.

2) Long term Variable O&M estimated based on decreased cellulase costs from mid term, equivalent to $0.12/gal/yr

3) Fixed O&M includes labor, maintenance supplies, insurance and property taxes

4) Variable O&M includes raw materials (sulfuric acid & lime for dilute acid, cellulase or ammonia & CSL for cellulase production, other chemicals) and solids disposal (i.e. ash and gypsum).

5) Net electricity production based on heat and power production with partially dried solid residuals (lignin, cell mass) and unfermented sugars (dried to a syrup), fired in a boiler. Note that the net electricity production for the steam explosion pretreatment is much higher than other pretreatment, as this method has lower steam requirements. Furthermore, cellulase is not made on site in the steam explosion case, which means a larger quantity of non-fermented sugars and residuals are available for power generation.

Summary Page - Costs & Yield Data, Fischer Tropsch Conversion to Middle Distillates

Inputs

Feedstock Type	**Poplar**
Economic Lifetime of Plant (Years)	25
Weighted Cost of Capital	10%

	Mid Term		
Applicable Feedstocks	woody & agricultural		
Applicable Size Range (dry tons/yr) (1)	> 185,000		
Feedstock Input (dry ton/yr)	700,000		Basis for model - BCL gasifier w/ SMR, with CC power generation
Feedstock Input (MMBtu/yr), LHV	11,760,000		
Yield FT Distillates (MGY) (2)	28.4		
Conversion Efficiency (LHV) (3)	42%		
Consumables and By-Products			
Yield FT Naptha (MGY) (4)	12.2		
Net Electricity Production (kWh/yr) (5)	540,859,442		
Water Consumption (1000 gal/yr)	33,506		
FT Distillate Production Costs			
Fixed O&M ($/yr) (6)	$	21,062,901	
Variable O&M ($/yr)	$	7,719,911	
Co-product credit ($/yr) (7)	$	(49,193,945)	
Annual Operating Cost ($/yr)	***$***	***(20,411,133)***	
Total Capital Investment ($) (8)	***$***	***669,718,684***	
Fixed Charge Rate		12.3%	
Non-Feedstock Production Cost ($/gal)	**$**	**2.17**	*Production cost for FT Distillates*

1) Based on capital cost information from Tijmensen et al. 2002

2) Based on projected LHV efficiency of 30.4% for BCL gasifier with SMR reformer. Distillate LHV is 125,684 Btu/gal. Based on data from Antares 2003a.

3) Total fuel conversion efficiency, includes distillates and naptha

4) Based on LHV efficiency of 12%. Naptha LHV is 115,263 Btu/gal. Based on data from Antares 2003a.

5) Electriciy production from unconverted syngas using combined cycle power plant. Changes in the efficiency of the Combined Cycle plant as a function of scale is not included in this analysis.

6) Fixed O&M includes annual maintinance and repair costs (2.3% of TCI), and labor costs based on data from Antares 2003a. The labor costs are scaled by facility size using a scaling factor of 0.25 as in Tjimensen et al. 2002.

7) Calculated using electricity credit of $0.057/kWh (based on the average cost for electricity in the industrial sector in 2005 from EIA 2006). Naptha credit is $63/bbl, based on the average over the last year ($599/tonne) from Plastemarte (2007). Density of naptha is 665 kg/m3 = 5.55 lb/gal.

8) Capital costs based on estimates from previous Antares study (2003c). The scaling factor is 0.74 for a biomass input of 185,000 to 750,000 dry ton/yr, and 0.91 for a biomass input greater than 750,000, following Tijmensen et al. 2002.

Feedstock	HHV (Btu/lb)	LHV (Btu/lb)
Corn Stover	8,185	7,600
Wheat Straw	8,500	8,000
Switchgrass	8,400	7,800
Poplar	9,000	8,400
Pine	9,130	8,675

Summary Page - Costs & Yield Data, Pyrolysis Oil Production & Upgrading

Inputs

Feedstock Type	**Wood**
Economic Lifetime of Plant (Years)	25
Weighted Cost of Capital	10%

	Mid Term (2015-2020)	
Applicable Feedstocks	woody & agricultural	
Applicable Size Range (dry tons/yr) (1)	30,000 - 800,000	
Feedstock Input (dry ton/yr)	700,000	
Yield Bio-oil (ton/yr)	528,500	
Yield Bio-oil (MGY)	106.8	
Conversion Efficiency (HHV)	75%	
Pyrolytic Lignin (ton/yr)	130,540	
Pyrolytic Lignin (MGY)	26.4	
Capital Cost Pyrolysis Production (Mil $) (2)	$ 74.55	
Hydrotreatment Process (3)		
H2 consumption (ton/yr)	5,874	
Light hydrocarbons produced (ton/yr)	19,581	
Gasoline produced (MGY)	11.8	
Diesel produced (MGY)	2.9	
Capital Cost Hydrotreatment (Mil $) (4)	$ 27.13	
Yield of By-Products (5)		
Solid Char (ton/yr)	112,000	
Non-condensable gas (ton/yr)	59,500	
Water-soluble bio-oil (ton/yr)	397,961	
CO2 Stream (ton/yr)	177,290	
Water consumption (1000 gal/yr) (6)	97,494	
Gasoline Production Costs		see table below for details
Fixed O&M ($/yr)	$ 9,807,570	
Variable O&M ($/yr)	$ 21,251,929	
Co-product credit ($/yr)	$ (13,756,197)	
Annual Operating Cost ($/yr)	***$ 17,303,302***	
Total Capital Investment ($)	***$ 101,680,480***	
Fixed Charge Rate	12.3%	
Non-Feedstock Production Cost ($/gal)	**$ 2.51**	*Gasoline production cost*

1) Based on reported sizes for pyrolysis oil production facilities in UOP 2005, Ringer et al. 2006, and Polagye et al. 2007.

2) Pyrolysis oil production capital cost based on data from: Cole Hill Associates 2004, Ringer et al. 2006, Polagye et al. 2007, UOP 2005. Total capital cost is scaled by facility size using a scaling factor of 0.77, as estimated from the data.

3) Calculated as percentages (by weight) of pyrolytic lignin, based on yields from UOP 2005. H2 consumption is 4.5%, Light ends production 15%, Gasoline production 30%, Diesel production 8%.

4) Hydrotreatment cost is based on data from UOP 2005, and scaled using a standard scaling factor of 0.6

5) The solid char and non-condensible gas are not assigned a value, as the char is combusted to provide heat for the pyrolysis reaction and the gas is recycled as a fluidizing gas. The heating value of the char (HHV) is ~12,900 Btu/lb (Mohan et al. 2006). Hydrotreatment generates a concentrated CO2 stream, which could have a market value (not considered here). Data for the CO2 yield is derived from UOP 2005.

6) Based on data from Ringer et al. 2006, a 200,750 dry ton per year facility uses about 160 thousand gal/hr water, mostly for cooling. Assuming only 2% of this water is lost in blowdown, the annual consumption is about 28,000 thousand gallons per year. This value is scaled based on feedstock input. No additional water consumption is added for hydrotreatment.

Feedstock Properties				Product Yields (1)			Bio-oil Properties			
Feedstock	**Moisture Content (wt%)**	**Ash (wt%)**	**HHV (Btu/lb)**	**Bio-oil (wt%)**	**Char (wt%)**	**Gas (wt%)**	**Pyrolytic Lignin (wt%) (2)**	**Bio-oil HHV (Btu/lb)**	**Bio-oil Energy Content (Btu/gal)**	**Bio-oil Density (lb/gal)**
Herbaceous Feedstocks										
Bagasse (3)	9.00%	8.00%	8,150	78%	13%	8%	24%	8,010	79,500	9.9
Corn Fiber (3)	6.00%	0.75%	8,115	74%	11%	14%	24%	7,675	73,500	9.6
Woody Feedstocks										
Wood (3)	7.50%	0.65%	7,650	76%	16%	9%	25%	7,600	75,500	9.9
Softwood (4)	2.40%	0.42%	7,138	70%	15%	15%	25%	7,138	71,519	10.0
Bark (3)	8%	4.00%	7,930	64%	22%	13%	25%	8,340	81,500	9.8
Softwood w/ bark (4)	3.50%	2.60%		70%	15%	15%	25%	7,052	70,069	9.9
Mixed Paper (3)	6.50%	11.05%	7,350	82%	12%	7%	25%	7,350	74,000	10.1

1) Yields include moisture content of products.

2) Lignin content of bio-oil is approximate, based on values from DynaMotive bio-oil analysis. Values for herbaceous feedstock pyrolytic lignin content from bagasse, and pryolytic lignin for woods based on softwood.

3) Source: Ensyn Group Inc. 2001. Wood data includes hardwoods and softwoods. Yields on an ash-free basis.

4) Source: DynaMotive Energy Systems Corporation, 2000.

O&M Costs (1)		**Value**	***Source***
Variable O&M (2)			
Waste Treatment ($/yr)	$	4,793,114	*Ringer et al. 2006*
Electricity Consumption (kWh/yr)		131,712,000	*Ringer et al. 2006*
Total Utility Cost ($/yr)	$	8,936,929	*UOP 2005, EIA AEO 2007*
Hydrogen ($/yr)	$	7,521,886	*UOP 2005*
Total Variable O&M ($/yr)	***$***	***21,251,929***	
Fixed O&M (3)			
Labor ($/yr)	$	4,215,143	*Polagye et al. 2007, Ringer et al. 2006*
Other Fixed Costs ($/yr)	$	5,592,426	*Polagye et al. 2007*
Total Fixed O&M ($/yr)	***$***	***9,807,570***	
Co-Products (4)			
Water-Soluble Bio-oil ($/yr)	$	-	
Diesel ($/yr)	$	5,153,670	*EIA AER 2005*
Light Hydrocarbons (LPG) ($/yr)	$	8,602,527	*EIA AER 2005*
Total Co-Product Value ($/yr)	***$***	***13,756,197***	

Assume net zero cost/value

1) All costs reported in 2006$, converted using CEPCI where needed.

2) Electricity consumption is for pyrolysis oil production portion process only. Total utility cost includes electricity consumption for entire process,using an electricity cost of 5.7 cents/kWh for pyrolysis production (based on the 2005 average cost for electricity in the industrial sector from EIA 2006) and utility cost for hydrotreatment from UOP 2005. Hydrogen cost is based on rate of hydrogen consumption and cost ($1,200/ton) from UOP 2005.

3) The labor cost is scaled using a factor of 0.31, which was derived using data from listed sources for pyrolysis oil production facilities. The base labor cost is from a plant with 550 dry ton per day biomass input from Ringer et al. 2006. Other fixed costs include maintenance, insurance, and overhead, with a total annual cost equivalent to 5.5% of the total capital investment for the entire facility (including pyrolysis oil production and hydrotreatment).

4) Assume non-condensable gases and char recycled into pyrolysis reaction, per Ringer et al. 2006. Assume water-soluble bio-oil has a net zero value, as has a low heating value and needs to be co-fired with natural gas for use. Value of diesel and light hydrocarbons based on average 2005 wholesale price from EIA AER 2005 for No. 2 diesel fuel ($1.73/gal) and Propane ($0.93/gal). Antares estimates of the added cost for compressing light hydrocarbons is neglibible and is not included.

Summary Page - Costs & Yield Data, Renewable Diesel Co-processing

Inputs

Feedstock Type (1)	**Virgin Oil**
Economic Lifetime of Plant (Years)	25
Weighted Cost of Capital	10%

1) Feedstock type does not affect the yield of the processes in this model. Typical heating value of these feedstocks are very similar, generally about 16,500 to 17,000 Btu/lb HHV (US EPA 2001). Although processing of yellow grease feedstocks may lead to higher capital costs due to additional pre-processing (such as desalting) and different metallurgy requirements, this has not been included as the added cost is expected to be minimal (a few percent according to discussions with industry contacts).

	Stand Alone	Co-processing	
Applicable Feedstocks	virgin oil, animal fat, waste grease	virgin oil, animal fat, waste grease	
Applicable Size Range (MGY) (1)	15 - 200	15 - 200	
Feedstock Input (ton/yr)	500,000	500,000	
Yield Renewable Diesel (ton/yr) (2)	415,000	407,000	
Yield Renewable Diesel (MGY)	128	125	
Conversion Efficiency (LHV) (3)	98%	96%	
Consumables and By-Products			
H2 consumption (ton/yr) (4)	7,500	19,000	
Light hydrocarbons / propane (ton/yr)	17,500	22,000	
CO2 / Water Generated (ton/yr) (5)	75,000	90,000	
Renewable Diesel Production Costs			See table below for details
Fixed O&M ($/yr)	$ 12,221,607	$ 1,932,942	
Variable O&M ($/yr)	$ 9,625,097	$ 24,350,599	
Co-product credit ($/yr)	$ (7,688,310)	$ (9,665,304)	
Annual Operating Cost ($/yr)	***$ 14,158,394***	***$ 16,618,237***	
Total Capital Investment - Near Term ($) (6)	***$ 222,211,033***	***$ 35,144,394***	
Total Capital Investment - Mid Term ($) (7)	***$ 178,006,565***	***$ 28,153,115***	
Fixed Charge Rate	12.3%	12.3%	
Non-Feedstock Production Cost Near Term ($/gal)	**$ 0.32**	**$ 0.17**	
Non-Feedstock Production Cost Mid Term ($/gal)	**$ 0.28**	**$ 0.16**	*Renewable Diesel production cost*

1) Estimated based on current and planned facility sizes for ConocoPhillips, Neste, and Petrobras. The smallest faciliy sizes produce around 1,000 barrels per day of renewable diesel, and the largest will be able to generate about 12,000 barrels per day.

2) Stand-alone yield is based on data from UOP (2005), co-processing yield is based on data for Petrobras H-BIO system (source: Petrobras n.d.). Yields are converted to volumetric quantities using a typical green diesel density of 6.5 lb/gal.

3) Calculated using a lower heating value of 16,000 Btu/lb for the oil/grease feedstock, and 123,200 Btu/lb for renewable diesel, based on data from UOP 2005.

4) Hydrogen consumption is based on feedstock input (by weight), and is about 1.5% for stand-alone and 3.8% for co-processing (UOP 2005).

5) Stand alone processing conditions lead to production of CO2 primarily, while co-processing conditions typically produce water. The amount of CO2 and water produced is calculated by difference of the inputs and other outputs. Result is similar to UOP 2005 estimate that water and CO2 output is equivalent to 12-16 wt% of feedstock input.

6) Capital costs based on reported costs of facilities under development from Neste (stand alone) and Petrobras (co-processing), using a scaling factor of 0.6 (equivalent to the scaling factor for pyrolysis hydrotreatment following UOP 2005).

7) Cost decreased based on next generation facility development with a learning rate of 20%, following McDonald and Schrattenholzer (2002). This rate is similar to that found for ethanol production facilities and retail petrol processing.

O&M Costs (1)	**Stand Alone**	**Co-processing**
Variable O&M (2)		
Total Utility Cost ($/yr)	$ 21,509	$ 21,509
Hydrogen ($/yr)	$ 9,603,588	$ 24,329,090
Total Variable O&M ($/yr)	***$ 9,625,097***	***$ 24,350,599***
Fixed O&M		
Total Fixed O&M ($/yr) (3)	$ 12,221,607	$ 1,932,942
Co-Product Value		
Propane ($/yr) (4)	$ 7,688,310	$ 9,665,304

1) All costs reported in 2006$, converted using CEPCI where needed.

2) Total utility cost is based on data for pyrolysis oil hydrotreatment from UOP 2005. Annual hydrogen cost is based on hydrogen consumption and cost data from UOP 2005. Any additional costs for catalysts and waste disposal are not included here due to lack of available data.

3) Fixed O&M costs include maintenance, insurance, and overhead. These costs are estimated to be 5.5% of near term capital cost, based on pyrolysis oil hydrotreatment O&M. Assume no added labor cost as process is part of larger refinery operation.

4) Based on reported wholesale price of propane ($0.93/gal) in 2005, from EIA AER 2005. Estimated added cost for compressing propane is negligible and has not been included.

D. GREET Model Assumptions and Limitations

Model Assumptions

In order to accurately assess WTW emissions, GREET makes critical assumptions about sources of energy generation and the calculation of energy emissions across the energy supply chain.

Detailed emissions data for VOCs, CO_2, NOx, PM10 and SOx were obtained from EPA emissions inventory data. There were limitations in the EPA data related to CH_4 and N_2O emissions from fuel combustion. Due to the limitations, these pollutants are not taken into account.

Energy efficiency in GREET is calculated by taking the energy output divided by energy input including energy in both process fuels and for a given Well to Tank (WTT) activity. Energy input per unit of energy product output is calculated in GREET from the energy efficiency of the activity.

Emission factors for VOCs, CO_2, NOx, PM10, CH_4 and N_2O for different combustion technologies fueled by different process fuels are continuously updated from two original sources: EPA's AP-42 document (EPA 1995) and the NEI database, which consist of emission inventory information for point sources collected from state and local air agencies. Data in this inventory are commonly used for air quality monitoring and human local air agencies.

Combustion CO_2 emission factors (in g/mmBTU of fuel throughput) are calculated by using a carbon balance approach, in which the carbon contained in a process fuel is burned minus the carbon contained in combustion emissions of VOCs, CO, and CH_4 is assumed to convert to CO_2.

GREET is designed to separate emissions of criteria pollutants into total emissions and urban emissions. Total emissions are the sum of emission occurring everywhere during the WTW chain. For existing facilities, such as petroleum refineries and electric power plants the share of urban and non-urban facilities by capacity is based on the locations of existing facilities, which is collected from the Energy Administration Information Administration and industry databases. For new facilities, such as plants constructed to produce hydrogen as a transportation fuel, the share is determined based on the specification of a given hydrogen production pathway.

Limitations

In general GREET follows widely accepted methods, but significant uncertainties and omissions remain and current methods are not considered adequate by all experts (Delucchi 2004; Pennington, Potting et al. 2004; Rebitzer, Ekvall et al. 2004; International Standards Organization 2006. No single approach may be able to address all concerns. There is an important trade-off between detail and breadth, typically manifested in the choice between detailed, engineering-type, process-specific LCAs of limited extent and extensive economy-wide analyses of limited detail. For an example of the latter, see Matthews and Small 2001. It is not clear how to resolve this tradeoff, and a highly detailed, economy-wide analysis may be impracticable. The present generation of transportation fuel LCA models such as GREET produces global warming intensity (GWI) values for each fuel pathway, but these values must be understood as both incomplete and, in many cases, highly uncertain.