Siting an Ethanol Plant in the Northeast

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EXECUTIVE SUMMARY

Ethanol is a liquid that can be used for transportation, power generation, chemicals, food, beverages, and other products. Ethanol can be produced from starch-rich materials, such as corn and cheese whey as well as cellulose-rich materials, such as wood waste, paper sludge, municipal solid waste, and woody crops grown for energy. The process for producing ethanol from starch-rich materials is well developed and fully commercialized. Processes for producing ethanol from cellulosic biomass are less technologically mature and no commercial facilities produce ethanol from cellulosic biomass.

PURPOSE OF THE REPORT

This report is intended to assist in the development and siting of biomass ethanol plants in the Northeast. Emphasis is placed on ethanol production from cellulosic biomass because the region has a large biomass resource, and numerous economic and environmental benefits are associated with using biomass for energy. When addressing markets for ethanol, this report focuses on the potential use of ethanol as motor fuel in public vehicle fleets. While use by public fleets is only one of many potential markets for ethanol, it is emphasized since Governors and state agencies can directly impact this market.

Project Developers

For developers of ethanol facilities, information is provided in this report on the likely market for fuel ethanol in the Northeast, the estimated size of the market, state environmental regulations likely to apply to biomass ethanol facilities, and federal and state incentives that may be available for biomass ethanol plants.

Environmental Regulators

For environmental regulators and others who may review and permit biomass ethanol facilities, information is provided on how ethanol is produced, likely emissions from biomass ethanol facilities, and the operating experience of two ethanol production facilities.

Transportation and Procurement Officials

For transportation and procurement officials, state energy planners, and economic development officials, information is provided on opportunities for using fuel ethanol in public fleets. A specification for fuel ethanol containing 75-85% ethanol is provided, as is a specification for ethanol refueling facilities.

BENEFITS OF BIOMASS ETHANOL

Numerous national and regional benefits could result from the development of an ethanol industry based on cellulosic biomass.

- Ethanol can be produced from indigenous renewable resources thereby reducing dependence on finite petroleum resources, much of which is imported from other countries.

- Ethanol used as a replacement for petroleum in vehicles reduces emissions of carbon monoxide (CO), nitrogen oxides (NOx), and volatile organic compounds (VOC), thereby improving air quality and reducing ground-level ozone and smog.

- Ethanol produced from biomass can reduce emissions of carbon dioxide (CO_2) , a contributor to global climate change.
- Ethanol produced from biomass can increase local employment and income and stimulate economic development in urban areas (for facilities that use

waste materials for feedstock) and in rural areas (for facilities that use forestry or agricultural materials for feedstock).

NATIONAL ISSUES AFFECTING ETHANOL USE

Current interest in increasing the production and use of ethanol as a motor fuel is driven largely by environmental concerns about emissions from vehicles burning fossil fuels. Major federal legislation intended to increase the production and use of fuels other than gasoline includes portions of the Clean Air Act Amendments of 1990 (CAAA) and the Energy Policy Act of 1992 (EPACT).

Clean Air Act

A major focus of the CAAA is reducing emissions from mobile sources. Under the CAAA, ethanol is recognized as a "clean fuel" that can help improve air quality by reducing CO emissions and may reduce emissions of NOx and VOC, both of which contribute to ground-level ozone and smog.

Reformulated Gasoline Program: Under the CAAA, a federal reformulated gasoline (RFG) program was created to combat high ozone levels by reducing emissions of ozone- or smog-forming agents from gasoline fueled vehicles, and gasoline storage and dispensing activities. The RFG program includes three components:

- Adding oxygenates to gasoline to increase its oxygen content;
- Decreasing the amount of ozone- and smog -forming agents in gasoline; and
- Establishing exhaust gas performance standards for gasoline.

The goal of the federal RFG program is to reduce the emission of ozone-and smog-forming agents in ozone nonattainment areas by at least 20% by 2000. As of 1995, about 67% of gasoline sold in the NRBP region was RFG. Vermont is the only state in the region that is not required to use RFG.

Oxygenated Fuels Program: Also under the CAAA, a federal oxygenated fuels program was created to reduce carbon monoxide levels in 39 metropolitan areas with high levels of CO. The program is designed to reduce CO emissions from mobile sources during the winter, when vehicle CO emissions are greatest. The program requires that gasoline sold in the areas during the winter must contain a minimum of 2.7% oxygen by weight.

Initially, several metropolitan areas in the NRBP region were required to participate in the program. Most of the areas have subsequently dropped out, since they were redesignated or requested redesignation for ozone attainment. The only area still required to participate is the New York City area (including northern New Jersey and portions of Connecticut). This area is required to use 2.7% oxygenated fuels from November 1 to February 29.

Clean Fuel Vehicle Objectives: Also under the CAAA, a federal clean fuel fleet program was created to help introduce vehicles specifically designed to use "clean fuels" such as ethanol, methanol, natural gas, propane, hydrogen, or electricity. Those metropolitan areas classified as serious, severe, or extreme nonattainment for ozone and with a population of 250,000 or more are identified in the program. Vehicle fleets within the identified areas are required to begin purchasing clean fuel vehicles. Fleets that must comply with the regulations include those that have 10 or more vehicles owned by a single person or entity and which are (or can be) centrally fueled. This includes private fleets as well as federal, state, or municipal fleets. Certain fleets are exempt, such as emergency vehicle fleets.

Metropolitan areas included in the clean fuel fleet program located in the NRBP area include Baltimore, Boston, "Greater Connecticut," New York City, Philadelphia, Providence, and Springfield. However, the states of Connecticut, Delaware, Massachusetts, and Rhode Island have "opted-out" of the clean fuel vehicles program and have substituted other programs which achieve the same

goals. New Hampshire also opted-out, but did so by creating more stringent requirements for fleets. New York opted-out for vehicles under 8,500 pounds.

Energy Policy Act of 1992

Under EPACT, ethanol is recognized as a renewable or "alternative" fuel that can be produced domestically, thereby decreasing the need for foreign petroleum. Alternative fuels are defined to be methanol, ethanol, or other alcohols, or mixtures of methanol, ethanol, or other alcohols in which the alcohol comprises at least 85% of the fuel by volume. The percent volume may be lowered to a minimum of 70% (with approval by the U.S. DOE) to allow for cold starting, safety, or other reasons. A variety of non-alcohol, non-petroleum fuels are also included in the definition of alternative fuels.

Fleet Purchasing Objectives: EPACT essentially mandates that "fleets" begin to purchase alternative fuel vehicles. EPACT defines fleets as groups of 20 or more light duty motor vehicles that meet the following criteria:

- Are located in a metropolitan area with a population of 250,000 or more (1980 census basis);
- Are refueled (or are capable of being refueled) at a central location; and
- Are owned or controlled by government or other parties owning or controlling 50 or more vehicles.

Light duty motor vehicles are defined as being either a truck or car with a gross vehicle weight (GVW) of 8,500 pounds or less. Certain fleets are specifically not included such as rental cars, emergency or law enforcement vehicles, military vehicles, non-road vehicles, and vehicles which are typically kept at residences at night.

EPACT requires that the annual purchase of new vehicles by fleets include a specific percentage of alternative fueled vehicles (with the percentage escalating annually). However, EPACT does not require they use alternative fuels.

HIGH ETHANOL CONTENT FUELS

"High ethanol content fuels" can be defined as fuels containing 70% or more of ethanol. Although ethanol can be used as fuel in the form of neat (100%) ethanol, most high ethanol content fuels contain some gasoline. The gasoline increases fuel performance during cold weather starting and operation, and serves as a denaturant. Examples include:

- Neat ethanol (containing 100% denatured ethanol);
- E95 (containing 95% denatured ethanol and 5% gasoline); and
- E85 (containing 85% denatured ethanol and 15% gasoline).

Approximately 36 facilities in the U.S. sell E85. Most are located in the Midwest. None are located in the Northeast, nor are there any central refueling facilities in the region providing high ethanol content fuels. An E85 refueling facility located in Washington, D.C. is the only facility located near the NRBP region. High ethanol content fuels can only be used in motor vehicles specifically designed and constructed for the fuel.

LOW ETHANOL CONTENT FUELS

"Low ethanol content fuels" typically contain 10% or less ethanol, with the rest being gasoline. Ethanol is added to the fuel to decrease certain tailpipe emissions or to increase the octane rating of the gasoline. Low ethanol content fuels include:

- Gasohol (containing up to 10% ethanol);
- Oxygenated gasoline (containing 7% ethanol); and
- Reformulated gasoline (containing 5% ethanol).

Low ethanol content fuels can be used in motor vehicles designed to use gasoline. Most manufacturers selling automobiles in the U.S. warranty their automobiles for use

with gasoline or gasoline/ethanol blends containing up to 10% ethanol.

FACTORS AFFECTING ETHANOL USE IN FUEL

Ethanol can be used in motor fuel in the form of neat (100%) ethanol or ethers produced from ethanol.

Neat Ethanol

The overall demand for and use of neat ethanol in low ethanol content fuels, such as oxygenated gasoline and RFG, may be limited in the future, if other sources of oxygenated fuels are available to reduce CO and hydrocarbon emissions from vehicles. This is because when ethanol (in its pure, neat form) is added to gasoline to produce gasoline/ethanol blends containing less than 22% ethanol, the ethanol increases the overall volatility of the fuel. This increases the emission of hydrocarbons during fuel storage and handling. Research indicates that emissions from gasoline mixed with relatively small amounts of ethanol during fuel storage and handling may outweigh decreased emissions from vehicle tailpipes.

However, as the amount of ethanol in gasoline increases, the volatility decreases. It appears that in blends containing more than about 22% ethanol (and 78% gasoline), fuel volatility is less of an issue and there is an overall net decrease of CO and possibly hydrocarbon emissions (compared to fuel containing only gasoline). Hence, the extent of future markets for neat ethanol blended into gasoline will depend in part on the mixture of the end product, and the availability and cost-competitiveness of other oxygenated fuels that also meet clean air objectives.

Ethers

In addition to ethanol, two ethers can be added to gasoline to increase the oxygen content. They are methyl tertiary butyl ether (MTBE) and ethyl tertiary butyl ether (ETBE). Both ethers are oxygenates produced from an alcohol (either methanol or ethanol) and isobutylene. Isobutylene is a by-product of oil and hydrocarbon refining. ETBE contains about 42% ethanol, and does not produce the undesirable emissions of fuels that contain blends of low amounts of neat ethanol with gasoline. Low ethanol content fuels containing ETBE may be used in conventional gasoline automobiles without modification.

Due to cost considerations, currently most, if not all, oxygenates are MTBE. Since the process of producing MTBE and ETBE is essentially the same, ETBE could be produced by refineries that produce MTBE. It is reported that slight process modifications would be needed in order to do so. MTBE production in the U.S. is reported to have reached about 215,000 barrels per day, and has increased to meet the demand for oxygenates.

Three companies in the U.S. that used to produce ETBE in small quantities stopped in 1995 due to cost considerations. The price of ethanol used for the ETBE was in the range of $1.25 per gallon, while the price for methanol was below $0.40 per gallon.

No ETBE refineries are located in the NRBP region, although ARCO Chemical Company operates a refinery in Richmond, Virginia. It is possible that MTBE refineries located in the region could be converted to produce ETBE from ethanol. However, there would likely need to be a decrease in the cost of ethanol (compared to the cost of methanol).

ETHANOL PRODUCTION COSTS

Currently, 38 plants in the U.S. have the capacity to produce about 1.5 billions gallons of ethanol per year. Most are located in the Midwest and use corn as the feedstock. Three plants utilize cheese whey or other cheese by-products as feedstock. One plant utilizes paper-making residue. One plant extracts ethanol from waste beer at a large brewery.

The process to convert biomass to ethanol includes five major components: preparing the feedstock, converting

the feedstock to ethanol, recovering the ethanol, producing the energy needed for the conversion process, and managing emissions.

The projected cost of producing ethanol from cellulosic biomass has decreased from about $3.00 per gallon in 1980 to about $1.17 per gallon in 1996. The projected 1996 production cost:

- Includes all raw material, operating costs, and return on capital investment;
- Excludes any price reductions that might occur as a result of tax credits or other incentives; and
- Assumes the use of best available technology, applied to ethanol production from cellulosic biomass.

Production prices could be lower, if waste feedstocks are used that would otherwise have to be disposed of in a solid waste management facility that charges a tipping fee to accept the material. Actual prices paid for corn ethanol in 1995 were about $1.25/gallon, which is sufficient to cover the projected production cost for ethanol from cellulosic biomass.

Considering future improvements in some but not all process steps, the projected production cost for ethanol from cellulosic biomass using mature, advanced technology will be $0.50/gallon in the future. This projected production cost:

- Assumes a plant scale of about 300 million gallons per year;
- Includes all raw material, operating costs, and return on capital investment;
- Excludes any price reductions that might occur as a result of tax credits or other incentives; and
- Assumes specific additional R&D in the future which achieves further advances in ethanol production technology.

PLANT EMISSIONS AND PERMITTING

Similar to many other industrial processes or plants, ethanol plants produce air, solid waste, and wastewater emissions. Biomass ethanol facilities may be required to apply for one or more permits by the state agency (or agencies) responsible for environmental permitting. The specific regulatory or permitting process used in each state varies.

Air Emissions

Sources of air emissions from biomass ethanol plants are flue gases from energy production (if a boiler is used on site), off-gasses from fermentation, and off-gases from product and chemical storage. If a plant includes a boiler or gasifier for energy production, the flue gas will be the largest and most significant air emission. Other emissions may also be present in smaller amounts, such as fugitive dust from feedstock processing and ash handling (if a boiler or gasifier is used). Many states regulate odor emissions, and ethanol plants may produce odors.

In general, it is expected that best available air pollution control technology will be capable of controlling flue gas emissions of CO, NO_X, and SO_2 and that any emissions of VOCs will likely be below regulatory standards. Permits will likely be needed for air emissions.

Solid Waste

Ethanol plants produce unreacted solids separated from the fermentation effluent during recovery of the ethanol and solids removed during wastewater treatment. Plants with energy production will likely use the unreacted solids as fuel in the boiler or gasifier, and will generate a bottom ash, fly ash, and possible fuel gas desulfurization solid instead. Some plants may generate non-processable residue which need to be managed as solid waste.

None of the solid wastes generated are expected to be classified as hazardous waste or to present a particular solid waste management problem. Permits may be needed

for disposal of ash and other solid wastes.

Wastewater

The biological process to convert biomass into ethanol requires process water. Distillation/dehydration processes "recover" the water as wastewater, which contains soluble and suspended organic and inorganic matter. Other sources of wastewater include the cooling tower and air pollution control equipment (if energy production is included in the plant). Some plants have the capability on site to treat the wastewater before it is discharged to a body of water. Other plants discharge untreated wastewater to a municipal wastewater treatment plant located off site. In some cases, the wastewater may need to be pretreated before discharge to an off-site treatment plant. Stormwater may also need to be collected and treated, before being discharged from the site.

It is anticipated that best available water pollution control equipment will be capable of reducing the biological oxygen demand (BOD) of the effluent and the amount of suspended solids in the effluent to meet discharge standards. Permits may be needed, especially if wastewater is discharged to a surface water rather than a treatment plant.

PUBLIC FLEET USE OF E85

As part of the national effort to expand the use of clean, alternative fuels for transportation, states are implementing initiatives to decrease the use of gasoline in public fleets. In the Northeast, few if any of such initiatives are focussed on stimulating ethanol production and use. However, they could be in the future.

Public fleets are uniquely posed to be among the first fleets in the Northeast to begin using high content ethanol fuels on a widespread basis.

- Under EPACT, federal fleets are already required to begin using alternative fueled vehicles. State fleet requirements begin in 1996. Municipal fleet requirements begin in 1999. Although EPACT does not require that the vehicles use alternative fuels, it does define alternative fuels to be those containing at least 70-85% alcohol.

- Under the CAAA, fleets in certain metropolitan areas are required to begin purchasing clean fueled vehicles. Ethanol is one of a variety of fuels specified in the CAAA as a clean fuel. Fleets covered by the CAAA must begin purchasing clean fueled vehicles in 1998.

- States in the NRBP region operate "alternative fuel programs" which help ensure compliance with both EPACT and CAAA, and which promote and encourage the use of clean, alternative fuels. Although ethanol is not presently a focus of the state programs, it could be in the future.

- Public sector use of ethanol and ethanol fueled vehicles could stimulate demand for both the fuel and vehicles, assist in developing the production and supply infrastructure needed to serve both public and private sector fleets, and assist in developing consumer awareness and confidence.

High ethanol content fuels are not presently used on an ongoing basis by public fleets in the Northeast. Small amounts may be used occasionally for pilot, demonstration projects. If priority were placed on using E85 in public fleets throughout the region in the future, as much as 175 million gallons per year of fuel could be used.

INCENTIVES FOR ETHANOL PRODUCTION

One strategy for facilitating the creation of a new industry is to provide incentives to those who are critical to successful development of the industry.
Incentives may be offered during commercialization of new technologies, during development and siting of new facilities that will stimulate economic growth, or during development of markets for new products. Since the founding of the United States, both federal and state

government have provided incentives for a wide variety of industrial, commercial, and agricultural activities. Such incentives provide a mechanism for furthering public policy objectives not otherwise adequately addressed through the marketplace.

Several federal incentives are available that stimulate development of the ethanol industry. The impact of such incentives is illustrated by the corn ethanol industry, which would be substantially smaller if federal tax credits did not exist for production of ethanol fuels. Initially, the motivation for the tax credits was to find alternatives to imported petroleum and to support development of an industry that would use valuable agricultural land for crops other than grain for human consumption. Clean air and alternative fuel objectives are now also addressed, in part, by the incentives.

A federal tax credit is currently available for:

- Producers or users of neat ethanol fuel (but not both);
- Producers or blenders of ethanol fuel mixtures (but not both) that produce or blend mixtures of neat ethanol and gasoline to produce E95, E85, or gasohol (which is 90% gasoline and 10% ethanol); and
- "Small ethanol producers" which are ethanol producers with a production capacity of 30 million gallons or less per year.

The credit for producers, users, or blenders of ethanol is $0.54 per gallon of ethanol (the credit for other alcohols is $0.60 per gallon). The credit is available only for ethanol not produced from petroleum, natural gas, or coal, and that has a proof of 190 or higher (which is equivalent to 95% alcohol or higher). The proof requirement allows denaturants (such as gasoline) to be added to the alcohol so that is not drinkable.

A separate credit of $0.10 per gallon is available for "small ethanol producers." This credit is available to qualified ethanol producers (with a production capacity of 30 million gallons per year or less), in addition to the other alcohol fuels credits. The ethanol produced by small producers must be at least 150 proof (which is equivalent to 75% alcohol) and the ethanol may be produced from petroleum, natural gas, or coal.

In addition, a variety of state industrial and economic development incentives are available for numerous industries and businesses, that may apply to biomass ethanol plants. No states in the Northeast currently offer incentives specifically for ethanol production, although states in other regions do. An example is Minnesota, which recently instituted a tax credit of $.20/gallon for ethanol produced in the state.

SITE CHARACTERISTICS THAT MATTER MOST

A sensitivity analysis was performed for this report to determine the relative importance of various site characteristics to the overall financial performance of a biomass ethanol plant. The site characteristics considered included physical requirements needed to operate a biomass ethanol plant, as well as characteristics that affect development, construction, and operating costs.

The "base case" biomass ethanol plant used in the sensitivity analysis is a theoretical plant producing 60.1 million gallons of ethanol per year, using 658,000 bone dry tons per year of cellulosic biomass as feedstock, and estimated to cost about $150.3 million.

In the base case, a required selling price for the ethanol of $1.18 per gallon is used. At this selling price, the plant has an internal rate of return (IRR) of 9.7% and a payback period of 9.7 years.

The sensitivity analysis indicates that production incentives, the cost of capital, and feedstock cost are the most important site characteristics that impact the economic viability of an ethanol plant. Delays in plant start-up negatively impact plant financing, and can result in an increase in the required ethanol selling price needed

to achieve certain financial returns. The availability of low cost power is not financially advantageous (compared to developing power generation capabilities on site) unless other factors come into play, such as potential difficulties or costs associated with obtaining air pollution control or other permits. Land purchase costs have a minimal impact on overall cost. Eliminating state corporate income taxes during the early years of operation also has minimal impact on overall costs, but could have a significant negative impact if tax credits cannot offset tax liabilities in future years.

Hence, when evaluating potential sites for a biomass ethanol plant, characteristics that matter the most to the required selling price of ethanol and/or the financial performance of a plant are the availability of production incentives, a lower cost of capital, and lower feedstock costs. This provides important guidance to energy and economic development officials interested in facilitating development of biomass ethanol plants in their state or region.

SECTION 1: INTRODUCTION

Capacity is currently in place in the U.S. to produce about 1.5 billion gallons of ethanol per year. Most ethanol is blended with gasoline and used for motor fuel, although some is used for chemicals, food production, and other products.

Ethanol can be produced from a variety of plant materials, including starch-rich materials such as corn and cheese whey as well as cellulose-rich materials, such as wood waste, paper sludge, municipal solid waste, and woody crops grown for energy.The process for producing ethanol from starch-rich materials, such as corn, is well developed and fully commercialized. Processes for producing ethanol from cellulosic biomass are less technologically mature which is primarily why no commercial facilities produce ethanol primarily from cellulosic materials.

Many anticipate the emergence of a fuel ethanol industry based on conversion of cellulose-rich biomass rather than starch crops. This interest is motivated by significant advantages of cellulosic materials: lower feedstock costs, more environmentally-benign feedstock production, a more favorable process energy balance, and a larger potential feedstock supply. Regional and national benefits expected to result from development of a "biomass ethanol" industry based on cellulosic biomass include: improved balance of payments (oil imports are the largest component of the foreign trade deficit), enhanced strategic security, increased rural job opportunities, broad-based benefits to the farm economy, and environmental benefits.

Environmental benefits include decreasing the volume of cellulose-rich wastes (e.g. paper sludge, municipal solid waste, and wood waste) requiring disposal. In addition, ethanol produced from biomass is gaining widespread acceptance as one of the most promising options for reducing transportation sector greenhouse gas emissions. This potential is recognized in the **Interim Report of the Interagency Presidential Advisory Committee on Reducing Greenhouse Gas Emissions Associated with Personal Vehicles**. Carbon monoxide and air toxics emissions may be lessened by utilization of ethanol. In addition, ethanol utilization could decrease emissions of ozone precursors including volatile organic compounds (VOC) and nitrogen oxides (NOx). However, this depends on the manner in which the ethanol is used.
According to best current information, ethanol blended with gasoline at levels less than about 22% results in ozone benefits in the winter, and is an ozone liability in the summer. When blended at ethanol levels greater than about 22%, net ozone benefits may result from ethanol utilization. If blended at ethanol levels above 85%, there is a likely ozone benefit. If ethanol is used as ethyl tertiarybutyl ether (ETBE), ozone benefits are expected regardless of blending level. Utilization of ethanol in hybrid or fuel-cell powered vehicles is expected to offer large emission benefits in the future.

In recognition of these benefits, biomass ethanol has been the subject of a major R&D effort during the last 15 years, led by the U.S. Department of Energy (DOE). The focus of this effort has been:

- Identification of feedstocks derived from low-cost, high production biomass energy crops, and development of techniques and technologies for production of such feedstocks; and

- Development of cost effective conversion processes and techniques that convert biomass into ethanol.

Progress in this effort has been significant, reducing projected costs for energy crop-based production from over $3/gallon in 1980 to about $1.17/gallon in 1996. The projected 1996 production cost:

- Includes all raw material, operating costs, and return on capital investment;

- Excludes any price reductions that might occur as a result of tax credits or other incentives; and

• Assumes the use of best available technology, applied to ethanol production from cellulosic biomass.

Production prices could be lower, if waste feedstocks are used that would otherwise have to be disposed of in a solid waste management facility that charges a tipping fee to accept the material. It is notable that actual prices paid for corn ethanol in 1995 were about $1.25/gallon, which is sufficient to cover the projected production cost for ethanol from cellulosic biomass.

A number of companies are examining the potential to develop biomass ethanol facilities. These include: large companies (e.g. Amoco and Cargill), medium sized companies (e.g. New Energy of Indiana), and several small companies (e.g. Afex Corporation, Arc Energy, Bioenergy International, Bionol, Energy Associates of Hawaii, and Independence Biofuel, Inc.). Many other companies are ready to respond to the construction, design, and other needs of the emerging biomass ethanol industry, although they are not likely to initiate activities with their own resources (e.g. Black and Veatch, Chem Systems, John Brown Engineering, and Stone and Webster, among others).
While the existence of immediate commercial opportunities involving biomass ethanol production is widely acknowledged, it is also important to appreciate the potential for continued improvements and cost reductions. One powerful indication of this is an analysis recently completed by Dr. Lee Rybeck Lynd in conjunction with Richard Elander and Charles Wyman of the National Renewable Energy Laboratory (NREL). The analysis addressed the question:

"What are the likely features and cost of biomass ethanol technology at a level of maturity comparable to a refinery?"

Considering future improvements in some but not all process steps, the projected production cost for ethanol from cellulosic biomass using mature, advanced technology will be $0.50/gallon in the future. This projected production cost:

• Assumes a plant scale of about 300 million gallons per year;

• Includes all raw material, operating costs, and return on capital investment;

• Excludes any price reductions that might occur as a result of tax credits or other incentives; and

• Assumes specific additional R&D in the future which achieves further advances in ethanol production technology.

SITING AN ETHANOL PLANT IN THE NORTHEAST

The primary reason no commercial ethanol production facilities are in operation yet in the Northeast is because it is difficult to compete on the basis of cost with Midwest states in producing corn and other starch-rich crops used by the existing fuel ethanol industry. However, a number of factors indicate the Northeast may be well-suited to production of ethanol from cellulosic materials.

• The existing and potential **biomass resource base** is significant in the Northeast. The region generates a substantial amount of biomass wastes, which are widely accepted as the most likely feedstocks for initial application of ethanol production technology. This is due to the region's high population density and correspondingly large and concentrated production of municipal wastes, as well as significant pulp and paper, paper recycling, and other forest products industries. Solid waste disposal costs in the Northeast are among the highest in the country. This is significant because opportunities to avoid disposal costs improve the cost-effectiveness of the application of biomass ethanol technology.

• The region's existing and potential **technology base** is also strong. Extensive expertise is available in the Northeast that could be applied to an

emerging biomass ethanol industry including several prominent process design firms (e.g. Chem Systems, Black and Veatch, and Stone and Webster), companies with interest and expertise in conversion technology (e.g. Bionol and Independence Biofuel, Inc.), academic R&D programs (e.g. Dartmouth, MIT, and Princeton), and major investment centers (e.g. New York and Boston). The pharmaceutical biotechnology industry has not done well during the last few years, and many project the emergence of "industrial biotechnology," "biocommodity engineering," and environmentally-focused "green biotechnology" as major growth areas for the future. Boston is one of the two largest centers of commercial activity in the nation in biotechnology, along with the San Francisco Bay area.

While development of a successful biomass ethanol industry will surely involve other regions, the Northeast can have a key role in future development of this industry. The region could position itself to be able, eventually, to export technology and expertise to the rest of the country, and perhaps the world.

THE PURPOSE OF THIS REPORT

The purpose of this report is to provide information that assists in the development and siting of biomass ethanol facilities in the Northeast. This study builds directly on a previous biomass resource survey, **The Potential for Producing Ethanol from Biomass in the Northeast** completed by C.T. Donovan Associates, Inc. and Dr. Lynd and published by the CONEG Policy Research Center, Inc. in September 1994. The resource survey identified potential biomass feedstocks for ethanol production and estimated their costs, availability, processing impacts, and other factors important to ethanol production. In addition, the survey identified key cost sensitivities and interrelationships between these.

Results of the biomass resource survey indicated that the amount of biomass materials discarded in the Northeast region (in the early 1990's) and potentially available from short rotation woody crops and herbaceous crops (in the future) could produce more than 2.7 billion gallons per year of ethanol.

A preliminary evaluation of factors affecting ethanol production indicated that the most important factors affecting the use of biomass feedstocks for ethanol production include:

- The amount of feedstock available;
- Feedstock cost;
- Potential ethanol yield from a feedstock, which is primarily a function of the carbohydrate content of a material and the reactivity of the material in the conversion process used to produce ethanol;
- Conversion process complexity and the status of RD&D and commercialization of the technologies and systems needed to produce ethanol from biomass; and
- Capital formation opportunities, including the cost of capital.

Overall, it was anticipated that forestry wood waste, paper sludge, and waste paper will have the highest long-term potential for ethanol production in the region. In the near-term, paper sludge, waste paper, and cheese whey were found to be most likely to be used to produce ethanol the soonest.

A subsequent workshop, **Siting an Ethanol Plant in the Northeast** addressed ways to facilitate development of biomass ethanol facilities in the Northeast. One theme that emerged from the workshop was that certain issues need to be addressed in any project proposal or business plan intending to site, build, and operate a fuel ethanol plant in the Northeast. This report addresses those issues summarized below:

- What are the market opportunities for fuel ethanol in the Northeast? How will ethanol be used and to whom will it be sold?
- For those not already familiar with ethanol

conversion technologies, how is ethanol produced from biomass? What is considered to be the "state-of-the-art" in ethanol production technologies?

• What is the experience of other ethanol production facilities? What can be learned from their experiences?

• What are likely emissions from biomass ethanol facilities? How are emissions regulated and what is involved in obtaining permits?

• What are important site characteristics to consider when planning a biomass ethanol facility? Which characteristics are major drivers affecting technical viability, economic performance, ability to get permits, etc.?

• What incentives are available for project developers/owners?

• What role can states have in facilitating development of ethanol facilities by increasing use of fuel ethanol in public fleets?

This report addresses the above questions, and is intended to assist in the development of biomass ethanol facilities in the region. Target audiences include:

• Those directly involved in developing, siting, and permitting biomass ethanol plants, such as project developers, feedstock suppliers, equipment manufacturers and retailers, construction and engineering firms, investors, environmental regulators, and environmental and public interest organizations.

• Those potentially involved in encouraging and facilitating development, siting, and permitting of biomass ethanol plants, including state economic development officials, state energy and transportation planners, and regional and state biomass program contacts.

Project Developers

For developers of biomass ethanol facilities, information is provided on likely markets for fuel ethanol in the Northeast, estimates of the size of those markets, state environmental regulations likely to apply to biomass ethanol facilities, and federal and state incentives that may apply to ethanol plants.

Environmental Regulators

For environmental regulators and others who may review and permit biomass ethanol facilities, information is provided on how ethanol is produced from biomass (including five process flow diagrams), likely emissions from biomass ethanol facilities, and the operating experience of two ethanol production facilities (located in other regions).

Transportation and Procurement Officials

For transportation and procurement officials, state energy planners, and economic development officials, information is provided on opportunities for using fuel ethanol in public fleets. While public fleets are only one of many potential markets for ethanol, they are emphasized in this report since it is a market that Governors and state agencies can directly impact.

THE INTENDED USE OF THIS REPORT

Market opportunities for ethanol in the Northeast are discussed in Section 2. The basics of how ethanol is produced from biomass are described in Section 3 and case studies are provided of two ethanol production facilities. Process flow diagrams are provided for five hypothetical biomass ethanol plants and emissions expected from the facilities are explained in Section 4. Federal and state incentives that may apply to biomass ethanol facilities are described in Section 5. Site characteristics needed for a successful ethanol plant are described in Section 6. Opportunities for using E85 in state vehicle fleets are discussed in Section 7.

Information on state environmental regulations expected

to apply to biomass ethanol facilities is provided in Appendix A. A specification for fuel containing 75-85% ethanol is presented in Appendix B as is a specification for ethanol refueling facilities. Presented in Appendix C is information on the financial performance of the base case biomass ethanol plant used in Section 6 to identify important site characteristics. References used for the report are presented in Appendix D.

This report provides background information that can be used to further advance the development of biomass ethanol plants in the Northeast. It is important to note that the report serves as a starting point for those interested in pursuing future projects in more detail. It is not intended to be a step-by-step guide to developing a biomass ethanol plant or to obtaining federal, state, or local regulatory approval or permits. State regulatory, permitting, and economic development contacts are provided for further information and guidance.

NORTHEAST REGIONAL BIOMASS PROGRAM

This report is published by the Northeast Regional Biomass Program (NRBP) as part of ongoing efforts to facilitate development of cost-effective and environmentally-acceptable biomass energy facilities in the Northeast region. The NRBP is one of five regional biomass programs funded throughout the nation by the U.S. Department of Energy. The NRBP is administered by the CONEG Policy Research Center, Inc. in Washington, D.C. Eleven states participate in the NRBP, including Connecticut, Delaware, Maine, Maryland, Massachusetts, New Hampshire, New Jersey, New York, Pennsylvania, Rhode Island, and Vermont.

The goal of the NRBP is to increase acceptance and application of biomass energy technologies by the private sector and local governments. To achieve this goal, the Program seeks to identify barriers to increased biomass energy use and to remove those barriers by providing information and technical assistance to private and public decision makers. Objectives of the program are to:

- Establish the availability of biomass resources in the Northeast.
- Identify and remove barriers to biomass energy development.
- Encourage private investment in commercial or nearly commercial biomass fuels harvesting, processing, and energy conversion technologies and applications.
- Contribute to solid waste management solutions and biomass energy utilization goals.
- Contribute to the understanding of environmental impacts of biomass utilization for energy, assist in mitigating negative impacts, and provide education about the positive impacts.
- Improve capabilities of state agencies with biomass-related responsibilities.
- Help member states coordinate efforts among the wide range of agencies involved in various aspects of resource management, energy productions, energy utilization, and environmental and public health.

SECTION 2:

MARKET OPPORTUNITIES FOR ETHANOL IN THE NORTHEAST

The use of ethanol as a motor fuel is not new or experimental. The Model T, for instance, was originally designed to run on ethanol. During World War II, concern about potential disruption of petroleum supplies renewed interest in ethanol as a motor fuel in both the U.S. and Europe. Ethanol was used as an aviation fuel by the Germans. In the 1980's, ethanol production from corn increased in the U.S. primarily as a response to the oil shortages of the 1970s and as a way to find new markets for products from agricultural land in the Midwest.

Today, local car dealers can supply certain vehicle models (at no extra cost) that use ethanol as fuel. Referred to as "Ethanol Flexible Fuel Vehicles" (or Ethanol FFV), the vehicles use either gasoline, ethanol fuels containing up to 85% ethanol, or a combination of gasoline and ethanol fuels. FFVs can also be supplied to use any combination of gasoline, methanol fuels containing up to 85% methanol, or a combination of gasoline and methanol. Currently available FFVs are designed to use either ethanol or methanol (and gasoline).

Presented below is an explanation of the properties of ethanol that affect its use for various markets as well as an overview of national clean air and alternative fuel objectives that stimulate production and use of ethanol for fuel. An assessment is provided of key market opportunities for fuel ethanol in the Northeast.
When addressing market-related issues, this section (and the rest of the report) focuses on the use of ethanol as fuel for motor vehicles. However, ethanol can also be used as fuel by other forms of transportation (e.g. airplanes), for power generation, and in the production of a wide variety of chemicals, foods, beverages, and other products (such as acetone, vinegar, citric acid, and various alcoholic beverages). Although these uses are not addressed in this report, markets may be available for such products in the Northeast and could complement fuel markets in the future.

WHAT PROPERTIES EFFECT USE OF ETHANOL AS FUEL?

Ethanol is an alcohol that can be produced from a variety of starch-rich materials such as corn, as well as cellulosic materials, such as wood waste, paper sludge, municipal solid waste, and energy crops. Key properties that affect the ability to use a liquid (including ethanol) as motor fuel include energy content, volatility, and self-ignition characteristics.

Energy Content

Energy content is the amount of energy expressed in British thermal units (Btu) per unit volume or weight of a material. Since both gasoline and ethanol are liquids, it is common to express the energy content on a per gallon basis. Ethanol contains 75,700 to 76,000 Btu/gallon, while gasoline contains 109,000 to 119,000 Btu/gallon (measured on a net heat of combustion basis). Hence, ethanol has 64-70% of the energy content of gasoline. One gallon of gasoline is equivalent to 1.43-1.56 gallons of ethanol (based on energy content).

Although ethanol has a lower energy content than gasoline, this does not negatively impact motor vehicle performance (such as power or acceleration). This is demonstrated by ethanol fueled vehicles, which have similar power and acceleration characteristics of gasoline fueled vehicles. However, energy content does impact the distance that can be driven per volume of fuel. Due to the lower energy content of ethanol, current ethanol fueled vehicles (i.e. ethanol FFVs) can travel only 64-70% of the distance of gasoline fueled vehicles when using the same amount of fuel. However, it is expected that future ethanol fueled vehicles will be able to take advantage of ethanol's higher

octane rating (compared to gasoline), and achieve greater efficiency than gasoline fueled vehicles. This means future ethanol fueled vehicles will achieve greater than 64-70% of the travel distance of gasoline fueled vehicles.

Volatility

Volatility is a measure of a liquid's capability to vaporize into gas. Internal combustion engines rely on fuel vaporization (by the carburetor or fuel injection system) prior to combustion. Gaseous fuel is injected into the combustion chamber(s) in an automobile engine, in order to achieve complete combustion and maximum energy recovery.

Motor fuel volatility must be within a relatively narrow range. The fuel must be volatile enough to be converted into a gas at low temperatures in order to ensure cold weather engine starting and operation. However, fuel must not be so volatile that it vaporizes within a vehicle's fuel tank, delivery system, or injection system during warm or hot weather. Vaporization causes "vapor lock" which limits or prevents fuel from being pumped to the engine, thereby resulting in stalling or decreased power.

Ethanol is less volatile than gasoline. As measured by the Reid Vapor Pressure (RVP), ethanol has a RVP of about 2.3 while gasoline has a RVP of 8 to 15 (higher RVP means greater volatility). The low volatility of ethanol (compared to gasoline) results in poor engine starting and operation in cold weather. In order to increase cold weather performance, gasoline may be added to ethanol, thereby increasing the volatility of the ethanol and gasoline mixture. Increased cold weather performance of E85 (containing 85% ethanol and 15% gasoline) compared to lower ethanol content fuels could result in larger market demand for the fuel in the future.

Self-Ignition

Self-ignition refers to when a fuel ignites and combusts under compression. In spark-ignited internal combustion engines (i.e. all gasoline automobile engines, but not diesel engines), self-ignition of fuel is detrimental and even harmful. Self-ignition is commonly referred to as "engine knock," and occurs when fuel and combustion air self-ignite prematurely when under compression Premature self-ignition results in an audible knock, decreases efficiency of the engine, and increases engine wear.

The ability of gasoline to resist knock or self-ignition is measured by the octane rating. The higher the octane rating, the more resistant a gasoline is to self-ignition. Gasoline has an octane rating of 86-94, depending on the "grade" (and price) of fuel. Neat ethanol has an octane rating of about 100.

Fuels with higher octane ratings can be used in engines with higher compression ratios. The higher the compression ratio, the more efficient is the engine. Thus, an engine designed to burn only high octane rating fuels (such as ethanol with an octane rating of 100) could be more efficient than engines designed to burn gasoline (with an octane rating of 86-94). However, ethanol fuel flexible vehicles must be designed to use the lower octane rating of gasoline, and cannot take advantage of increased compression ratios and corresponding increased efficiency.

NATIONAL ISSUES AFFECTING ETHANOL PRODUCTION AND USE

Current interest in increasing the production and use of ethanol from cellulosic biomass as a motor fuel is driven largely by environmental concerns about emissions from vehicles burning fossil fuels. Ethanol used as a replacement for petroleum in vehicles could reduce emissions of carbon monoxide (CO), nitrogen oxides (NO_X), and volatile organic compounds (VOC). Ethanol is a fuel that can be produced from renewable resources in the U.S., thereby reducing dependence on finite petroleum resources, much of which is currently imported from other countries. Ethanol produced from biomass can also reduce emissions of the greenhouse gas carbon dioxide (CO_2) if the biomass is grown and harvested on a long-term sustainable basis, thereby absorbing an equal or greater amount of CO_2 during growth than is released once the biomass is combusted for fuel.

Major federal legislation intended to increase the

production and use of fuels other than gasoline includes portions of the Clean Air Act Amendments of 1990 (CAAA) and the Energy Policy Act of 1992 (EPACT). The CAAA strengthened the original Clean Air Act by adding specific air pollution control programs and increasing enforcement. A major focus of the CAAA is reducing emissions from mobile sources. EPACT has a completely different focus and is intended to alleviate dependence on foreign oil. Provisions in EPACT range from encouraging energy conservation and improved efficiency to promoting nuclear energy. EPACT established goals for replacing the petroleum content of motor fuel with non-petroleum fuels produced within the U.S.

Both the CAAA and EPACT recognize ethanol as a fuel that can help achieve goals set forth in the acts. Under the CAAA, ethanol is recognized as a "clean fuel" that helps achieve air quality goals by reducing emissions of carbon monoxide, nitrogen oxides, and volatile organic compounds. Under EPACT, ethanol is recognized as a renewable or "alternative" fuel that can be produced domestically, thereby decreasing the need for foreign petroleum.

Reformulated Gasoline Objectives

Under the CAAA, a federal reformulated gasoline (RFG) program was created to combat high ozone levels in the atmosphere by reducing emissions of ozone- or smog-forming agents from gasoline fueled vehicles, and gasoline storage and dispensing activities. The RFG program includes three components:

- Adding oxygenates to gasoline to increase its oxygen content;
- Decreasing the amount of ozone- and smog -forming agents in gasoline; and
- Establishing exhaust gas performance standards for gasoline.

The goal of the federal RFG program is to reduce the emission of ozone-and smog-forming agents in ozone nonattainment areas by at least 20% by 2000.

The RFG program identifies and defines the nine worst nonattainment areas for ozone, and requires that RFG be used year-round in those areas. Other areas are classified as "opt-in" areas. States located in opt-in areas are not required to use RFG in order to meet air quality standards for ozone. Opt-in states may choose to require the use of RFG, as a way to meet air quality standards for ozone. If they do not, they must institute other practices that result in air quality standards being met. A large portion of the NRBP region is either an RFG required area or an "opt-in" area. Each state in the region has chosen to require the use of RFG in the "opt-in" areas located in their state. As of 1995, about 68% of gasoline sold in the NRBP region is RFG. Vermont is the only state in the region that does not have either an RFG required or "opt-in" area located in the state.

The federal RFG program requires that RFGs either meet performance standards or contain a minimum of 2% oxygen and a maximum of 1% benzene by weight. Ethanol is an oxygenate that can be used in RFG. In order to achieve 2% oxygen by weight, gasoline and neat ethanol must be blended in a ratio of 95 to 5, based on volume.

Oxygenated Fuels Objectives

Under the CAAA, a federal oxygenated fuels program was created to reduce carbon monoxide levels in 39 metropolitan areas with high levels of CO. The program is designed to reduce CO emissions from mobile sources during the winter, when vehicle CO emissions are greatest. The program requires that gasoline sold in the areas during the winter must contain a minimum of 2.7% oxygen by weight.

Initially, several metropolitan areas in the NRBP region were required to participate in the oxygenated fuel program. Most of the areas have dropped out of the program, since they were redesignated or requested redesignation for ozone attainment. The only area still required to participate is the New York City area

(including northern New Jersey and portions of Connecticut). This area is required to use 2.7% oxygenated fuels from November 1 to February 29.

Ethanol is an oxygenate that can be used in oxygenated fuels. To achieve 2.7% oxygen by weight, gasoline and ethanol must be blended in a volume ratio of 93 to 7.

Clean Fuel Vehicles Objectives

Under the CAAA, a federal clean fuel fleet program was created to help introduce vehicles specifically designed to use "clean fuels" such as ethanol, methanol, natural gas, propane, hydrogen, or electricity. Those metropolitan areas classified as serious, severe, or extreme nonattainment for ozone and with a population of 250,000 or more are identified in the program. Vehicle fleets within the identified areas are required to begin purchasing clean fuel vehicles. As of 1995, 21 metropolitan areas nationwide met the requirement for ozone nonattainment and population. Denver was also added due to its carbon monoxide levels and population. Fleets that must comply with the regulations include those that have 10 of more vehicles owned by a single person or entity and which are (or can be) centrally fueled. This includes private fleets as well as federal, state, or municipal fleets. Certain fleets are exempt, such as emergency vehicle fleets.

The schedule required by the CAAA for purchasing clean fuel vehicles is presented in Table 2-1. The U.S. Environmental Protection Agency which administers the program hopes it will result in about one million new clean fuel vehicles by the year 2010.

Metropolitan areas included in the clean fuel fleet program located in the NRBP area include Baltimore, Boston, "Greater Connecticut," New York City, Philadelphia, Providence, and Springfield. However, the states of Connecticut, Delaware, Massachusetts, and Rhode Island have "opted-out" of the clean fuel vehicles program and have substituted other programs which achieve the same goals. New Hampshire also opted-out, but did so by creating more stringent requirements for fleets. New York opted-out, but only for only vehicles under 8,500 pounds.

As noted above, ethanol is one of the clean fuels meeting requirements of the federal program.

Fleet Purchasing Objectives

EPACT essentially mandates that "fleets" begin to purchase alternative fuel vehicles. EPACT defines a fleet as groups of 20 or more light duty motor vehicles that meet the following criteria:

- Are located in a metropolitan statistical area or consolidated metropolitan statistical area with a population of 250,000 or more (1980 census basis);
- Are refueled (or are capable of being refueled) at a central location; and
- Are owned or controlled by government or a private sector entity.

Light duty motor vehicles are defined as being either a truck or car with a gross vehicle weight (GVW) of 8,500 pounds or less.

Various types of fleets are specifically not included such as rental cars, emergency or law enforcement vehicles, military vehicles, non-road vehicles, and vehicles which are typically kept at residences at night.

Under EPACT, alternative fuels are defined to be methanol, ethanol, or other alcohols, or mixtures of methanol, ethanol, or other alcohols in which the alcohol comprises at least 85% of the fuel by volume. The percent volume percent may be lowered to a minimum of 70% (with approval by the U.S. DOE) to allow for cold starting, safety, or other reasons. A variety of non-alcohol, non-petroleum fuels are also included in the definition of alternative fuels.

EPACT requires that the annual purchase of new vehicles by fleets include a specific percentage of alternative fueled vehicles. Alternative fueled vehicles are defined to include either dedicated, dual, or flexible fueled vehicles. The percentage depends on the type of fleet, and differs for

federal, municipal, and private fleets. EPACT requirements for the percentage of alternative-fueled vehicles to be purchased in a given year are presented in Table 2-1.

It is important to note that although EPACT requires certain fleets to purchase alternative fueled vehicles, it does not require they use alternative fuels. Examples of alternative fueled vehicles include dual or flexible fuel vehicles, such as the Ford Taurus which is currently commercially available. Dual or flexible fuel vehicles can use either alternative fuel and/or gasoline in any combination. Fleets can choose to use only gasoline in their "alternative fueled" vehicles.

Production Incentives

In response to the "energy crisis" in the late 1970s and early 1980s, Congress created alcohol fuel credits for certain mixtures of alcohols not produced from fossil fuels. The credits are in the form of income tax credits, and are intended to reduce the selling price of ethanol motor fuels to an amount comparable to petroleum-based fuels. In general, the tax credits are available to either:

- Producers or users of neat ethanol fuel (but not both);

- Producers or blenders of ethanol fuel mixtures (but not both) that produce or blend mixtures of neat ethanol and gasoline to produce E95, E85, or gasohol (which is 90% gasoline and 10% ethanol); and

- "Small ethanol producers" which are ethanol producers with a production capacity of 30 million gallons or less per year.

The credit for producers, users, or blenders of neat ethanol is $0.54 per gallon of ethanol (the credit for other alcohols is $0.60 per gallon). The credit is available only for ethanol not produced from petroleum, natural gas, or coal, and that has a proof of 190 or higher (which is equivalent to 95% alcohol or higher). The proof requirement allows denaturants (such as gasoline) to be added to the alcohol so that is not drinkable.

A separate credit of $0.10 per gallon is available for "small ethanol producers." This credit is available to qualified ethanol producers (with a production capacity of 30 million gallons per year or less), in addition to the other alcohol fuels credits. The ethanol produced by small producers must be at least 150 proof (which is equivalent to 75% alcohol) and the ethanol may be produced from petroleum, natural gas, or coal.

POTENTIAL MARKETS FOR FUEL ETHANOL

"High ethanol content fuels" can be defined as fuels containing 70% or more of ethanol. Although ethanol can be used as fuel in the form of neat (100%) ethanol, most high ethanol content fuels contain some gasoline which increases fuel performance during cold weather starting and operation, and serves as a denaturant. High ethanol content fuels must be used in motor vehicles designed and constructed for the fuel. Currently, local car dealers can supply certain vehicle models with an ethanol FFV option at no additional charge to the consumer.

"Low ethanol content fuels" typically contain 10% or less ethanol, with the rest being gasoline. Ethanol is added to the fuel to decrease certain tailpipe emissions or to increase the octane rating of the gasoline. Low ethanol content fuels can be used in motor vehicles designed to use gasoline. Most manufacturers selling automobiles in the U.S. warranty their automobiles for use with gasoline or gasoline/ethanol blends containing up to 10% ethanol.

High Ethanol Content Fuels

"High ethanol content fuels" include neat ethanol (containing 100% denatured ethanol), E95 (containing 95% denatured ethanol and 5% gasoline), and E85 (containing 85% denatured ethanol and 15% gasoline). High ethanol content fuels are produced either by ethanol producers (who blend ethanol with gasoline), or a separate company that purchases ethanol produced by others, blends it with gasoline, and distributes the fuel.

Approximately 36 facilities in the U.S. have the capability to produce E85. Most are located in the Midwest; none are located in the Northeast. Once produced, E85 is sold and distributed through a network of retail outlets (such as gas stations) or central refueling facilities (for public or private sector fleets). No retail outlets currently sell E85 (or other high ethanol content fuels) in the Northeast, nor are there any central refueling facilities in the region providing the fuels. An E85 refueling facility located in Washington, D.C. is the only facility located near the NRBP region.

Low Ethanol Content Fuels

Low ethanol content fuels include gasohol (containing up to 10% ethanol), oxygenated gasoline (containing 7% ethanol) and reformulated gasoline (containing 5% ethanol). Ethanol can be added to low ethanol content fuels in the form of either neat (100%) ethanol, or in the form of ethers that are produced from ethanol.

The overall demand for and use of neat ethanol in oxygenated gasoline and RFG may be limited in the future, if other sources of oxygenated fuels are available to reduce CO and hydrocarbon emissions from vehicles. This is because when ethanol (in its pure, neat form) is added to gasoline to produce gasoline/ethanol blends containing 22% or less ethanol), the ethanol increases the overall volatility of the fuel. This increases the emission of hydrocarbons during fuel storage and handling. Research indicates that emissions from gasoline mixed with relatively small amounts of ethanol during fuel storage and handling may outweigh decreased emissions from vehicle tailpipes.

However, as the amount of ethanol in gasoline increases, the volatility decreases. It appears that in blends containing more than about 22% ethanol and 78% gasoline, fuel volatility is less of an issue and there is an overall net decrease of CO and possibly hydrocarbon emissions (compared to fuel containing only gasoline). Hence, the extent of future markets for neat ethanol blended into gasoline will depend in part on the mixture of the end product, and the availability and cost-competitiveness of other oxygenated fuels that also meet clean air objectives.

Ether Production: In addition to neat ethanol, two ethers can be added to gasoline to increase the oxygen content. They are methyl tertiary butyl ether (MTBE) and ethyl tertiary butyl ether (ETBE). Both oxygenates are produced from an alcohol (either methanol or ethanol) and isobutylene. Isobutylene is produced as a by-product during oil or hydrocarbon refining. ETBE contains about 42% ethanol, and does not produce the undesirable emissions that some fuels do that contain blends of low amounts of neat ethanol with gasoline. Low ethanol content fuels containing ETBE may be used in conventional gasoline automobiles without modification.

Due to cost considerations, currently most, if not all, oxygenates are MTBE. Since the process of producing MTBE and ETBE is essentially the same, ETBE could be produced by refineries that produce MTBE. It is reported that slight process modifications would be needed in order to do so. MTBE production in the U.S. is reported to have reached about 215,000 barrels per day, and has increased to meet the demand for oxygenates.

According to an article published in **Alcohol Week's** New Fuels Report on December 18, 1995, three companies used to produce ETBE in small quantities, but recently stopped due to cost considerations. The article reports the price for ethanol used to produce ETBE was in the range of $1.25 per gallon, while the price for methanol was below $0.40 per gallon.

No ETBE refineries are located in the NRBP region, although ARCO Chemical Company has a refinery in Richmond, Virginia. It is possible that MTBE refineries located in the region could be converted to produce ETBE from ethanol. However, there would likely need to be a drastic decrease in the cost of ethanol (compared to the cost of methanol).

POTENTIAL DEMAND FOR HIGH ETHANOL CONTENT FUELS

High ethanol content fuels are not currently available or used in the NRBP region. Under both the Clean Air Act and the Energy Policy Act, various federal, state, municipal, and private fleets are required over time to purchase alternative- or clean-fueled vehicles. Requirements of the CAAA or EPACT could be met by purchasing vehicles capable of using high ethanol content fuels, such as E85. Overall, the authors of this study expect E85 will be the most widely used high ethanol content fuel in the Northeast and that use of neat ethanol or E95 will be more limited. This is because E85 contains 15% gasoline, which reduces cold starting and cold operation problems associated with fuels containing lesser amounts or no gasoline.

Because government fleets are either required to purchase alternative-fueled vehicles by the federal CAAA or EPACT and/or may be required to do so by state or local governments in the future, they may be one of the earliest and most identifiable markets for high content ethanol fuels.

Since both CAAA and EPACT require fleets (subject to the requirements of both acts) to purchase alternative- or clean-fueled vehicles as a portion of their total fleet purchases, fleets will likely phase in the use of clean or alterative fuels over time.

The purchase requirements of both acts are presented in Table 2-1. As shown in the table, 75% of new vehicles purchased by federal fleets must be alternative-fueled vehicles by 1999, 75% of new vehicles purchased by state fleets must be alternative-fueled vehicles by 2000, and 70% of new vehicles purchased by county and municipal fleets must be alternative-fueled vehicles by 2006.

Factors Affecting Market Development

Key factors affecting markets for E85 and other high ethanol content fuels are discussed below.

Availability of Other Fuels: The availability of other alternative or clean fuels. Although both the CAAA and EPACT create markets for alternative or clean fuels, neither specifies which fuel. Ethanol must compete with other fuels based on fuel price, vehicle purchase costs, vehicle maintenance costs, and other factors. When comparing ethanol to methanol, the key cost issues is fuel price.

Fuel Prices: Despite the current income tax credit for ethanol fuels, the price of ethanol greatly exceeds the cost of methanol. According to one source, ethanol sells for about $1.25/gallon while methanol sells for less than $0.40/gallon. Even when the fact that the energy content of methanol on a volume basis is about 75% of ethanol is taken into consideration, ethanol still costs considerably more. It is unlikely fleets will use ethanol or other high ethanol content fuels if other alternative fuels (such as methanol) are available at substantially lower prices.

Refueling Patterns: The ability to supply the fuel to vehicle fleets or individual vehicles. Centrally-fueled vehicles may be one of the earliest and most identifiable markets for alternative fuels. Information on the refueling patterns of fleets located in the NRBP region is presented in the report, Refueling Alternative Fuel Vehicles, Lessons Learned from the Marketplace published by the CONEG Policy Research Center, Inc. in May 1995. The report was completed as part of the "Clean Fuels Corridor" project which is aimed at identifying the need for and ultimately establishing alternative- fuel or clean-fuel refueling stations for public use in the Northeast. The study presented results from surveying 40 state and federal fleets, and nine municipal fleets. The survey assessed "refueling patterns" by investigating which fleets could be refueled at home (i.e. centrally), at other state or federal refueling locations, or at commercial refueling stations (i.e. gas stations). Results indicate that 42-63% of federal and state fleets primarily refuel at home. (The percent varies among fleet sizes.) For municipal fleets, 84% primarily refuel at home.

Limits in Fleet Requirements: Although both the CAAA and EPACT specify requirements for government fleets to purchase alternative- or clean-fueled vehicles, some fleets are exempt. Examples include emergency fleets and fleets that are not centrally fueled. The amount of fleets in the NRBP region that are not subject to the requirements of either act is unknown, as is the amount of fuel used by the

fleets. However, information presented in the Clean Fuel Corridor Market Study published by the CONEG Policy Research Center, Inc. indicates that about 50% of federal, state, county, and local fleets are centrally fueled. The amount of government fleets actually required to purchase alternative or clean fuels may be significantly less than 50%, because some types of fleets are exempt from CAAA and EPACT requirements.

Private Fleet Requirements: In addition to government fleets, both the CAAA and EPACT specify requirements for private fleets to purchase alternative- or clean- fueled vehicles. The requirements are less aggressive than those for public fleets, but over time they will stimulate demand for alternative fuels (including but not limited to ethanol).

Estimate of Market Demand

Presented in Table 2-2 is information on the amount of gasoline used in the 11 NRBP states by federal, state, county, and municipal fleets. The table is based on 1994 data published by the Office of Highway Information Management within the U.S. Department of Transportation. As shown in the table, an estimated 39 million gallons of gasoline were used by federal fleets and 318 million gallons were used by state, county, and municipal fleets, resulting in a combined total of 357 million gallons.

Ethanol and gasoline are not equivalent in terms of energy content: one gallon of gasoline is equivalent to 1.34-1.44 gallons of ethanol. Assuming gasoline is equivalent to 1.39 gallons of ethanol, the amount of gasoline used by federal agencies in the NRBP region in 1994 was equivalent to 54 million gallons of E85. The amount used by state, county, and municipal fleets was equivalent to 422 million gallons. This is a combined equivalent of 496 million gallons of E85.

Information on current fuel use provides a benchmark for estimating possible demand in the future. Based on the above information, it appears that potential use of E85 by public sector fleets in the future is likely to be no more than about 500 million gallons and could be substantially less. One market estimate based on what are believed to be reasonable assumptions about future market activity is presented below.

If the following is assumed:

- Public fleets travel about the same amount in the future as they did in 1994;
- About 50% of public fleets have the capacity to refuel centrally in the future; and
- All public fleets with alternative-fueled vehicles use E85 as fuel.

Then:

- Once federal fleets in the NRBP region reach a point in which 75% of all vehicles are alternative-fueled vehicles, they will require about 20 million gallons of E85 per year.
- Once state, county, and municipal fleets in the region reach a point in which 70% of all vehicles are alternative-fueled vehicles, they will require about 155 million gallons of E85 per year.
- This results in an estimated potential demand of about 175 million gallons per year of E85 for government fleets in the Northeast region.

POTENTIAL MARKET DEMAND FOR LOW ETHANOL CONTENT FUELS

As describe above, two oxygen containing fuels are required to be used in the 11 NRBP states, including oxygenated fuels which contain 2.7% oxygen by weight, and reformulated gasoline which contains 2% oxygen by weight. Ethanol or ETBE could be used as the source of oxygen in either of the fuels. RFG is required to be used in all, or part of each of the NRBP states, except Vermont. Oxygenated fuels are required to be used only in the metropolitan New York City area, including northern New Jersey and Connecticut. RFG must be used year round while oxygenated fuels are required only during the winter.

Factors Affecting Market Demand

Key factors that affect markets for neat ethanol or ethanol in the form of the ether ETBE as an oxygenate in low ethanol content fuels in the NRBP region are discussed below.

Fuel Price: As discussed above, despite the current income tax credit for ethanol used in fuels, the price of ethanol greatly exceeds the cost of methanol. Similar to ethanol, methanol can be used as an oxygenate, or more likely would be used to produce MTBE, which is another oxygenate with properties similar to ETBE. As noted above, ethanol is priced at about $1.25/gallon while methanol is priced at about $0.40/gallon.

Availability of Other Oxygenates: Although the CAAA and/or state regulations require oxygenated fuels to be sold in certain portions of the NRBP region, the regulations do not specify which oxygenate must be used. Ethanol must compete with other oxygenates based on price, availability, fuel performance, and other factors. Depending on the economics of producing oxygenated gasoline, the price of ethanol will need to be lower than it currently is to compete with other oxygenates.

Estimate of Market Demand

Presented in Table 2-3 is the total amount of liquid fuel used for both highway use and non-highway use by private, commercial, and government entities in the 11 NRBP states in 1994. This is based on information published by the Office of Highway Information Management within the U.S. Department of Transportation. As shown in the table, nearly 22 billion gallons of liquid fuel were used for highway and non-highway vehicle use in the region. (This includes gasoline, gasohol, and RFG. (Information on additional quantities of other oxygenated fuels is not available, and is therefore not included in the table.)

The portion of total liquid fuel use believed to be RFG can be estimated by applying data developed by ARCO Chemical Company, based on information published by the Energy Information Administration within the U.S. Department of Energy. The percentage of liquid fuel used in each state for highway and non-highway transportation that is believed to be RFG is presented in Table 2-3. When combined for the region as a whole, it is estimated that nearly 15 million gallons of RFG were used in the Northeast in 1994, or about 67% of total gasoline use.

As discussed above, gasoline and ethanol must be blended in a 95 to 5 volume ratio in order to achieve a 2% oxygen content by weight. If all RFG used in the NRBP region contained ethanol or ETBE as the oxygenate, then the demand for ethanol (as either ethanol or ETBE) would be about 741 million gallons per year.

SECTION 3:

ETHANOL PRODUCTION FROM BI0MASS

Also referred to as ethyl alcohol or grain alcohol, ethanol is the alcohol product of a fermentation process. Ethanol is produced by converting plant material to sugar, fermenting the sugar to alcohol, and then separating the water-alcohol mixture using a process such as distillation.

The term "biomass" refers to plant or animal material of recent origin. Many types of biomass can potentially be used to produce ethanol. This includes starch-rich materials, such as corn and cheese whey as well as cellulose-rich materials, such as wood waste, paper sludge, municipal solid waste, and short rotation woody crops grown for energy (such as hybrid poplar).

The process for producing ethanol from starch-rich materials, such as corn, is well developed and fully commercialized. Processes for producing ethanol from cellulosic biomass are in various stages of research, development, and demonstration (RD&D) and are not yet fully commercialized. Prior to the early 1990s, the projected production cost of ethanol from cellulosic biomass (referred to as "biomass ethanol" or "cellulosic ethanol") exceeded that produced from corn (referred to as "corn ethanol"). In addition, a number of technical issues regarding the cellulosic biomass conversion process remained unresolved. During the past five years, commercial interest in production of ethanol from cellulosic biomass has increased markedly, reflecting advances in both the technology and the cost-competitiveness of conversion processes.
Presented below is a summary of the existing corn ethanol industry, and an explanation of how ethanol is produced from corn. Information is provided on how ethanol can be produced from cellulosic biomass and on current and anticipated production costs and selling prices. Case studies are provided of two ethanol plants currently in operation. One plant uses corn as the feedstock; the other uses paper-making residue.

A SNAPSHOT OF THE ETHANOL INDUSTRY

Currently, 38 plants in the U.S. have the capacity to produce about 1.5 billion gallons per year of ethanol. Most are located in the Midwest and use corn as the feedstock. Three plants utilize cheese whey or other cheese by-products as feedstock, one plant utilizes paper-making residue. One plant extracts ethanol from waste beer at a large brewery. A list of facilities that produce ethanol is presented in Table 3-1.

ETHANOL PRODUCTION FROM CORN

Corn is currently converted to ethanol by processes based on either dry or wet milling. The dry milling
process entails mechanical grinding, cooking, enzymatic hydrolysis to form glucose, fermentation,
product recovery via distillation, and solids drying. In addition to producing ethanol, the dry milling process results in production of "distiller's dried grains and solubles" (DDGS) which are sold as a "medium protein" animal feed containing about 26% protein. Wet milling involves separating protein, oil, and fiber from the starch prior to ethanol production, and results in the co-products corn oil, corn gluten meal, corn gluten, and feed. Thereafter, fermentation and product recovery are carried out in a manner similar to dry milling. Wet milling currently accounts for about 2/3 of the ethanol produced in the U.S.

For plants that utilize either wet or dry milling, the value of co-products greatly improves the process economics. The "net cost of corn" (the corn price less the value of co-products) is quite variable. The cost of producing ethanol from corn varies from $1.10 to $1.90 per gallon, depending on the cost of corn, co-products prices, and the type and scale of production technology. During 1993,

corn ethanol sold for $1.15 to $1.40 per gallon. Presented in Table 3-2 is a summary of the production costs of ethanol from corn.

WHAT IS CELLULOSIC BIOMASS?

Cellulosic materials that can be used to produce ethanol include waste materials from processes other than fuel production (e.g. agriculture and forest products industries), or energy crops grown specifically for the purpose of fuel production. The three major components of most native cellulosic materials are cellulose, hemicellulose, and lignin. Cellulose and hemicellulose typically comprise roughly 2/3 of the dry mass of biomass materials and can be fermented into ethanol. Lignin makes up most of the remaining 1/3 of the dry mass which can not be fermented into ethanol.

Cellulose is a polymer of glucose, a six-carbon sugar or hexose, joined by beta-linkages. Linear cellulose chains are typically arrayed in a parallel arrangement with extensive hydrogen bonding between them. The result is a highly ordered, crystalline material that is recalcitrant to rapid reaction under many conditions. Cellulose comprises about 2/3 of the total carbohydrate content of most woody plants and about 1/2 of the total carbohydrate content of herbaceous plants.

Hemicellulose is a polymer that occurs in association with cellulose and generally comprises 20-35% of the dry mass of biomass. Characterized by a branched structure, hemicellulose is essentially non-crystalline and generally more reactive than cellulose. Hemicellulose is composed of several sugars, with the identity and proportion of sugars depending on the type of plant material considered. Xylose, a five carbon sugar or pentose, is the dominant constituent of hemicellulose in plants other than softwoods.

Lignin is a random polymer of phenylpropylene subunits. These subunits are joined to other subunits by ether and carbon-carbon linkages, and are also covalently bound to hemicellulose. Lignin occurs as a "net" surrounding carbohydrate-rich microfibrils in plant cell walls, and also occurs in the interstitial space between mature plant cells. The mass fraction of lignin in plant material varies from 7-30%, with agricultural residues generally lower than hardwoods, and hardwoods generally lower than softwoods. Lignin is essentially non-biodegradable during ethanol production processes. The heating value of lignin is 5/3 that of carbohydrates and lignin contributes a significant fraction of the overall heating value of woody materials.

TRANSITION TO CELLULOSIC BIOMASS FROM CORN

Although the current ethanol industry is based primarily on corn, ethanol derived from cellulosic materials has the potential to offer substantial advantages, including:

- Lower costs for feedstocks and production overall;
- A larger potential resource base of feedstock;
- More environmentally-benign feedstock production;
- A more favorable process energy balance; and
- Reductions in greenhouse gas emissions.

The National Renewable Energy Laboratory (NREL) funded by the U.S. Department of Energy (DOE), private companies, biotechnology and engineering laboratories, and other R&D organizations are developing processes for producing ethanol from biomass. NREL operates the largest and most comprehensive RD&D program for conversion of cellulosic biomass to ethanol in the world.

ETHANOL PRODUCTION FROM CELLULOSIC BIOMASS

The process to convert biomass to ethanol includes five major components: preparing the feedstock, converting the feedstock to ethanol, recovering the ethanol, producing the energy needed for the conversion process, and managing emissions.

Processes used to convert cellulosic biomass to ethanol are differentiated primarily based on the methods used to achieve hydrolysis and fermentation, the two steps that are the least technologically mature and the most specific to ethanol production. For hydrolysis, processes can be categorized depending on whether they utilize mineral acids (e.g. sulfuric acid) or cellulase enzymes. Although acid-based processes are more technologically mature, enzymatic processes have roughly equal projected costs and are expected to have an increasing cost advantage over time as technology is improved. In addition, processes relying on acids generally have greater environmental liabilities compared to enzymatic processes.

Because of these considerations, most if not all studies that project technology for large-scale production of ethanol from cellulosic biomass feature enzymatic hydrolysis. In the near term, it is likely that opportunities exist for commercial application of both acid- and enzyme-based processes. Acid-based processes have one significant advantage over enzymatically-based processes: they are equally effective with softwoods and hardwoods. By contrast, current enzymatic processes are effective for hardwoods and herbaceous materials, but not for softwoods.

Pretreatment

When addressing the production of ethanol from biomass, "pretreatment" denotes processes by which cellulosic biomass is made amenable to the action of hydrolytic enzymes. All naturally occurring, and most refined, cellulosic materials require pretreatment to become accessible to the enzymes that mediate hydrolysis. Typically, hydrolysis yields in the absence of pretreatment are less than 20% of what is theoretically possible, whereas yields after pretreatment often exceed 90% of what is theoretically possible. The limited effectiveness of current enzymatic processes relative to softwoods is believed to be due to the relative difficulty of pretreating these materials.

Many different pretreatment processes can be used. Most processes involve reducing the size of woody materials to at least the size of fuel chips (i.e. about the size of a matchbook). Some processes anticipate reducing the size even more. Heat is commonly used, often by injecting steam. Many processes use acids, such as dilute sulfuric acid (currently favored by the design being pursued by NREL). The most thoroughly-characterized pretreatment processes include dilute-acid pretreatment, steam explosion including acid-catalyzed steam explosion, ammonia fiber explosion, and treatment with organic solvents. Additional processes proposed but not as well studied include use of milling, supercritical fluids, irradiation, biological delignification, oxidizing agents, alkali, and liquid hot water.

Mechanistic understanding of why pretreatments work is incomplete, and design of pretreatment devices is largely empirical. Moreover, it is clear that different mechanisms are more important for different processes. Many pretreatment processes involve near-complete hydrolysis of the hemicellulose portion of biomass materials, with some also dissolving lignin to some degree. Pretreatment tends to have a pervasive impact on process performance and economics, with many of the most important impacts of the choice of pretreatment process manifested in other process steps.

Important performance metrics of pretreatment processes include: fiber reactivity; the extent of recovery of pentose sugars in non-degraded form, the extent of hydrolyzate inhibition; the extent of size reduction required; reactor size, weight (a function of operating pressure and size), and materials of construction (which vary according to the corrosiveness of the process considered); and production of process residues (e.g. gypsum arising from the neutralization of sulfuric acid with lime). The ideal pretreatment process would:

- Produce reactive fiber;
- Yield pentoses in non-degraded form;

- Exhibit no significant inhibition of fermentation;
- Require little or no size reduction;
- Entail reactors of reasonable size built of materials with a moderate cost; and
- Not produce solid residues.

The most thoroughly-studied pretreatment processes (which include dilute acid hydrolysis and steam explosion) do not meet these criteria; liquid hot water pretreatment may, but requires more investigation before a definitive evaluation can be made.

Biological Conversion

Once pretreatment is complete, the biomass is biologically converted. A common element in essentially all proposed processes for producing ethanol from cellulosic biomass is microbial fermentation. A variety of microorganisms (generally either bacteria or yeast) ferment carbohydrates to ethanol under oxygen-free conditions. Cells carrying out such fermentations do so to obtain energy (in the form of adenosine triphosphate), and are thus dependent upon ethanol production for growth and long-term survival. The net result of fermentation is:

Carbohydrate + Cell mass ------>
Ethanol + CO_2 + More cell mass

In the absence of cell production, the maximum possible yield of ethanol is 0.51 (mass ethanol/mass carbohydrate, corresponding to 51% of the carbohydrate converted to ethanol on a mass basis) with the balance being carbon dioxide. Typically, about 5-12% of the carbohydrate is converted to cells, which results in most proposed ethanol production processes converting not more than 47% of the fermented carbohydrate to ethanol.

The ideal system for producing ethanol from cellulosic biomass would involve a microorganism or combination of microorganisms that simultaneously exhibit the following properties:

- Synthesis of an active cellulase enzyme system at high levels;
- Fermentation and growth on sugars arising from both cellulose and hemicellulose; and
- Production of ethanol at high selectivity and high concentration.

All described microorganisms and combinations of microorganisms fall short of this ideal. Most commonly, this is because of one of two limitations: an inability to both utilize the range of carbohydrates present in biomass (e.g. cellulose and xylan) while also producing ethanol at high yield; or differing requirements for oxygen for various functions essential to the process. Approaches to address these limitations are a key focus of R&D. For example, there has been a concerted effort to develop improved pentose fermenting microorganisms using recombinant DNA technology.

Four biologically-mediated events occur in the course of producing ethanol from cellulosic biomass: cellulase production, cellulose hydrolysis, hexose fermentation, and pentose fermentation. Process configurations proposed for the biological steps differ in the degree to which these events are integrated.

As presented in Figure 3-1, separate hydrolysis and fermentation (SHF) involves four bioreactors. Simultaneous saccharification and fermentation (SSF) consolidates hydrolysis and cellulose fermentation with cellulase production carried out in a separate step by different organisms. Either two or three bioreactors are involved, depending on how hemicellulose sugars are processed. Consolidated bioprocessing (CBP) accomplishes cellulase production, hydrolysis, and fermentation simultaneously in a single bioreactor.

The state-of-the-art currently involves SSF, with cofermentation of hexoses and pentose sugars a focus for near-term development. The difference between SHF and SSF is one of arrangement of the same components. In both of these alternatives, one microorganism is used to

produce cellulase, and a second is used to carry out fermentation. Based on extensive study by the National Renewable Energy Laboratory, the SSF approach appears to enjoy a substantial economic advantage over SHF.

As depicted in Figure 3-1, CBP is the logical endpoint in the evolution of biomass conversion technology. CBP (also called direct microbial conversion or DMC) is less well-developed than SSF, but is expected to offer the lowest costs if limitations of current systems can be overcome.

The key difference between CBP and other biomass processing strategies is that a single microbial community is employed for both cellulase production and fermentation. This difference has several significant ramifications, including no capital or operating costs for dedicated enzyme production, greatly reduced diversion of substrate for enzyme production, and compatible enzyme and fermentation systems. Dedicated cellulase production, e.g. by an aerobic fungus such as *Trichoderma reesei*, is relatively slow and expensive - some would say prohibitively expensive for biological commodity applications. As a result, there is a strong economic incentive to operate with low cellulase loadings and hence large and expensive SSF reactors.

CBP is in principal not subject to this constraint. Relative to a state-of-the-art SSF plant, a projected 50% reduction in the cost of ethanol production exclusive of substrate, a 31% reduction in the cost of production overall, and a savings of $0.31 per gallon are projected for a hypothetical high-yielding CBP system.

Product Recovery

Purification of ethanol from the concentration produced by fermentation to concentrations useful as fuels is accomplished via distillation. Distillation involves the counter-current contacting of an
ascending vapor stream and a descending liquid stream. These streams are arranged so that at any given point in the column, the vapor contains less than the equilibrium amount of one or more volatile components in comparison to the liquid with which it is in contact. As a result, the vapor is enriched in the more volatile component(s) as it moves up the column.
Distillation is a standard unit operation of chemical engineering, and thus the product recovery section of an ethanol plant can be designed with a high degree of certainty and little or no development work. This situation is in sharp contrast to that for pretreatment and biological conversion, where design is largely empirical and technology has generally not been proven on a commercial scale for cellulosic materials.

Essentially all ethanol resulting from fermentation is recovered from the fermentation broth in a stripping or beer column. The ethanol is then concentrated in a rectifying column to a concentration less than or equal to that of the ethanol-water azeotrope (about 95% ethanol by weight). If essentially water-free ethanol is desired, purification beyond the azeotrope can be achieved by further distillation in the presence of an entraining agent (such as benzene or cyclohexane) which is subsequently recovered, adsorption using corn grits or some other solid material, or by pervaporation or other membrane-based operations.

Regardless of the fermentative organism employed, ethanol production from cellulosic biomass is likely to involve operation at lower product concentrations (e.g. less than or equal to 5% of the total weight, which is commonly referred to as "5% weight basis") than is typical of ethanol production from corn. This is the result of both biological and processing constraints. Although the maximum concentration of ethanol tolerated by industrial yeasts and *Zymomonas* is on the order of 10% weight basis at 30°C, the tolerance of microorganisms to ethanol generally decreases with increasing temperature. All SSF designs operate at near the maximum temperature tolerated by the fermentative organism in order to maximize cellulase activity, consistent with the dominant cost impact of cellulase production relative to distillation.

For example, the current NREL SSF design is operated at 37°C, at which the maximum ethanol concentration tolerated by both yeast and *Zymomonas* is reduced by half to 5% weight basis. On the processing side, cellulosic

slurries become progressively more paste-like and difficult to handle at solids concentrations exceeding 15% weight basis (the NREL design uses 16 percent weight). At a representative carbohydrate content for cellulosic feedstocks, approximately 2/3 on dry weight basis, a 15% weight basis feed corresponds to a potential ethanol concentration of 5% weight basis.

Utilities

Facilities require electricity and steam to produce ethanol, and may produce more of both than is needed on-site. In such circumstances, the extra electricity and/or steam may be sold to another end user.

Lignin comprises about 25% of the mass of dry hardwood and represents 1/3 or more of the heating value of woody materials. The non-fermentable lignin remaining after ethanol production can in principle be converted to chemicals, but is likely to be burned in a boiler as a process fuel and/or to cogenerate electricity.

For woody feedstocks, combustion of process residues is sufficient to provide all of the steam and power required by a plant, with some electricity usually exported for sale. Rankine cycle-based biomass combustion and power generation is employed commercially today. Significant advances in the overall thermal efficiency of biomass power generation are expected in the future from use of advanced gasification and combined cycle gas turbines/heat recovery boilers. As cellulose ethanol technology matures, the energy required by various process steps may decrease and cogeneration of electricity may increase.

Air, Ash, and Wastewater Emissions

Ethanol facilities produce air, ash, and wastewater emissions which must be managed in some way.

Emissions vary depending on the type and amount of feedstock used, type of pretreatment, whether energy is produced on-site, and/or overall production capacity. Presented in Section 4 is discussion of the types of emissions expected to be produced by biomass ethanol plants. Process flow diagrams are presented for five, theoretical biomass ethanol plants and emissions expected from each plant are summarized in tables. The process flow diagrams provide a conceptual understanding of the processes and steps used to produce ethanol at each of the five facilities, and the summaries of emissions provide a basis of understanding and comparing emissions among different facilities.

In general, it is anticipated that best available air pollution control technology will be capable of controlling flue gas emissions of nitrogen oxides, sulfur dioxide, and carbon monoxide and that any emissions of volatile organic compounds will likely be below regulatory standards. Permits will be needed for air and maybe ash emissions.

Solid waste disposal will be required for boiler ash and flue gas desulfurization solids. The amount of ash generated will depend largely on whether acid is used in pretreatment/hydrolysis, which results in generation of precipitates upon neutralization. None of the solid wastes generated are expected to be classified as hazardous waste or to present a particular solid waste management problem. Permits may be needed for disposal of the ash and other solid wastes.

It is anticipated that available water pollution control equipment will be capable of reducing the biological oxygen demand (BOD) of the effluent and the amount of suspended solids in the effluent to meet discharge standards. Permits may be needed for wastewater discharges, especially if the wastewater is discharged to a surface water rather than to a treatment plant.

BIOMASS ETHANOL COSTS FROM CURRENT TECHNOLOGY

No commercial facilities currently produce ethanol from cellulosic biomass using enzymatic hydrolysis. Thus, understanding of the cost of such processes is based on projections developed from laboratory data and, in some cases, data from pilot projects. Information on production costs presented in this report is based on information developed by the National Renewable Energy Laboratory. The most recent publicly-available NREL designs are based on the use of hybrid poplar as the feedstock in an SSF process involving fermentation via yeast and cellulase production by *Tricoderma reesei*. Feedstock is assumed to be available at a cost of $42 per bone dry ton delivered.

Presented in Table 3-3 is an estimate of the production cost of ethanol developed based on the NREL SSF design. The projected selling price of ethanol is estimated to about $1.18 per gallon. This includes both operating costs and allowances for capital recovery (which are embedded in costs referred to in the table as "Capital, Labor, & Related.") This does not include any price reductions that might occur as a result of various federal or state credits. Major drivers in the price include the costs of raw materials, biological conversion (most notably SSF), pretreatment, and equipment for the power cycle. Process energy requirements (including steam at two pressures and electricity) is represented in terms of lost electricity revenue (with electricity priced at $.04 per kiloWatt-hour [kWh]).

Of the overall projected selling price of $1.18 per gallon, capital recovery accounts for about $.50 per gallon. Thus the cost of capital has a large impact on the price of ethanol and overall economic viability. Data in Table 3-3 represent a return on investment (ROI) of 14.2%, when assumptions used for construction time and capacity build-up reflect the use of mature technology. The data represent a ROI of 10%, when assumptions used for construction time and capacity build-up are more representative of a first-of-a-kind commercial plant.

Although a $1.18/gallon selling price for ethanol is competitive with current prices for corn ethanol, the risk associated with a cellulose-based plant is higher than a corn-based plant, and a 10% ROI is not expected to be sufficient for the added risk. Thus, production of ethanol from cellulosic energy crops is expected to be roughly cost-competitive with production from corn when capital is available at a comparable cost, but not when capital is only available at a higher cost.

Opportunities to use waste materials as feedstocks, such as wood separated from the waste stream, paper sludge, or municipal solid waste, could result in lower feedstock costs and therefore lower production costs (and selling prices) for biomass ethanol. If generators of such materials otherwise have to pay for disposal, they may be able to provide the material as feedstock at low-, no-, or negative-cost. Such opportunities are site-specific and depend on a variety of market issues, such as the availability and cost of disposal options, the types and amounts of waste generated, and other potential uses for the residues.

BIOMASS ETHANOL COSTS FROM ADVANCED TECHNOLOGY

Presented in Table 3-4 are results of an analysis conducted for NREL which addressed the following question:

"What are the likely features and cost of a facility producing ethanol from cellulosic biomass at a level of maturity comparable to a refinery?"

An advanced technology scenario was developed representing estimates of the most likely features of mature, commercialized biomass ethanol technology. Cost reductions are included (compared to those presented in Table 3-3) due to increased scale, reduced feedstock costs, and improved conversion technology. A plant scale of nearly 300 million gallons per year is assumed, which is similar to the largest existing corn ethanol facility (with the capability to produce 310 million gallons per year). This capacity is expected to be sufficient to realize most benefits of economy of scale. A feedstock cost of $38.60

per bone dry ton delivered is assumed which corresponds to the average cost projected by Perlack and Wright for 2020. Conversion technology improvements are assumed for pretreatment and biological conversion but not other process steps.

As shown in Table 3-4, the selling price of biomass ethanol are projected to be about $.50 per gallon when using advanced technology. Similar to the production/selling price presented in Table 3-3, this includes both operating costs and allowances for capital recovery (which are embedded in costs referred to in the table as "Capital, Labor, & Related.") This does not include any price reductions that might occur as a result of various federal or state credits.

Improved conversion technology is by far the largest contributor to reducing the cost of ethanol production, with conversion-related cost reduction for the advanced scenario 3 times larger than that associated with scale and 10 times larger than that associated with less expensive feedstock. The largest conversion-related cost reductions are due to an over 8-fold reduction in the cost of biological conversion. More efficient biological processing is the major factor behind increasing electricity exports in the advanced technology scenario, and is a significant factor in reducing the cost of raw materials and increasing process yields. Improvements in biological processing result primarily from the use of consolidated processing. This would require combining the properties of separate existing microorganisms into a single organism or system of organisms.

CASE STUDY:

NEW ENERGY OF INDIANA

Presented below is a case study of New Energy of Indiana (NEI), an ethanol plant in South Bend, Indiana. The information is taken from published reports by Hunsaker et al. and Miller at al. In addition, information on production capacity and the number of employees is from an interview with Larry Russo, Project Development Manager at the company at the time that research was done for this study.

Constructed in 1984, the plant uses corn as the feedstock and a dry milling process. The plant is designed to produce up to 52 million gallons per year of ethanol; about 85 million gallons per year are actually produced. The plant produces anhydrous ethanol (greater than 99.5% by weight), distiller's dry grains with solubles (DDGS), and carbon dioxide, all of which are sold at prevailing market prices.

In the early 1990's, NEI had a Cooperative Research and Development Agreement (CRADA) with the National Renewable Energy Laboratory, the goal of which was to make process modifications that permit cellulosic components of corn to be converted to ethanol (in addition to commonly used corn starch). NEI built a small demonstration pilot plant at their facility, and results of their R&D efforts contributed to the growing body of knowledge about the potential for converting cellulosic materials to ethanol.

NEI was the first of three ethanol plants built with federal loan guarantees under the auspices of the Energy Security Act. The cost of the plant was $186 million; $141 million of the cost was financed, 90% of which was guaranteed by the U.S. Department of Energy. The plant has about 162 employees.

PROCESS DESCRIPTION

Corn used as feedstock at the plant is delivered by truck and then reduced in size using hammermills. A mash is prepared from milled corn, enzyme, lime, water, and steam, and transferred to fermentation tanks. Yeast is added, and fermentation is allowed to proceed in batch mode. When fermentation is complete, the fermented mash (referred to as "beer") is sent to a beer column which gives rise to two streams. One stream is partially enriched in ethanol. The second stream is essentially ethanol-free stillage which contains solids originating from unfermented corn as well as yeast.

Further concentration of ethanol is achieved in a rectifying column producing azeotropic ethanol (95% weight basis). The azeotropic ethanol is further enriched by benzene dehydration to achieve essentially anhydrous ethanol (greater than 99.5% weight basis). The resulting product is denatured with unleaded gasoline, prior to shipping.

Stillage is sent to centrifuges and mechanical evaporators, resulting in a fibrous material of approximately 50% moisture. This is then dried further in steam-heated rotary kiln drier, resulting in biologically-stable material sold as DDGS.

Carbon dioxide contained in fermentation off-gases is recovered in a degasser, passes through a packed

EMISSION	PERMITTED LEVEL (Tons/Yr)	ACTUAL EMISSIONS (% of Permitted Levels)	ACTUAL EMISSIONS (Tons/Yr)
SO_2	1,804	80%	1,443
NO_X	1,052	80%	842
TSP	87	<50%	<44
VOC	87	<50%	<44
CO	62	<50%	<31

tower CO_2 scrubber, and is piped to an adjacent facility that compresses and sells the CO_2 for industrial or commercial use.

As noted above, the design capacity of the plant is 52 million gallons per year; actual production is about 85 million gallons per year. Capacity expansion was achieved by alleviating process steps and expanding fermentation capacity.

AIR EMISSIONS

New Energy of Indiana operates under an air pollution control permit issued by the St. Joseph County Health Department. The plant is subject to both federal New Source Performance Standards (NSPS) and Prevention of Significant Deterioration (PSD) requirements. PSD review was required because the plant was expected to emit more than 100 tons per year of sulfur dioxide (SO_2) or nitrogen oxides (NO_x). The operating permit also addresses the emission of total suspended particulates (TSP), volatile organic compounds (VOCs), and carbon monoxide (CO).

Presented below are emission limits in the facility's air permit as well as the actual emissions from the facility, measured during periodic compliance monitoring. The information is based on data presented in **A NEPA Follow-up Study of DOE Loan Guarantee Fuel Ethanol Plants** prepared by Hunsaker et al. As shown in the table, the facility operates well below regulatory standards. Actual emissions are <50% of permit levels for TSP, VOC, and CO and 80% of permit levels for SO2 and NOx.

The plant was required to obtain both a construction permit and an operating permit. The operating permit was issued once the plant was constructed, and emission testing demonstrated the plant could comply with conditions contained in the construction permit.

WASTEWATER DISCHARGES

Wastewater generated by the NEI plant is treated at a wastewater pretreatment facility located on-site prior to discharge to a municipal wastewater treatment plant (MWWTP). Pretreatment consists primarily of neutralization. The wastewater consists of process, sanitary, and some non-process wastewaters.

PARAMETERS	AMOUNT
Flow	1.3 MGD
BOD Concentration Loading	 1,500 to 1,800 mg/l 8.3 to 9.7 ton
Suspended Solids Concentration	 500 mg/l

Presented below is information on wastewater quality and quantity. The information is based on data presented in the NEPA follow-up study prepared by Hunsaker et al.

According to the NEPA follow-up study, actual wastewater flow, biological oxygen demand (BOD) concentration and loading, and suspended solids concentration exceed what was predicted for the plant. Prior to construction, municipal officials in South Bend believed capacity at the municipal wastewater treatment plant was underutilized, and that it would be desirable to have an additional source of BOD and organic loading. Once the NEI plant began generating wastewater (at higher flows and BOD loadings than expected), the municipal treatment plant became overloaded and exceeded BOD limits in its National Pollution Discharge Elimination System (NPDES) permit. Subsequent facility and operational changes at the treatment plant combined with operational changes at NEI greatly decreased occurrences of NPDES permit violations. A portion of the upgrade at the treatment facility is funded by surcharges to NEI levied when their wastewater exceeds BOD limits.

SOLID WASTE MANAGEMENT

Most "residuals" generated during ethanol production at NEI are DDGS, which are sold as animal feed. Fly ash is also generated by a coal-fired boiler and is disposed of at the municipal landfill.

ODORS

NEI produced unexpected odors when the plant started operating, causing significant public concern which ultimately lead to a law suit against the company by a local citizens' group. The source of the odor was determined to be the DDGS dryer and the odor was controlled by adding a dry chlorine scrubber to the dryer stack. More information about the odors is presented in the report, **Investigation of Odorous Emissions from a Fuel Ethanol Plant** prepared by Miller et al.

The use of driers to produce DDGS is specific to corn ethanol plants, and would not be part of a cellulosic ethanol plant. It is unlikely that the same odors generated (and eventually controlled) by the NEI plant would be produced by a cellulosic biomass ethanol plant. However, cellulosic biomass plants could produce other odors and should be carefully considered during plant design and siting.

OVERALL OPERATING EXPERIENCE

Staff of NEI report that the plant owners are satisfied with the facility and expect the facility to remain in operation in the future.

Several other dry mills that produce ethanol stopped operating during the last several years. This is believed to be due to relatively high corn prices, low ethanol prices, and the fact that dry mills are dedicated to ethanol production (whereas wet mills can produce multiple products in accordance with market demand).

CONTACT

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CASE STUDY:

GEORGIA PACIFIC COMPANY

Georgia-Pacific Company (G-P) operates a facility at its pulp and paper mill in Bellingham, Washington that produces ethanol from sugars present in sulfite waste liquor. The waste liquor is a by-product of the paper-making process. In operation since 1945, the plant is the oldest non-beverage ethanol facility in the U.S. The plant was built in large part to satisfy wartime requirements for incorporating alcohol into the manufacture of munitions and synthetic rubber.

The pulp and paper mill where the ethanol plant is located produces about 250 tons per day of paper and 450 tons per day of bleached softwood pulp. The ethanol plant produces about 20,000 gallons per day of chemical-grade, anhydrous ethanol, or about 7 million gallons per year). The labor needed to operate the ethanol plant is estimated to be 18 employees.

Ethanol is sold to the chemical process industry as well as fuel markets. Information on prices obtained for the ethanol is not available.

The Georgia-Pacific ethanol plant was selected as a case study because it uses a feedstock other than corn and because it is incorporated into a larger plant. Incorporation of an ethanol production facility into an existing plant that already has power generation, wastewater treatment, or other key capabilities can decrease ethanol production costs and increase overall economic viability.

PROCESS DESCRIPTION

The sulfite-based pulping process used at the pulp and paper plant involves cooking in the presence of sulfurous acid and calcium bisulfite. The spent sulfite liquor is recovered when paper fiber is drained and washed. The spent liquor contains soluble sugars liberated from the wood during the pulping process. The liquor is steam-stripped to remove sulfur dioxide (which is subsequently reused), filtered, heated or cooled to the fermentation temperature (28°C), and adjusted to a pH of 4.8 using lime or ammonia. Urea is then added as a source of nitrogen for yeast growth. Hexose sugars present in the spent sulfite liquor is fermented to ethanol.

Currently, other sugars in the spent sulfite liquor are not fermented although Georgia-Pacific is interested in investigating this possibility. Fermentation is accomplished in four continuously-fed tanks connected in series with yeast recovered via centrifugation and recycled. Excess yeast is produced in the process, which is recovered and sold. A beer containing approximately 1% ethanol is recovered by distillation in a beer still, followed by rectifying and purification columns. A residual organic material, consisting primarily of lignin originating from the pulping process is separated in the first stage of distillation, with the resulting slurry being evaporated and sold.

AIR EMISSIONS

The ethanol plant operates under the pulp and paper mill's air pollution control permit, and did not go through a separate permitting process when it was built. Air emissions from the ethanol plant are primarily from fermentation off-gases and are believed to be low due to the relatively low fermentation temperature.

WASTEWATER DISCHARGES

The ethanol plant receives spent sulfite liquor from the pulp and paper mill as feedstock, and releases a roughly equal quantity of wastewater back to the mill. Wastewater from the ethanol plant is treated by the mill's wastewater treatment facility. A small amount of wastewater is removed from the bottom of the distillation columns in order to remove organic residues. The residues are concentrated via multi-effect evaporation and the condensate is discharged to the mill's wastewater treatment plant.

SOLID WASTE MANAGEMENT

Residues generated by the ethanol plant consist of excess yeast and a dried organic material. Both residues are sold.

ODORS

Odors from the ethanol plant have not been a problem.

OVERALL OPERATING EXPERIENCE

Representatives of Georgia-Pacific state the company is satisfied with the cost-effectiveness of the ethanol plant, and that the company anticipates producing ethanol at the Bellingham mill indefinitely.

Since spent sulfite liquor produced by the pulp and paper plant is used as feedstock, the ethanol plant does not include feedstock receiving and handling facilities, acid hydrolysis, or other feedstock pretreatment processes. In addition, since the ethanol plant was added to an existing pulp and paper mill, it is able to utilize the existing steam, power generation, and wastewater treatment facilities. Hence, the cost of ethanol production is significantly lower than it would be at a new, stand-alone ethanol plant.

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SECTION 4:

EMISSIONS FROM BIOMASS ETHANOL PLANTS

The purpose of this section is to describe the types of emissions expected from biomass ethanol facilities and to provide an overview of the environmental regulations likely to apply to such facilities. In addition to information on emissions provided in this section, presented in Appendix A is information on environmental regulations that may apply to biomass ethanol plants in each of the Northeast states. Emphasis is placed in this report on state regulations and permitting, since states are expected to have jurisdiction over most, if not all, regulations and permitting affecting biomass ethanol plants. This section and Appendix A serve as a starting point for those interested in pursuing these issues in further detail. They are not intended to be step-by-step guides to developing or obtaining regulatory approval for a biomass ethanol plant.

WHAT ARE THE MAJOR EMISSIONS?

Biomass ethanol facilities produce a variety of liquid and gaseous emissions and are likely to be required to apply for one or more permits by the state agency (or agencies) responsible for environmental permitting. The specific regulatory or permitting process used in each state varies. In order to obtain the necessary permits, developers of biomass ethanol plants must have a thorough understanding of the emissions to be generated by a plant. Permit applicants will be expected to provide information on plant emissions. Similar to other industrial processes or plants, ethanol plants may impact three key environmental media that affect human health and safety, and thus are subject to government regulations. These include air, land, and water. The air, solid waste, and wastewater emissions that can be expected to be generated by biomass ethanol plants are summarized below.

Air Emissions

The major sources of air emissions from biomass ethanol plants are flue gases from energy production (if present), off-gasses from fermentation, and off-gases from product and chemical storage. If a plant includes a boiler or gasifier for energy production, the flue gas will be the largest and most significant air emission. Other emissions may also be present in smaller amounts, such as fugitive dust from feedstock processing and ash handling (if a boiler or gasifier is used). Many states regulate odor emissions, and ethanol plants may produce odors.

Solid Waste

Ethanol plants generate significant quantities of solid wastes. Major examples include unreacted solids separated from the fermentation effluent during recovery of the ethanol and solids removed during wastewater treatment. Plants with energy production will likely use the unreacted solids as fuel in the boiler or gasifier, and will generate a bottom ash, fly ash, and possible fuel gas desulfurization solid instead. Some plants may generate significant quantities of non-processable feedstocks, which may also need to be managed as solid waste.

Wastewater

The biological process to convert biomass into ethanol requires large quantities of process water. Distillation/dehydration processes "recover" the water as wastewater, which contains soluble and suspended organic and inorganic matter. Other sources of wastewater include the cooling tower and air pollution control equipment (if energy production is included in the plant). Some plants have the capability on site to treat the wastewater before it is discharged to a body of water. Other plants plan to discharge untreated wastewater to a public- or privately-owned wastewater treatment plant located off site. In some cases, the wastewater needs to be pretreated before discharge to an off-site wastewater treatment plant. Stormwater may also be collected and treated, before being

discharged from the site.

EMISSIONS FROM FIVE HYPOTHETICAL PLANTS

The types and amounts of emissions produced by a biomass ethanol facility vary based on the type of feedstock used, type of pretreatment, whether energy is produced, the amount of ethanol produced, and other factors. During the regulatory and permitting process, permit applicants will likely be asked to anticipate the emissions expected from their proposed plant.

Presented in Figures 4-1 to 4-5 are process flow diagrams that illustrate the emission characteristics of five, theoretical biomass ethanol plants. The emissions expected from each plant are summarized in Tables 4-1 to 4-5. The expected emissions were developed based on data presented by Corbus and Putsche. The process flow diagrams provide a conceptual understanding of the processes and steps used to produce ethanol at each of the five facilities. The process scenarios vary in the feedstock used, type of pretreatment, whether energy is produced on-site, and/or production capacity. The diagrams and summaries of emissions provide a basis for understanding and comparing emissions among different facilities. Actual facilities that could be built in the Northeast in the future might be quite similar to, or very different from the five theoretical examples.

STATE REGULATIONS

In order to identify environmental regulations that could affect a biomass ethanol facility, air pollution control, solid waste management, recycling, and wastewater agencies in the 11 states participating in the Northeast Regional Biomass Program were contacted for this report. Each agency was sent a survey questionnaire that asked them to provide information on regulations, permits, and other pertinent information that might apply to a biomass ethanol plant. Responses are presented in Appendix A, for each state that responded to the questionnaire.

The questionnaires asked regulators to provide information based on a "base case" process scenario for a theoretical, representative biomass ethanol facility. The base case provided was the wood waste-to-ethanol plant described above as Scenario A in Figure 4-1 and Table 4-1. Emissions from plants that use other feedstocks or have different production capacities could vary significantly. Hence, the actual regulations or permits that apply to a plant could vary from those discussed for each state in Appendix A.

Numerous factors impact how, why, where, and when state environmental agencies regulate various emissions from a facility. Some factors are relatively consistent among states in the Northeast. For instance, almost all of the Northeast is nonattainment for ozone per the federal National Ambient Air Quality Standards, and states are undertaking a variety of activities to address this issue. Other factors vary considerably among states (and, in some cases, among regions within a state). Examples include federal and state water quality objectives and regulations, and state "recycling" objectives, definitions, and programs.

Despite the myriad of environmental regulations in place in the Northeast region, several conclusions can be made about how a biomass ethanol facility is likely to viewed by a state environmental regulatory agency.

- All states will likely classify a wood waste-to-ethanol plant as a major source of nitrogen oxides (NO_x) and possibly carbon monoxide (CO). This will greatly impact requirements to obtain an air pollution control permit, including permit fees, requirements to achieve the Lowest Achievable Emission Rate (LAER), emission offsets, testing and monitoring requirements, and the amount of time needed to obtain a permit.

- If a biomass ethanol plant accepts "clean," or source separated waste materials as feedstock, the plant will probably not be considered a solid waste management

facility. If the plant accepts municipal solid waste, or "contaminated" or non-separated waste materials, it will probably be considered a solid waste management facility. Wood waste not including treated wood materials and paper sludge are likely to be viewed as "clean" and/or source separated materials. Construction and demolition wood waste would likely be considered solid waste or municipal solid waste.

- It appears that most states will not consider a biomass ethanol process to be a form of recycling, even if a waste material is used as feedstock. The rationale provided by state recycling directors/staff for this is the following. A biomass ethanol plant produces fuel, and other processes that produce fuel or energy from waste are often not considered a form of recycling. In addition, after the ethanol is produced, it can only be used once to produce energy and cannot be used or recycled again to produce energy or something else. This thinking and approach indicates that biomass ethanol plants and the ethanol product itself are not likely to be eligible for recycling-based incentives or preferences. However, this has not been tested yet in most, if not all, Northeast states.

- Some states may consider a biomass ethanol process a "beneficial use" of a material that would otherwise be waste, which could reduce or possibly eliminate requirements that would otherwise apply to facilities that accept and use solid wastes. Classification as a "beneficial use" facility may decrease regulatory oversight and permitting requirements otherwise implemented by state solid waste regulatory authorities.

- Wastewater discharges could be a major issue, due to the total amount expected to be generated by biomass ethanol plants. Ethanol plants need to be located in an area that either is near a surface water with sufficient assimilative capacity or near a public or private wastewater treatment facility with sufficient volume or nutrient removal capacity.

SECTION 5:

INCENTIVES FOR ETHANOL PLANTS

One strategy for facilitating the creation of a new industry is to provide incentives to those who are critical to successful development of the industry. Incentives may be offered during commercialization of new technologies needed for an industry, during development and siting of new facilities that will stimulate economic growth, or during development of markets for new products. Incentives may apply to the industry itself (referred to as "market push"), or to end users of the product (referred to as "market pull"). Incentives may be limited in duration, with the expectation that over time the marketplace will develop, mature, and operate successfully on its own. Since the founding of the United States, both federal and state government have provided incentives for a wide variety of industrial, commercial, and agricultural activities. Such incentives provide a mechanism for furthering public policy objectives not otherwise adequately addressed through the marketplace.

Several incentives are available that stimulate development of the ethanol industry and create markets for fuel ethanol. The impact of such incentives is illustrated by the corn ethanol industry, which would be substantially smaller if federal tax credits did not exist for production of ethanol fuels. Initially, the motivation for the tax credit was to find alternatives to imported petroleum and to support development of an industry that would use valuable agricultural land for crops other than grain for human consumption. Clean air objectives are now also addressed, in part, by the incentives.

"Market push" incentives decrease the cost of production by decreasing plant development or operating costs. Federal alcohol fuels tax credits are examples of incentives that reduce the cost (and therefore the price) of ethanol. In addition, various states provide tax credits to a businesses that invest in equipment or hire new employees. Such credits lower a company's tax liability, reduce operating costs for the company, and therefore reduce production costs.

"Market pull" incentives increase demand for a product and may provide tax credits or price reductions for those who purchase a product. The federal Clean Air Act Amendments of 1990 (CAAA) and the Energy Policy Act (EPACT) are examples of federal incentives that increase market demand for clean, alternative fuels (including, but not limited to, ethanol).

Presented below is a summary of federal and state incentives that apply to producers and users of fuel ethanol. Most of the federal incentives are intended to either replace gasoline with a "clean" fuel or replace foreign sources of petroleum with "alternative" domestic (and renewable) sources. Ethanol is suitable as both a clean and an alternative fuel (as are other fuels, such as methanol, natural gas, propane, hydrogen, and electricity). Most state incentives are broad-based economic development incentives directed at a wide range of industries, not specifically biomass or ethanol industries. The ethanol industry is one of many industries that could benefit from the incentives. No states in the Northeast have developed incentives targeted solely and specifically at ethanol plants and markets. (This has been done in other states, however. For example, Minnesota has a $0.20/gallon ethanol production tax credit which is intended to increase the production of ethanol in the state and reduce prices charged to consumers.)

Information on federal incentives is based on a literature search done for this report. Information on state incentives is based on responses to a written questionnaire distributed to the Economic Development Director and State Biomass Contact in each of the NRBP states. Each state was asked to provide information on what incentives might apply to a biomass ethanol plant in their state. Contacts for further information are provided for both those states that responded to the questionnaire and those that did not.

FEDERAL INCENTIVES

Major federal incentives that apply to the ethanol industry are contained in the federal CAAA, EPACT, and Alcohol

Fuels Tax Credits. Amendments in 1990 strengthened the original Clean Air Act by adding specific air pollution control programs and by increasing enforcement. A major focus of the CAAA is reducing emissions from mobile sources. EPACT has a different focus, which is to reduce U.S. dependence on foreign oil through provisions which range from encouraging energy conservation and efficiency to promoting nuclear energy. EPACT includes goals for replacing the petroleum content of motor fuel with domestically produced non-petroleum fuels.

Both the CAAA and EPACT recognize ethanol as a fuel that can help achieve goals set forth in the acts. Under the CAAA, ethanol is recognized as a "clean fuel" that reduces emissions of carbon monoxide, nitrogen oxides, and volatile organic compounds. Under EPACT, ethanol is recognized as a renewable or "alternative" fuel that can be produced domestically and can decrease the need for foreign petroleum.

CLEAN AIR ACT AMMENDMENTS OF 1990

Reformulated Gasoline Program

The reformulated gasoline (RFG) program was created to combat ozone by reducing ozone- or smog-forming agents from mobile sources and motor fuel storage and dispensing activities. The program includes three components:

- Adding oxygenates to gasoline to increase its oxygen;
- Decreasing the amount of ozone- and smog-forming agents in gasoline; and
- Setting exhaust gas performance standards for gasoline.

The goal of the program is to reduce emissions of ozone- and smog-forming agents in ozone nonattainment areas by at least 20% by 2000.

The RFG program defines the nine worst nonattainment areas for ozone, and requires that RFG be used year-round in these areas. Other areas are permitted to "opt-in." States with opt-in areas are not required to use RFG but may choose to, in order to reduce ozone- and smog-forming agents and to meet air quality standards for ozone. A large portion of the NRBP region is either a required or "opt-in" area and states have already chosen to require the use of RFG in their "opt-in" areas. About 67% of gasoline sold in the region is RFG. Vermont is the only state in the Northeast that does not have a required or an "opt-in" area.

The RFG program requires that RFGs either meet performance standards or contain a minimum of 2% oxygen and a maximum of 1% benzene by weight. Ethanol is an oxygenate that can be used in RFG. However, blending ethanol in gasoline in low concentrations increases the Reid Vapor Pressure of the RFG and results in undesirable air emissions when used in the summertime. ETBE (which is made from ethanol) can also be used as oxygenate in RFG. ETBE is preferable as an oxygenate (compared to adding low concentrations of neat ethanol) because it and does not result in undesirable air emissions during the summer. Because of this, it is most likely that ethanol will be used to produce ETBE and then ETBE will be used as the oxygenate in RFG.

Oxygenated Fuels Program

The oxygenated fuels program was created to reduce carbon monoxide levels in 39 metropolitan areas with high levels of CO. The program is designed to reduce CO emissions from mobile sources during the winter, when vehicle CO emissions are greatest. The program requires that gasoline sold in the areas contain a minimum of 2.7% oxygen by weight.

Initially, several metropolitan areas in the NRBP region were required to participate in the program. Most have dropped out since they have been redesignated, or have requested redesignation, for ozone attainment. The only area currently required to participate is the metropolitan New York City area (including northern New Jersey and Connecticut). The area must use oxygenated fuels containing at least 2.7% oxygen between November 1 and February 29.

For this program, either ethanol or ETBE can be used as an oxygenate in fuels. To achieve a fuel with 2.7% oxygen, gasoline is blended with either neat ethanol or ETBE in a 93 to 7 volume.

Clean Fuel Fleet Program

The clean fuel fleet program was created to help introduce vehicles specifically designed to use "clean fuels," such as ethanol, methanol, natural gas, propane, hydrogen, or electricity. Under this program, vehicle fleets in metropolitan areas with a population of 250,000 or higher and classified as serious, severe, or extreme nonattainment for ozone, must begin purchasing clean fuel vehicles. Nationwide, 21 metropolitan areas meet the requirements for ozone nonattainment. (In addition, Denver was added due to high carbon monoxide levels.) Fleets that must comply with the regulations include those that have 10 or more vehicles owned by a single person or entity and that are (or can be) centrally fueled. Federal, state, and local fleets are included, as well as private fleets. Certain fleets are exempted, such as emergency vehicle fleets. (The schedule required by the CAAA for purchasing clean fuel vehicles is presented in Section 2, Table 2-1). The U.S. Environmental Protection Agency hopes the program will result in about one million new clean fuel vehicles by the year 2010.

Metropolitan areas included in the clean fuel fleet program in the NRBP include Baltimore, Boston, "Greater Connecticut," New York City, Philadelphia PA, Providence, and Springfield. However, at the state level, Connecticut, Delaware, Massachusetts, and Rhode Island "opted-out" of the clean fuel vehicles program, and substituted other programs which achieve the same goals. Hew Hampshire also opted-out by creating more stringent requirements for fleets. New York opted-out for vehicles under 8,500 pounds.

ENERGY POLICY ACT OF 1992

EPACT basically mandates that "fleets" begin to purchase alternative fuel vehicles. EPACT defines fleets as groups of 20 or more light duty motor vehicles that meet the following criteria:

- Are located in a metropolitan statistical area or consolidated metropolitan statistical area with a population of 250,000 or more (1980 census basis);
- Are capable (or could be capable) of being refueled at a central location; and
- Are owned or controlled by a governmental or private sector entity.

Light duty motor vehicles are defined as trucks or cars with a gross vehicle weight (GVW) of 8,500 pounds or less. Certain fleets are specifically not included such as rental cars, emergency or law enforcement vehicles, military vehicles, non-road vehicles, and vehicles typically kept at residences at night.

Under EPACT, alternative fuels are defined to be methanol, ethanol, or other alcohols (or mixtures of methanol, ethanol, or other alcohols) in which the alcohol comprises at least 85% of the fuel by volume. (This may be lowered to a minimum of 70% by the U.S. Department of Energy to allow for cold starting, safety, or other vehicle-related reasons.) Other non-alcohol, non-petroleum fuels are also included in the definition

EPACT requires that a portion of annual purchases of new vehicles be dedicated, dual, or flexible fueled vehicles. The schedule is presented in Section 2, Table 2-1. Although EPACT requires certain fleets to purchase alternative fueled vehicles, it does not require the fleets to use alternative fuels. Fleets could choose to use gasoline in their alternative fueled vehicles.

ALCOHOL FUELS TAX CREDITS

Alcohol Credit

In response to the "energy crisis" in the late 1970s and early 1980s and interest in utilizing valuable farmland in the Midwest, Congress created an alcohol fuel credit for certain mixtures of alcohols not produced from fossil fuels. The credit is in the form of an income tax credit, and is

intended to reduce the selling price of ethanol motor fuels to an amount comparable to petroleum-based fuels. The tax credit is available to producers or users (but not both) of alcohol fuels. The tax credit for ethanol fuel is $0.54/gallon. (The credit for other alcohols is $0.60/gallon). The credit is available only for ethanol not produced from petroleum, natural gas, or coal, and that has a proof of 190 or higher (which is equivalent to 95% alcohol or higher). The proof requirement allows denaturants (such as gasoline) to be added to the alcohol so that it is not drinkable. The credit can not be used in addition to the alcohol mixture credit.

There is no limit on the maximum amount of income tax credit that can be taken. However, the credit is available at 100% for a tax liability of $25,000. At tax liabilities over $25,000, the credit is available at 75%.

The tax credit does not necessarily reduce the cost of producing or blending of ethanol. Since the credit applies to a producer or blender's income tax liability, the credit has no value if the producer or blender does not have any income tax liability (for a particular tax year), or if the tax liability works out to be equivalent to less than $0.54/gallon. The credit may or may not result in reductions in prices charged for ethanol. Depending on market conditions and prices, a producer or blender may choose to not pass the value of the tax credit onto the price charged for the ethanol.

Alcohol Mixture Credit

This credit is the same as the alcohol credit, except that it applies to fuels with an ethanol content as low as 5.7%. It can not be used in addition to the Alcohol Credit.

Small Ethanol Producer Credit

A separate credit of $0.10 per gallon is available for "small ethanol producers." This credit is available to qualified ethanol producers (with a production capacity of 30 million gallons per year or less). The credit applies to the first 15 million gallons of production and may be used in addition to the alcohol credit or the alcohol mixture credit. Ethanol produced by small producers must be at least 150 proof (which is equivalent to 75% alcohol) and the ethanol may be produced from petroleum, natural gas, or coal.

SECTION 6:

SITE CHARACTERISTICS FOR A BIOMASS ETHANOL PLANT

Presented below is a discussion of the site characteristics most important to the technical and economic viability of a biomass ethanol plant. The section identifies and discusses those characteristics that are most important to the physical operation of a plant, the ethanol production cost, and the overall financial performance of the plant as an investment.

Site characteristics required for a successful ethanol plant can be divided into two groups: physical characteristics and cost characteristics. Physical characteristics address the physical requirements needed to support a plant. Cost characteristics impact the cost of developing, constructing, and operating a plant.

PHYSICAL CHARACTERISTICS

Physical characteristics include those site requirements needed to construct and operate a biomass ethanol plant. An example is sufficient land area. If an ethanol plant "footprint" requires 10 acres and only 8 acres are available, then the site will not be suitable. Other important site requirements include:

- Availability of a reliable supply of feedstock in the quantity needed for the plant;
- Sufficient steam, electrical power, water, and other utilities needed to operate the plant;
- Sufficient solid waste management capacity either on-site or within a reasonable distance of the plant;
- Sufficient wastewater treatment capabilities; and
- Sufficient transportation infrastructure to deliver feedstock, transport ethanol products to markets, and haul solid waste to management or disposal facilities.

A biomass ethanol plant must also be able to obtain federal, state, and local zoning and siting requirements as well as environmental permits or approvals required for air, water, and solid waste emissions.

Presented in Table 6-1 are key physical characteristics required for a cellulosic biomass ethanol plant. The "base case" plant assumed in the table has the capacity to produce 10 million gallons per year of ethanol. Noted in the table is whether each physical characteristic is proportional to production capacity. For characteristics that are proportional, the amount shown in the table can be multiplied by the capacity of a proposed plant to determine the amount required for a different size plant.

COST CHARACTERISTICS

Cost characteristics include those site characteristics that affect the financial performance of a biomass ethanol plant. Some have minor impacts on financial performance, while others have significant impacts. The most important cost characteristics include:

- The cost of capital, which depends on how a project is financed. Typically, the interest rate paid for debt financing is a major driver in the cost of capital.
- The feedstock cost, which is the price paid for feedstock delivered to a plant.
- Whether any production incentives or tax credits are available specifically for ethanol production.
- Whether any investment tax credits or other economic development incentives are available to new industries locating in an area, as a way to attract industry to the area, create new jobs, and stimulate economic development.

- The cost of electricity or steam (if purchased from others) or the capital costs of constructing and operating electricity and steam generating facilities (if generated on-site as part of the ethanol plant).

- The cost of purchasing land.

- The cost of any delays in permitting, construction, start-up, and commercial operation of a plant, once financing has been obtained. Such delays prevent a plant from generating revenue as initially scheduled from the sale of ethanol, power, or by-products. Once a plant receives financing and a specific schedule is agreed to for beginning commercial operation, developers and operators begin incurring operating costs, financing charges, and tax liabilities. These costs are incurred in anticipation of certain revenue flows from ethanol production and sales.

ANALYSIS OF SITE CHARACTERISTICS

A sensitivity analysis was performed for this report to determine the relative importance of various site characteristics to the overall financial performance of a biomass ethanol plant. The "base case" plant used in the sensitivity analysis is a theoretical plant using the SSF technology. The plant produces 60.1 million gallons of ethanol per year, uses 658,000 bone dry tons per year of cellulosic biomass as feedstock, and is estimated to cost about $150.3 million. Cost information was developed by Lynd, Elander, and Wyman and will be published in the article, "Likely Features and Costs of Mature Biomass Technology" in Applied Biochemistry and Biotechnology in 1996.

Presented in Table 6-1 is a breakdown of the ethanol production cost for the plant. Presented in Table 6-2 is a breakdown of the overall capital cost for the plant. Information on the financial performance of the plant is presented in Appendix C.

Presented in Table 6-3 are results of the sensitivity analysis. In the base case used in the sensitivity analysis, a required selling price for the ethanol of $1.18 per gallon is used. At this selling price, the plant has an internal rate of return (IRR) of 9.7% and a payback period of 9.7 years. Presented in Table 6-3 are the impacts of each cost characteristic on the production cost of ethanol, assuming an IRR of 9.7% is achieved. The table also includes the impact on the IRR and payback period, assuming the selling price remains at $1.18/gallon.

It is important to note that information in the tables (and in this section overall) applies to a hypothetical plant envisioned as a "base case" for this discussion. Results of sensitivity analyses for other biomass ethanol plants (either real or hypothetical) could have different out comes.

Production Incentives

In addition to existing federal tax incentives for ethanol production, states may offer incentives for ethanol production. Minnesota, for example, recently instituted a tax credit of $.20/gallon for ethanol produced in the state. No states in the Northeast offer such an incentive.

As shown in Table 6-3, a production incentive can either decrease the required selling price of ethanol or increase the financial performance of the plant, or a mixture of both. For example, if the IRR of 9.7% is not varied, the required selling price of ethanol could decrease by the same amount as the production incentive. Alternatively, if the selling price is not varied, the IRR would increase from 9.7% to 14.4% and the payback period would decrease from 9.7 to 8.0 years, thereby improving the financial performance of the plant.

The importance of production incentives was also noted by developers of ethanol facilities interviewed for this report. At least one developer stated that it was unlikely a new ethanol plant would be sited in the Northeast if a state incentive was not in place that lowered the ethanol production cost.

Cost of Capital

Capital costs are the single largest cost of producing

cellulosic ethanol. Based on cost projections for the SSF design completed for the National Renewable Energy Laboratory by Lynd, Elander, and Wyman, capital recovery accounts for about $0.50/gallon of the $1.18/gallon production cost for cellulosic ethanol, or 42.4% of the total production cost.

As shown in Table 6-3, decreasing the interest rate (to 5% on 75% of the financed portion of the plant) decreases the required selling price by $0.15/gallon. Of significance is the impact on the IRR and payback period (assuming a selling price of $1.18/gallon). The IRR increases to 21.2%, and the payback period decreases to 6.2 years.

Feedstock Cost

Feedstock cost is the second largest cost of producing cellulosic ethanol, representing 30.7% of the total cost of producing ethanol (based on the current NREL SSF design and assuming a feedstock cost of $42/bone dry ton). Out of an ethanol production cost of $1.18/gallon, feedstock cost represents $0.46/gallon. Reducing feedstock cost significantly reduces the production cost of cellulosic ethanol.

The sensitivity analysis completed for this report indicates that decreasing feedstock cost by $10/bone dry ton (from $42 to $32/bone dry ton) decreases the required selling price by $0.11/gallon. The impact on IRR (assuming the same ethanol selling price) is an increase to 12.5%, while the payback period decreases to 8.6 years.

Delay in Plant Start-up

Delays in the start-up and commercial operation of an ethanol plant result in an increase in financing costs. A one-year delay in commercial operation, for example, increases the selling price by $0.06/gallon. Assuming the selling price is maintained at $1.18/gallon, the IRR decreases from 9.7% to 8.5%, and the payback period increases from 9.7 years to 10.7 years.

Low Cost Utilities

It would seem reasonable to assume that if low-cost utilities are available from off-site sources, it is most cost-effective for an ethanol plant to purchase the power rather than build, operate, and finance power generating facilities on-site. However, the sensitivity analysis indicates this is not necessarily so (although other ethanol plants may differ). Purchasing low-cost off-site power actually increases the required selling price of ethanol, and decreases the financial attractiveness of the plant. This is due to two factors.

One is the loss of revenue that could be received from selling excess power. The other is the increased cost of managing solid waste generated during ethanol production that could be used to produce power on site.

The base case plant used in the sensitivity analysis assumes power generation is done on site and that excess electrical power is sold for $0.04/kW-hr. As shown in Table 6-3, purchasing electrical power at $0.025/kW-hr and steam at $0.50/1,000 pounds increases the required selling price for ethanol by $0.04/gallon. If the selling price of $1.18/gallon is maintained, the IRR decreases from 9.7% to 8.3% and the payback period increases from 9.7 years to 10.5 years.

Decreased Land Cost

Decreasing the cost of land has minimal impact on the required ethanol selling price, IRR, and payback period. This is because land cost is a relatively small component of the overall capital cost of an ethanol plant.

Elimination of State Corporate Income Tax

Reducing or eliminating state income taxes for corporations for the first five years of operation has minimal impact on the required ethanol selling price, IRR, and payback period. This is because during the first four years of operation, the plant is projected to have a negative net income. A positive net income is not expected until year five. Corporate income taxes are assumed to be based on net income.

However, there could be a negative impact of eliminating tax liability, if tax credits earned when corporate income losses occur in the first years of operation cannot be carried forward to offset future tax liabilities (when

income is earned). Some states may require companies taking advantage of tax abatement or reduction programs not to carry forward tax credits. Using the base case ethanol plant as an example, if tax credits accrued during the first four years of operation cannot be carried forward, the increased tax liability would be as high as $440,000 once the plant shows a net positive income.

CONCLUSIONS

Production incentives, the cost of capital, and feedstock cost are the most important site characteristics that impact the economic viability of an ethanol plant. Delays in plant start-up negatively impact plant financing, and can result in an increase in the required ethanol selling price needed to achieve certain financial returns. The availability of low cost power is not financial advantageous (compared to developing power generation capabilities on site) unless other factors come into play, such as potential difficulties or costs associated with obtaining air pollution control or other permits. Land purchase costs have a minimal impact on overall cost. Eliminating state corporate income taxes during the early years of operation also has minimal impact on overall costs, but could have a significant negative impact if tax credits cannot offset tax liabilities in future years.

What is the "bottom line"? When considering a site for a biomass ethanol plant, site characteristics that matter the most to the required selling price of ethanol and/or the financial performance of a plant are production incentives, lower cost of capital, and lower feedstock costs. This provides important guidance to energy and economic development officials interested in facilitating development of biomass ethanol plants in their state or region.

CONNECTICUT INCENTIVES

Contacts

Department of Economic Development
865 Brook Street
Rocky Hill, Connecticut 06067-3405
(860) 258-4202

Air Management Bureau
Department of Environmental Protection
79 Elm Street
Hartford, Connecticut 06106-5127
(860) 424-3935
(860) 424-4063 (fax)

DELAWARE INCENTIVES

Contacts

Economic Development Office
99 Kings Highway
P.O. Box 1401
Dover, Delaware 19903
(302) 739-4271

Department of Agriculture
Forestry Section
Blackbird State Forest
502 Black Forest Road
Smyrna, Delaware 19977
(302) 653-6505
(302) 653-2869 (fax)

MAINE INCENTIVES

According to the Department of Economic and Community Development, Maine offers a variety of financial and support programs that are intended to support businesses making capital investments or hiring new employees in the state. Although the Department has not been involved with a biomass ethanol plant, it has worked with other industries that recycle or use waste materials as feedstock, including numerous wood-fired power plants and industrial boilers.

Business Equipment Property Tax

This program applies to equipment placed in service (or under construction) after April 1, 1995. The program may be linked to the Municipal Tax Increment Financing (described below) to reduce the total property tax expense on new equipment to zero for 12 years.

Maine Jobs and Investment Tax Credit

This program provides a state income tax credit for investments in personal property that generate 100 new jobs or more within two years of when the property was placed in service.

Municipal Tax Increment Financing (TIF)

In the Municipal TIF program, a municipality finances certain costs associated with a business or industrial development project. TIFs work by capturing all or a portion of the expected property taxes the project will generate, and returning them to finance portions of the project.

State Tax Increment Financing (TIF)

The State TIF program works in conjunction with the municipal program by "returning" up to 25% of individual state income tax withholding resulting from an activity that increases employment to the municipality. The municipality uses the money to finance project costs.

Sales Tax Exemption

A 6% state sales tax exemption applies for equipment used directly in production. In addition, 95% of fuel and electricity used in production is also exempt from state sales tax.

Maine Investment Tax Credit

This state income tax credit applies to equipment used directly for production. The credit is worth 1% of the equipment costs, and may be taken for 5 years (resulting in a total credit is 5%).

Finance Authority of Maine

FAME is an independent state agency developed in 1983 to assist business development and create new employment opportunities in Maine. FAME works closely with the state's lending, financial, economic development, and business communities in the formulation and implementation of innovative financial services and programs for business and industry. A wide variety of programs are offered by FAME, such as the Commercial Loan Program, Working Capital Loan Insurance Program, Non-Traditional Lenders' Loan Insurance Program, Agricultural Operating Loan Insurance Program, and the Economic Recovery Loan Program.

Contacts

Maine offers additional programs which assist developers in locating plant sites, finding feedstocks or services, hiring and training employees, and obtaining permits.

Finance Authority of Maine
83 Western Avenue
P.O. Box 949
Augusta, Maine 04332-0949
Voice: (207) 623-3263
Fax: (207) 623-0095

Department of Economic and Community
Development
33 Stone Street
State House Station #59
Augusta, Maine 04333
Voice: (207) 287-3153
Fax: (207) 287-5701

State Planning Office
Economic Division
State House Station #38
Augusta, Maine 04333
Voice: (207) 287-8938
Fax: (207) 287-8059

MARYLAND INCENTIVES

According to the Department of Business and Economic Development, Maryland works on a project-by-project basis to tailor the state's resources to the needs of a particular plant developer. Although the Department has not been involved with a biomass ethanol plant, it has worked with other industries that recycle or use waste materials as feedstock. The state has a policy objective to attract new businesses involved with environmental technology and recycling.

Tax-Exempt Industrial Revenue Bonds

Bonds are issued by the Maryland Industrial Financing Authority.

Loan Insurance

Loan insurance is available for up to 80% or $1 million (whichever is lower) through the Maryland Industrial Financing Authority.

Bond Insurance

Bond insurance is available for of up to 100% or $5 million on taxable bonds issued by the Maryland Industrial Financing Authority.

Direct Loans

Direct loans are available through the Maryland Industrial Land Act, Community Development Block Grant Program, and Maryland Industrial and Commercial Redevelopment Fund.

State Property Tax Credits

State property tax credits are available for projects located in Maryland Enterprise Zones. The credit is available for 10 years.

State Income Tax Credits

State income tax credits are available for wages paid to new employees by projects located in Maryland Enterprise Zones. The credit is available for 3 years.

Federal Wage Tax Credits

Federal wage tax credits are available for projects located in the Baltimore Empowerment Zone. This program is combined with state property and income tax credits for projects in Maryland Enterprise Zones. The federal wage credit is available for 9 years.

Employee Training Grants

Grants are available which cover up to 50% of the cost of training new employees.

Contacts

The University of Maryland and the Department of Business and Economic Development also offer technical, siting, and permitting assistance.

Office of Industry Sector Assistance
Department of Business and Economic Development
217 East Redwood Street, Suite 1200
Baltimore, Maryland 21202

Voice: (410) 767-6869
Fax: (410) 333-6608

Alternative Energy Programs
Maryland Energy Administration
45 Calvert Street
Annapolis, Maryland 21401-1907
Voice: (410) 974-2190
Fax: (410) 974-2250

MASSACHUSETTS INCENTIVES

According to the Office of Business Development, 20 state and quasi-public agencies with over 40 programs provide financing options for industry and business in the state. The Office of Business Development offers various services, including:

- Regulatory and licensing assistance.
- One-stop permitting for construction-related, state-issued permits.
- Training and recruiting assistance.
- Site selection services

Examples of economic and development incentives available in the state are presented below.

Investment Tax Credit

A 3% credit is available for the corporate excise tax for construction of facilities and the purchase or lease of equipment.

Economic Opportunity Areas

Additional incentives are available in geographic areas classified as Economic Opportunity Areas. The incentives include a 5% investment tax credit, 10% abandoned building tax deduction, special municipal tax assessments, municipal tax incremental financing (TIF), and priority status for state capital funding.

Tax-Exempt Equipment Leasing

Tax-exempt equipment leasing is available through the Massachusetts Industrial Finance Agency.

Massachusetts Manufacturing Partnership

This partnership between the Office of Business Development and the Bay State Skills Corporation provides technical assistance to new or expanding businesses. The partnership utilizes academic resources in the state (such as Harvard University and Massachusetts Institute of Technology) to assist businesses.

Massachusetts Strategic Environmental Partnership (STEP)

STEP is an innovative program started in 1994 to promote growth of new environmental and energy-efficient technologies in the state. STEP uses existing public and state services to help innovative technologies reach commercial viability and success. STEP services include: technology assessments; business planning; technology demonstration and purchasing; research, testing, monitoring, and technical assistance; expedited permitting and guidance; technology transfer; and state purchasing of environmental products.

Special Commission on Forestry Management Practices

This commission was formed to identify and create uses for abundant forestry residues and low quality wood in the state. The commission is familiar with the concept of using wood and wood waste to produce ethanol, and is interested in facilitating the development of such facilities in the future.

Contacts
Office of Business Development
One Ashburton Place
Room 2101

Boston, Massachusetts 02108
Voice: (800) 522-7482 or (617) 727-3206
Fax: (617) 727-8797

STEP
Office of Business Development
One Ashburton Place, Room 2101
Boston, Massachusetts 02108
Voice: (800) 522-7482 or (617) 727-3206
Fax: (617) 727-8797

Special Commission on Forestry Management
Practices
(617) 722-1540

Renewables Office
Division of Energy Resources
Suite 1500
100 Cambridge Street
Boston, Massachusetts 02202
Voice: (617) 727-4732
Fax: (617) 727-0030

NEW HAMPSHIRE INCENTIVES

Contacts

Department of Resources and Economic Development
P.O. Box 1856
172 Pembroke Road

Concord, New Hampshire 03302
(603) 271-2411

Governor's Office of Energy and Community Services
57 Regional Drive
Suite 3
Concord, New Hampshire 03301-8506
(603) 271-2611

NEW JERSEY INCENTIVES

The Department of Commerce and Economic Development works with governmental and private economic development organizations to provide technical, financial, and other assistance to business and industry. The Department of Labor and the Department of State also offer technical assistance programs and the New Jersey Economic Development Authority also offers financial assistance programs. Other financial assistance programs are available at the regional, county, or local level. Examples of key programs are summarized below.

Tax-Exempt Bond Program

This program offers low-interest loans to manufacturers.

Loan Guarantees

Loan guarantees are available for up to $1 million for working capital and $1.5 million for fixed assets. Guarantees are typically limited to 30-50% of the loan amount.

Property Tax Abatements and Exemptions

Abatements and exemptions are authorized by state law for industrial and commercial property located in municipalities needing redevelopment.

New Jobs Investment Tax Credit

A tax credit is available for companies investing in new or expanded facilities that create new jobs. The credit applies to the corporate business tax.

Manufacturing Equipment and Employment Tax Credit

This tax credit applies to companies investing in manufacturing equipment (with a recovery life of 4 years or more). The credit applies to the corporate business tax.

Urban Enterprise Zones

Urban enterprise zones promote growth and development in 20 of the state's economically distressed areas. Several financial incentives are available to companies locating in the zones, including one-time tax credits for hiring full-time employees, subsidized unemployment insurance, and sales tax exemptions.

Workforce Development Partnership Program

Administered by the state Department of Labor, this program utilizes contributions to the Unemployment Insurance Fund to support worker training. The program includes grants and other reimbursements that help defray the costs of training employees.

Utility Rates Incentives

Rate incentives are offered by utilities to encourage industries and businesses to locate, expand, and create jobs in the state and to occupy vacant real estate. The incentives include credits, flexible rates, rate discounts, and waivers.

Contacts

Although the Department has not been involved with a biomass ethanol plant, the state has worked with other industries that recycle or use waste materials as feedstock.
Division of Economic Development
Department of Commerce and Economic Development

♦ Site Characteristics ♦

444444444444444444444444444444444444444444

20 West State Street, CN 820
Trenton, New Jersey 08625-0820
(609) 292-0700

Department of Environmental Protection and Energy
Division of Parks and Forestry
CNN 404
Trenton, New Jersey 08625
(609) 292-2531
(609) 984-0378 (fax)

NEW YORK INCENTIVES

According to the Department of Economic Development, the state makes a "maximum effort" to assist and facilitate economically viable projects that produce jobs and/or income. The state provides technical, siting, permitting, and marketing assistance. The Recycling Market Development Program (within the Department of Economic Development) provides specialized assistance in finding markets for products from waste or recycled materials.

Both the Department and the New York State Energy Research and Development Authority (NYSERDA) are knowledgeable about biomass ethanol and have worked with potential developers of ethanol plants. NYSERDA recently published the results of a detailed screening study for a waste biomass ethanol plant. The study investigated various biomass feedstocks and locations throughout the state. The study found that state financial incentives would play a key role in making a project more attractive.

Financial Assistance

Financial assistance is available in the form of direct loans or interest subsidy grants through the Empire State Development Corporation (ESDC).

Infrastructure Loans and Grants

Loans and grants are available for construction, modification, or improvement of water and sewer lines, access roads, rail lines, power lines, docks, wharves, etc. that are outside a facility's walls. Loans or grants are typically available from the ESDC's Regional Economic Development Partnership Program (REDPP) or the State Department of Transportation's Industrial Access Program (DOT-IAP).

State and Local Tax Credits

New York state and local tax credits are claimed to be some of the most generous in the country. A credit of 5% against the corporate franchise tax is available for new capital investments (if improvements exceed $350 million or if they are paid by personal income taxpayers). An additional employment incentive credit of 1.5 - 2.5 % is available, depending on the increase in employment. Other credits are available for investments in air pollution or water pollution control equipment. Local property taxes may be reduced by "payment in lieu of taxes" agreements, in which the payments are eligible for low interest bonds through local Industrial Development Agencies.

Electric and Gas Incentive Rates

Reductions in electric or gas rates may be offered to industrial facilities through the New York Power Authority or local utilities.

Skills Training Assistance

Partial grants are available for training new employees through the ESCD's REDPP or the Department of Economic Development's Skills Training Program.

Biomass Energy Projects

NYSERDA has assisted numerous biomass industries in the state by risk-sharing with industry the cost of commercializing new technologies and by supporting a wide range of R&D projects. Ethanol is one of many biomass-based chemicals NYSERDA has invested in as one way to assist industry and economic development in the state.

Contacts

Tax Issues
New York State Department of Economic Development
One Commerce Plaza
Albany, New York, 12245
Voice: (518) 474-8670

Grants and Loans, Technical, Siting, Permitting, and

Marketing Assistance
New York State Department of Economic Development
One Commerce Plaza
Albany, New York, 12245
Voice: (518) 473-1325

Specialized Product Marketing
Office of Recycling Market Development
New York State Department of Economic Development
One Commerce Plaza
Albany, New York, 12245
Voice: (518) 486-6291

State Biomass Contact
New York State Energy Research and Development
Authority
Two Empire State Plaza
Suite 1901
Albany, New York 12223-1253
Voice: (518) 465-6251, Ext 288
Fax: (518) 432-4630

PENNSYLVANIA INCENTIVES

Contacts

Department of Commerce
433 Forum Building
Harrisburg, Pennsylvania 17120
(717) 787-3003

Forestry Advisory Services
Department of Environmental Resources
P.O. Box 8552
Harrisburg, Pennsylvania 17105-8552
(717) 787-2105
(717) 783-5109 (fax)

RHODE ISLAND INCENTIVES

According to the Rhode Island Economic Development Corporation, a variety of financial and technical programs are available that could assist a biomass ethanol plant to locate in the state. In addition, the State Energy Office can serve as a liaison between agencies and can review the need and cost of a facility as part of the siting review done by the state Public Utility Commission.

Financial incentives include low interest bonds, tax-exempt bonds, bond insurance, tax credits, and tax exemptions or stabilization. Other programs include financial assistance for training, discounted electrical utility rates, and expedited permit process. Key programs are summarized below.

Industrial Revenue Bonds

Bonds with competitive interest rates are available through the Industrial Development Corporation. Interest rates may be reduced if a bond is less than $10 million, since the interest on "Small Issue Bonds" is tax-exempt.

Investment Tax Credit

A tax credit of 4% is allowed against the Business Corporation Taxes and/or Rhode Island personal income tax. The credit is available for certain items such as buildings, and machinery and equipment (including installation).

Sales Tax Exemption

A sales tax exemption is available for machinery, equipment, replacement parts, tangible personal property, and public utility services.

Property Tax Exemptions

A property tax exemption is available for manufacturing equipment, machinery, and inventories. In addition, municipalities state may exempt from property tax (or "stabilize") office equipment or other property.

Job Training Programs

The Department of Employment and Training and the Human Resources Investment Council provide funding for training new employees or upgrading existing employees.

Economic Development Utility Discount Rate

A reduced electric utility rate is available for new or expanding companies for up to 48 months. The rate reduction varies between 12-20%, depending on the utility and the year.

Expedited Permitting

Expedited permitting is available for projects of "critical economic concern."

Contacts

Economic Development Corporation
7 Jackson Walkway
Providence, Rhode Island 02903
Voice: (401) 277-2601
Fax: (401) 277-2102

State Energy Office
275 Westminster Street
Providence, Rhode Island 02903-3415

(401) 277-3370
(401 277-1260

Office of Environmental Coordination
Department of Environmental Management
83 Park Street
Providence, Rhode Island 02903
(401) 277-3434

VERMONT INCENTIVES

According to staff of the Agency of Development and Community Affairs, the following incentive programs may apply to a biomass ethanol plant.

Mortgage Insurance

Mortgage insurance may be provided by the Vermont Economic Development Authority (VEDA). The insurance is issued to the lending bank, and may be used to insure repayment of funds used to acquire land, buildings, machinery and equipment, or for working capital. The interest rate is determined by VEDA. The limit is $10 million, or 90% of the project value.

Industrial Revenue Bonds

IRBs are available for any manufacturing firm eligible for tax-exempt financing under the U.S. Internal Revenue Code. Bonds may be used to acquire land, buildings, improvements, machinery, and equipment. The interest rate is negotiated with the bond holder. The limit is $10 million for any one project (subject to some caps).

Direct Loans

Loans are available for owners or operators of manufacturing processes (and other activities) for the acquisition of land, buildings and improvements, machinery, and equipment. The interest rate is fixed at 5.5% and the loan amount is limited to $500,000 for land and buildings, and $300,000 for machinery and equipment.

Rural Economic Activity Loans

Rural economic activity loans are issued by the Vermont 503 Corporation, with priority given to manufacturing and assembly businesses (including agricultural processing facilities). Loans may be used to acquire fixed assets and to fund growth in inventory and accounts receivable. The interest rate is 8% for fixed asset loans under $25,000, and 5.5% for amounts over $25,000. Working capital loans are at the prime rate plus 2%, with a cap of 8%.

Regional and Local Loan Funds

There are many regional and local revolving loan funds throughout Vermont. The funds are capitalized from various sources, often with federal funds. They are typically governed by non-profit development corporations. The funds may be used in conjunction with other sources or financial incentives to leverage additional monies, or to finance projects independently.

Other Assistance

The Agency of Development and Community Affairs assists industries seeking to locate in Vermont by facilitating zoning issues, providing site assistance, locating sources of raw materials, and providing permitting guidance. In conjunction with the Agency of Natural Resources, the Agency applied for and received a grant to increase the use of recovered or recycled plastics by Vermont manufacturers.

Contacts

Vermont Economic Development Authority
56 East State Street
Montpelier, Vermont 05602
(802) 223-7226

Vermont 503 Corporation
56 East State Street
Montpelier, Vermont 05602
(802) 223-7226

Department of Economic Development
Agency of Development and Community Affairs
109 State Street
Montpelier, Vermont 05609-0501
Voice: (802) 828-3221
Fax: (802) 828-3258

Department of Forests, Parks & Recreation
103 South Main Street, 10 South
Waterbury, Vermont 05671-0601
(802) 241-3671
(802) 244-1481 (fax)

SECTION 7:

THE POTENTIAL FOR USING E85 IN PUBLIC FLEETS

As part of the national effort to expand the use of clean, alternative fuels for transportation, states are implementing a variety of initiatives designed to decrease the use of gasoline in public sector fleets. In the Northeast, few if any of such initiatives are focussed on stimulating ethanol production and use. However, they could be in the future.

Presented below is a discussion of why fleets owned and operated by the public sector might consider using ethanol as a clean, alternative fuel. This is followed by a discussion of key factors that limit use of high ethanol content fuels in public fleets. Information on current fuel contracting procedures by states is provided, as are results of a survey of procurement officials in three states in the Northeast. The three states were selected for the survey because they are mandated to significantly reduce ground level ozone and smog, and have relatively large public fleets. To assist states interested in using high ethanol content fuel in the future, a specification for fuel ethanol is discussed below and provided in Appendix B. Also discussed below and included in Appendix B is a specification for ethanol refueling facilities.

WHY SHOULD PUBLIC FLEETS USE ETHANOL?

High content ethanol fuels such as E95 (containing 95% ethanol and 5% gasoline) and E85 (containing 85% ethanol and 15% gasoline):

- Are clean fuels expected to reduce tailpipe and evaporative emissions, compared to gasoline.

- Can be produced in the U.S. and used in place of petroleum-based fuels, much of which are imported from other countries.

- Can be produced on a long-term sustainable basis from both starch-rich products such as corn and cellulosic biomass materials such as wood waste, paper sludge, municipal solid waste, and energy crops.

Public sector fleets are uniquely posed to be among the first fleets in the Northeast to begin using high content ethanol fuels on a widespread basis.

- As discussed in Sections 2 and 5, under the federal Energy Policy Act of 1992, federal, state, and municipal fleets are required to begin using alternative fueled vehicles. Ethanol is one of a variety of fuels specified in EPACT as an alternative fuel. Federal fleets are already required to begin using alternative fueled vehicles. State fleet requirements begin in 1996. Municipal fleets requirements begin in 1999.

- Under the federal Clean Air Act Amendments of 1990, fleets in certain metropolitan areas are required to begin purchasing clean fueled vehicles. Ethanol is one of a variety of fuels specified in the CAAA as a clean fuel. Fleets covered by the CAAA must begin purchasing clean fueled vehicles in 1998.

- States in the NRBP region operate "alternative fuel programs" which help ensure compliance with both EPACT and CAAA, and which promote and encourage the use of clean, alternative fuels. Although ethanol is not presently a focus of the state programs, it could be in the future.

- Public sector use of ethanol and ethanol fueled vehicles could stimulate demand for both the fuel and vehicles, assist in developing the production and supply infrastructure needed to serve both public and private sector fleets, and assist in developing consumer awareness and confidence.

POTENTIAL USE OF E85 BY PUBLIC FLEETS

High ethanol content fuels are not presently used on an ongoing basis by public fleets in the Northeast. Small amounts may be used occasionally for pilot, demonstration projects. As noted in Section 2, if priority were placed on using E85 in public fleets throughout the region in the future, as much as 175 million gallons per year of fuel could be used.

In order for E85 to be used within the region, both the fuel and vehicles which can use the fuel must be available. They must either be cost-competitive with other fuels and vehicles, or public policies must be in place that enable states to pay more for them (at least initially, until the industry fully develops). State procurement and transportation officials must be familiar with the fuels and vehicles, able to procure them through their existing practices, able to refuel the vehicles, and confident that they will meet state requirements for performance, convenience, and safety.

FACTORS AFFECTING E85 USE BY PUBLIC FLEETS

Presented below is a summary of key factors affecting the use of E85 (or other high ethanol content fuels) by public sector fleets in the Northeast. This is based on surveys and/or interviews conducted for this report with:

- State procurement officials responsible for purchasing alternative fuels, vehicles, and refueling stations;
- Automobile and diesel truck manufacturers;
- Operators of alternative fuels databases; and
- Ethanol producers.

In addition, findings presented in **Refueling Alternative Fuel Vehicles, Lessons Learned from the Market Place** published by the CONEG Policy Research Center, Inc. in May 1995 are incorporated. The report focuses on fleet manager attitudes towards a "clean fuels corridor," in which various alternative fuels could be available along major interstate highways in the NRBP region. Volume II of the report, **Focus Group Summary of Fleet Manager's Attitudes Towards Clean Fuels Corridor and Alternative Fuel Vehicles** documents attitudes of a focus group held for managers of private fleets and one held for managers of public fleets.

Fuel Availability

Currently, no refueling facilities in the Northeast provide E85 or other high ethanol content fuels. A total of 36 ethanol refueling sites exist in the continental U.S., including one in Washington, D.C. (which is the closest one to the NRBP region). The region is experiencing a classic "chicken and egg" dilemma. Until the fuel is available, fleets are hesitant to invest in vehicles that can use E85. Until there is demand for the fuel, ethanol producers and distributors are reluctant to develop the required supply and refueling infrastructure. However, through their purchasing policies and activities, federal and state governments have a unique opportunity to expedite the development of such markets.

Vehicle Availability

In the past, dedicated or fuel flexible vehicles (FFV) capable of using E85 were only available by special order for demonstration projects. However, this is changing. Starting in model year 1995, Ford offers an ethanol FFV version of the Taurus sedan, a popular vehicle for fleets. General Motors plans to introduce an ethanol FFV version of its S-15 pickup truck in the near future.

Fuel Cost

The selling price of E85 currently substantially exceeds the price of gasoline and other clean or alternative fuels. The higher price is a significant barrier to the purchase of ethanol by public fleets, and will severely limit future use unless specific public policy objectives are in place that enable procurement officials to purchase the higher-priced fuel.

Fuel Performance

E85 contains less energy than gasoline (when measured in Btus per volume), thus vehicles fueled with E85 have a smaller driving range than gasoline fueled vehicles. Although E85 is generally expected to perform adequately in most situations, it does not perform as well as gasoline in cold weather. Until there is more direct experience with the fuel in cold weather, fleet managers in states with the coldest weather (e.g. Maine, New Hampshire, and Vermont) may be reluctant to choose ethanol over other fuels.

Competition with Other Fuels

E85 is one of numerous clean or alternative fuels that meet requirements of the CAAA and EPACT. Fleets required to purchase (or lease) alternative or clean fueled vehicles will choose the vehicle and fuel based on availability, cost, performance, and other factors. None of the alternative fuel programs currently in operation in the Northeast are integrating high ethanol content fuels into their public fleets.

STATE PROCUREMENT PRACTICES

The purchase of motor fuel by state governments is done by receiving competitive bids for the fuel and developing a standard contract with a motor fuel supplier (or suppliers). Contracts are issued to the most competitive bid(s) received. Contracts describe the type and quantity of fuel and include specifications for oxygenate content, volatility, Reid Vapor Pressure, octane rating, etc. Contracts are typically issued based on the amount of fuel expected to be used, with the actual amount supplied dependent on usage.

Presented in Table 7-1 is information on procurement policies and practices for gasoline or alternative fuels (including ethanol) in three Northeast states. The information was provided by procurement officials in Connecticut, New York, and Pennsylvania. These states were asked to provide information, because they have relatively large public fleets and are required to achieve significant improvements in ground level ozone and smog in the near future. Hence, they are states that might potentially use relatively large quantities of fuel ethanol in the near future.

As shown in the table, it appears that unless specific decisions are made to do otherwise in the future, ethanol is not likely to be a major fuel used by state fleets to meet clean and alternative fuel objectives.

ETHANOL FUEL SPECIFICATIONS

To assist states in potentially using high ethanol content fuels in the future, a specification for fuel ethanol is provided in Appendix B. The specification provides procurement officials with the information needed to properly define E85 characteristics in bid solicitations to fuel suppliers. The specification applies to fuels with an ethanol content ranging from 75-85%. The specification was developed by Chrysler, Ford, and General Motors and was provided by the Vehicle Environmental Engineering Department of Ford Motor Company in Dearborn, Michigan. According to a representative of Ford, the "big three American automobile manufacturers are still learning about fuel ethanol, and the specification could change in the future."

Also included in Appendix B is a draft specification for ethanol refueling facilities. The specification includes fuel ethanol compatibility standards and recommended dispensing equipment. The standards and recommended equipment are intended to prevent contamination of E85 during storage and dispensing. These (or similar) standards and equipment will likely be required at E85 refueling facilities and stations in the future. The specification was also provided by the Vehicle Environmental Engineering Department of Ford Motor Company.

APPENDIX A:

STATE ENVIRONMENTAL

REGULATIONS

CONNECTICUT

Presented below is a summary of Connecticut air pollution control, solid waste, and wastewater regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to state air pollution control, solid waste management, wastewater, and recycling offices in Connecticut. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A.

Responses to the questionnaire are presented below, as are contacts for further information. Based on design and location of plant, other regulations may apply. As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual biomass ethanol facility may vary from those discussed below. For permit information in general, contact:

Department of Environmental Protection
Hartford, Connecticut
(860) 424-3003

AIR POLLUTION REGULATIONS

Key Regulations are contained in **Regulations of Connecticut State Agencies** as follows:
Section 22a-174-1, Definitions.

Section 22a-174-3, Permits to construct and permits to operate stationary sources or modifications.

Section 22a-174-4, "Source" monitoring, record keeping, reporting and authorization of inspection of "air pollution" "sources."

Section 22a-174-5, Methods for sampling, emission testing, sample analysis, and reporting.

Section 22a-174-18, Control of particulate "emissions."

Section 22a-174-19, Control of sulfur compound emissions.

Section 22a-174-20, Control of organic compound emissions.

Section 22a-174-21, Control of carbon monoxide emissions.

Section 22a-174-22, Control of nitrogen oxide emissions.

Section 22a-174-23, Control of odors.

Section 22a-174-29, Control of "Hazardous Air Pollutants."

Section 22a-174-33, Title V Sources.

Odor Regulations

Under Section 22a-174-23, "no person shall cause or permit the emissions of substances or combination of substances which create or contributes to an odor, in the ambient air, that constitutes a nuisance."

Source Classification

Based on information presented in Table 4-1, the biomass ethanol plant would be classified as follows:

AIR POLLUTANT	SOURCE CLASSIFICATION
Nitrogen Oxides	Major
Sulfur Oxides	Synthetic Minor
Particulate Matter	Synthetic Minor
Lead	Minor
Carbon Monoxide	Major
Volatile Organic Compounds	Major (in Severe non-attainment areas) Synthetic Minor (in Serious non-attainment areas)
Acetaldehyde	Minor
Formaldehyde	Minor

Nonattainment Areas

AIR POLLUTANT	STATUS	LOCATION
Ozone	Severe	Towns of Bethel, Bridgeport, Bridgewater, Brookfield, Danbury, Darien, Easton, Fairfield, Greenwich, Monroe, New Canaan, New Fairfield, New Milford, Newtown, Norwalk, Redding, Ridgefield, Sherman, Stamford, Stratford, Trumbull, Weston, Westport, and Wilton
Ozone	Serious	Rest of state
Particulate Matter (PM-10)		City of New Haven

Permits Required

A Construction Permit, Operating Permit, and Title V permit would be required.

Permit Application Fees

Permit fees vary depending on the type of permit(s) required, yearly emissions, if modeling is required, and if Best Available Control Technology (BACT) or Lowest Achievable Emission Rate (LAER) reviews are required. The fee for construction and operation permit for a plant that emits greater than 100 tons per year of any pollutant is $2,000. The cost of BACT or LAER review is $1,000 each.

Contact

The Bureau of Air Management within the Connecticut Department of Environmental Protection has permitted several industrial, commercial, or institutional boilers that use wood or wood waste as fuel.

Bureau of Air Management
Department of Environmental Protection
79 Elm Street
Hartford, Connecticut 06106-5127
(860) 424-3450

SOLID WASTE MANAGEMENT REGULATIONS

Solid waste management regulations are contained in Sections 22a-209-1 through 22a-209-16 of the **Regulations of Connecticut State Agencies**, as stipulated in the **State Statute C.G.S. 22a-208**.

Plant Classification

A wood waste-to-ethanol plant would be classified as a Solid Waste Volume Reduction Plant. Volume reduction plants are defined to be "any location or structure, whether located on land or water, where more than two thousand pounds per hour of solid waste generated elsewhere may be reduced in volume, including but not limited to, resources recovery facilities and other incinerators, recycling facilities, pulverizers, compactors, shredders, balers and compost facilities."

Permits Required

To date, staff of the Waste Management Bureau within the Department of Environmental Protection has not received an application for a biomass ethanol plant. It is expected that a plant would be required to obtain both a Solid Waste Management Facility Permit to Construct and a Permit to Operate.

Contact

Waste Engineering and Enforcement
Department of Environmental Protection
79 Elm Street
Hartford, Connecticut 06106-5127
(860) 424-3366

WASTEWATER TREATMENT REGULATIONS

Sections 22a-430-3 through 22a-430-7 of the **Regulations of Connecticut State Agencies** cover wastewater discharge permit regulations, including the National Pollution Discharge Elimination System (NPDES), pretreatment, and groundwater discharges.

Under Connecticut's Water Quality Standards, all surface waters have a quality goal of Class B or higher. The discharge from a biomass ethanol plant would be to either Class B (fresh water) or Class SB (saline water), or to a publicly-owned treatment plant.

Permits Required for Discharge to Surface Water

An NPDES discharge permit issued by the Connecticut Department of Environmental Protection (DEP) is required for any wastewater discharge to surface water. In addition, two General Stormwater Discharge Permits would likely be required for a biomass ethanol plant, one for construction, and one for operation of an industrial facility.

Permits Required for Discharge to a Treatment Facility or to Groundwater

A state permit is required for any wastewater discharge to a publicly-owned treatment works (POTW) or to groundwater.

Contacts

The survey response noted that although the Bureau of Water Management within the DEP has not reviewed a biomass ethanol plant, the permitting staff have considerable education, training, and experience in civil, sanitary, industrial, and chemical engineering to "appropriately and quickly review a permit application from such a facility."

Bureau of Water Management
Department of Environmental Protection
79 Elm Street
Hartford, Connecticut 06106-5127
(860) 424-3829

RECYCLING REGULATIONS

Department of Environmental Protection
Bureau of Waste Management
79 Elm St., 4th Floor
Hartford, Connecticut 06106-5127
(203) 424-3234

DELAWARE

Presented below is a summary of Delaware air pollution control regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state agency responsible for air pollution control, solid waste management, wastewater treatment, and recycling in Delaware. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information. (Responses were not received from the solid waste management, wastewater treatment, and recycling agencies/programs and therefore are not included below.)

As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

AIR POLLUTION REGULATIONS

According to staff of the Division of Air and Waste Management, the following regulations apply to a biomass ethanol plant:

Regulation No. 2: Construction, Installation, and Operation Permit Requirements. Regulation No. 3: Ambient Air Quality Standards.

Regulation No. 4: Particulate Emissions from Fuel Burning Equipment.

Regulation No. 8: Sulfur Dioxide Emissions from Fuel Burning Equipment.

Regulation No. 12: Control of Nitrogen Oxides Emissions.

Regulation No. 14 Visible Emissions.

Regulation No. 19: Control of Odorous Air Contaminants.

Regulation No. 20: New Source Performance Standards.

Regulation No. 24: Control of Volatile Organic Compounds.

Regulation No. 25: Requirements for Preconstruction Review.

Regulation No. 30: Title V and State Operating Permit Program.

Source Classification

Based on information presented in Table 4-1, it could not be determined if the biomass ethanol plant would be a major source or minor source. Due to the ozone non-attainment areas in the state (noted below), a major source is one that emits 25 tons per year or more volatile organic compounds (VOCs) or nitrogen oxides (NO_x)in Kent and New Castle Counties, or one that emits 50 tons per year of VOCs or 100 tons per year of NO_x in Sussex County.

Major sources in all counties must comply with Lowest Achievable Emission Rate (LAER) requirements, including obtaining emission offsets of 1.3 to 1 in Kent and New Castle Counties and emission offsets of 1.15 to 1 in Sussex County.

Nonattainment Areas

Kent and New Castle Counties are classified as severe non-compliance for ozone. Sussex County is classified as marginal non-compliance for ozone.

Odor Regulations

Under Regulation 19: Control of Odorous Air Contaminants, "No person shall cause or allow the emission of air contaminants such as to cause or create a condition of air pollution."

Permits Required

Both a construction and a Title V/State operating permit must be applied for and obtained. Permit fees are charged by the Department of Natural Resources and Environmental Conservation. The amounts were not provided in the survey response.

Contacts

Division of Air and Waste Management
Department of Natural Resources and Environmental Conservation
89 King Highway
Dover, Delaware 19903

SOLID WASTE MANAGEMENT REGULATIONS

Solid Waste Division
Department of Natural Resources and Environmental Control
89 Kings Highway
P.O. Box 1401
Dover, Delaware 19903
(302) 739-4403

WASTEWATER TREATMENT REGULATIONS

Department of Natural Resources and the Environment
Watershed Management
89 Kings Highway
Dover, DE 119903
(302) 739-5726

RECYCLING REGULATIONS

Solid Waste Division
Department of Natural Resources and Environmental Control
89 Kings Highway
P.O. Box 1401
Dover, Delaware 19903
(302) 739-4403

MAINE

Presented below is a summary of Maine wastewater treatment regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state air pollution control, solid waste management, wastewater treatment, and recycling agency in Maine. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information. (Responses were not received from the state air pollution control, solid waste management, and recycling agencies/programs, and therefore are not included below.)

As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

WASTEWATER TREATMENT REGULATIONS

Permits Required for Discharge to Water

Both a Maine Waste Discharge License and a federal NPDES permit are required for a discharge to surface water. The License is issued by the Maine Department of Environmental Protection (DEP). The NPDES permit is issued by the U.S. Environmental Protection Agency.

Permits Required for Discharge to a Treatment Facility

A state permit is not required for a facility that generates wastewater discharged to a publicly-owned treatment facility. Instead, the receiving treatment facility must agree to accept the wastewater. Pretreatment may be required.

Contact

Staff of the DEP have not reviewed or permitted a biomass ethanol plant or similar facility.

Department of Environmental Protection
State House Station 17
Augusta, Maine 04333

AIR POLLUTION REGULATIONS

Department of Environmental Protection
Bureau Air Quality Control
State House Station 17
Augusta, Maine 04333
(207) 289-2437

SOLID WASTE MANAGEMENT REGULATIONS

Department of Environmental Protection
Bureau of Hazardous Materials and Solid Waste Control
State House Station #17

Augusta, Maine 04333
(207) 287-7688

RECYCLING REGULATIONS

Department of Environmental Protection
Bureau of Hazardous Materials and Solid Waste Control
State House Station #17
Augusta, Maine 04333
(207) 287-7688

MARYLAND

Presented below is a summary of Maryland air pollution control and wastewater treatment regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state air pollution control, solid waste management, wastewater treatment, and recycling agency in Maryland. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information. (Responses were not received from the state solid waste management and recycling agencies/programs, and therefore are not included below.)

As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

AIR POLLUTION REGULATIONS

Air pollution control regulations are found in **Code of Maryland Regulation (COMAR)**, Title 26, Subtitle 11 Air Quality.

Source Classification

Based on information provided in Table 4-1, it cannot be determined if the biomass ethanol plant would be a major or minor source. Information on sources classified as major stationary sources is presented in Table A-1. Information on sources required to obtain Title V permits is presented in Table A-2.

Nonattainment Areas

AIR POLLUTANT	STATUS	LOCATION
Ozone	Severe	Baltimore metropolitan area and Cecil County (included in the Philadelphia-Wilington-Trenton metropolitan area)
Ozone	Serious	Washington metropolitan area
Carbon Monoxide	Will be reclassified as attainment soon	Baltimore central business district, and small portions of Prince George and Montgomery Counties.

Odor Regulations

Odor regulations are contained in COMAR 26.11.06.09, which states that "A person may not cause or permit the discharge into the atmosphere of gases, vapors, or odors beyond the property line in such a manner that a nuisance of air pollution is created."

Permits Required

A Construction Permit, Operating Permit, and a Part 70 (i.e.Title V) permit are required.

Permit Application Fees

Permit to construct: $200 to $20,000, depending on whether New Source Review (NSR) or Prevention of Significant Deterioration (PSD) approval is required.
State permit to operate: None.

Part 70 permit: $200 plus an emission-based fee for each ton of regulated pollutant emitted per year. The maximum fee is $200,000. For 1996, the emission-based fee was $25/ton/year of regulated pollutant. The fee is adjusted each year based on the Consumer Price Index.

Contacts

The Department of the Environment maintains an Environmental Permits Center which works directly with new businesses seeking to locate in the state.

Air Quality Permits Program
Air and Radiation Management Administration
Department of the Environment
2500 Broening Highway
Baltimore, Maryland 21224

Environmental Permits Center
Department of the Environment
(410) 631-3772

WASTEWATER TREATMENT REGULATIONS

Specific regulations were not identified by the Industrial Discharge Permits Division within the Maryland Department of the Environment. The "basic" water use designation in the state is "Class 1," which is protective of water contact recreation, fishing, aquatic life and wildlife, and agricultural and industrial water supply. Discharges to a Class 1 water (or higher use designated water) is dependant on the assimilative capacity of the water.

Permits Required for Discharge to Water

A state discharge permit is required for discharges to surface water. Since the state has delegated authority to issue NPDES permits, the state permit also serves as a federal NPDES permit.

In many cases, the assimilative capacity of surface waters is limited, and wastewater discharges may be required to

have suspended solids and BOD concentrations below 30 mg/l. Since nutrients are a major concern in the Chesapeake Bay and many of its tributaries, phosphorous or nitrogen removal may also be required.

Permits Required for Discharge to a Treatment Facility

The plant wastewater effluent would be expected to meet pretreatment regulations contained in **Code of Maryland Regulations** (COMAR), 26.08.08 Pretreatment Requirements to Control Industrial Users of Publicly Owned Treatment Works.

Contacts

The Department of the Environment maintains an Environmental Permits Center which works directly with new business seeking to locate in the state.

Industrial Discharge Permits Division
Water Management Division
Department of the Environment
2500 Broening Highway
Baltimore, Maryland 21224

Environmental Permits Center
Department of the Environment
(410) 631-3772

SOLID WASTE MANAGEMENT REGULATIONS

Department of the Environment
Solid Waste Program
2500 Broening Highway
Baltimore, Maryland 21224
(410) 631-3318

RECYCLING REGULATIONS

Office of Waste Recycling
Solid Waste Management Administration
2500 Broening Highway
Baltimore, Maryland 21224
(410) 799-1930

MASSACHUSETTS

Presented below is a summary of Massachusetts air pollution control, solid waste management, wastewater treatment, and recycling regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state agency responsible for air pollution control, solid waste management, wastewater treatment, and recycling in Massachusetts. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information.

As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

AIR POLLUTION CONTROL REGULATIONS

Source Classification

According to staff of the Division of Air Quality Control, the biomass ethanol plant described in Table 4-1 would be a major source of nitrogen oxides (NO_x) and a minor source of volatile organic compounds (VOCs). However, the staff notes that VOC emissions from the wastewater treatment processes were not accounted for, and could possibly change the classification.

Nonattainment Areas

The entire state is classified as serious nonattainment for ozone.

Odor Regulations

According to staff of the Division of Air Quality Control, an "odor problem" is a violation of air pollution control regulations, and must be resolved. A specific regulatory reference(s) was not provided.

Permits Required

Air pollution control permits are issued by regional offices of the MA Department of Environmental Protection. Once a site is selected, all contact is with the regional office. The permits needed are determined during the review process.

Permit Application Fees

The Division estimates the fee would be $11,250 since a major Comprehensive Plan Application would be required.

Contact

Division of Air Quality Control
Department of Environmental Protection
Executive Office of Environmental Affairs
One Winter Street

Boston, Massachusetts 02108
(617) 292-5618

SOLID WASTE MANAGEMENT REGULATIONS

Key solid waste management regulations are contained in **310 Code of Massachusetts Regulations (CMR)**, 16.00 Site Assignments Regulations for Solid Waste Facilities and **310 Code of Massachusetts Regulations**, 19.00 Solid Waste Management.

Plant Classification

According to staff of the Division of Solid Waste, the classification of a facility depends on the feedstock used to produce ethanol. If an ethanol plant accepts only clean, untreated wood waste as feedstock, then it would not be classified as a solid waste management facility, and would not be subject to solid waste management regulations. If municipal solid waste, paper sludge, or treated wood waste are used as feedstock, then the facility could be classified as a solid waste management facility. If the facility were classified as a solid waste management facility, it is likely it would be further classified as a resource recovery facility.

Permits Required

The plant would be required to obtain site assignment, a permit to construct, and a permit to operate.

Contact

Division of Solid Waste
Department of Environmental Protection
Executive Office of Environmental Affairs
One Winter Street
Boston, Massachusetts 02108
(617) 292-5868

WASTEWATER TREATMENT REGULATIONS

Specific regulations were not identified by the Water Pollution Control Division within the Massachusetts Department of Environmental Protection.

Permits Required for Discharge to Water

A combined federal NPDES and state discharge permit is required for a discharge to surface water. Staff of the Water Pollution Control Division state that of primary concern for a discharge from a wood waste-to-ethanol plant will be BOD and toxicity.

Permits Required for Discharge to a Treatment Facility

Local sewer ordinances and pretreatment requirements must be complied with. They vary among municipalities.

Contact

Office of Watershed Management
40 Institute Road
North Grafton, Massachusetts 01536
(508) 792-7470

RECYCLING REGULATIONS

As noted above, key solid waste management regulations are contained in **310 Code of Massachusetts Regulations (CMR)**, 16.00 Site Assignments Regulations for Solid Waste Facilities and **310 Code of Massachusetts Regulations**, 19.00 Solid Waste Management. Recycling is in 310 CMR 19.006 as the means to

"... recover materials or by-products which are:
(a) reused; or

(b) used as an ingredient or a feedstock in an industrial or manufacturing process to make a marketable product; or

(c) used in a particular function or application as an effective substitute for a commercial product or commodity."

'Recycle' does not mean to recover energy from the combustion of the material."

According to staff of the Division of Solid Waste, the conversion of MSW, paper sludge, or wood waste to ethanol might meet the definition of recycling if waste materials used as feedstock were clean and source separated. This is only a preliminary determination and final determination would be made after further discussion within the Division.

Permits Required

The facility would be required to notify or register with the appropriate regional office of the state DEP.

Recycling facilities are subject to significant less regulatory review, oversight, and reporting requirements than are solid waste management facilities. Facilities that are classified as recycling facilities or recycling related businesses may be able to obtain certain funds designated for recycling or environmental projects.

Contact

For permitting a recycling facility:

Division of Solid Waste
Department of Environmental Protection
Executive Office of Environmental Affairs
One Winter Street
Boston, Massachusetts 02108
(617) 292-5868

NEW HAMPSHIRE

Presented below is a summary of New Hampshire air pollution control, solid waste management, and wastewater treatment regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state agency responsible for air pollution control, solid waste management, wastewater treatment, and recycling in New Hampshire. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information. (A response was not received from the state agency/program responsible for recycling, and therefore is not included below.)

As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

AIR POLLUTION CONTROL REGULATIONS

According to staff of the Air Resources Division within the Department of Environmental Services, air pollution control rules that would apply to a wood waste-to-ethanol plant include:

Part ENV-A 607 Permit Applicability

Part ENV-A 1211 NO_x

Part ENV-A 1300 Toxics Rule

Source Classification

Based on information on the biomass ethanol plant presented in Table 4-1, it is not possible to determine if the plant would be classified as a major or minor source. Major thresholds for new sources are:

Air Pollutant	Threshold
Nitrogen Oxides	100 tons/year
Sulfur Dioxide	250 tons/year
Particulate Matter (PM-10)	250 tons/year
Carbon Monoxide	250 tons/year
Volatile Organic Compounds Acetaldehyde Formaldehyde	50 tons/year 10 tons/year 10 tons/year or 25 tons/year combined

Nonattainment Areas

All of New Hampshire is classified as nonattainment for ozone. The counties of Hillsborough, Merrimack, Rockingham, and Strafford are classified as serious nonattainment. The rest of the state is classified as marginal nonattainment.

Odor regulations

None.

Permits Required

All new sources must obtain a temporary or construction permit. Minor and synthetic minor sources must obtain a state permit to operate. Major sources must obtain the combined state permit to operate and Title V permit.

Permit Application Fees

The permit fee system is emission based. Permit applications that require more extensive review, such as Prevention of Significant Deterioration (PSD) or Lowest Achievable Emission Rate (LAER) review, will be assessed additional hourly costs.

Contacts

Air Resources Division
NH Department of Environmental Services
64 North Main Street
P.O. Box 2033
Concord, New Hampshire 03302-2033

SOLID WASTE MANAGEMENT REGULATIONS

According to Staff of the Waste Management Division of the Department of Environmental Services, no specific regulations would apply to a wood waste-to-ethanol plant unless it accepted unprocessed construction and demolition (C/D) waste directly from generators of the material.

Plant Classification

The plant would not be classified as a solid waste management facility unless it accepted unprocessed C/D waste.

Permits Required

Solid waste management permits would not be required unless the plant accepted unprocessed C/D waste.

Contacts

According to staff of the Waste Management Division, a wood waste-to-ethanol has been proposed in the state.

For information on regulations:

Planning and Community Assistance
Waste Management Division
Department of Environmental Services
64 North Main Street
P.O. Box 2033
Concord, New Hampshire 03302-2033

For information on permitting:

Permit Application and Design Review Section
Waste Management Division
Department of Environmental Services
64 North Main Street
P.O. Box 2033
Concord, New Hampshire 03302-2033

WASTEWATER TREATMENT REGULATIONS

According to staff of the Department of Environmental Services, key regulations which would affect a wood waste-to ethanol plant are Env-Ws 401 through 403, and Env-Ws 430 through 438. Since New Hampshire is not a delegated state to issue National Pollution Discharge Elimination System permits, new sources will need to comply with the National Environmental Protection Act.

Permits Required for Discharge to Water

The state has designated all surfaces water in the state as Class A or B. There are currently no Class C surface waters. The higher use designations for all surface waters in the state implies higher levels of treatment may be required for discharges into the waters.

Both a New Hampshire Surface Water Discharge Permit and a federal NPDES Permit are required for a discharge to surface water. In addition, federal Stormwater Permits are required for both construction and operation of an ethanol plant.

Permits Required for Discharge to a Treatment Facility

Staff of the Department did not indicate if a permit is required, but did state that such a discharge is subject to the requirements of Env-Ws 904.

Contacts

NPDES and State Permits:

Surface Water Quality Bureau
Department of Environmental Services
64 North Main Street, 3rd Floor
Concord, New Hampshire
(603) 271-2457

Pretreatment:

Surface Water Quality Bureau
Department of Environmental Services
64 North Main Street, 3rd Floor
Concord, New Hampshire
(603) 271-2457

RECYCLING REGULATIONS

Governor's Recycling Program
Office of Planning
2 1/2 Beacon Street
Concord, New Hampshire 03301
(603) 271-1098

NEW JERSEY

Presented below is a summary of New Jersey solid waste management regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state agency responsible for air pollution control, solid waste management, wastewater treatment, and recycling in New Jersey. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information. (Responses were not received from the state agency/program responsible for air pollution control, solid waste management, and recycling and therefore are not included below.)

As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

SOLID WASTE MANAGEMENT REGULATIONS

According to staff of the Division of Solid and Hazardous Waste within the Department of Environmental Protection, key regulations that impact facilities that process or handle solid waste are contained in **New Jersey Administrative Code (JAC**), 7:26 et.seq.

Plant Classification

If an ethanol plant accepts municipal solid waste as feedstock, then the plant would be considered a solid waste management facility (and ore specifically, either a thermal destruction or resource recovery facility). If the plant accepts non-MSW materials as feedstock (such as agricultural residue), the plant would not be considered a solid waste management facility.

Permits Required

If a plant accepts MSW, a solid waste management facility permit would be required.

Contacts

The DEP has not reviewed an ethanol plant, but has reviewed and permitted numerous recycling, MSW resource recovery, thermal destruction, and medical waste facilities.

To obtain a copy of the solid waste management regulations:

New Jersey Office of Administrative Law
(609) 588-6500

To arrange a pre-application meeting:

(609) 984-6650

To obtain information on permitting:
Bureau of Recycling and Planning
(609) 984-3438

Office of Permitting
(609) 984-5950

Regulation Element
(609) 633-1418

AIR POLLUTION REGULATIONS

Department of Environmental Protection
Air Quality Management Office
401 E. State St., CN 418
Trenton, New Jersey 08625
(609) 292-6710

WASTEWATER TREATMENT REGULATIONS

Department of Environmental Protection
Division of Water Quality
401 E. State St., CN 029, 2nd Floor
Trenton, New Jersey 08625
(609) 292-4543

RECYCLING REGULATIONS

Recycling and Planning Element
Division of Solid Waste, EPA
401 E. State St., CN414
Trenton, New Jersey 08625
(609) 530-8115

NEW YORK

Presented below is a summary of New York recycling regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state agency responsible for air pollution control, solid waste management, wastewater treatment, and recycling in New York. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information. (Responses were not received from the state agency/program responsible for air pollution control, solid waste management, and wastewater treatment and therefore are not included below.)

As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

RECYCLING REGULATIONS

Regulations affecting recycling and recycling facilities are found in Title 6 of the **Official Compilation of Codes, Rules and Regulations**, Part 360 Solid Waste Management Facilities (Part 360 Regulations).

Definition of Recycling

Recycling is defined in the Part 360 Regulations as the means "... to use recyclables in manufacturing a product." Recyclable is defined as "...solid waste that exhibits the potential to be used repeatedly."

Definition of a Recycling Facility

A handling and recovery facility for recycling is defined in the Part 360 Regulations as "... a solid waste processing facility, other than collection and transfer vehicles, at which nonputrescible recyclable are separated from the solid waste stream or at which previously separated nonputrescible recyclables are processed."

Facility Classification

According to staff of the Bureau of Waste Reduction and Recycling, a wood waste-to-ethanol plant would not be considered a recyclables handling and recovery facility. The plant might be classified as a refuse-derived fuel (RDF) processing facility. Or, the plant could apply for a "Beneficial Use Determination" on the basis that it is beneficially using solid waste. If classified as a beneficial use, the facility would not be likely to be classified as a solid waste management facility.

Permits Required

The permit(s) required depend on the facility classification

Since a wood waste-to-ethanol facility would not be considered a recyclables handling and recovery facility, it would not be subject to the requirements of Subpart 360-12 Recyclables Handling and Recovery Facilities.

If the facility were classified as an RDF processing facility, then it would be required to meet requirements of Subpart 360-3 Solid Waste Incinerator or Refuse-Derived Fuel Processing Facilities or Solid Waste Pyrolysis Units.

If the facility obtained a beneficial use determination (BUD) for the waste feedstock used to produce ethanol, it would not be subject to the requirements of the Part 360 Regulations.

Staff of the Bureau state that it has not been determined whether waste materials used as feedstock in a biomass ethanol plant would count towards state or local recycling goals.

Contacts

Permitting:

Bureau of Waste Reduction and Recycling
Department of Environmental Conservation
50 Wolf Road
Albany, New York 12233-4015
(518) 457-7337

Facility Classification:

Bureau of Waste Reduction and Recycling
Department of Environmental Conservation
50 Wolf Road
Albany, New York 12233-4015
(518) 457-7337

AIR POLLUTION REGULATIONS

Department of Environmental Conservation
Division of Air Resources
Bureau of Abatement Planning
50 Wolf Road
Albany, New York 12233
(518) 457-0631

SOLID WASTE MANGEMENT REGULATIONS

Department of Environmental Conservation
Division of Solid Waste
50 Wolf Road
Albany, New York 12233
(518) 457-3446

WASTEWATER TREATMENT REGULATIONS

Department of Environmental Conservation
Division of Water
50 Wolf Road
Albany, New York 12233
(518) 457-3446

PENNSYLVANIA

Presented below is a summary of Pennsylvania air pollution control and wastewater treatment regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state agency responsible for air pollution control, solid waste management, wastewater treatment, and recycling in Pennsylvania. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information. (Responses were not received from the state agency/program responsible for solid waste management and recycling and therefore are not included below.)

As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

AIR POLLUTION CONTROL REGULATIONS

State air pollution control regulations are contained in **Pennsylvania Code Title 25**, Environmental Resources, Chapters 121 -143, Air Resources.

Source Classification

Based on the information on a wood waste-to-ethanol plant presented in Table 4-1, it can not be determined whether the plant would be classified as a major or minor source. There are three types of major sources in Pennsylvania:

- Major facility;
- Major NO_x emitting facility; and
- Major VOC emitting facility.

Facilities that are not classified as major facilities are either minor or synthetic minor facilities.

Nonattainment Areas

The entire state is nonattainment for NOx and VOCs. Portions of Warren County are nonattainment for SO2.

Odor Regulations

Under Subchapter 123.31 of Title 25, malodorous emissions must be controlled by incineration or similar technology. Malodorous emissions must not be detectable beyond the property line.

Permits Required

Air pollution control permits are issued by six regional offices, except in Allegheny and Philadelphia Counties, which have their own local air quality agencies. Staff of the Bureau of Air Quality note that the Bureau has no active permits for a wood waste-to-ethanol plant or similar facility.

As specified in Title 25, Chapter 127, the applicant submits what is referred to as a "Plan Approval Application." Upon completion of a satisfactory engineering review of the project plans, a plan approval is issued to the applicant and construction may begin. Once the facility is operating properly and the terms and conditions are met, the facility will be issued an operating permit (following a satisfactory facility inspection.)

In addition to the state permits, Pennsylvania is also delegated to review Title V permit application and issue Title V permits.

Permit Application Fees

Fees are charged for plan approvals, operating permits, and Title V permits and depend on the type of review(s) required by the facility. Permit fees are contained in Subchapters 127.701 through 127.705 of Title 25.

Contact

Division of Permits
Bureau of Air Quality
Department of Environmental Protection
Rachel Carson State Office Building
P.O. Box 8468
Harrisburg, Pennsylvania 17105-8468
(717) 787-9256

WASTEWATER TREATMENT REGULATIONS

According to staff of the Bureau of Water Quality Management within the Department of Environmental Protection, the following chapters of **Pennsylvania Code Title 25, Environmental Resources** are the key regulations:

Chapter 16. Water Quality Toxics Management Strategy-Statement of policy.

Chapter 91. General Provisions.

Chapter 92. National Pollution Discharge Elimination System.

Chapter 93. Water Quality Standards.

Chapter 95. Wastewater Treatment Requirements.

Chapter 97. Industrial Wastes.

Permits Required for Discharge to Water

Industrial wastewater permitting is done out of regional offices of the Pennsylvania DEP. The regional office covering the area where the project is proposed should be contacted for further information on permits or regulations.

Both a Water Quality Management Part I (National Pollution Discharge Elimination System) permit and a Water Quality Management Part I (Construction and Operation) permit are required for a discharge to surface water. Since Pennsylvania has been delegated authority by the U.S. Environmental Protection Agency to review and issue NPDES permits, Part 1 permits issued by the state DEP serve as NPDES permits.

Permits Required for Discharge to a Treatment Facility

Discharges to publicly-owned treatment facilities are governed by Federal pretreatment regulations and local pretreatment programs or ordinances.

Contacts

Division of Permits and Compliance
Bureau of Water Quality Management
Department of Environmental Protection
Rachel Carson State Office Building
P. O. Box 8465
Harrisburg, Pennsylvania 17105-8465
Voice: (717) 787-8184
Fax: (717) 772-5156

SOLID WASTE MANAGEMENT REGULATIONS

Division of Municipal & Residual Waste
Bureau of Land Recycling & Waste Management
Rachel Carson State Office Building
P. O. Box 8472
Harrisburg, Pennsylvania 17105-8472
(801) 538-6775

RECYCLING REGULATIONS

Division of Waste Minimization & Planning
Bureau of Land Recycling & Waste Management
Rachel Carson State Office Building
P. O. Box 8471
Harrisburg, Pennsylvania 17105-8471
(717) 787-9870

RHODE ISLAND

Presented below is a summary of Rhode Island air pollution control and wastewater treatment regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state agency responsible for air pollution control, solid waste management, wastewater treatment, and recycling in Rhode Island. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information. (Responses were not received from the state agency/program responsible for solid waste management and recycling and therefore are not included below.)

As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

AIR POLLUTION CONTROL REGULATIONS

According to staff of the Division of Air Resources within the Rhode Island Department of Environmental Management, key regulations that would affect a wood waste-to-ethanol plant are contained in the following **Air Pollution Control Regulations** (APC Regulations):

Regulation No. 1: Visible Emissions.

Regulation No. 6: Opacity Monitors.

Regulation No. 7: Emission of Air Contaminants Detrimental to Persons or Property.

Regulation No. 8: Sulfur Content of Fuels.

Regulation No. 9: Air Pollution Control Permits.

Regulation No. 13: Particulate Emissions From Fossil Fuel Fired Steam or Hot Water Generating Units.

Regulation No. 16: Operation of Air Pollution Control Systems.

Regulation No. 17 Odors.

Regulation No. 20: Burning of Alternative Fuels.

Regulation No. 27: Control of Nitrogen Oxide Emissions.

Regulation No. 28: Operating Permit Fees.

Regulation No. 29: Operating Permits.

Source Classification

Based on information on the wood waste-to-ethanol plant presented in Table 4-1, the plant would be classified as a major source of NOx and CO and a minor source of SO_2, particulate matter, and VOCs.

Nonattainment Areas

The entire state is nonattainment for ozone.

Odor Regulations

Odors are regulated and must be controlled, per regulations contained in APC Regulation No. 17 Odors.

Permits Required

Staff of the Division of Air Resources state that a biomass-to-ethanol plant has not been reviewed by the Division.

Both a Preconstruction Permit (required under APC Regulation No. 9) and an Operating Permit (required under APC Regulation No. 29) are required.

Permit Application Fees

The Department charges a filling fee of: $1,271 for minor sources;
$4,620 for complex minor sources; or $25,410 for major sources.
Fees charged for operating permits have not been established yet.

Contact

Division of Air Resources
Department of Environmental Management
291 Promenade Street
Providence, Rhode Island 02908
(401) 277-2797

WASTEWATER TREATMENT REGULATIONS

According to staff of the Division of Water Resources, key regulations include:

Regulations for the Rhode Island Pollutant Discharge Elimination System.

Rhode Island Water Quality Regulations for Water Pollution Control.

Policy of the Implementation of the Antidegradation Provisions of the Rhode Island Water Quality Regulations.

Rhode Island Pretreatment Regulations.

Permits Required to Discharge to Water

A Rhode Island Pollutant Discharge Elimination System Permit is required for a discharge to surface water.

Permits Required to Discharge to a Treatment Facility

A discharge to a publicly-owned treatment facility will need to comply with Rhode Island Pretreatment Regulations.

Contact

According to staff, the Division has not reviewed a biomass ethanol facility.

Permits Section
Division of Water Resources
Department of Environmental Management
291 Promenade Street
Providence, Rhode Island 02908
Voice: (401) 277-3961 Ext. 7225
Fax: (401) 521-4230

SOLID WASTE MANAGEMENT REGULATIONS

Solid Waste Section
Air and Hazardous Materials
291 Promenade Street
Providence, Rhode Island 02908
(401) 277-2797

RECYCLING REGULATIONS

Solid Waste Management Corporation
260 W. Exchange St.
Providence, Rhode Island 02903

(401) 831-4440

VERMONT

Presented below is a summary of Vermont air pollution control, solid waste management, wastewater treatment, and recycling regulations expected to apply to a theoretical 25 million gallon per year ethanol plant. Described as Scenario A in Figure 4-1 and Table 4-1, the plant would use 633 bone dry tons of wood waste per day to produce ethanol, would use dilute sulfuric acid in the pretreatment process, and would generate energy on site.

The regulations were identified by sending a written questionnaire to the state agency responsible for air pollution control, solid waste management, wastewater treatment, and recycling in Vermont. Regulators were asked to provide information on which environmental regulations apply to a theoretical biomass ethanol plant with the characteristics of Scenario A. Responses to the questionnaire are presented below, as are contacts for further information.
As noted previously, this information is intended for general purposes only. Specific regulations that may apply to an actual ethanol facility may vary from those discussed below.

AIR POLLUTION CONTROL REGULATIONS

Key regulations are contained in Chapter 5 of the **Environmental Protection Regulations, Air Pollution Control Regulations**.

Source Classification

Based on information on the wood waste-to-ethanol plant presented in Table 4-1, it can not be determined whether the plant would be classified as a major or minor source. Major sources are those that emit 50 tons/year or more of any one criteria pollutant.

Nonattainment Areas

Vermont is classified as being in attainment for all air contaminants, and is unclassified for ozone.

Odor Regulations

Under Subchapter 5-241, Prohibition of Nuisance and Odors, no objectional odors can be emitted beyond a facility's property line.

Permits Required

Both a New Source Construction Permit and an Operating Permit are required. The New Source Construction Permit is transferable and does not have an expiration date. An Operating Permit is required for sources that emit 10 tons/year or more.

Permit Application Fees

Permit application fees are $9,500 for major sources and $500 for minor sources and do not include additional fees charged for engineering review, impact analysis, observance and review of emission tests, audits of continuous emissions monitoring, audits of ambient air quality monitoring, and implementing public comment requirements.

Contact

The Air Pollution Control Division of the Vermont Agency of Natural Resources has permitted two large power plants and numerous smaller industrial, commercial, and institutional boilers that use wood and wood waste as fuel. The Division recently amended the permit of a large wood-

fired power plant to include construction of a gasifier which will use wood for fuel.

Engineering Services Section
Air Pollution Control Division
Agency of Natural Resources
Waterbury, Vermont 05671-0402
Voice: (802) 241-3840
Fax: (802) 241-2590

SOLID WASTE MANAGEMENT REGULATIONS

Key regulations are contained in Chapter 6 of **Environmental Protection Regulations, Solid Waste Management Rules**.

Plant Classification

If a facility accepts only clean, untreated wood or residues from forestry activities, then it would not classified as a solid waste management facility. If a facility accepts other types of wood that are considered solid waste, then it would be classified as a Solid Waste Treatment Facility.

Permits Required

Similar to any facility that accepts, stores, or treats solid waste, ethanol plants that accept wood waste considered to be solid waste would be required to apply for a Solid Waste Facility Certification, as required under Subchapter 6-304 of the Solid Waste Management Rules. Plants that accept wood not considered solid waste are not required to obtain a certification.

Contact

The Solid Waste Management Division within the Agency of Natural Resources reports that it has not permitted or reviewed an ethanol plant or similar facility.

For solid waste management regulations:

Solid Waste Management Division
Agency of Natural Resources
103 South Main Street
Waterbury, Vermont 05671-0407
Voice: (804) 241-3444
Fax: (802) 241-3273

For facility certification:

Solid Waste Management Division
Agency of Natural Resources
103 South Main Street
Waterbury, Vermont 05671-0407
Voice: (804) 241-3444
Fax: (802) 241-3273

RECYCLING REGULATIONS

Key regulations affecting recycling and recycling facilities are found in Chapter 6 of **Environmental Protection Regulations, Solid Waste Management Rules**.

Definition of Recycling/Facility Classification

Under Subchapter 2 of the Solid Waste Management Rules, "recycle" is defined as "the process of utilizing solid waste for the production of raw materials or products, but shall not include processing solid waste to produce energy or fuel products." Based on this definition, a wood waste-to-ethanol plant would not be considered a recycling facility.

Permits Required

No permits related to recycling are required since an ethanol plant would not be classified as a recycling facility. If the plant were classified as a solid waste treatment facility, then it would be required to apply for a Solid Waste Facility Certification.

Contact

Recycling and Resource Conservation Section
Solid Waste Management Division
Agency of Natural Resources
103 South Main Street
Waterbury, Vermont 05671-0407
Voice: (804) 241-3444
Fax: (802) 241-3273

WASTEWATER TREATMENT REGULATIONS

Key regulations are contained in **Vermont Water Quality Standards, Vermont Water Pollution Control Permit Regulations**, and **40 Code of Federal Regulations** (CFR), Part 122.

Permits Required for Discharge to Water

A permit issued under the Vermont Water Pollution Control Permit Regulations is required for a discharge to surface water.

Contact

The Public Facilities Division within the Vermont Agency of Natural Resources reports that it has not reviewed or permitted a wood waste-to-ethanol plant or similar facility.

Discharge Permit Section
Agency of Natural Resources
103 South Main Street
Waterbury, Vermont 05671-0407
(802) 241-3822

APPENDIX B:

F U E L E T H A N O L SPECIFICATIONS AND REFUELING FACILITY SPECIFICATION

APPENDIX C:

FINANCIAL PERFORMANCE FOR THE BASE CASE ETHANOL PLANT

APPENDIX D:

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TABLE 2-1: FEDERAL REQUIREMENTS FOR ALTERNATIVE- AND CLEAN-FUELED GOVERNMENT FLEETS

	CLEAN AIR ACT		ENERGY POLICY ACT (e)		
Year (a)	**GVW < 8,500 lb** (b)	**GVW < 26,000 lb** (c)	**Federal Fleets**	**State Fleets**	**Municipal Fleets** (d)
1993			7,500		
1994			11,250		
1995			15,000		
1996			25%	10%	
1997			33%	15%	
1998	30%	50%	50%	25%	
1999	50%	50%	75%	50%	20%
2000	70%	50%	75%	75%	20%
2001	70%	50%	75%	75%	20%
2002	70%	50%	75%	75%	30%
2003	70%	50%	75%	75%	40%
2004	70%	50%	75%	75%	50%
2005	70%	50%	75%	75%	60%
2006	70%	50%	75%	75%	70%

(a) The year refers to vehicle model year, except for EPACT. For EPACT, the year refers to the fiscal year.

(b) Includes requirements for fleets to purchase "clean-fueled vehicles" for vehicles with a gross vehicle weight (GVW) of 8,500 pounds or less.

(c) Includes requirements for fleets to purchase "clean-fueled vehicles" for vehicles with a gross vehicle weight (GVW) of 8,500 pounds or more, but less than 26,000 pounds.

(d) Includes both county and local municipalities.

TABLE 2-2: 1994 GASOLINE USED BY GOVERNMENT FLEETS IN THE NRBP REGION (a) (b)

STATE	FEDERAL FLEETS (x 1,000 gallons)	STATE, COUNTY, AND MUNICIPAL FLEETS (x 1,000 gallons)	TOTAL (x 1,000 gallons)
Connecticut	2,259	19,867	22,126
Delaware	459	4,891	5,350
Maine	1,095	9,506	10,601
Maryland	4,479	25,586	30,065
Massachusetts	4,215	33,642	37,857
New Hampshire	730	8,702	9,432
New Jersey	5,336	47,079	52,415
New York	12,051	84,681	96,732
Pennsylvania	7,726	70,970	78,696
Rhode Island	573	7,832	8,405
Vermont	356	5,343	5,699
TOTAL GASOLINE USE	**39,279**	**318,099**	**357,378**
E85 EQUIVALENT	**54,598**	**442,158**	**496,796**

(a) "Gasoline" includes gasoline, reformulated gasoline, and gasohol.
(b) Based on 1994 data published by the Office of Highway Information, U.S. Department of Transportation.

TABLE 2-3: 1994 GASOLINE, REFORMULATED GASOLINE, AND GASOHOL USE IN THE NRBP REGION (a) (b)

STATE	TOTAL GASOLINE, RFG, AND GASOHOL USED (x 1,000 gallons)	% RFG (c)	PORTION WHICH IS RFG (x 1,000 gallons)
Connecticut	1,402,619	100%	1,402,619
Delaware	357,147	100%	357,147
Maine	623,544	55%	342,949
Maryland	2,173,837	88%	1,912,977
Massachusetts	2,454,029	100%	2,454,029
New Hampshire	550,696	88%	484,612
New Jersey	3,486,576	97%	3,381,979
New York	5,543,467	53%	2,938,038
Pennsylvania	4,719,351	25%	1,179,838
Rhode Island	371,084	100%	317,084
Vermont	309,582	0	0
TOTAL	**21,991,932**		**14,825,270**

(a) "Gasoline" includes gasoline, reformulated gasoline, and gasohol.
(b) Based on 1994 data published by the Office of Highway Information, U.S. Department of Transportation.
(c) Amount (as a percentage) of RFG used in each state compared to gasoline. Percentages were compiled by the ARCO Chemical Company, based on data compiled by the USDOE's Energy Information Administration.

TABLE 3-1: ETHANOL PLANTS OPERATING IN THE U.S. (a)

ETHANOL PLANT	LOCATION	CAPACITY (x 1,000,000 Gallons/Yr)
Archer Daniels Midland	Decatur, IL	310
Archer Daniels Midland	Peoria, IL	200
Archer Daniels Midland	Cedar Rapids, IA	200
Archer Daniels Midland	Clinton, IA	160
Pekin Energy Company	Pekin, IL	100
Minnesota Corn Processors	Columbus, NE	85
New Energy Company of Indiana	South Bend, IN	75
Cargill, Inc.	Blair, NE	70
AE Staley Manufacturing Company	Loudon, TN	40
Minnesota Corn Processors	Marshall, TN	35
Cargill, Inc.	Eddyville, IA	35
Chief Ethanol Fuels, Inc.	Hastings, NE	28.5
Archer Daniels Midland	Walhalla, ND	28
High Plains Corporation	Colwich, KS	20.8
The Hubinger Company	Keokuk, IA	18
Corn Plus	Winnebago, MN	15
Alchem Limited	Grafton, ND	12
Giant Refining, Inc.	Portales, NM	12
Midwest Grain Products, Inc.	Pekin, IL	12
Grain Processing Corp.	Muscatine, IA	10
Reeve Agri Energy, Inc.	Garden City, KS	7.5
Broin Enterprises	Scotland, SD	7
Manildra Energy, Inc.	Hamburg, IA	6
Midwest Grain Products, Inc.	Atchison, KS	6
Heartland Grain Fuel	Aberdeen, SD	5
Morris Ag Energy Company, Inc.	Morris, MN	5
J.R. Simplot Company	Caldwell, ID	4
Georgia Pacific Corp.	Bellingham, WA	3.5
J.R. Simplot Company	Burly, ID	3
Golden Cheese of California	Corona, CA	2.6
Alcotech, Inc.	Ringling, MT	2
Parallel Products	Cucamonga, CA	2
Kraft, Inc.	Melrose, MN	1.4
Minnesota Clean Fuels	Dundas, MN	1.2
ESE Alcohol, Inc.	Leoti, KS	1
Dairymen's Cooperative	Tulare, CA	0.7
Pabst Brewing Company	Olympia, WA	0.7
Vienna Correctional Center	Vienna, IL	0.5
TOTAL	**38**	**14,905**

(a) Based on information published by Information Resources, Inc., updated with information published in **Oxy-Fuel News**.

TABLE 3-2: COST SUMMARY FOR ETHANOL PRODUCTION FROM CORN (a)

	<40 Million Gallons Per Year	40 to 250 Million Gallons Per Year
Capital & Related ($/annual gallon)	$3.35	$2.23 - 2.78
Corn (less co-product revenue) ($/gallon)	-0.01 - 0.78	-0.01 - 0.78
Fuel (coal and electricity) ($/gallon)	0.15 - 0.21	0.15 - 0.21
Secondary Raw Materials ($/gallon)	0.04 - 0.12	0.04 - 0.12
Maintenance ($/gallon)	0.11 - 0.16	0.11 - 0.16
Personnel ($/gallon)	0.18	0.06
TOTAL	**$3.84 - 4.80**	**$2.60 - 4.11**

(a) From Wyman and Goodman (1994), based on values presented by the USDA (1987), adjusted to 1990 dollars.

TABLE 3-3: BIOMASS ETHANOL COSTS - CURRENT TECHNOLOGY (a)

Feedstock: 658,000 Dry tons/year
Plant capacity: 60.1 Million gallons/year

Installed capital cost: $150.3 Million

	Capital, Labor, & Related Costs (¢/gal.)	Energy Cost (¢/gal.)	Total Cost (¢/gal.)	% of Total Processing Cost	% of Overall Cost
RAW MATERIALS					
Feedstock			45.97		39.00
Other			9.78		8.30
Subtotal - Raw Material			**55.75**		**47.30**
PROCESSING					
Pretreatment	13.75	6.55	20.30	32.70	17.20
Biological Conversion					
Cellulase Production	1.55	1.67	3.22	5.20	2.70
SSF	13.83	3.34	17.17	27.70	14.60
Pentose Conversion	3.22	0.99	4.21	6.80	3.60
	18.60	6.00	24.60	39.60	20.90
Distillation	2.74	5.10	7.84	12.60	6.70
Power Cycle	28.61	-26.96	1.65	2.70	1.40
Other	7.34	0.36	7.70	12.40	6.50
Subtotal - Processing	**71.04**	**-8.95**	**62.09**	**100.00**	**52.70**
TOTAL			**117.84¢**	**100%**	**100%**

TABLE 3-4: BIOMASS ETHANOL COSTS - ADVANCED TECHNOLOGY (a)

Feedstock: 2,738,000 Dry tons/year **Installed capital cost:** $268.4 Million
Plant capacity: 294.9 Million gallons/year

	Capital, Labor, & Related Costs (¢/gal.)	Energy Cost (¢/gal.)	Total Cost (¢/gal.)	% of Total Processing Cost	% of Overall Cost
RAW MATERIALS					
Feedstock			35.84		71.30
Other			0.95		1.90
Subtotal - Raw Materials			**36.79**		**73.20**
PROCESSING					
Pretreatment	3.22	5.63	8.85	65.50	17.60
Biological Conversion	1.95	1.00	2.95	21.80	5.90
Distillation	1.79	2.83	4.62	34.20	9.20
Power Cycle	14.06	-22.03	-7.97	-59.00	-15.80
Other	4.74	0.32	5.06	37.50	10.10
Subtotal - Processing	**25.76**	**-12.25**	**13.51**	**100.00**	**27.00**
TOTAL			**50.30¢**		**100%**

(a) From Lynd, Elander, and Wyman based on the simultaneous saccharification and fermentation (SSF) design by the National Renewable Laboratory.

TABLE 4-1: PROJECTED EMISSIONS FROM SCENARIO A

Feedstock: Wood Waste
633 Bone dry tons/day
Pretreatment: Dilute Sulfuric Acid

Energy Production: Circulating Fluidized Bed Boiler
Ethanol Production Capacity: 25 Million gallons/year

AIR EMISSIONS

SOURCE	**POLLUTANT**	**UNCONTROLLED EMISSION**			**BACT ESTIMATE**	**ANTICIPATED REMOVAL EFFICIENCY**	**CONTROLLED EMISSION RATE**	
		Lb/MMBtu	**ppmvd**	**mg/dscm**	**(a)**	**%**	**Lb/MMBtu**	**Tons/Year**
Fermentation Off-gases	Ethanol	NA	57	110	CTG (b)	NA	NA	5.07
Product and Chemical Storage	VOCs	NA	NA	NA	CTG (b)	NA	NA	0.63

Boiler Stack	NOx	0.4	NA	NA	SNCR (c)	65	0.14	121
	SO2	0.239	NA	NA	Lime (d)	80	0.1	47.5
	PM-10	0.03	NA	NA	FF (e)	99	0.024	25.9
	Lead	7.9 x 10^-6	NA	NA	Lime (d)	90	0.79 x 10^-6	<1
	CO	0.150	NA	NA	GCP (f)	NA	0.150	130
	VOCs	0.025	NA	NA	GCP (f)	NA	0.025	21.5
	Acetaldehyde	3.86 x 10^-4	NA	NA	GCP (f)	NA	3.86 x 10^-4	0.32
	Formaldehyde	2.48 x 10^-4	NA	NA	GCP (f)	NA	2.48 x 10^-4	0.32

TABLE 4-1: (Continued)

SOLID WASTE

Amount: 75 Tons/day
Classification: Non-hazardous
Moisture Content: 50% (Overall)
Composition (Major Components): Boiler bottom ash
Boiler fly ash
Flue gas desulfurization solids
Solids removed during wastewater treatment

WASTEWATER

Volume: 490,000 Gallons/day
Treatment Process: Anaerobic digestion followed by aerobic polishing

Effluent Quality: BOD5 - 30 mg/l
COD - 60 mg/l
TSS - 30 mg/l

(a) Best Available Control Technology.
(b) Complies with Control Technology Guidelines established by the U.S. EPA
(c) Selective non-catalytic reduction.
(d) Lime injection.
(e) Fabric filters.
(f) Good combustion pratices.

TABLE 4-2: PROJECTED EMISSIONS FROM SCENARIO B

Feedstock: Wood Waste
633 Bone dry tons/day
Pretreatment: Hot Water

Energy Production: Circulating Fluidized Bed Boiler
Ethanol Production Capacity: 25 Million gallons/year

AIR EMISSIONS

SOURCE	**POLLUTANT**	**UNCONTROLLED EMISSION**			**BACT ESTIMATE**	**ANTICIPATED REMOVAL EFFICIENCY**	**CONTROLLED EMISSION RATE**	
		Lb/MMBtu	**ppmvd**	**Mg/dscm**	**(a)**	**%**	**Lb/MMBtu**	**Tons/Year**
Fermentation Off-gases	Ethanol	NA	57	110	CTG (b)	NA	NA	5.07
Product and Chemical Storage	VOCS	NA	NA	NA	CTG (b)	NA	NA	0.63

Boiler Stack	NOx	0.4	NA	NA	SNCR (c)	65	0.14	121
	SO2	0.080	NA	NA	Lime (d)	80	0.1	15.8
	PM-10	0.03	NA	NA	FF (e)	99	0.024	25.9
	Lead	7.9 x 10^-6	NA	NA	Lime (d)	90	0.79 x 10^-6	<1
	CO	0.150	NA	NA	GCP (f)	NA	0.150	130
	VOC	0.025	NA	NA	GCP (f)	NA	0.025	21.5
	Acetaldehyde	3.86 x 10^-4	NA	NA	GCP (f)	NA	3.86 x 10^-4	0.32
	Formaldehyde	2.48 x 10^-4	NA	NA	GCP (f)	NA	2.48 x 10^-4	0.32

TABLE 4-2: (Continued)

SOLID WASTE

Amount: 50 Tons/day
Classification: Non-hazardous
Moisture Content: 50% (Overall)
Composition (Major Components): Boiler bottom ash
Boiler fly ash
Flue gas desulfurization solids
Solids removed during wastewater treatment

WASTEWATER

Volume: 490,000 Gallons/day
Treatment Process: Anaerobic digestion followed by aerobic polishing

Effluent Quality: BOD5 - 30 Mg/l
COD - 60 Mg/l
TSS - 30 Mg/l

(a) Best Available Control Technology.
(b) Complies with Control Technology Guidelines established by the U.S. EPA
(c) Selective non-catalytic reduction.
(d) Lime injection.
(e) Fabric filters.
(f) Good combustion pratices.

TABLE 4-3: PROJECTED EMISSIONS FROM SCENARIO C

Feedstock: MSW **Energy Production:** Boiler
725 Bone dry tons/day **Ethanol Production Capacity:** 25 Million gallons/year
Pretreatment: Dilute sulfuric acid

AIR EMISSIONS

SOURCE	POLLUTANT	UNCONTROLLED EMISSION		BACT ESTIMATE	ANTICIPATED REMOVAL EFFICIENCY	CONTROLLED EMISSION RATE	
		ppmvd	Mg/dscm	(a)	%	Lb/MMBtu	Tons/Year
Fermentation Off-gases	Ethanol	57	110	CTG (b)	NA	NA	5.07
Product and Chemical Storage	VOCS	NA	NA	CTG (b)	NA	NA	0.73

Boiler Stack	NOx	205	392	SNCR (c)	65	71.8 ppmv	129
	SO2	190	507	SD/FF (d)	80	38 ppmv	47.5
	PM-10	NA	2900	FF (e)	99	29 Mg/dscm	27.5
	Lead	1.42 x 10^-3	0.012	SD/FF (d)	95	2.6 x 10^-5	<1
	CO	126	147	GCP (f)	NA	126 ppmv	138
	VOCs	37	25	GCP (f)	NA	13.4 lb/hr	23.2
	HCl	20	30	SD/FF (d)	95	1 ppmv	1.4
	Mercury	NA	NA	C/Na2S(g)	80	NA	<0.4
	Cadmium	NA	NA	SS/FF (d)	97	NA	<0.4
	Dioxins/Furans	NA	NA	SD/FF (d)	97	NA	<0.4
	Acetaldehyde	0.21	0.38	GCP (f)	NA	0.08 lb/hr	0.32
	Formaldehyde	0.19	0.23	GCP (f)	NA	0.05 lb/hr	0.2

TABLE 4-3: (Continued)

SOLID WASTE

Amount: 73.6 Tons/day
Classification: Non-hazardous
Moisture Content: 50% (Overall)
Composition (Major Components): Boiler bottom ash
Boiler fly ash
Flue gas desulfurization solids
Solids removed during wastewater treatment

WASTEWATER

Volume: 490,000 Gallons/day
Treatment Process: Anaerobic digestion followed by aerobic polishing
Effluent Quality: BOD5 - 30 Mg/l
COD - 60 Mg/l
TSS - 30 Mg/l

(a) Best Available Control Technology.
(b) Complies with Control Technology Guidelines established by the U.S. EPA
(c) Selective non-catalytic reduction.
(d) Spray dryers and fabric filters.
(e) Fabric filters.
(f) Good combustion pratices.
(g) Carbon or sodium sulfide injection.

TABLE 4-4: PROJECTED EMISSIONS FROM SCENARIO D

Feedstock: MSW
725 Bone dry tons/day
Pretreatment: Dilute Sulfuric Acid

Energy Production: None
Ethanol Production Capacity: 25 Million gallons/year

AIR EMISSIONS

SOURCE	POLLUTANT	UNCONTROLLED EMISSION		BACT ESTIMATE	ANTICIPATED REMOVAL EFFICIENCY	CONTROLLED EMISSION RATE
		ppmvd	Mg/dscm	(a)	%	Tons/Year
Fermentation Off-gases	Ethanol	57	110	CTG (b)	NA	5.07
Product and Chemical Storage	VOCs	NA	NA	CTG (b)	NA	0.63

TABLE 4-4: (Continued)

SOLID WASTE

Amount: 233 Tons/day
Classification: Non-hazardous
Moisture Content: 50% (Overall)
Composition (Major Components):Unconverted biomass (primarily lignin and carbohydrates)
Other unconverted inert materials
Gypsum (resulting from neutralization of acid used in pretreatment)
Solids removed during wastewater treatment
Solids generated during fermentation and cellulase production

WASTEWATER

Volume: 490,000 Gallons/day
Treatment Process: Anaerobic digestion followed by aerobic polishing
Effluent Quality: BOD5 - 30 Mg/l
COD - 60 Mg/l
TSS - 30 Mg/l

(a) Best Available Control Technology.
(b) Complies with Control Technology Guidelines established by the U.S. EPA

TABLE 4-5: PROJECTED EMISSIONS FROM SCENARIO E

Feedstock: Paper Sludge
108 Bone dry tons/day
Pretreatment: None

Energy Production: None
Ethanol Production Capacity: 3 Million gallons/year

AIR EMISSIONS

SOURCE	POLLUTANT	UNCONTROLLED EMISSION		BACT ESTIMATE	ANTICIPATED REMOVAL EFFICIENCY	CONTROLLED EMISSION RATE
		ppmvd	Mg/dscm	(a)	%	Tons/Year
Fermentation Off-gases	Ethanol	57	110	CTG (b)	NA	0.61
Product and Chemical Storage	VOCs	NA	NA	CTG (b)	NA	0.09

TABLE 4-5: (Continued)

SOLID WASTE

Amount: 139 Tons/day
Classification: Non-hazardous
Moisture Content: 35% (Overall)
Composition (Major Components): Mineral components of paper (clay, calcium carbonate, titanium dioxide, and fillers)
Unconverted biomass (primarily lignin)
Solids removed during wastewater treatment
Solids generated during fermentation and cellulase enzyme production

WASTEWATER

Volume: None (No net production of wastewater above that already produced by the paper mill).

(a) Best Available Control Technology.
(b) Complies with Control Technology Guidelines established by the U.S. EPA

TABLE 6-1: SUMMARY OF PHYSICAL CHARACTERISTICS

PHYSICAL CHARACTERISTICS	UNITS	AMOUNT REQUIRED (Per 10 Million Gallons/Year)	IS AMOUNT REQUIRED PROPORTIONAL TO ETHANOL PRODUCTION?
Feedstock, Weight Basis	Bone dry tons/year	100,000 to 140,000	Yes
Feedstock, Volume Basis	Cubic yards/year	300,000 to 700,000	Yes
Land	Acres	5 to 15	No
Steam	Pounds/hour	24,000 to 48,000	Yes
Electrical Power	Mega Watts (a)		
With cogeneration		0.9 to 3.5	Yes
Without cogeneration		-2.7 to -3.7	Yes
Water	Million gallons per day	0.2 to 1.1	Yes
Wastewater	Million gallons per day	0.2 to 1.1	Yes
Solid Waste, Weight Basis	Wet tons/year	7,000 to 160,000	Yes
Solid Waste, Volume Basis	Cubic yards/year	8,000 to 190,000	Yes

(a) A positive value indicates that electrical power must be purchased or obtained from off-site sources. A negative value indicates that excess electrical power is generated and is available to sell or provide to off-site sources.

TABLE 6-2: BIOMASS ETHANOL PLANT CAPITAL COSTS (a)

PLANT COMPONENT	CAPITAL COST (x $1,000)	
Pretreament		$29,090
Biological Conversion		
Cellulase Production	$3,280	
SSF	$29,260	
Pentose Conversion	$6,810	
Subtotal		$39,350
Distillation		$5,800
Power Cycle		$60,530
Other		$15,530
TOTAL		**$150,300**

(a) Based on 1994 cost projections for a 60.1 million gallons/year cellulosic biomass ethanol plant, calculated by Lynd, Elander, and Wyman.

TABLE 6-3: BIOMASS ETHANOL PLANT SENSITIVITY ANALYSIS (a)

COST CHARACTERISTIC	IMPACT/GALLON ($/Gallon) (b) (c)	ETHANOL SELLING PRICE ($/Gallon)	INTERNAL RATE OF RETURN % (d)	PAYBACK PERIOD (Years) (d)	COMMENTS
Base Case	N/A	1.18	9.7%	9.7	
Production Incentive of $0.20/Gallon	- 0.20	0.98	14.4%	8.0	
Decreased Cost of Capital (e)	- 0.15	1.03	21.2%	6.2	Lowers investment hurdle, can leverage capital to increase return on external investors risk capital
Decreased Feedstock Costs (f)	- 0.11	1.07	12.5%	8.6	Reduces production costs
Decreased Land Costs (g)	Minimal	1.18	9.7%	9.7	Small capital cost decrease
State Corporate Taxes Eliminated for 5 Years	Minimal	1.18	9.7%	9.7	No impact due to minimal tax liability in first 5 years Potential large impact on future tax liability
Low Cost Power Available (h)	+ 0.04	1.22	8.3%	10.5	Lowers capital costs, but increases production costs due to power purchases and solid waste disposal
Plant Start-up Delayed by 1 Year	+ 0.06	1.24	8.5%	10.7	Increases financing costs, lowers return on investment

(a) Based on 1994 cost projections by Lynd, Elander, and Wyman. A discussion of the financial performance of the base case ethanol plant is presented in Appendix C.

(b) Based on an internal rate of return (IRR) of 9.7% and a payback period of 9.7 years.

(c) Negative values (-) represent a decrease in the required selling price, positive values (+) represent an increase in the price.

(d) Represents an IRR and payback period necessary to achieve an ethanol production cost of $1.18/gallon.

(e) 75% of plant capital costs are assumed to be financed at a 5% interest rate.

(f) Feedstock cost is reduced from $42/BDT to $32/BDT.

(g) Land purchase costs are reduced by $1,000/acre, based on an 100-acre site.

(h) Electrical power is purchased for $.025/kW-hr and steam is purchased for $0.50/1,000 pounds. Capital and operating costs for on-site power generation facility are eliminated. Residuals generated by ethanol production are disposed of in a solid waste management facility.

TABLE 7-1: STATE ETHANOL PROCUREMENT PRACTICES

	CONNECTICUT	NEW YORK	PENNSYLVANIA
Key regulations affecting gasoline procurement.	Federal regulations	ASTM D4814-93 and D4815 NYCRR 225 and 230 (Environmental Conservation Law) NYCRR 224 (Agriculture and Markets) 40CFR Sections 80.40, .41, .82 ANSI/ASTM D975 Clean Air Act Part 80	No information provided
Key factors affecting types and amount of gasoline purchased.	Fuel requirements to meet needs of state fleets Federal regulations regarding reformulated or oxygenated fuels	Fuel requirements to meet needs of state fleets Federal regulations regarding reformulated or oxygenated fuels	No information provided

Is there a preference for alternative or clean fuels?	Per federal regulations regarding reformulated or oxygenated	Per federal regulations regarding reformulated or oxygenated No preference given to other oxygenated fuels, but it is permissible to blend ethanol as long as it meets gasoline specifications	No information provided
Plans to purchase E85 in future	None	None	No information provided
Do state rules, specifications, or policies permit procurement of E85?	Information not provided	Yes, however users of vehicles capable of using E85 are needed before purchasing could begin	No information provided
Would the state be willing to pay more for vehicle capable of using E85?	No	Cannot answer, since outside the purview of the procurement office	No, state is "leaning" toward compressed natural gas as an alternative fuel
Would the state be willing to fund the conversion of vehicles to use E85?	No	Cannot answer, since outside the purview of the procurement office	No, state is "leaning" toward compressed natural gas as an alternative fuel
Would the state be willing to fund installation of E85 fuel storage and delivery facilities?	No	Cannot answer, since outside the purview of the procurement office	No, state is "leaning" toward compressed natural gas as an alternative fuel