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Potential Air Emission Impacts of Cellulosic Ethanol Production at Seven Demonstration Refineries in the United States

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ABSTRACT

This paper reports on the estimated potential air emissions, as found in air permits and supporting documentation, for seven of the first group of precommercial or “demonstration” cellulosic ethanol refineries (7CEDF) currently operating or planning to operate in the United States in the near future. These seven refineries are designed to produce from 330,000 to 100 million gal of ethanol per year. The overall average estimated air emission rates for criteria, hazardous, and greenhouse gas pollutants at the 7CEDF are shown here in terms of tons per year and pounds per gallon of ethanol produced. Water use rates estimated for the cellulosic ethanol refineries are also noted. The air emissions are then compared with similar estimates from a U.S. cellulosic ethanol pilot plant, a commercial Canadian cellulosic ethanol refinery, four commercial U.S. corn ethanol refineries, and U.S. petroleum refineries producing gasoline. The U.S. Environmental Protection Agency (EPA) air pollution rules that may apply to cellulosic ethanol refineries are also discussed. Using the lowest estimated emission rates from these cellulosic ethanol demonstration facilities to project air emissions, EPA’s major source thresholds for criteria and hazardous air pollutants might not be exceeded by cellulosic ethanol refineries that produce as high as 25 million gal per year of ethanol (95 ML). Emissions are expected to decrease at cellulosic ethanol refineries as the process matures and becomes more commercially viable.

INTRODUCTION

Recent interest in separating biofuel production from food production¹ has caused a shift in focus in the United

IMPLICATIONS

Development of the next generation of biofuels is already underway with the recent development and operation of approximately 25 cellulosic ethanol demonstration refineries in the United States. These fledgling biofuel refineries, many funded in part by the U.S. Department of Energy, are attempting to show that the production of fuel from non-food but carbon-neutral sources is economically and technically feasible. The environmental impacts in terms of air and water are being closely watched; this paper shows that low impacts appear to be achievable.

States as well as globally from using corn grain toward the use of cellulosic material as a feedstock for ethanol production.^{2,3} In the near future, corn grain is expected to comprise only 6% of biofuel feedstock in the United States.⁴ The primary challenge in producing cellulosic ethanol is that more processing and energy are needed than with corn grain to break down the complex polymers in cellulosic material and release the cellulosic sugar so that it can be fermented and converted to ethanol. The advantage of cellulosic and other “renewable biofuels” (i.e., fuels that can be regenerated) is that these fuels may have lower net greenhouse gas (GHG) or global warming pollutant emissions in a full lifecycle analysis than the fossil fuels they replace because biofuels are made from biological material that has removed GHGs, such as carbon dioxide (CO₂), from the environment.

This paper addresses the potential air emission impacts of cellulosic ethanol production using information from seven U.S. cellulosic ethanol demonstration facilities (7CEDF) already operating or planned in the near future. These demonstration facilities range in size from 330,000 to 100 million gallons of ethanol produced per year (gal/yr). Two of the cellulosic ethanol demonstration facilities began ethanol production in the first quarter of 2009. All 7CEDF are expected to be producing ethanol by 2011. The air impacts of these demonstration facilities are primarily addressed here, but water consumption is also noted.

The average emission estimates or permit limits for these 7CEDF were also compared with permitted emission limits for four commercial U.S. corn ethanol facilities, one cellulosic ethanol demonstration facility in Canada, and one cellulosic ethanol pilot plant in the United States. In addition, the average emissions estimated for the same pollutants from U.S. petroleum refineries producing gasoline were compared with the 7CEDF. A recently published U.S. Environmental Protection Agency (EPA) hazardous air pollutant (HAP) rule that may apply to many cellulosic ethanol production facilities is discussed here along with other EPA air pollution rules potentially applicable to cellulosic ethanol facilities.

Some issues are still being debated in regard to the production and use of biofuels in general, and in regard to the net environmental benefit considering all factors, including land-use changes⁵⁻⁷; net energy used/

produced^{8–11}; impacts on the natural, agricultural, and economic resources in the full lifecycle of biofuel feedstock production,^{9,12,13} including the transportation of biomass feedstock, products, and other process materials¹⁴ and water demand^{15–17}; the fuel efficiency/energy production of ethanol versus traditional gasoline^{18,19}; and the impact on the environment, including air and water.^{10,12,15,18,20–25} This paper focuses on addressing air pollution emissions from only the refinery part of the overall ethanol production process.

BACKGROUND

In 2006, President Bush set forth a goal in an “Advanced Energy Initiative” to make cellulosic ethanol production practical and competitive by 2012.²⁶ The total biofuel production goal outlined in this energy initiative was to produce enough ethanol per year in the United States from all types of biofuel feedstocks to displace 30% or more of the country’s 2004 petroleum consumption by 2030.²⁷ The so-called “30 × 30”²⁸ goals of the Advanced Energy Initiative would require up to 60 billion gal of cellulosic ethanol by 2030, which corresponds to approximately 1 billion dry t of biomass feedstock per year—a more than 7-fold increase in production from the amount of biomass currently consumed for all bioenergy and bio-based products.²⁹ The Energy Independence and Security Act of 2007 (EISA)³⁰ actuated this initiative by requiring the national supply of renewable fuels to reach 36 billion gal by 2022, with approximately half of this amount from cellulosic biofuels.

In keeping with the EISA requirements, in February 2010, EPA revised the Renewable Fuel Standard (RFS2)³¹ that includes standards for use of cellulosic biofuels as a compliant renewable fuel. The RFS2³¹ specifies the volume of cellulosic biofuel (e.g., cellulosic ethanol) that must be used in transportation fuel each year. The cellulosic ethanol demonstration facilities discussed in this paper are a result of this new U.S. energy focus. Some of these early cellulosic ethanol demonstration facilities are recipients of funding from the U.S. Department of Energy (DOE) that directly supports these energy goals.³² The Renewable Fuels Association (RFA), considered the industry’s voice for bioethanol production in the United States and Canada and the U.S. trade association for the ethanol industry, currently cites approximately 25 cellulosic ethanol demonstration facilities planned or in development in the United States.³³

In 2007, the Biomass Program of DOE’s Office of Energy Efficiency and Renewable Energy (EERE) began funding cellulosic ethanol demonstration facilities.³⁴ The DOE believes that cellulosic ethanol can yield a greater net energy benefit than corn ethanol and result in lower lifecycle GHG emissions.³⁵ From 2005 to 2008, DOE allocated approximately \$500 million toward cellulosic biofuel production by funding commercial facilities and demonstration projects, supporting the development of fermentative organisms and enzymes, and advancing the thermochemical biofuel processes.^{36–40} DOE recently announced another \$800 million from President Obama’s Recovery Act allocated to accelerate biofuels research and

commercialization, with \$480 million for integrated pilot- and demonstration-scale biorefineries that produce advanced biofuels.⁴¹ This funding will help develop innovative conversion technologies, including the generation of more desirable catalysts and feedstock with \$20 million of the total allocated for bioethanol research.

CELLULOSIC ETHANOL PRODUCTION PROCESSES^{21,42–46}

There are many types of cellulosic materials that can be used as fuel sources, such as forestry waste (chips and sawdust from lumber mills), wood, and green yard waste (dead trees, and tree branches); leftover leaves and husks of corn plants (called “stover”) and other agricultural wastes and residues, such as from sugar cane (bagasse), beet, and grapes; grasses, such as switch grass and other energy crops of fast-growing vegetation; municipal solid waste (household garbage and paper products); industrial wastes (black liquor, a paper manufacturing byproduct); and even algae.⁴⁷

On the biochemical level, cellulosic biomass is composed mostly of cellulose, hemicellulose, and lignin. Cellulose is the most common form of carbon in biomass, accounting for 40–60% by weight of the biomass.⁴⁸ Cellulose is a complex of encapsulated sugar polymers (i.e., polysaccharides) made from glucose, a six-carbon sugar. Hemicellulose is made from various five- and six-carbon sugars and is relatively easy to hydrolyze into simple sugars as compared with cellulose, but its sugars are more difficult to ferment. Lignin is a complex polymer that provides the structural support for plants and makes up approximately 10–29% by weight of the biomass. Lignin is the material remaining after the sugars in biomass have been converted to ethanol via fermentation, which can be used to produce steam and electricity through combustion in boilers.⁴⁸ Cellulosic biofuel can be produced in a biochemical route or in a thermochemical route. The following is a brief description of each process type.

Biochemical Conversion

In a typical cellulosic ethanol refinery, the cellulosic material is delivered to the facility and stored in a feedstock storage area where any separation and physical or simple chemical pretreatment can occur. As needed, cellulosic material is withdrawn from storage, sometimes washed, and then taken into a pretreatment area where the biomass is further broken down physically, chemically, or biochemically with enzymes. Techniques are being developed to introduce bacteria into the cellulosic material while it is in the storage areas so that the breakdown of cellulosic material can start earlier in the process and result in more efficient or economical refining processes.^{49,50}

Chemical pretreatment is done using acids (e.g., sulfuric acid), bases (e.g., sodium hydroxide), organic solvents, or other chemicals such as peroxide and ammonia (NH₃). The acid-treated materials may be neutralized with lime in the tanks after acid treatment. Several proprietary cellulosic ethanol processes have been recently developed to streamline the preparation of cellulosic material for fermentation, such as a combination dilute-acid hydrolysis/lime neutralization/fermentation process,⁵¹ a concentrated-acid

hydrolysis process,⁵² and a process that converts starch to glucose without heat.⁵³

In addition to acids, enzymes (cellulases) are also used to break down the cellulose before fermentation. This process simulates the reaction in stomach ruminants of cows and sheep, where enzymes are produced by bacteria to break down the cellulose in feed grasses.^{54,55} Proprietary or genetically modified enzymes or fungi that produce other enzymes such as *Trichoderma reesei* have been developed recently that specifically target cellulosic material.^{56–58} A proprietary strain of *Clostridium (Clostridium phytofermentans)* has been developed that breaks down cellulosic material with only minor pretreatment for use in ethanol production.⁵⁹ The DOE and U.S. Department of Agriculture support research in the area of developing enzymes specifically for breaking down cellulosic material for biofuel.^{60–62}

Cellulosic sugars are converted to ethanol in the next biochemical process step using microorganisms in fermentation. Commercially available yeast derived from brewer's yeast (*Saccharomyces cerevisiae*) may be used for fermentation, or yeast may be produced on-site. Genetically modified yeasts (e.g., genetic improvements to *S. cerevisiae*) have been developed specifically for cellulosic ethanol sugars.^{63–65} The resulting mixture of ethanol and water is distilled into pure ethanol product, which is then condensed and denatured with gasoline to obtain a product that is 95% ethanol and 5% gasoline by weight. Any water and other vapors are recycled throughout the process as possible. The dewatered solids (i.e., the lignin byproduct) and other solid wastes obtained from the biochemical production process can be burned in a solid fuel boiler. Cleaned biogas from the anaerobic digestion of distillation residues can be compressed and used as on-site fuel. Most cellulosic ethanol facilities use on-site boilers for steam and process heat; in some cases, the boilers also are used for on-site electricity.

In addition to lignin, other byproducts from the biochemical cellulosic ethanol processes include methanol, gypsum ($\text{CaSO}_4 \cdot 2 \text{H}_2\text{O}$), and biomass wastes that are used as animal feed.⁶⁶ Process cooling towers are often used to provide a chilled water system and, consequently, can be a major source of water consumption by cellulosic ethanol facilities. Many cellulosic ethanol facilities have on-site wells to generate process water. Wastewater generated in the refining process can be sent to a publicly owned treatment works (POTW) or treated on-site.

Thermochemical Conversion

In the thermochemical conversion of cellulosic biomass, heat is used to gasify and catalytically convert biomass to alcohol (or other hydrocarbons) using chemicals or a combination of heat and pressure.⁴⁵ Anaerobic pyrolysis is also used as an alternative to gasification to produce fuels such as bio-oil; however, this process is not used to make ethanol.⁴³ Alternatively, the gasified cellulosic material from the thermochemical process can be distilled and fermented as in the biochemical process but with different enzymes (hydrogenases) and bacteria (aceto-genic) used for fermentation.⁶⁷

In the first stage of the thermochemical conversion process, the feedstock is broken down, primarily using

heat, and then partially oxidized or reformed with a gasifying agent (air, oxygen, or steam), which produces synthesis gas (syngas), a mixture of carbon monoxide (CO) and hydrogen (H_2) gas. The makeup of syngas will vary because of the different types of feedstocks, their moisture content, the type of gasifier used, the gasification agent, and the temperature and pressure in the gasifier. In the second and third stages, the syngas undergoes cleanup and conditioning to create a contaminant-free gas having the appropriate H_2 -to-CO ratio before the catalytic conversion step. Among the contaminants removed during cleanup/conditioning/scrubbing are tars, acid gas (chlorine, sulfur), NH_3 , alkali metals, and other particulates. Sulfur polishing reduces hydrogen sulfide (H_2S) levels, and the H_2 -to-CO ratio is adjusted using water-gas shift. In the conditioning stage, the syngas is filtered, compressed, and sent sequentially to absorption and stripping towers where CO_2 and organic compounds (e.g., benzene and toluene) are removed and are returned to the beginning of the conversion process.

In the last stage, the syngas is upgraded to fuels using a combination of heat and pressure (compression) in the presence of catalysts in a modified Fischer-Tropsch process,⁶⁸ which is the synthesis of hydrocarbons from CO hydrogenation over transition metal catalysts. The reacted gas is then cooled and distilled, and the liquid stream is separated into ethanol, methanol, some higher alcohols, and water. Alternatively, the co-products can be recycled back through the Fischer-Tropsch reactors to increase the yield of ethanol. Excess water is sent to a wastewater treatment plant on-site or at a POTW. No lignin is produced as a byproduct in a complete thermochemical pathway, but a high biomass-to-ethanol conversion rate can be achieved.²¹

Because of the high energy intensity of the thermochemical conversion process, there are few restrictions on the physical or chemical properties of the biomass feedstock used in this process. Biochemical processes can complement the thermochemical conversion process by providing residual materials for further thermochemical processing, which in turn can convert lignin-rich, but nonfermentable, material into ethanol or other fuels.⁴⁶

Fuel Use

Any ethanol production process can use recovered or waste lignin from the biochemical process as fuel in boilers and other on-site energy equipment. As stated above, lignin makes up approximately 10–29% by weight of the biomass. A biochemical cellulosic ethanol facility generates approximately 4000 t of lignin for every million gallons of ethanol produced,^{21,69,70} which is approximately 8 lb lignin generated per gallon ethanol produced or greater than 1 lb lignin per lb ethanol (1.2 lb/lb). In terms of energy, this translates to approximately 1.4 energy units from lignin for every unit of ethanol produced. Lignin has a relatively high latent heat content, similar to midgrade coal, which ranges from 9000 to 14,000 Btu/lb. Another advantage of lignin combustion is that lower air emissions are expected than with coal in terms of nitrogen oxides (NO_x) and sulfur oxides (SO_x); the latter because of the lower sulfur content of lignin as compared with coal. Sulfur has been measured to be less than

0.1% of softwood-derived lignin and 0.3% of corn stover-derived lignin.⁷¹ However, lignin combustion has higher air emissions of NO_x and SO_x as compared with natural gas. The most important attribute of burning lignin for fuel is that there is no new carbon added to the environment because the carbon emitted as CO₂ is biogenic in origin. In other words, the CO₂ emitted from lignin combustion is that which has been removed from the atmosphere by the living plants that produce lignin. The use of lignin for biorefinery energy, process heat, and steam as opposed to the use of fossil fuel is a unique and environmentally significant feature of cellulosic ethanol refineries, especially as compared with stand-alone corn ethanol refineries that burn fossil fuel.

ESTIMATED AIR EMISSIONS AND LIMITS

The 7CEDF that are discussed here are (in alphabetical order) BlueFire⁷² in California, Genera (Dupont/Danisco)⁷³ in Tennessee, Mascoma⁷⁴ in New York, POET Project Liberty⁷⁵ in Iowa, Range Fuels (Soperton)^{76–78} in Georgia, Verenium⁷⁹ in Louisiana, and Western Biomass (K.L. Process Design)⁸⁰ in Kentucky. Table 1 shows the company name, location of the facility, type of cellulosic input material (feedstock), ethanol production level, permit approval date (if applicable), and timeline for facility startup. In the discussion in this paper, the word “permit documentation” is used to represent information in permits, supporting permit documentation, or National Environmental Policy Act (NEPA) Environmental Assessments, unless otherwise noted.

For five of the 7CEDF, the emissions estimates or limits were obtained from approved permit documentation: BlueFire,⁷² Genera,⁷³ Mascoma,⁷⁴ Verenium,⁷⁹ and Western Biomass.⁸⁰ For the other two facilities, Range Fuels (Soperton)^{76,77} and POET Liberty,⁷⁵ DOE first prepared Environmental Assessments as required by the NEPA.^{81,82} One of the two facilities with a NEPA Environmental Assessment (i.e., Range Fuels) also has an approved permit,⁷⁸ whereas for POET Liberty,⁷⁵ only the NEPA Environmental Assessment was available at the time of this study because the facility completion date is too far into the future. When approved, the permit for POET Liberty will be available from the Iowa Department of Natural Resources, Des Moines, IA.⁸³

In all of the permit documentation, continuous operation (24 hr/day, 7 days/week [24 × 7]) was assumed for the cellulosic ethanol demonstration facilities. Also, if control devices were planned at the facility, the estimates of potential to emit in the permits appeared to take into account the expected performance of the control devices. Therefore, the estimated emissions or limits cited here reflect controlled emissions, where applicable. In many cases, the control efficiencies of the control devices were cited in the permits as required operating conditions; if so, the control device efficiencies are also shown here. The failure to cite control devices, emission estimating methodology, individual process unit emissions, or other process details in the permit documentation should not be considered conclusive evidence that these issues were not considered in preparing the permits for these refineries.

Both of the NEPA Environmental Assessments and some of the other facility permit documentation also reported the results of air pollution impact modeling that

used the permitted emission rates. The results of the modeling showed there were no significant impacts on air quality projected for in the surrounding area because of the estimated air emissions from the cellulosic ethanol refinery and EPA’s major pollution source thresholds for Prevention of Significant Deterioration (PSD)⁸⁴ purposes were not reached.

All of the 7CEDF discussed here except one (Range Fuels^{76–78}) use the biochemical process to produce ethanol. As shown in Table 1, various feedstocks are used. Most of the 7CEDF are located near their feedstock sources (i.e., near agricultural land or forests). The BlueFire facility in Lancaster, CA⁷² is located close to a landfill that will provide some of the municipal waste it receives to be used instead as feedstock at the cellulosic ethanol refinery. California has identified municipal waste as one of their main potential biofuel feedstocks.⁸⁵

It should be noted that the POET Liberty cellulosic demonstration facility (Iowa), which uses corn cobs for feedstock, has clarified that the corn cob residue left over after corn is harvested for food only accounts for 6% of the agricultural residue (by weight) that is usually left on the corn fields to aid in growing the next crop of corn; the remainder of the corn stover (stalks, etc.) that is not used for ethanol production comprises the bulk (94%) of the agricultural residue.⁷⁵ This illustrates that the proper selection of feedstocks enables facilities involved with ethanol production to avoid a large (negative) impact on crop residues that may be needed for maintaining farmland for food production, contrary to some criticisms of cellulosic biofuel production.

All 7CEDF have plans for on-site boilers to produce steam and process heat; in some cases, the boilers will also be used to produce on-site electricity. One facility is constructing an electricity substation on-site to avoid the need for additional transmission lines.⁷⁵ Four of the 7CEDF plan to burn lignin in their boilers (with natural gas used for startup in some cases); these boilers range in size from 13 to 267 million Btu per hour (MMBtu/hr) of steam production. Three of the 7CEDF plan to use natural gas to fuel their boilers, with the size of the boilers ranging from 9 to 42 MMBtu/hr.

The following sections present the air emissions estimates and permitted air emissions limits for the 7CEDF and the air emissions estimating methods and planned air pollution control methods cited in the permit documentation. Facility-wide and process-level emissions estimates are presented, where available.

Pollutants and Processes

The total annual estimated air emissions or permit limits for these 7CEDF address five of the six pollutants called “criteria pollutants,” namely CO, nitrogen dioxide (NO₂), particulate matter (PM), sulfur dioxide (SO₂), and ozone (through control of volatile organic compounds [VOCs]), which are regulated by EPA under the National Ambient Air Quality Standards program.⁸⁶ In some cases, EPA-designated HAP⁸⁷ and CO₂ (a GHG) emissions are also estimated. All 7CEDF had emission limits or estimates for CO, NO_x, PM, SO_x, and VOCs; six of the 7CEDF had a facility-wide emission limit for HAPs. For PM emissions, although all 7CEDF had at least one PM limit, only three

Table 1. U.S. cellulosic ethanol demonstration facility information as provided in air permits and other documentation.⁷²⁻⁸⁰

| Facility (Location) | Ethanol Production (gal/yr) | Cellulosic Feedstock | Feedstock Use Rate (t/day) | Process | Boiler Size and Fuel Source | Timeline |
|-------------------------------|-----------------------------|--|----------------------------|---|---|---|
| Range Fuels (Soperton, GA) | 100,000,000 | Timber and forest wood residue; wood-based energy crops | 2,625 (dry) | Thermochemical. Gasify then catalysis. | 267 MMBtu/hr Tail gas | Broke ground 2007. Completion after 2011. DOE Environmental Assessment, October 2007; Supplemental January 2009. Permit approved June 2007. Revised permit pending 2009. Commercial scale. Construction planned 2010; complete 2011. Design under development March 2009. Final DOE Environmental Assessment, September 2008. Demonstration plant at existing commercial corn ethanol facility. |
| POET Liberty (Emmetsburg, IA) | 25,000,000 | Corn cobs | 750 | Biochemical. Dilute acid. Bifac fractionation/separation. | 126 MMBtu/hr lignin (waste) and biogas from process | Permit for proposal to construct approved February 2009. Will utilize waste from nearby landfill. Commercial scale. Permit approved October 2006. Startup and commissioning "validation" stage, January 2009. Commercialization will follow. Demonstration plant. |
| BlueFire (Lancaster, CA) | 3,000,000 | Green yard/wood waste; landfill sorted municipal solid waste | 170 (dry) | Biochemical. Concentrated acid Arkenol process. | 80 MMBtu/hr lignin (waste) and landfill gas | Permit to construct December 2006. Began construction 2007. Started producing ethanol March 2009. Will run 1.5 yr. Pilot/demonstration plant. |
| Verenium (Jennings, LA) | 2,000,000 | Bagasse, wood chips | 140 (wet) | Biochemical. SunOpta dilute acid hydrolysis. | 9 MMBTU/hr natural gas | Construction began early 2008 and completed December 2008. Permit approved June 2008. Started producing ethanol February 2009. Demonstration plant. |
| Western Biomass (Upton, WV) | 1,580,000 | Wood waste (chips) | 96 (dry) | Biochemical. Thermomechanical shear pretreatment; Novozyme enzymes. | 13 MMBtu/hr lignin (waste) | Broke ground October 2008 with ethanol production planned end of 2009. Permit approved March 2009. Pilot scale. |
| Mascoma (Rome, NY) | 500,000 | Wood chips, switch grass, willow, etc. | 480 | Biochemical. | 17 MMBtu/hr natural gas | |
| Genera Energy (Vonore, TN) | 330,000 | Corn stover, switch grass, hardwood chips | 33 | Biochemical. Genecor (Danisco) enzymes. | 42 MMBtu/hr natural gas | |

Notes: All facilities use the biochemical process (fermentation) except Range Fuels, which uses the thermochemical process.

facilities had total PM emission estimates or limits in addition to PM less than or equal to 10 μm (PM_{10}) or PM less than or equal to 2.5 μm ($\text{PM}_{2.5}$). Three facilities had only PM_{10} emissions estimates and one facility had only total PM emissions.

In terms of HAP emissions, the following compounds were identified as emitted in measurable quantities from the 7CEDF: acetaldehyde, acetic acid, acrolein, benzene, ethyl benzene, formaldehyde, hexane, naphthalene, toluene, and xylene. In addition, NH_3 and H_2S were estimated as potentially emitted from some cellulosic biofuel refineries. Although not EPA-controlled pollutants, some states have regulations for control of air emissions of NH_3 and H_2S . H_2S can be emitted with biogas from anaerobic wastewater processes. NH_3 may be used in the pretreatment of biomass; hence, some NH_3 emissions may result from this part of the refining processes.

The VOCs that are thought to be responsible for odors from fermentation are dimethyl disulfide, dimethyl sulfide, and methyl mercaptan.⁸⁸ Wastewater treatment can generate VOCs, HAPs, methane, CO_2 , and H_2S . CO emissions are emitted from combustion processes, pretreatment and refining processes (e.g., fermentation and distillation), and molecular sieves units. Boilers generate NO_x and sometimes SO_x ; however, these pollutants are not likely to be emitted from any other part of the ethanol production facility. Cellulosic ethanol refinery boilers that use biomass or coal for fuel also generate PM of all sizes. Cooling towers also generate PM (although to a much smaller extent) from dissolved water treatment chemicals emitted in cooling water entrained in the airstream that is carried out of the tower through the induced draft fan stack as "drift" PM.

Three of the 7CEDF had CO_2 emissions estimates that were provided for information purposes only and not used to establish any permit limits. The sources of CO_2 were estimated to be primarily from fuel combustion (boilers). In some cases, process CO_2 emissions were also estimated from the liberation of CO_2 during fermentation of glucose and other sugars to ethanol in the biochemical pathway and from gasification in the thermochemical pathway.⁴⁵ Only one of the three facilities (POET Liberty,⁷⁵) estimated process and combustion CO_2 , in which approximately 25% of the CO_2 was estimated to be from the refinery processes and the remainder from boilers. Negligible amounts of nitrous oxide (N_2O) and methane, both GHGs, are thought to be emitted in ethanol production from biomass,^{42,45} although methane also can be emitted in measurable quantities from anaerobic wastewater treatment units along with CO_2 if the gases are not collected or used as fuel.

For the two cellulosic ethanol facilities with NEPA Environmental Assessments (Range Fuels^{76,77} and POET Liberty⁷⁵), the emission estimates were only facility-wide and were not provided at the process level in the documentation. For the other five cellulosic ethanol demonstration facilities, the permit emission limits were also based on the individual pollutant, the process unit, or both.

The process units with emission estimates or control device performance requirements in the permit documentation were mostly grouped into seven process areas:

(1) material receiving, handling, and storage; (2) refining processes (fermentation/distillation); (3) liquid storage; (4) product loading (which also included roadway emissions from vehicle traffic); (5) fugitive leaks; (6) boilers and cooling towers; and (7) wastewater treatment. For the purposes of this analysis, boilers and cooling towers have been combined into one process area; the only pollutant expected from cooling towers is PM, whereas boilers may have PM, CO , NO_x , and SO_x emissions depending on the fuel type and composition.

"Potential-to-Emit" Methodology

In most cases, the permitted emission limits for the 7CEDF were based on estimates of the potential to emit that were documented in the permit documentation. Table 2 shows the emission estimating methods cited in the permit documentation of the 7CEDF at the process-unit level where available. The emission estimating procedures cited in the permit documentation for the 7CEDF include the following:

- EPA predictive models, such as TANKS,⁸⁹ WATER9,⁹⁰ and Assessment System for Population Exposure Nationwide (ASPEN)⁹¹
- Source test at a particle board feedstock dryer
- EPA's AP-42 (Compilation of Emission Factors)⁹²
- EPA's SPECIATE (2002)⁹³ database of speciation profiles
- Facility experience with similar unit performance and current unit design
- EPA guidance documents (e.g., for leak estimating⁹⁴)
- Permits for similar units
- Source tests at a related operation⁹⁵
- Literature⁹⁶⁻⁹⁸
- Mass balance calculations
- Engineering judgment

No quality assessments were performed in the work reported here in regard to the emissions estimating procedures found in the permit documentation of the 7CEDF. If the quality of the emission estimating methods were to be assessed for future permitting efforts at cellulosic ethanol production facilities, the suitability of an emission factor to the process being estimated (in this case, cellulosic ethanol production) would be as important to the quality of the final emissions estimate as the quality of the data used in developing the estimating method. In other words, a "good" emission factor or tool that is used to estimate the emissions of a process that is not very similar to the process for which the emission factor was developed may not be a better emission estimate than an emission factor developed with "lower quality" data for the same process. In addition, because of the wide variety in feedstocks used, the variation in actual emissions among cellulosic ethanol facilities may be intrinsically high. Since most of the state permits require emissions testing in the first year of operation, better estimates of the potential emissions will be possible soon after the facilities start normal operation.

Air Pollution Control Methods

Various types of air pollution control equipment are in place or planned for the 7CEDF. Table 3 shows the control

Table 2. Emissions estimating methods cited in permit documentation of the 7CEDF.⁷²⁻⁸⁰

| Facility ^b | Emissions Estimating Methods Cited ^a by Process Unit | | | | | | | |
|--------------------------|---|--|--|---|---------------------------------------|---------------------------------------|---------------------------------------|-----------------------------|
| | Ethanol Production (gal/yr) | Material Receiving, Handling, and Storage | Refinery | Liquid Storage | Product Loading | Fugitive Leaks | Boilers and Cooling Towers | Wastewater Treatment |
| Range Fuels ^b | 100,000,000 | | | Emission factors, mass balance, engineering judgment, and source tests ^c | | | | |
| POET Liberty | 25,000,000 | Source test (dryer), EPA AP-42, mass balance | EPA AP-42 | Mass balance | Mass balance | Emission factors from EPA rule (HON) | Mass balance | No emission estimates |
| BlueFire | 3,000,000 | | | | | | | EPA WATER9 model, EPA AP-42 |
| Verenium | 2,000,000 | EPA AP-42; other permit | EPA WATER9, FATE models; literature; other permits | EPA TANKS model and SPECIATE database | EPA AP-42 | EPA VOC Leak Estimating guidance | EPA AP-42 | EPA WATER9 model, EPA AP-42 |
| Western Biomass | 1,580,000 | Emission estimating methods not cited | Emission estimating methods not cited | Emission estimating methods not cited | Emission estimating methods not cited | Emission estimating methods not cited | Emission estimating methods not cited | No emission estimates |
| Mascoma | 500,000 | EPA AP-42; EPA ASPEN model; mass balance | EPA ASPEN model and mass balance | EPA TANKS model | EPA TANKS model | No emission estimates | EPA AP-42 | EPA TANKS model |
| Genera Energy | 330,000 | Mass balance; engineering judgment | EPA AP-42, material balance | No emission estimates | Engineering judgment | No emission estimates | EPA AP-42 | No emission estimates |

Notes: ^aReferences: EPA AP-42⁹²; ASPEN model⁹¹; TANKS model⁸⁹; FATE model⁹⁷; SPECIATE database⁹³; VOC Leak Estimating guidance⁹⁵; HON (40 CFR, Part 63, Subparts F, G, H, I)¹³¹. ^bAll facilities use the biochemical process (fermentation) except Range Fuels, which uses the thermochemical process. ^cTotal facility emission estimates only, as provided by DOE.

Table 3. Control methods planned for the 7CEDF by process and pollutant.⁷²⁻⁸⁰

| Facility ^b (fuel used) | Ethanol Production (gal/yr) | Air Pollutants and Control Methods or Devices (and Control Efficiency) by Process Unit ^a | | | | | | |
|---------------------------------------|--------------------------------|---|--|---|--|---------------------------------|---|--|
| | | Material Receiving, Handling, and Storage | Refinery | Liquid Storage | Transportation and Loading ^c | Fugitive Leaks | Boilers and Cooling Towers | Wastewater Processes |
| Range Fuels ^b (biomass) | 100,000,000 | PM: filtration, water spray | CO: catalytic oxidizers | VOCs/HAPs: internal floating roof tanks | VOCs/HAPs: flares | No control cited | CO: catalytic oxidizers; NO _x : SCR | No control cited |
| POET Liberty (biomass) | 25,000,000 | PM: baghouse; VOC/HAP: wet scrubber (95%/50%) | VOCs/HAPs: wet scrubber and thermal oxidizer (98%) | VOCs/HAPs: internal floating roof | PM: pave roads, 10-mi/hr limit, maintenance; VOC: flares | No control cited | PM (SO ₂): ESP (with dry injection); PM: high-efficiency mist eliminator (cooling tower) | CO ₂ : compression (for fuel); H ₂ S: scrubber |
| BlueFire (biomass) | 3,000,000 | PM: baghouse | VOCs/HAPs: vapor recovery/scrubber | VOCs/HAPs: phase I vapor recovery nozzles | VOCs/HAPs: phase I vapor recovery nozzles | No control cited | PM: baghouse, design (cooling tower); NO _x : SNCR with NH ₃ ; SO ₂ : limestone | No control cited |
| Verenium (natural gas) | 2,000,000 | PM: baghouse (99%) | VOCs/HAPs: wet scrubber (98%) | VOCs/HAPs: internal floating roof | VOCs: flare (98%) | VOCs: leak detection and repair | NO _x : low-NO _x burners; operating hour limit (both) | VOCs: flare |
| Western Biomass (biomass) | 1,580,000 | No control cited | VOCs/HAPs: emission limit VOCs 7 t/yr; HAPs 1.7 t/yr | No control cited | PM dust suppression (water and chemical) | No control cited | No control cited | No control cited |
| Mascoma (natural gas) | 500,000 | PM: enclosed building (98%); VOC: wet scrubber (90%) | VOC: wet scrubber (90%), leak detection and repair | No control cited | No control cited | No control cited | No control cited | No control cited |
| Genera Energy (natural gas) | 330,000 | No control cited | VOCs/HAPs: thermal oxidizer (98%); NH ₃ : sulfur acid packed scrubber (98%) | No control cited | No control cited | No control cited | NO _x : low NO _x burners (50%) | No control cited |

Notes: ^aPercentages in parentheses are the control device efficiencies provided in the permit documentation. ^bAll facilities use the biochemical process (fermentation) except Range Fuels, which uses the thermochemical process. ^cThis category includes PM emissions from roadways due to vehicle traffic but does not include vehicle tailpipe emissions. ESP = electrostatic precipitator, SCR = selective catalytic reduction, SNCR = selective noncatalytic reduction.

devices or control methods planned for each cellulosic ethanol demonstration facility, by process unit where available, with any control efficiencies noted from the permit documentation. The amount of emissions control cited in the permit documentation of these 7CEDF varied by facility and by process unit and ranged from very efficient control devices (with >90% control efficiency) to no control device cited at all.

All 7CEDF had plans to control at least one pollutant from the refining process (fermentation/distillation); for six of the 7CEDF, the pollutants were VOCs (HAPs). For the seventh facility, Range Fuels,⁷⁶⁻⁷⁸ which uses a thermochemical process, the control methods cited in the permit documentation were only for CO from the refining operations. Four of the 7CEDF will burn lignin in their boilers; the remaining three plan to use natural gas as fuel, as shown in Table 3.

Air Emissions Estimates

Table 4 shows the permitted emission estimates or limits for air pollutants from the 7CEDF. These emission estimates or limits were facility-wide, by individual process units, or both. All facilities had estimates or limits for CO, NO_x, PM, SO_x, and VOCs. Six of the 7CEDF had facility-wide emission estimates or limits in addition to VOCs; three of the six also had individual HAP estimates or limits. All facilities had at least one PM emission estimate or limit as total PM (or PM ≤ 30 μm), PM₁₀, or PM_{2.5}, but only three facilities estimated emissions for more than one size of PM, and no facility estimated emissions estimates or limits for all three PM sizes. From the permit documentation, it appeared that the emission estimates or limits took into account the level of control expected from the planned control devices or techniques.

It should be noted that these early demonstration cellulosic ethanol biorefineries are expected to be less efficient and produce greater emissions and waste streams than facilities with an optimized design from a more mature technology.⁹⁹ The variation in CO₂ emission estimates seen among the estimates from the refining process is likely to be primarily due to differences in the estimated efficiency of the combustion units that is incorporated into the CO₂ emission factors and may not be real variations in emissions.

The air emissions are shown in two sets of units. The first set is annual emissions in tons per year (t/yr) that were cited as annual emissions in the permit documentation or extrapolated to annual assuming continuous (24 × 7) operation. The second set of units is estimated or allowable emissions normalized to ethanol production, in pounds of pollutant per 1000 gal of ethanol produced (lb/1000 gal).

Table 4 also shows an average emission level for each pollutant developed from a straight average of the permit estimates or limits for the 7CEDF. These average emissions include emissions estimates or limits for facilities with and without air controls planned for some or all of their process areas. However, the averages are based on the currently expected operation of the 7CEDF.⁴⁵ Note

that the average PM₁₀ emission rate for the 7CEDF of 7 lb/1000 gal ethanol excludes the relatively high normalized PM₁₀ value for Genera Energy⁷³ of 115 lb/1000 gal, which is the result of the relatively high permitted high cooling tower emissions rate of 4 lb/hr (or 17 t/yr). The annual PM₁₀ emission rate for Genera Energy⁷³ is moderate compared with the other cellulosic ethanol demonstration facilities, where the average PM₁₀ annual emissions are 44 t/yr; however, when the PM₁₀ emissions at Genera Energy⁷³ are normalized to the relatively small amount of ethanol produced (330,000 gal), the normalized emission rate is much higher than the other six demonstration facilities, which ranged from 3 to 15 lb/1000 gal ethanol.

Tables 5 and 6 show emission estimates or limits of VOCs and PM, respectively, for five of the 7CEDF by individual process areas as available in the permits. As noted above, two facilities with DOE Environmental Assessments (Range Fuels⁷⁶⁻⁷⁸ and POET Liberty⁷⁵) had only facility-wide estimates and did not have process-level estimates or limits. For simplicity in the case of multiple PM emission sizes, only the PM₁₀ emission estimates or limits are shown in Table 6 if limits for other PM sizes were also available. For the two cellulosic ethanol demonstration facilities (Mascoma⁷⁴ and Range Fuels⁷⁶⁻⁷⁸) that did not have PM₁₀ emissions or limits, only total PM emission estimates or limits are shown in Table 6. The emissions estimates or limits for VOCs and PM₁₀ for an "average" process were developed from a simple straight average of the available data and are shown in Tables 5 and 6 in units of t/yr and lb/1000 gal ethanol. On the basis of the above estimates, the relative contribution of each process to the total facility VOC and PM emissions can be seen. As discussed above, the PM₁₀ average on a normalized lb/1000 gal basis does not include the relatively high PM₁₀ emission rate permitted for the cooling towers at Genera Energy.⁷³

Best Expected Air Emission Rates

An analysis was performed using the best emission rate from the six cellulosic ethanol demonstration facilities that use the biochemical process to predict emissions at various levels of cellulosic ethanol production. Using the lowest emission rate for each pollutant, air emissions were predicted for various levels of ethanol, ranging from 100,000 gal/yr to 100 million gal/yr ethanol produced. This analysis showed that the major source threshold of 100 t/yr of criteria pollutant emissions for chemical manufacturing facilities (as per the EPA PSD⁸⁴ limits) and the major source threshold for HAPs (where a major source is defined to be emissions ≥10 t/yr or ≥25 t/yr, for any individual or total HAPs, respectively) might not be triggered at production levels as high as 25 million gal/yr. This level of emissions reflects the use of control devices or control methods on most major process units; however, more data are needed to determine the significance of this estimated production level limit. The details of this analysis are shown in the online supporting information (published at http://secure.awma.org/onlinelibrary/samples/10.3155-1047-3289.60.9.1118_supplmaterial.pdf).

Table 4. Estimated air emissions or limits from the 70EDF.⁷²⁻⁸⁰

| Facility ^a /Data | Ethanol Production (gal/yr) | Air Pollutant | | | | | | | | | | | Total HAPs/ VOCs (%) |
|---|-----------------------------|---------------|------------------|-------------------|-----------------|-----------------|-----|-----------------|------|------------|---------------------------|---------------------|-------------------------|
| | | PM Total | PM ₁₀ | PM _{2.5} | SO _x | NO _x | CO | CO ₂ | VOCs | Total HAPs | Acetaldehyde ^b | Hexane ^b | |
| Estimated emissions (t/yr) | | 98 | - | 64 | 13 | 96 | 92 | 866,875 | 80 | 18 | - | 6.2 | 23 |
| Range Fuels | 100,000,000 | 183 | 182 | - | 108 | 167 | 210 | 279,450 | 51 | - | - | - | |
| POET Liberty | 25,000,000 | - | 13 | - | 22 | 24 | 22 | 6,123 | 24 | 5.5 | - | 23 | |
| BlueFire | 3,000,000 | - | 3.3 | - | 0.19 | 13 | 5.5 | - | 18 | 0.78 | 0.083 | 3.7 | |
| Verenium | 2,000,000 | - | 2.6 | - | 5.6 | 4.7 | 4.7 | - | 17 | 3.0 | - | 17 | |
| Western Biomass | 1,600,000 | 5.8 | - | - | 0.046 | 16 | 6.3 | - | 23 | 4.1 | - | 17 | |
| Mascoma | 500,000 | 3.3 | - | - | 0.12 | 11 | 17 | - | 23 | 1.6 | - | 7.1 | |
| Genera Energy | 330,000 | - | 19 | - | - | 47 | 51 | 384,149 | 34 | 5.5 | 3.1 | 15 | |
| Average ^c | 20,000,000 | 73 | 44 | 64 | 21 | 5.6 | 4.7 | 6,123 | 17 | 0.78 | 0.083 | 4 | |
| Minimum | 330,000 | 3.3 | 2.6 | 64 | 0.05 | 167 | 210 | 866,875 | 80 | 4.1 | 6.2 | 23 | |
| Maximum | 100,000,000 | 183 | 182 | 64 | 108 | 167 | 210 | 866,875 | 80 | 4.1 | 6.2 | 23 | |
| Estimated emissions (lb/1000 gal ethanol) | | 2.0 | - | 1.3 | 0.25 | 1.9 | 1.8 | 17,338 | 1.6 | 0.36 | 0.12 | 23 | |
| Range Fuels | 100,000,000 | 15 | 15 | - | 8.6 | 13 | 17 | 22,356 | 4.1 | - | - | - | |
| POET Liberty | 25,000,000 | - | 8.3 | - | 15 | 16 | 15 | 4,082 | 16 | 3.7 | - | 23 | |
| BlueFire | 3,000,000 | - | 3.3 | - | 0.19 | 13 | 5.5 | - | 18 | 0.78 | 0.08 | 3.7 | |
| Verenium | 2,000,000 | - | 3.3 | - | 7.0 | 7.0 | 5.9 | - | 22 | 3.8 | - | 17 | |
| Western Biomass | 1,600,000 | 7.3 | - | - | 0.18 | 62 | 25 | - | 93 | 16 | - | 17 | |
| Mascoma | 500,000 | 13 | - | - | 0.75 | 68 | 103 | - | 138 | 10 | - | 7.1 | |
| Genera Energy | 330,000 | - | 115 | - | 4.5 | 26 | 25 | 14,592 | 42 | 5.8 | 0.10 | 15 | |
| Average ^c | 20,000,000 | 9.2 | 7.4 ^d | 1.3 | 0.18 | 1.9 | 1.8 | 4,082 | 1.6 | 0.36 | 0.08 | 3.7 | |
| Minimum | 330,000 | 2.0 | 3.3 | 1.3 | 15 | 68 | 103 | 22,356 | 138 | 16 | 0.12 | 23 | |
| Maximum | 100,000,000 | 15 | 15 ^d | 1.3 | 7 | 7 | 7 | 22,356 | 138 | 16 | 0.12 | 23 | |
| Number facilities used | | 4 | 4 | 1 | 7 | 7 | 7 | 3 | 7 | 6 | 2 | 6 | |

Notes: ^aAll facilities use the biochemical process (fermentation) except Range Fuels, which uses the thermochemical process. ^bAcetaldehyde and hexane are HAPs. ^cCalculated as a straight average of the data, except as noted. ^dNote that the PM₁₀ "average" and "maximum" in lb/1000 gal do not include the PM₁₀ emissions from the cooling tower at Genera Energy. This permitted emission rate for the PM₁₀ from the cooling tower at Genera Energy was relatively high (114 lb/1000 gal) and was not consistent with the PM₁₀ emission rates from the other facilities or the other processes at the Genera Energy refinery.

Table 5. Estimated VOC emissions, by process unit, for the 7CEDF.^{a72-80}

| U.S. Cellulosic Ethanol Demonstration Refinery | | | | | | | | | | |
|--|--------------------------|--------------|----------|----------|-----------------|---------|---------------|--------------|-----------------------|----------------------------|
| Process Unit/Data | Range Fuels ^b | POET Liberty | BlueFire | Verenium | Western Biomass | Mascoma | Genera Energy | Unit Average | Unit Percent of Total | Number Facilities Averaged |
| Estimated emissions (t/yr) | | | | | | | | | | |
| Feedstock receiving, handling, and storage | - | - | 17 | 1.0 | 2.0 | 5.4 | 15 | 8.1 | 35 | 5 |
| Refining process | - | - | 0.73 | 9.1 | 7.3 | 17 | 1.2 | 7.0 | 30 | 5 |
| Product and fuel storage | - | - | 0.18 | 0.43 | 0.50 | 0.69 | - | 0.45 | 1.9 | 4 |
| Product loading | - | - | 0.17 | 0.27 | 3.1 | - | 5.3 | 2.2 | 9.5 | 4 |
| Fugitive leaks | - | - | 1.6 | 6.6 | 4.2 | - | - | 4.1 | 18 | 3 |
| Boilers and cooling towers | - | - | 4.1 | 0.65 | 0.30 | 0.42 | 1.0 | 1.3 | 5.6 | 5 |
| Wastewater treatment | - | - | - | 0.27 | - | 0.16 | - | 0.22 | 0.92 | 2 |
| Total plant emissions | 80 | 51 | 24 | 18 | 17 | 23 | 23 | 34 | NA | 7 |
| Estimated Emissions (lb/1000 gal ethanol) | | | | | | | | | | |
| Feedstock receiving, handling, and storage | - | - | 11 | 0.87 | 2.5 | 22 | 92 | 26 | 42 | 5 |
| Refining process | - | - | 0.48 | 8.2 | 9.2 | 66 | 7.2 | 18 | 30 | 5 |
| Product and fuel storage | - | - | 0.12 | 0.39 | 0.63 | 2.7 | - | 0.97 | 1.6 | 4 |
| Product loading | - | - | 0.11 | 0.24 | 3.9 | - | 32 | 9.2 | 15 | 4 |
| Fugitive leaks | - | - | 1.1 | 6.0 | 5.3 | - | - | 4.1 | 6.8 | 3 |
| Boilers and cooling towers | - | - | 2.8 | 0.59 | 0.38 | 1.7 | 6.0 | 2.3 | 3.7 | 5 |
| Wastewater treatment | - | - | - | 0.24 | - | 0.6 | - | 0.45 | 0.74 | 2 |
| Total plant Emissions | 2 | 4 | 16 | 18 | 22 | 93 | 138 | 42 | NA | 7 |
| Percent VOCs that are HAPs | 23 | - | 23 | 4.1 | 17 | 17 | 7.1 | 15 | NA | 6 |
| Ethanol production (gal/yr) | 100M | 25M | 3M | 2M | 1.6M | 0.5M | 0.33M | NA | NA | NA |

Notes: ^aData not provided are indicated in this table by -. ^bAll facilities use the biochemical process (fermentation) except Range Fuels, which uses the thermochemical process. NA = not applicable, M = million.

Table 6. Estimated PM emissions, by process unit, for the 7CEDF.^{a,72-80}

| Process Unit/Data | Cellulosic Ethanol Demonstration Refinery and PM Species | | | | | | | | | | Number Facilities Averaged PM ₁₀ |
|--|--|-------------------------------|---------------------------|---------------------------|----------------------------------|------------------|--------------------------------|---|---|----|---|
| | Range Fuels ^b PM Total | POET Liberty PM ₁₀ | BlueFire PM ₁₀ | Verenium PM ₁₀ | Western Biomass PM ₁₀ | Mascoma PM Total | Genera Energy PM ₁₀ | Average ^{c,d} PM ₁₀ | Unit Percent ^{c,d} of Total PM ₁₀ | | |
| Estimated emissions (t/yr) | | | | | | | | | | | |
| Feedstock receiving, handling, and storage | - | - | 0.34 | 0.29 | 0.80 | 1.3 | - | 0.47 | 4.6 | 3 | |
| Refining process | - | - | - | - | - | - | 0.16 | 0.16 | 1.6 | 1 | |
| Product and fuel storage | - | - | - | - | - | - | - | - | - | - | |
| Product loading | - | - | - | 1.9 | 0.60 | - | - | 1.3 | 12 | 2 | |
| Fugitive leaks | - | - | - | - | - | - | - | - | - | - | |
| Boilers and cooling towers ^c | - | - | 12 | 1.1 | 1.2 | 2.0 | 19 | 8.3 | 81 | 4 | |
| Wastewater treatment | - | - | - | 0.0022 | - | - | - | 0.0022 | 0.022 | 1 | |
| Total plant emissions | 98 | 182 | 13 | 3.3 | 2.6 | 3.3 | 19 | 44 | NA | 5 | |
| Estimated emissions (lb/1000 gal ethanol) | | | | | | | | | | | |
| Feedstock receiving, handling, and storage | - | - | 0.22 | 0.29 | 1.0 | 5.3 | - | 0.51 | 7.9 | 3 | |
| Refining process | - | - | - | - | - | - | 1.0 | 1.0 | 16 | 1 | |
| Product and fuel storage | - | - | - | - | - | - | - | - | - | - | |
| Product loading | - | - | - | 1.9 | 0.76 | - | - | 1.3 | 21 | 2 | |
| Fugitive leaks | - | - | - | - | - | - | - | - | - | - | |
| Boilers and cooling towers ^c | - | - | 8.1 | 1.1 | 1.5 | 7.9 | 114 | 3.6 | 56 | 3 | |
| Wastewater treatment | - | - | - | 0.0022 | - | - | - | 0.0022 | 0.035 | 1 | |
| Total plant emissions | 2.0 | 15 | 8.3 | 3.3 | 3.3 | 13 | 115 | 7.4 | NA | 5 | |
| Ethanol production (gal/yr) | 100M | 25M | 3M | 2M | 1.6M | 0.5M | 0.33M | NA | NA | NA | |

Notes: ^aData not provided are indicated in this table by -. ^bAll facilities use the biochemical process (fermentation) except Range Fuels, which uses the thermochemical process. ^cOnly PM₁₀ emissions or limits are included in the averages shown; for facilities without PM₁₀ emissions or limits, total PM emissions are shown but not included in the PM₁₀ average. ^dThe "Average PM₁₀" in lb/1000 gal and the "Unit Percent of Total PM₁₀" in lb/gal do not include the PM₁₀ emissions from the cooling tower at Genera Energy. The permitted emission rate for PM₁₀ from the cooling tower at Genera Energy was relatively high (114 lb/1000 gal) and not consistent with the PM₁₀ emission rates from the other six cellulosic ethanol demonstration facilities or the other processes at the Genera Energy refinery. NA = not applicable, M = million.

COMPARISON TO U.S. CELLULOSIC ETHANOL PILOT FACILITY

The average emission estimates or limits for CO, NO_x, PM, SO_x, VOCs, HAPs, and CO₂ from the 7CEDF were compared with similar permit data from a cellulosic ethanol pilot plant of POET, Inc.¹⁰⁰ The POET pilot facility is located in South Dakota and is owned by the same company that operates one of the 7CEDF (POET Project Liberty in Iowa); the POET pilot facility is also colocated with one of POET's corn ethanol facilities. The POET pilot cellulosic ethanol facility produces 30,000 gal/yr ethanol and uses corn cobs in a biochemical production process, as in POET's Project Liberty facility in Iowa. The POET pilot facility has a lignin-fired boiler that is rated at 126 MMBtu/hr, which is the same size and uses the same biofuel as the boiler at the POET Project Liberty demonstration facility. The POET pilot facility also uses an anaerobic digester for the wastes. The permit for the pilot POET facility was approved in April 2008.¹⁰⁰ Startup of the POET pilot facility began in late 2008, with the first ethanol produced in January 2009. (The POET Project Liberty cellulosic ethanol demonstration plant in Iowa is not scheduled to complete construction until 2011.⁷⁵) The emission estimating techniques and controls used at the POET pilot facility are similar to those for the POET Project Liberty facility; these are described in more detail in the online supporting information.

Table 7 shows the average estimated emissions or limits from the 7CEDF as compared with the POET pilot facility as well as compared with the POET Project Liberty cellulosic ethanol demonstration facility in Iowa. From Table 7 it can be seen that the smaller POET pilot facility emits much less than its own demonstration facility on an annual (t/yr) basis, as well as much less than the average of all 7CEDF, as expected. The emissions levels for the POET pilot facility, which ranged from 1 to 12 t/yr for criteria pollutants (and 0.1 t/yr for HAPs), are well below the 100-t/yr major source level for chemical manufacturing facilities for PSD⁸⁴ purposes. However, the POET pilot facility has higher normalized emission rates, on a lb/1000-gal ethanol basis, for all pollutants except NO_x and CO. These high normalized emission rates for the pilot facility are not surprising because of the inefficiencies in operating a much smaller facility with a new technology.

COMPARISON TO CANADIAN CELLULOSIC ETHANOL DEMONSTRATION FACILITY

The average emission estimates or limits for CO, NO_x, PM, SO_x, VOCs, HAPs, and CO₂ from the 7CEDF were compared with similar permit data from a Canadian cellulosic ethanol demonstration facility. Iogen Corporation (Iogen)^{88,101} has one of the first cellulosic ethanol demonstration plants in Canada in Ottawa, Ontario that is designed to produce 1 million gal/yr ethanol. The Iogen Ottawa plant delivered its first ethanol shipment to Royal Dutch Shell in September 2008.¹⁰²

Canada has an indigenous supply of potential biomass feedstocks for bioethanol production, the key ones including forestry waste, corn stover, and cereal grain straw. Environment Canada²¹ estimated that the amount of bioethanol that could be produced from the cellulosic feedstocks in Canada is in the following ranges: 250–500 million

Table 7. Comparison of estimated emissions between U.S. and Canadian cellulosic ethanol demonstration facilities and U.S. pilot plant.

| Facility (Location)/Type | Ethanol Production (gal/yr) | Air Pollutant ^a | | | | | | | | | | | | |
|--|-----------------------------|----------------------------|------------------|-------------------|-----------------|-----------------|------|-----------------|-----|-----------|--------------|---------------------|---|-----|
| | | PM Total | PM ₁₀ | PM _{2.5} | SO _x | NO _x | CO | CO ₂ | VOC | Total HAP | Acetaldehyde | Total HAPs/VOCs (%) | | |
| Estimated emissions (t/yr) | | 1.6 | 1.4 | — | 12 | 0.10 | 0.10 | — | 1.4 | 0.10 | — | — | — | 7.1 |
| POET (South Dakota) pilot | 30,000 | | | | | | | | | | | | | |
| POET Liberty (Iowa) demonstration ^b | 25,000,000 | 183 | 182 | — | 108 | 167 | 210 | 279,450 | 51 | — | — | — | — | — |
| Average 7CEDF ^c | 19,000,000 | 73 | 44 | 64 | 21 | 47 | 51 | 384,149 | 34 | 5.5 | 1.6 | — | — | 15 |
| Iogen (Canada) demonstration | 1,000,000 | 4.2 | — | — | 0.17 | 29 | 24 | 40,401 | 10 | 9.5 | 0.038 | — | — | 97 |
| Estimated emissions (lb/1000 gal ethanol) | | 107 | 93 | — | 827 | 6.7 | 6.7 | — | 93 | 6.7 | — | — | — | 7.1 |
| POET (South Dakota) pilot | 30,000 | | | | | | | | | | | | | |
| POET Liberty (Iowa) demonstration ^b | 25,000,000 | 15 | 15 | — | 8.6 | 13 | 17 | 22,356 | 4.1 | — | — | — | — | — |
| Average 7CEDF ^c | 19,000,000 | 9.2 | 7.4 ^e | 1.3 | 4.5 | 26 | 25 | 14,592 | 42 | 5.8 | 1.0 | — | — | 15 |
| Iogen (Canada) demonstration | 1,000,000 | 8.0 | — | — | 0.33 | 55 | 46 | 76,459 | 19 | 18 | 0.072 | — | — | 97 |

Notes: ^aData not provided are indicated in this table by —. ^bPOET Liberty is also included in the average of the 7CEDF and is shown separately in this table to compare to POET's pilot facility located in another state. ^cThe average PM₁₀ emission rate for the 7CEDF does not include the PM₁₀ value for Genera Energy at 115 lb/1000 gal, which is based on a relatively high permitted cooling tower emissions rate considering the size of the facility and is not reflective of the PM₁₀ emission rates from the other cellulosic facilities or the other processes at the Genera Energy refinery.

gal/yr from corn stover, 500-1600 million gal/yr from wheat straw, and 1600 million gal/yr from forest residues. Environment Canada reported that the Canadian provinces with the greatest supplies of feedstock include Quebec (forestry residue and corn stover), Ontario (forestry residue, corn stover, and wheat straw), Manitoba and Saskatchewan (wheat straw), Alberta (forestry residue and wheat straw), and British Columbia (forestry residue).²¹

At Iogen's cellulosic ethanol facility in Ottawa, wheat straw (and potentially oat and barley straw and other agricultural residues) is used at a rate of 40 t/day in a biochemical process to produce approximately 1 million gal/yr of ethanol. Iogen's Ottawa facility has two boilers fueled by natural gas with a total power capacity of 34 MMBtu/hr. Table 7 shows the average estimated air emissions or limits for the Iogen cellulosic ethanol refinery in Ottawa, Canada.¹⁰¹ The methods used to estimate emissions for Iogen's Ottawa facility included EPA's AP-42⁹² for combustion sources and mass balance and control device manufacturer's specifications for VOC/HAP and PM sources. The air emission control devices or methods at Iogen's cellulosic ethanol facility include a fermentation vent scrubber, a packed bed scrubber on other refining process units, and a baghouse in the feedstock receiving, handling, and storage area.

Emissions of CO₂ from the refinery process at Iogen's Ottawa facility were estimated from fermentation chemistry using a 1.8:1 CO₂-to-glucose ratio, which is slightly lower than the 2:1 stoichiometric ratio. The use of this lower rate was to account for the breakdown of sugars for cell production and byproducts. In the permit documentation, Iogen's refinery process CO₂ was estimated to comprise 7% of the total estimated CO₂ facility emissions, which included fuel combustion sources.⁸⁸

The estimated emissions from the Iogen facility, shown in Table 7, are lower than the average of the 7CEDF for all pollutants, except for HAPs, for which the Canadian level is similar to the 7CEDF (9.5 t/yr HAPs for Iogen and 6 t/yr HAPs for the average of the United States). The estimated emissions from the Iogen facility for all pollutants are also below the 100-t/yr PSD⁸⁴ major source threshold for U.S. chemical manufacturing facilities.

On a normalized lb/1000-gal ethanol basis, the estimated emissions or limits of the Canadian cellulosic ethanol facility are approximately the same as the U.S. average of 7CEDF, as seen in Table 7. The exception is the estimated CO₂ emissions for Iogen, which, at approximately 76,500 lb/1000 gal ethanol, are 3 times higher than the 7CEDF average of approximately 14,600 lb/1000 gal ethanol and over twice as high as the highest estimated CO₂ emissions among the 7CEDF at 22,400 lb/1000 gal ethanol. However, this difference may be due to the choice of CO₂ emission factors, which incorporate an estimate of the energy efficiency of the boilers and may not reflect truly different CO₂ emissions than those from the 7CEDF boilers.

COMPARISON TO COMMERCIAL CORN ETHANOL FACILITIES

The average estimated emissions for CO, NO_x, PM, SO_x, VOCs, HAPs, and CO₂ from the 7CEDF were also compared with similar permit data for four commercial U.S.

corn ethanol facilities that were selected randomly from available permit documentation. These four commercial corn ethanol refineries were Abengoa Bioenergy of Illinois, LLC., Inc., in Madison, IL¹⁰³; Abengoa Bioenergy Corporation in York, NE¹⁰⁴; Lifeline Foods, LLC., in St. Joseph, MO¹⁰⁵; and Pacific Ethanol, Inc., in Boardman, OR.¹⁰⁶ The ethanol production levels at the four corn ethanol facilities ranged from 40 to 100 million gal/yr ethanol, with the average of all four corn ethanol plants at approximately 73 million gal/yr. The four corn ethanol facilities use the dry milling process, which is currently the most widely used corn ethanol production process in the United States.¹⁰⁷ Detailed information for these corn ethanol facilities in terms of feedstock rate, ethanol production rate, and estimated air emissions or limits are shown in the online supporting information for this paper.

The emission estimating methods cited in the permit documentation of the corn ethanol facilities included the following: EPA's AP-42⁹² TANKS⁸⁹ program and fugitive leak guidance,⁹⁴ other permits (Best Available Control Technology [BACT] limits), and manufacturer's specifications. The control devices or methods cited in the permit documentation of these four corn ethanol facilities included the following, listed by process area:

- Material receiving, handling and storage: baghouse, scrubber, cyclone, and thermal oxidizer
- Refining process: scrubber, thermal oxidizer, cyclone, and baghouse
- Liquid storage: internal floating roof tank
- Product load-out (and roads): vapor recovery, flare, and paving and sweeping roads
- Fugitive leaks: EPA leak detection and repair program
- Boilers: low-NO_x burners and flue gas recirculation
- Wastewater treatment: flare and combustor

Background information cited in the permit documentation in regard to the methods used to estimate emissions, control devices or techniques, and boiler ratings and fuel at these corn ethanol facilities are shown in the online supporting information.

Table 8 compares the average estimated emissions from the 7CEDF to the average of the four corn ethanol facilities in terms of t/yr and lb/1000 gal ethanol, as available. This comparison shows that the estimated air emissions or limits from the 7CEDF, which on average are smaller than the commercial corn ethanol facilities, are equal to or lower than the corn ethanol facilities on an annual (t/yr) basis. The average estimated emissions for the 7CEDF and corn ethanol facilities are approximately equal to or below the 100-t/yr PSD⁸⁴ major source threshold for chemical manufacturing facilities. Note that all emissions from the corn ethanol facilities are below the current 250-t/yr major source limit for PSD⁸⁴ purposes for ethanol manufacturing processes that use the biochemical process to produce ethanol for fuel or food.

The comparisons in Table 8 of the average estimated air emission of the 7CEDF to the commercial corn ethanol facilities rates normalized to lb/1000 gal ethanol show that the average emission rates or limits of the 7CEDF are approximately 10 times higher than the rates from the corn ethanol facilities. The ratios of the average estimated

Table 8. Comparisons of estimated emissions between U.S. cellulosic ethanol demonstration and corn ethanol commercial facilities.^a

| Average Data | Ethanol Production (gal/yr) | Air Pollutant ^a | | | | | | | | | | Total HAPs/ VOCs (%) | | | | | | | | |
|--|-----------------------------|----------------------------|-------------------------------|-------------------|-----------------|-----------------|-----|-----------------|------|------------|--------------|-------------------------|--------|--|--|--|--|--|--|--|
| | | PM Total | PM ₁₀ ^c | PM _{2.5} | SO _x | NO _x | CO | CO ₂ | VOCs | Total HAPs | Acetaldehyde | | Hexane | | | | | | | |
| Estimated emissions (t/yr) | | | | | | | | | | | | | | | | | | | | |
| Cellulosic ethanol demonstration | 19,000,000 | 73 | 44 | 64 | 21 | 47 | 51 | 384,149 | 34 | 5.5 | 1.6 | 3.1 | 15 | | | | | | | |
| Corn ethanol, commercial ^b | 72,500,000 | 72 | 52 | — | 28 | 98 | 111 | — | 116 | 19 | 7.3 | 4.6 | 21 | | | | | | | |
| Ratio cellulosic/corn | 0.26 | 1.0 | 0.8 | — | 0.8 | 0.5 | 0.5 | — | 0.3 | 0.3 | 0.2 | 0.7 | 0.7 | | | | | | | |
| Estimated emissions (lb/1000 gal ethanol) | | | | | | | | | | | | | | | | | | | | |
| Cellulosic ethanol, demonstration ^c | 19,000,000 | 9.2 | 7.4 | 1.3 | 4.5 | 26 | 25 | 14,592 | 42 | 5.8 | 5.6 | 0.10 | 15 | | | | | | | |
| Corn ethanol, commercial ^b | 72,500,000 | 1.7 | 1.3 | — | 1.0 | 2.7 | 3.1 | — | 3.1 | 0.58 | 0.24 | 0.12 | 21 | | | | | | | |
| Ratio cellulosic/corn | 0.26 | 5.5 | 5.5 | — | 4.4 | 10 | 7.9 | — | 14 | 10 | 23 | 0.9 | 0.7 | | | | | | | |
| Number facilities—cellulosic/corn | | 4/3 | 4/4 | 1/0 | 7/4 | 7/4 | 7/4 | 3/0 | 7/4 | 6/4 | 3/3 | 2/1 | 6/4 | | | | | | | |

Notes: ^aData not provided are indicated in this table by —. ^bThe average feedstock rate for the four corn ethanol facilities is 850,000 t/yr. See the online supporting information for details of the four corn ethanol facilities. ^cThe average PM₁₀ emission rate (in lb/1000 gal ethanol) for the cellulosic ethanol facilities does not include the PM₁₀ value for Genera Energy at 115 lb/1000 gal, which is based on a relatively high permitted cooling tower emissions rate considering the size of the facility and is not reflective of the PM₁₀ emission rates from the other cellulosic facilities or the other processes at the Genera Energy refinery.

emissions from the 7CEDF to the average of the four commercial corn ethanol facilities ranged from 1 to 25, in which VOCs and acetaldehyde (a HAP) were at the high end with ratios of 14 and 23, respectively, and SO_x and hexane (a HAP) were at the low end with ratios of 4 and 1, respectively. The large differences in normalized emission rates between cellulosic ethanol versus corn ethanol reflect the efficiency of the more mature and fully commercialized corn ethanol process as opposed to the emerging cellulosic ethanol technology being demonstrated at the 7CEDF.

COMPARISON TO PETROLEUM REFINERIES PRODUCING GASOLINE

The average estimated emissions of CO, NO_x, PM, SO_x, VOCs, HAPs, and CO₂ from the 7CEDF and four commercial corn ethanol facilities described above were compared with the estimated emissions of the same pollutants from petroleum refineries that produce gasoline on the basis of lb/1000 gal fuel produced.

Petroleum/Gasoline Refinery Air Emissions

The emissions of criteria pollutants and CO₂ from petroleum/gasoline refineries were estimated using a model widely used by EPA, DOE, and others to estimate emissions from transportation energy use. The model, called GREET (Greenhouse gases, Regulated Emissions, and Energy use in Transportation),¹⁰⁸ was developed by Argonne National Laboratory for DOE's EERE program and is full lifecycle model that can evaluate various vehicle and fuel combinations on a full fuel-cycle/vehicle-cycle basis. The GREET model simulates production of different refining products and allocates energy use and emissions associated with producing a given product in a weighted approach according to the mass of each product and the refining processes necessary for its production, as per DOE methodology.^{10,109,110} Refinery output estimates include all refinery products such as conventional and reformulated gasoline, aviation gasoline, jet fuel, kerosene, distillate fuel oil, residual fuel oil, petrochemical feedstocks, naphtha, lubricants, and other miscellaneous products.

The petroleum/gasoline refinery air emission estimates developed here were based on assumptions and emission factors used in the GREET model for the entire U.S. petroleum industry for the production of gasoline, except for the HAP emissions, which were based on total nationwide estimated emissions of HAPs for 153 U.S. petroleum/gasoline refineries in 2002. These HAP data were obtained as part of a risk and technology review for EPA's proposed residual risk rule "National Emission Standards for Hazardous Air Pollutants (NESHAP) from Petroleum Refineries"¹¹¹ and were used in analyses¹¹² performed for the RFS2.³¹ Note that petroleum refineries are subject to several EPA air regulations that date back to 1973.¹¹³ Petroleum refineries have NESHAP¹¹⁴ and New Source Performance Standards (NSPS)¹¹⁵ rules that require control of air emissions. More information on air pollution rules that apply to petroleum refineries can be found on the EPA website at <http://www.epa.gov/ttn/atw/petrefine/petrefpg.html>.

The estimated emissions for petroleum/gasoline refineries obtained from the GREET model were divided by

the amount of energy produced by those refineries in 2002 to obtain emission factors, in grams per MMBtu, which were then converted to lb/gal gasoline using the average heat content of gasoline. The resultant emission factors represent 2002 gasoline production technology and emission standards, which can be considered a conservatively high estimate.

CO₂ Emissions from Petroleum and Bioethanol Refineries

In terms of GHG emissions from biorefineries, CO₂ is estimated to be the GHG pollutant emitted in the largest quantity,^{10,42,45} although small amounts of other GHGs (e.g., N₂O and methane) also may be emitted. The information available indicates that at petroleum/gasoline refineries, CO₂ is also the predominant GHG species and is responsible for over 95% of the total GHG emissions.^{116,117} Because of this and because CO₂ emissions estimates were the only available GHG emissions estimated in the 7CEDF permit documentation, CO₂ is the only GHG compared here among the three types of refineries.

The CO₂ emissions for cellulosic ethanol, corn ethanol, and petroleum/gasoline refineries were divided into two types for the comparison: CO₂ emissions from biomass and CO₂ emissions from fossil fuel combustion. Any biomass-derived CO₂ emissions (called biogenic) were considered to have a near-zero effect on the environment in terms of global warming potential because the biogenic CO₂ was originally taken up by the living biomass that eventually composed the biorefinery feedstocks. These biomass CO₂ emissions were considered biogenic whether they were from the refining process or from combustion in boilers because biomass carbon was the only source of carbon in CO₂. Therefore, all estimated CO₂ emissions from corn or cellulosic ethanol refining processes were considered biogenic, and any CO₂ emissions from burning of biomass or gas derived from biomass (biogas or syngas) in boilers were also considered biogenic CO₂. Of course, burning of fossil fuel in any boilers at cellulosic or corn ethanol refineries are considered fossil fuel sources of CO₂. All CO₂ emissions estimates for petroleum/gasoline refineries, whether in the refining process or from combustion in boilers, were considered fossil fuel emissions because of the classification of petroleum as a fossil fuel.

Of the 7CEDF, four facilities (60%) reported using biogenic material in their boilers (see Table 1). Therefore, as a simplifying assumption for this analysis, all fuel used at cellulosic ethanol refineries was assumed to be biomass. On the other hand, three of the four corn ethanol facilities in this study (75%) use natural gas in their boilers (see online supporting information). Therefore, the CO₂ emissions estimated for boilers at corn ethanol refineries were considered to be fossil fuel derived for the purpose of this comparison. Note that one of the four corn ethanol facilities, Abengoa in Nebraska,¹⁰⁴ uses syngas, a biomass-derived fuel, in its boiler; therefore, the assumption that fossil fuel is used for energy may not be true for all corn ethanol refineries, especially those that are colocated with cellulosic ethanol refineries in what is called an "integrated" biorefinery.

Of the four cellulosic ethanol refineries burning biomass in their boilers, only three estimated CO₂ emissions. Of these three cellulosic ethanol refineries, only one had an estimate of the CO₂ emissions distribution between the cellulosic ethanol refining processes, at 25% of the total CO₂, with the remainder of the CO₂ emissions attributed to the boilers.⁷⁵ In addition, the permit documentation for the Canadian cellulosic ethanol demonstration facility⁸⁸ cited a distribution of 7 and 93% between the cellulosic ethanol refining process and the boilers, respectively. But because all of the estimated CO₂ emissions for cellulosic ethanol production are assumed to be biogenic in origin, the breakdown between process CO₂ and energy CO₂ was not needed in this analysis.

Emission estimates for CO₂ from the four corn ethanol refineries were not included in their permits; therefore, the emissions of CO₂ from corn ethanol facilities were developed as part of this study and are described below. The fossil fuel CO₂ emissions estimated for boilers at corn ethanol refineries were estimated using a (dry mill) emission factor developed by the California Air Resources Board (CARB)¹¹⁶ that assumed natural gas as the boiler fuel. The CARB emission factor for CO₂ emissions from (dry mill) corn ethanol refineries burning natural gas was 35.3 g of GHGs emitted per million Joules of ethanol produced (6.1 lb CO₂ per gallon ethanol), with CO₂ comprising approximately 95% of the total GHG emissions. The CARB emission factor was developed using a modification of DOE's GREET model called the "California-modified GREET Model" (greet1.7ca_v98.xls).¹¹⁸

The CO₂ emissions for the corn ethanol refining process were estimated using knowledge of the stoichiometry of the fermentation process,¹¹⁹ with the simplifying (and worst-case) assumption that 100% of biomass sugar is converted to ethanol. In this scenario, 1 mole of the six-carbon glucose is fermented to 2 moles of ethanol and 2 moles of CO₂, resulting in a ratio of ethanol produced to CO₂ emitted of 1:1 on a mass basis.^{119,120} Using this approach, an emissions factor for CO₂ of 7700 lb/1000 gal ethanol was developed in this study for corn ethanol refining using the molecular weight and density of each compound. As discussed above, the permit documentation of the Canadian cellulosic facility⁸⁸ cited an assumed ratio of CO₂ emissions to glucose during fermentation at 1.8:1, rather than the 2:1 stoichiometric ratio. The stated reason for the use of the lower ratio was to account for the breakdown (and loss) of sugars for cell production and byproducts.⁸⁸ This phenomenon supports the 1:1 CO₂-emissions-to-ethanol ratio used in this study as an assumption that the stoichiometric ratio is a worst-case scenario.

Comparison of Refinery Air Emissions between Petroleum/Gasoline, Corn, and Cellulosic Ethanol

Table 9 shows the estimated emission values discussed above for average cellulosic ethanol, corn ethanol, and petroleum/gasoline refineries. From the values in Table 9, it can be seen that for the permitted criteria pollutants and HAPs, the estimated air emission rates from an average petroleum/gasoline refinery and corn ethanol refinery are very similar on a normalized (lb/1000 gal fuel) basis.

Table 9. Comparison of estimated emissions between U.S. cellulosic and corn ethanol facilities and petroleum refineries producing gasoline.

| Refinery, Type | Estimated Emissions (lb/1000 gal fuel produced ^a) | | | | | | | | | |
|---|---|--------------------------|----------|-------------------------------|-------------------|-----------------|-----------------|-----|------|-------|
| | CO ₂ | | PM Total | PM ₁₀ ^c | PM _{2.5} | SO _x | NO _x | CO | VOCs | HAPs |
| | Biogenic ^b | Fossil Fuel ^c | | | | | | | | |
| Cellulosic ethanol, demonstration ^d | 14,592 | 0 | 9.2 | 7.4 | 1.3 | 4.5 | 26 | 25 | 42 | 5.8 |
| Corn ethanol, commercial ^e | 7,700 | 6,100 | 1.6 | 1.3 | – | 1.0 | 2.6 | 3.0 | 3.0 | 0.55 |
| Petroleum, commercial (gasoline) ^{f,g} | 0.0 | 2,600 | – | 0.78 | 0.45 | 2.5 | 3.7 | 1.4 | 0.65 | <0.01 |

Notes: ^aNote that for every unit of energy that can be produced from a gallon of ethanol (from corn or cellulosic material), 50% more energy (a factor of 1.5) can be obtained from a gallon of gasoline. ^bIncludes CO₂ emissions from energy and nonenergy (i.e., refining process) sources at the facilities. Biogenic sources include feedstock and waste material (e.g., lignin). ^cIncludes CO₂ emissions from on-site energy sources that use traditional fossil fuel (e.g., natural gas, coal, etc.). ^dThese emissions are the average of the estimates or limits from the permit documentation from the 7CEDF in this paper.^{72–80} The CO₂ emissions estimates assume biomass is used as fuel for all energy sources. For PM₁₀ emissions, limits from the Genera Energy permit were excluded from the cellulosic average (as described above) because of the relatively high cooling tower permitted emission rate that was not reflective of the other cellulosic facilities with PM₁₀ data. ^eThe biogenic CO₂ from corn ethanol refineries is based on a 1:1 (w/w) CO₂-to-ethanol ratio as derived from fermentation stoichiometry. Corn fuel combustion CO₂ is estimated using California's GREET 1.7 model,¹¹⁸ which assumes natural gas as the fuel. ^fPetroleum refinery emission estimates for all pollutants except HAPs are based on U.S. petroleum refinery emission factors for gasoline production using DOE's GREET 1.7 model¹¹⁰ and input values appropriate for 2005–2030. The HAP estimates for petroleum refineries were based on total nationwide estimated emissions of air toxics for 153 U.S. petroleum refineries in 2002 that were obtained from data collected as part of a risk and technology review for EPA's NESHAP from petroleum refineries proposed rule.¹¹¹ These HAP estimates were also used in the analyses¹¹² performed for the proposed RFS2.³¹ ^gPetroleum refineries are subject to several federal and state environmental regulations that have resulted in the use of numerous environmental controls that include air pollutant control equipment.^{113,114} More information on the air pollution rules that apply to petroleum refineries can be found on the EPA website at <http://www.epa.gov/ttn/atw/petrefine/petrefpg.html>.

In contrast, the normalized emission rates for the 7CEDF, on the average, were a factor of 10 higher on the average than the other two refinery types, although the annual emissions (t/yr) were the same order of magnitude between the corn ethanol and cellulosic ethanol facilities. The lower process efficiency for cellulosic ethanol is most likely the cause of the higher normalized emissions rates and is because of the emerging nature of this process, as noted above. It should be noted that for every unit of energy that can be produced from a gallon of ethanol from corn or cellulosic material, 50% more energy (factor of 1.5) can be obtained from a gallon of gasoline. This fact will be important for lifecycle comparisons between bio-fuels and conventional fuels and for calculating the potential national levels of emissions of criteria and HAP pollutants from production of each fuel type; however, these issues are beyond the scope of this paper.

Table 9 also shows the estimated biogenic and fossil fuel CO₂ emission impacts for the three types of refineries. The contribution of each refinery type to GHG emissions and potential global warming is assumed only to include the fossil-fuel-derived CO₂. As discussed above, biogenic CO₂ generated in the ethanol refinery process has a near-zero effect on the environment because the CO₂ emitted is from sequestration (i.e., withdrawal) of atmospheric CO₂ by the biomass feedstock during its growth. Therefore, the average cellulosic ethanol refinery, with no additional CO₂ emissions from fossil fuel combustion, has a near-zero GHG emissions impact and therefore has the lowest GHG impact of the three types of fuel refineries. Even taking into account the higher energy that can be obtained per gallon of gasoline as compared with ethanol as discussed above, the GHG emissions from gasoline production in a refinery are still much higher than a biorefinery that burns only lignin for fuel.

It is interesting to note that the normalized CO₂ emissions estimated from corn ethanol refineries, as shown in Table 9, are higher than the normalized CO₂ emissions estimated for petroleum refineries producing gasoline at 6100 and 2600 lb/1000 gal fuel produced, respectively, for which corn ethanol facilities were assumed to burn fossil fuel in their boilers for this comparison. The higher combustion CO₂ emissions for corn ethanol refineries may be due to the lower estimated combustion efficiencies used in the GREET model for their boilers as compared with the efficiencies in GREET for boilers at petroleum/gasoline refineries. Regardless of boiler efficiencies, if corn ethanol refineries use biomass for heat and energy production, as in the Abengoa, NE, corn ethanol facility¹⁰⁴ and possibly other corn ethanol facilities, the net CO₂ emissions levels from corn ethanol refineries would also be near zero as with cellulosic ethanol refineries.

WATER AND OTHER ENVIRONMENTAL IMPACTS

Cellulosic ethanol refineries use water in the production process and generate wastewater and solid waste. Although the air route may have the highest potential for environmental impacts, the water consumption rate of cellulosic ethanol production is often mentioned as a concern, especially in comparisons between cellulosic and corn ethanol production; therefore, water consumption is also discussed here. In addition, wastewater discharges may be significant if untreated; wastewater discharge permits are likely to be required in addition to air permits at cellulosic biorefineries. The wastewater impacts, solid waste, and other environmental impacts of cellulosic biorefineries are discussed in the online supporting information. The general conclusions from the environmental assessments prepared by DOE for some of these initial demonstration cellulosic ethanol facilities,

considering all pollution pathways, were that there was no significant impact in any area.⁷⁵⁻⁷⁷

Although lifecycle assessments of biofuel production consider water consumption during the refining stage an important parameter to be included, a fact often overlooked is that the water consumption from feedstock production on agricultural fields greatly exceeds any estimates for biorefinery water use.^{15,17} Using available data from corn ethanol production as an example, a total of 780 gal of water is needed to grow corn that is used to produce a gallon of ethanol¹⁵; this is approximately 200 times higher than the water use estimated for a corn ethanol biorefinery. However, if agriculture water use is mostly rain-fed, then water used within the biorefinery can be the primary point of water consumption for the entire process.¹⁵

At the biorefinery, fresh water may be obtained from municipal water treatment plants, on-site wells, process recycling, or (potentially) wastewater with varying resource impacts assigned to each type of water source. Water at a cellulosic ethanol facility is used for boiler makeup and blow down as well as cooling. In the refining processes, water is used for hydrolysis of the cellulosic material. In filter presses, water is used in backwash, cleaning of filters and other equipment, and in some control equipment (e.g., wet scrubbers).^{15,42,45,99,121} In this discussion, water consumption is considered to the total volume withdrawn from outside water sources.

Literature estimates of water consumption at cellulosic ethanol refineries were between 2 and 7 gal of water per gallon of ethanol produced (gal/gal)^{15,99,122} irrespective of the ethanol processing method. The estimated water consumption at corn ethanol facilities was found to be 4 gal/gal on the average,^{15,45} with a range from more than 3 to 6 gal/gal.^{16,122,123} As a comparison, water use in petroleum refining is estimated to be approximately 1.5 gal/gal.^{15,122}

The thermochemical conversion process used to produce ethanol from cellulosic matter holds the possibility of achieving a lower water use rate than the biochemical process.⁴⁵ Phillips et al.¹⁵ developed a thermochemical cellulosic ethanol process design that would require only approximately 2 gal/gal, which is half that required for corn ethanol plants. In this design, some of the water savings are obtained from improvements in cooling tower and boiler feed operations, which the authors state also may be applicable to other bioethanol plants, such as

cellulosic ethanol. Water use at cellulosic ethanol refineries using the biochemical process is also expected to be able to be reduced to a much lower level than the current estimates because these cellulosic ethanol facilities can theoretically be designed for zero wastewater discharge if recycling of process water is done to the maximum extent possible.⁹⁹ It is believed that cellulosic ethanol facilities will eventually be able to recycle much of the water that is used in the process⁹⁹ to minimize the amount of fresh water needed on a daily basis.

Table 10 shows the estimated annual water use rates in gallons of water consumed per gallon of ethanol produced (gal water/gal ethanol) for the four cellulosic ethanol demonstration facilities as obtained or extrapolated from daily or hourly information in the permit documentation. The values ranged from 1 to 13 gal/gal with an average of 8 gal/gal with the one thermochemical facility (Range Fuels⁷⁶⁻⁷⁸) at the low end of the range, as expected for the thermochemical process. The average water use rate for the 7CEDF in this study at 8 gal/gal ethanol is slightly higher than the 2- to 7-gal/gal range reported in the literature for cellulosic ethanol, double the estimated average corn ethanol rate of 4 gal/gal ethanol, and 5 times the estimated rate at petroleum refineries of 1.5 gal/gal. The higher rate for cellulosic ethanol facilities from this study may be due to the extrapolation of the water rates from daily or hourly to annually, because the facilities have overestimated their potential water use before actual operation of the facility, or both.

APPLICABLE EPA AIR REGULATIONS

Cellulosic ethanol facilities are potentially subject to several air pollution regulations. This section discusses the current EPA regulations that may be applicable. Although state regulations also may apply to cellulosic ethanol facilities, these are not addressed in this paper. Because this discussion on potentially applicable EPA regulations for cellulosic ethanol demonstration facilities is based on a general facility profile, it is not intended to be used as an applicability determination for any one facility. Cellulosic ethanol facilities are a relatively new type of facility; therefore, the applicability of some of these regulations has not been explicitly determined as yet. Owners/operators who are contemplating startup of a cellulosic ethanol facility are advised to obtain an updated regulatory analysis by an experienced professional.

Table 10. Water use rates reported in permits of four cellulosic ethanol demonstration facilities.^{72,74,75,78}

| Facility ^a /Data | Ethanol Production (gal/yr) | Water Use | | |
|-----------------------------|-----------------------------|--------------------------------------|-------------|---------------|
| | | Water/Ethanol (gal/gal) ^b | Daily (gal) | Water Source |
| Range Fuels ^a | 100,000,000 | 1 | 320,000 | Wells, city |
| POET Liberty | 25,000,000 | 6 | 430,000 | Wells, city |
| BlueFire | 3,000,000 | 13 | 110,000 | Wells |
| Verenium | 2,000,000 | 12 | 60,000 | Not specified |
| Average | | 8 | 200,000 | |

Notes: ^aAll facilities use the biochemical process (fermentation) except Range Fuels, which uses the thermochemical process. ^bWater-to-ethanol ratios were obtained by extrapolating the reported daily water use rate, assuming continuous operation (365 days/yr).

This section discusses the regulations that may apply to cellulosic ethanol facilities with comments on potential differences in applicability between the biochemical and the thermochemical process and between ethanol production from corn and cellulosic material. Although many of the applicable EPA air regulations discussed here may also apply to corn ethanol facilities, this summary is not intended to cover all EPA air regulations for corn ethanol facilities. Some EPA air regulations cited below will almost always apply to cellulosic ethanol facilities, whereas others may apply to only some cellulosic ethanol facilities depending on the equipment at the facility.

Ethanol made by natural fermentation in the biochemical process, with corn and cellulosic feedstocks, has been determined not to be subject to some EPA air rules because the "natural" fermentation used in the ethanol production process is identical to the fermentation process used in the production of ethanol for human consumption. If a fermentation process step follows a thermochemical pretreatment process to produce ethanol, then the overall facility process also may be considered a natural fermentation process; otherwise, the thermochemical process to produce ethanol is considered a chemical manufacturing process. These distinctions are noted below. Lastly, aspects of the RFS2³¹ for transportation fuel, which contains provisions for cellulosic ethanol production, are discussed here. Background on the various types of EPA emissions and performance standards can be found in the online supporting information.

Background on Corn Ethanol Refinery Regulations

Although the commercial development of corn ethanol facilities preceded cellulosic ethanol facilities, the regulatory applicability of some EPA rules to corn ethanol facilities is still being decided, and these decisions may also affect the regulatory applicability for cellulosic ethanol facilities. Therefore, a significant regulatory event in the background of the corn ethanol regulatory history is discussed here along with a recent PSD⁸⁴ applicability issue that was decided for existing corn ethanol facilities but that also applies to cellulosic ethanol facilities.

In 2002, EPA found 12 corn ethanol facilities in Minnesota to be in violation of the Clean Air Act (CAA)¹²⁴ for failure to obtain PSD⁸⁴ or minor source permits for new construction or modifications. These corn ethanol facilities were found to emit greater than 100 t/yr of VOCs, PM, or CO from feed dryers, fermentation units, gas boilers, cooling cyclones, ethanol load-out operations, and fugitive dust from roads. The major source definition for PSD⁸⁴ purposes for these facilities at the time was 100 t/yr of any criteria pollutant. Under consent decrees made in 2002 between the United States and the corn ethanol facilities, the plants were required to install thermal oxidizers that reduce VOC emissions by 95% or more from the feed dryers; to meet more restrictive emission limits for NO_x, PM, CO, and VOCs (which includes some HAPs); to obtain permits; and to pay civil penalties (fines).¹²⁵

In May 2007, EPA published a rule called "Treatment of Certain Ethanol Production Facilities under the 'Major

Emitting Facility' Definition"¹²⁶ (2007 Corn PSD rule) that changed the PSD⁸⁴ applicability for corn ethanol facilities. In this rule, EPA redefined the regulatory definition of a chemical process facility for PSD⁸⁴ by permitting purposes to exclude corn ethanol facilities that produce ethanol for fuel. This exclusion changed the major source applicability level from 100 to 250 t/yr; previously, this level only applied to corn milling operations that produced ethanol for human consumption. The 2007 Corn PSD rule¹²⁶ extended the exclusion to all facilities that produce ethanol through a "natural fermentation" process in which, as the rule stated, "items such as corn, sugar beets, sugar cane, or *cellulosic biomass* are used as feedstock" (italics added) regardless of whether the ethanol is produced for human consumption, fuel, or industrial purposes. Note that this exemption would not apply to cellulosic ethanol produced exclusively by the thermochemical process because no natural fermentation is used in that production pathway. The 2007 Corn PSD rule¹²⁶ also redefined the requirement to include fugitive emissions in the major source applicability determination and excluded facilities that produce ethanol for fuel using natural fermentation from having to include fugitive emissions. Note, as above, the fugitive emission exemption also would not apply to cellulosic ethanol produced exclusively by the thermochemical process. The above PSD⁸⁴ determinations do not necessarily affect the applicability to bioethanol facilities for other EPA rules, such as the NSPS¹²⁷ and NESHAP.¹²⁸

Potentially Applicable Air Regulations for Cellulosic Ethanol Refineries

Cellulosic ethanol facilities may be subject to EPA air regulations because of their emissions of criteria air pollutants (in NSPS¹²⁷ of Part 60, Volume 40 of the Code of Federal Regulations [CFR]¹²⁹) and HAPs (in NESHAP¹²⁸ of Part 63, Volume 40 of the CFR¹²⁹). The HAP likely to trigger regulatory applicability is acetaldehyde, although emissions of other HAPs may occur (e.g., hexane, formaldehyde, acrolein, and methanol). Note that ethanol, although a VOC, is not a HAP. Because cellulosic ethanol facilities are not likely to be major HAP sources nor routinely colocated with major HAP sources, cellulosic ethanol facilities in these cases would not be subject to major HAP rules such as the NESHAP for "Organic HAP from the Synthetic Organic Chemical Manufacturing Industry (HON)."¹³⁰ However, cellulosic ethanol facilities may be subject to the NESHAP for Area Sources of Chemical Manufacturing in 40 CFR Part 63 Subpart VVVVVV (Subpart 6V)¹³¹ in addition to several NSPS¹²⁷ for Synthetic Organic Chemical Manufacturing (SOCMI), and possibly NSR¹³²⁻¹³⁴ and PSD⁸⁴ regulations.

Table 11 shows the EPA air rules that will affect most cellulosic ethanol facilities as long as the applicability criteria of the rules are met by the facility, the applicability criteria of the rule, and the pollutants controlled by the rule. Although some of these rules may be determined to be applicable in general to cellulosic ethanol facilities, some facilities may only be required by the rule to do recordkeeping or reporting. Table 12 shows information for rules that may be applicable to only some cellulosic ethanol facilities.

Table 11. EPA air pollution regulations potentially applicable to most cellulosic ethanol refineries.

| Rule (CFR citation) | Applicability Criteria | Pollutants Controlled |
|--|---|--|
| NESHAP (40 CFR Part 63) Chemical Manufacturing Area Source Categories—Subpart 6V (40 CFR Part 63.11494) | Any chemical manufacturing facility (in NAICS code 325 series) at a nonmajor source of HAPs that emits acetaldehyde and/or 1,3-butadiene, 1,3-dichloropropene, chloroform, ethylene dichloride, hexachlorobenzene, methylene chloride, quinoline, arsenic compounds, cadmium compounds, chromium compounds, lead compounds, manganese compounds, nickel compounds, hydrazine. | HAPs |
| NSPS (40 CFR Part 60) Volatile Liquid Storage Tanks—Subpart Kb (40 CFR Part 60.110b) | Volatile liquid storage $\geq 20,000$ gal (75 m ³). Does not apply if tank is $\geq 20,000$ gal and $<40,000$ gal (151 m ³) with liquid <2.2 psi (15 kPa) or if tank is $>40,000$ gal and liquid is <0.5 psi (3.5 kPa). At cellulosic ethanol facilities, may only apply to gasoline storage tanks. | VOCs |
| Industrial Steam-Generating Units—Subpart Db (40 CFR Part 60.40b) | Steam-generating boilers with heat input capacity >100 MMBtu/hr (29 MW) built after September 18, 1984. Fuels affected include natural gas, wood, and municipal solid waste. | PM: coal, oil, wood; SO ₂ : coal and oil; NO _x : all fuels |
| Small Industrial Steam-Generating Units—Subpart Dc (40 CFR Part 60.40c) | Steam-generating boilers with input capacity of ≤ 100 MMBtu/hr (28 MW) but ≥ 10 MMBtu/hr (2.9 MW) built after June 9, 1989. Reporting required for all fuel types. | PM: coal, oil, and wood (>30 MMBtu/hr); SO ₂ : coal and oil |
| Equipment Leaks of VOC in the SOCMI—Subpart Ww (40 CFR Part 60.480a) | SOCMI facilities built after November 7, 2006 with production >1000 Mg/yr (1102 t/yr), which is equivalent to 335,000 gal/yr ethanol. Ethanol is on the list of applicable chemicals. | VOCs |

Notes: For copies of the rules, summary “Fact Sheets,” and other compliance and implementation tools, see the EPA’s Technology Transfer Network (TTN) webpages at <http://www.epa.gov/ttn>.

The Subpart 6V area source NESHAP for Chemical Manufacturing¹³¹ affects facilities that use corn and cellulosic matter in the biochemical and thermochemical processes to produce ethanol if the applicability criteria of the rule are met. Subpart 6V¹³¹ affects area sources of HAPs at chemical manufacturing facilities in nine specific chemical manufacturing categories, as well as any other chemical manufacturing facility with a North American Industrial Classification System (NAICS) code that begins with “325” and that emit 1 or more of the 15 HAPs listed below. Facilities that produce ethanol as a fuel, which have the NAICS code 325193 for “industrial organic chemical production of ethanol alcohol,” are subject to Subpart 6V if any emission point at the facility has measurable emissions of any one of 15 HAPs listed in the rule shown below, which includes acetaldehyde.

- Organic compounds: 1,3-butadiene, 1,3-dichloropropene, acetaldehyde, chloroform, ethylene dichloride, hexachlorobenzene, methylene chloride, and quinoline
- Metal compounds: arsenic, cadmium, chromium, lead, manganese, and nickel compounds as well as hydrazine

Batch and continuous chemical production processes are regulated under Subpart 6V, which affects all equipment used at the facility in chemical production, such as storage tanks, organic liquid transfer operations, cooling towers, and wastewater treatment. The entire facility is affected by Subpart 6V even if only one part of the process emits 1 of the 15 HAPs; however, the control requirement for process points with low HAP emissions are in most cases management practices that the facility may be already doing. Facilities that are subject to Subpart 6V need

to meet the rule requirements shown in Table 11 by October 29, 2012 if the facility began construction before October 6, 2008. Sources that began construction after October 6, 2008 are considered new sources and must comply with the rule upon startup or October 29, 2009, whichever is later. Additional information about Subpart 6V can be found on the EPA’s air toxics website for area sources (<http://www.epa.gov/ttn/atw/area/arearules.html>).

Most cellulosic ethanol facilities are also required to comply with a NSPS¹²⁷ that regulates fugitive emissions of VOC emissions from SOCMI (Subpart VVa) and a NSPS¹²⁷ that regulates VOCs from SOCMI storage tanks (Subpart Kb). Cellulosic ethanol facilities also may be subject to air regulations because of on-site operation of boilers and cooling towers utilized for process heat and steam. These regulations include the NSPS¹²⁷ boiler rules (Subparts Dc and Db) that address criteria pollutants (PM, SO₂, NO₂) from two boiler size categories and future NESHAP^{128,135} for boilers at both major and area sources that will address HAP emissions. However, the information presented here does not include EPA rules that address emissions from internal combustion engines or turbines that may run fire pumps at cellulosic ethanol facilities because this equipment may not be widely used.

EPA RFS2

As mentioned above, the EPA in February 2010 revised the Renewable Fuel Standard (RFS2)³¹ that implemented the 2007 expansion of the national biofuels mandate from the EISA.³⁰ CAA Section 211¹³⁶ (40 CFR Part 80, Subpart K) defines the various terms used in RFS2,³¹ including those that are specific to cellulosic biofuel production.

The EISA³⁰ included a requirement for 100 million gal of cellulosic biofuel beginning in 2010 that rises to 16 billion gal of cellulosic biofuel by 2022.

For the first time, the EPA in RFS2³¹ set volume standards for specific categories of renewable fuels including cellulosic. The EPA intends to issue a proposed rule each spring and a final rule by November 30 of each year to set the renewable fuel standards for each ensuing year for all fuels. More information about the renewable fuel standard can be found on the EPA website at <http://www.epa.gov/otaq/renewablefuels/420f10007.htm>

In developing the cellulosic fuel standard, EPA utilized an updated market analysis that considered detailed information from pilot and demonstration scale plants, an Energy Information Administration analysis, as well as other publically and privately available market information.³¹ The result was that the 2010 cellulosic biofuel standard was set at 6.5 million ethanol-equivalent gallons, significantly less than that set forth in EISA³⁰ for 2010. However, EPA believes the industry is poised to expand production over the next several years, so while the cellulosic standard has been set lower than required, EPA states that the growth of the cellulosic biofuel industry will continue to be assessed for future fuel standards.³¹ Furthermore, the advanced biofuel and total renewable standard for 2010 in RSF2.³¹

The EISA³⁰ also set the first mandatory GHG reduction thresholds for various categories of fuels. Therefore, the RFS2³¹ required that the lifecycle GHG emissions of the renewable fuels must be less than the lifecycle GHG emissions of the 2005 baseline average gasoline or diesel fuel that it replaces. Different levels of reductions were required for each fuel type category. Cellulosic biofuels are required to meet a minimum of 60% lifecycle performance GHG improvement, as required by the EISA. Compliance with the GHG threshold requires a comprehensive evaluation of the renewable fuel as well as the baseline for gasoline and diesel on the basis of their lifecycle emissions. As mandated by the EISA,³⁰ GHG emissions assessments must evaluate the aggregate quantity of GHG emissions including both direct emissions and significant indirect emissions such as significant emissions from land use changes related to the full lifecycle of the fuel. EPA's lifecycle methodology in RFS2³¹ required breaking new scientific ground and using analytical tools in new ways. Throughout the development this lifecycle analysis, a collaborative, transparent, and science-based approach was used. However, as the state of scientific knowledge continues to evolve in this area, EPA has stated that it recognizes that the lifecycle GHG assessments are likely to be updated as well. The EPA is committed to reassessing these determinations and lifecycle estimates in the future.³¹

SUMMARY AND CONCLUSIONS

The 7CEDF discussed in this paper are the first of approximately 25 facilities planned for the near future in the United States. Canada is now using cellulosic feedstocks obtained from the vast forest and grasslands available in that country to also produce ethanol for fuel. The production of ethanol from cellulosic material, although an emerging commercial process, has its roots in the well-established industries

that produce ethanol for beverages and, more recently, fuel from corn. The specific technical challenges of using cellulosic feedstock are currently being actively addressed by research being performed in the United States and around the world. Because of the potentially low net CO₂ emission impact when plant-derived materials are used as feedstocks to produce fuel, cellulosic ethanol shows a great potential for improvement in GHG emissions compared with production of gasoline in petroleum refineries, as well as providing a renewable fuel source for U.S. energy independence. The cellulosic ethanol production process also appears to be better in terms of net GHG emissions when compared with ethanol made from corn, with this difference appearing to be solely from the availability and subsequent use of cellulosic matter as fuel in process boilers instead of fossil fuel. The relative GHG emission contribution of these biofuels in terms of a full lifecycle assessment of GHG emissions is controversial and is still being debated at this time.

The permits for the 7CEDF planned for the near future and reported here have emission estimates or limits for typical pollutants that are on the average below the more restrictive 100-t/yr PSD⁸⁴ major source threshold for chemical manufacturing facilities. These estimates will need to be confirmed by source tests that are required for most of the cellulosic ethanol demonstration facilities once they are fully operating. Regardless of whether or not the actual emissions at cellulosic ethanol refineries are currently similar to the estimates shown in this paper, it is expected that the emissions from cellulosic ethanol production will be reduced further as the process reaches maturity and the processes are fully optimized.

It is also likely that the use of air pollution control devices or methods at future cellulosic ethanol facilities will show more homogeneity in performance and application than the variation shown in this first group of demonstration facilities. As the air pollution controls used at cellulosic ethanol facilities become more uniform, the normalized air emissions of all pollutants, in terms of mass of pollutant per volume of ethanol, should converge to similar levels from facility to facility. The air pollution regulations in place and being developed today that apply to the cellulosic ethanol and other biofuel industries will be able to guide the almost certain high growth rate of biofuel industries in the near future so that the benefits in the availability of these new fuels do not outweigh the impact on society from its production.

Caution is advised in using any of the emission estimates or permit limits reported here for the cellulosic ethanol demonstration facilities for decision-making estimates because the emission estimates or permit limits are primarily based on general emission factors and other general emission estimating procedures (e.g., mass balance and models) and may not reflect the actual performance of cellulosic ethanol facilities. Because of the wide variety in feedstocks used, the variation in emissions among the various types of cellulosic ethanol facilities may be intrinsically high. The estimated emissions or permitted limits reported here should be replaced with actual emissions data once several of the cellulosic ethanol facilities begin to operate because source tests are

required by most permits within the first year of startup. The routine level of emissions from these facilities may not be apparent for several years until the technology reaches full commercialization and technological maturity.

CONVERSION FACTORS

- 1 Btu = 1.055 kJ
- 1 Btu/gal = 4.0 kJ/L
- 1 Btu/lb = 2.33 kJ/kg
- 1 gal = 3.79 L
- 1 lb = 453 g = 0.453 kg
- 1 lb/1000 gal = 0.12 g/L
- 1 t = 0.9 Mg
- 1 t/yr = 0.9 Mg/yr
- 1 W = 1 J/sec

DISCLAIMER

The quality of the estimated emissions cited in this paper has not been evaluated by EPA for the purpose of estimating emissions from cellulosic ethanol refineries. The methods used to estimate potential emissions from these refineries, as cited in the permit documentation, included various techniques such as EPA emission factors, guidance documents, models, and databases as well as literature, mass balance calculations, permit data for similar units, and engineering judgment. In all cases, the emissions estimates were not derived from emission test data for the same process; for some facilities or emission points, no documentation was provided as to how the estimated emissions or permit limits were developed.

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