POTENTIAL BENEFITS OF CO-LOCATING BIOMASS-BASED ETHANOL PRODUCTION AT COAL-FIRED POWER PLANTS

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ABSTRACT

Co-locating biomass-based ethanol production facilities adjacent to coal-fired power plants could provide attractive economic and environmental benefits for these power plants, including reduced fuel costs, as well as reduced NO_x and greenhouse gases (GHG) emissions. Hydrolysis technology for producing ethanol from renewable, low-cost cellulosic biomass (such as wood chips, grass clippings or waste paper) is now in the initial phase of commercial development. The lignin byproduct from the ethanol plant is an energy-dense renewable fuel that can be cofired in a coal boiler, and the coal plant could provide process steam for the ethanol plant. Significant NO_x emissions reductions (20% to 30%) may be possible if the lignin is cofired as a water slurry mixed with coal fines (providing a beneficial means for their disposal). Emerging plans for NO_x emissions trading and renewable portfolio standards could enhace the value of this approach.

INTRODUCTION

In the U.S., about 1.3 billion gallons of ethanol are currently consumed as fuel in the automotive sector.[1] Most of this fuel is used as a 10 percent blend with gasoline, either to boost the octane of gasoline or to provide added oxygen content to gasoline. (Increasing the oxygen content of gasoline helps reduce emissions of carbon monoxide from automobiles in communities that are out of compliance with air quality standards.) The U.S. Congress has recently extended the federal excise tax exemption for ethanol fuel to the year 2007.

Virtually all of the ethanol currently used in the U.S. is made from starch-based crops (primarily corn) using conventional fermentation technologies. Advanced fermentation technologies have been developed that allow the use of a wide variety of abundant, low-cost, renewable biomass materials for conversion to ethanol. This biomass material, known as lignocellulosic biomass, includes organic matter such as wood chips, saw dust, waste paper, crop residues, grass clippings, and a variety of fast growing woody and herbaceous energy crops. Energy crops are expected to yield 5 to 10 dry tons per acre per year. There are over 30 million acres of set-aside farm land that could be used to grow perennial energy crops (the roots of these crops remain in the soil from year to year, even with crop harvests, providing continued protection from soil erosion). At a yield of 80 gallons of ethanol per dry ton of biomass, this set-aside land could provide 12 billion to 24 billion gallons of ethanol per year.

Advanced fermentation technologies use acids and/or enzymes to break down (i.e., hydrolyze) lignocellulosic biomass into material that can be fermented to ethanol. Technologies that use acid for the process, known as acid hydrolysis technologies, are being commercially developed today. Ethanol production technologies that use enzymes, known as enzymatic hydrolysis technologies, are also well along in the development cycle. The primary commercialization hurdle for enzymatic technology has been the need to reduce enzyme production costs. Three commercial acid-hydrolysis ethanol plants are currently being developed, two in California and one in New York; a fourth facility is being developed in Louisiana that may use either enzymatic or acid hydrolysis.[2]

Acid-hydrolysis technologies include weak acid and concentrated acid processes. Concentrated acid hydrolysis technology is somewhat further advanced than weak acid hydrolysis. However, one potential advantage of weak acid systems is that they could be converted to enzymatic hydrolysis plants once the cost of enzymes have been reduced. Enzymatic hydrolysis systems will typically have a weak acid pretreatment phase and are expected to provide improved efficiencies/yields in converting biomass to ethanol.

BENEFITS OF CO-PRODUCTION

Cellulosic biomass, such as wood, typically contains about 25 percent lignin. While the lignin cannot be fermented to ethanol, it is an energy-dense material. The lignin by-product from the ethanol production process can be used as a boiler fuel to produce steam to meet the process heat and electricity needs of the ethanol plant. For a stand-alone hydrolysis-based ethanol production facility, approximately one-third of the capital cost would be for an on-site power plant, including a ligninfueled boiler and a turbine generator system.[3] Co-locating an ethanol plant next to an existing coal-fired power plant offers the potential for significant cost savings by avoiding the need for a new on-site power plant. Lignin could be sent to the existing power plant for fuel. In return, the power plant could provide process steam and electricity needed for the ethanol production process, with some excess electricity available for export to the grid. Figure 1 provides an overall flow diagram for the co-production approach. The co-production approach is similar to direct cofiring of biomass in coal-fired boilers. The difference is that a preprocessing step is added where the fermentable portion of the biomass is used to make ethanol as a co-product, while the remaining non-fermentable biomass is cofired as a fuel in a coal-fired power plant boiler.

Co-locating ethanol production at existing coal-fired power plants could potentially accelerate commercialization and deployment of hydrolysis-based ethanol technology, while providing economic and environmental benefits to coal-fired power plants. From the perspective of the ethanol plant, the co-location approach offers a number of benefits, including: a supply of process steam, a market for the lignin by-product, reduced capital costs, reduced siting and permitting difficulties, shared management and overhead costs, shared operating and maintenance costs, as well as existing industrial infrastructure. From the perspective of the coal-fired power plant, potential benefits include: increased energy efficiency with cogeneration, potentially lower fuel costs (if lignin is provided to the coal plant at a cost below that for coal), reduced emissions of greenhouse gases, potential reductions in NO_x emissions, and additional revenue from steam/electricity sales to the ethanol plant.

Greenhouse Gas Benefits

The co-production of ethanol at existing coal-fired power plants could offer a cost-effective option for electric utilities to reduce net emissions of greenhouse gases in three ways: 1) Reducing coal use by cofiring renewable biomass fuel in the form of lignin; 2) Increasing the thermal efficiency of coal use (via cogeneration, with lower grade process steam used by the ethanol facility); and 3) By producing liquid renewable fuel that offsets petroleum fuel use for transportation.

The thermal efficiency gains from combined heat and power production and the resulting greenhouse gas benefits for the co-location approach will be dependent on the configuration of specific coal-fired power plants. As a transportation fuel, corn-based ethanol results in about 20% less GHG emissions than gasoline, and cellulose-based ethanol (used in the form of E85, a blend of 85% ethanol and 15% gasoline) results in 80% less GHG emissions than gasoline, based on conservative estimates from the U.S. Department of Energy and Argonne National Laboratory.[4, 5]

ISSUES REGARDING LIGNIN UTILIZATION

What are the characteristics of the lignin that is produced as a by-product from the ethanol process, and how will these characteristics effect the way that it is delivered and utilized as a fuel at a coal-fired power plant? Lignin is in the “stillage” from the ethanol plant and must be dewatered. There are a number of ways that dewatering can be done. To a certain extent; the drying approach selected can be tailored to the needs of the boiler/power plant where it is to be used as fuel. One possibility for the drying process is to use a centrifuge, followed by a rotary vacuum filter.[6] This would produce a lignin cake with about 55 percent solids, which could then be used as a boiler fuel. It is possible that low-grade waste heat could be available for further drying of the lignin. Another potential approach is to deliver lignin in the form of a slurry to the coal boiler. If lignin can be delivered in a suitable slurry, this approach offers potential advantages in transporting lignin to an adjacent power plant and in feeding the lignin into the coal boiler for combustion. There has been some promising work done in the U.S. to evaluate coal/water slurries for fueling power plants.[7]

Dry lignin from hardwood has a heating value of about 10,600 Btu/lb and dry lignin from softwood has a heating value of about 11,300 Btu/lb. Dry woody biomass has a heating value of approximately 8,700 Btu/lb and dry herbaceous biomass is about 7,500 Btu/lb.[8] Bituminous coal has roughly 13,000 Btu/lb. The cost of coal for power plants is typically in the range of $1 to $1.20/MMBtu (million Btu) and the cost of coal will generally determine the value of the lignin as an alternate fuel source for the power plant (on a $/MMBtu basis).

Potential NO_x Impacts/Benefits of Lignin Cofiring

Lignin/water slurries could provide reduced NO_x emissions at existing coal-fired power plants. Tests by the GPU electric utility in Pennsylvania and by Pennsylvania State University found that cofiring a coal-water slurry in an existing coal-fired power plant significantly reduced NO_x emissions.[9] The NO_x reduction begins occurring when the slurry input is at a 10% level (energy basis) and reaches full benefit levels when cofired at a 20% level. A 20% slurry will likely reduce NO_x emissions by 20%. It is quite possible that lignin/water slurries will provide a similar effect.

Electric utilities are under increasing pressure to reduce NO_x emissions. For example, On Sept. 24, 1998, the U.S. Environmental Protection Agency (EPA) directed 23 Midwestern and Northeastern states to reduce NO_x emissions by 28% by the year 2003. This EPA directive includes the implementation of a NO_x trading system that is technology neutral.[10] NO_x trades are expected to be valued between $1500/ton to $2700/ton of avoided NO_x emissions. Testing is needed to verify the ability of lignin/water slurries to reduce NO_x emissions. If a NO_x benefit is demonstrated with this approach, utilities may view a lignin/water slurry as a premium fuel for cofiring in coal-fired power plants. As a premium fuel, lignin could have a higher value, thus improving the economics of ethanol production with the co-location approach. For coal plants with low NO_x burners, a 20% NO_x reduction for lignin/water slurries could provide a credit per gallon of ethanol produced ranging from 2.4 cents/gallon to 4.0 cents/gallon (corresponding to the $1500/ton to $2700/ton trade values for avoided NO_x emissions). For coal plants without low NO_x burners, a 20% NO_x reduction for lignin/water slurries could provide a credit per gallon of ethanol produced ranging from 3.5 cents/gallon to 6.3 cents/gallon (corresponding to the $1500/ton to $2700/ton trade values for avoided NO_x emissions). Thus NO_x credits for cellulose-derived ethanol (with co-location at a coal-fired power plant) could be valued somewhere between 2.3 and 6.3 cents/gallon. Assuming that the NO_x credit has a value of 3 cents/gallon, from the perspective of the coal plant a 50 million gallon per year ethanol facility could provide $1.5 million in NO_x credits for an adjacent coal-fired power plant. Another option (and potential side benefit) would be for coal-fired power plants to blend their coal fine residues with the lignin/water slurry, adding fuel value to the slurry, while solving problems with the management and disposal of coal fines.

ETHANOL FACILITY SCALE

It is useful to have a sense of the likely scale anticipated for a cellulose-based ethanol facility, and how this scale would compare to coal-fired power plants. Assuming a yield of 80 gallons of ethanol per dry ton of biomass, a 25 million gallon per year ethanol plant would use an amount of biomass similar to a 43 megawatt stand-alone biomass power plant. This scale is in the range of typical larger biomass power plants that have been developed in the U.S. (assuming the biomass power plant operates at a 25% conversion efficiency -- a reasonable state-of-the-art facility using a boiler for biomass conversion). With wood as the feedstock for ethanol production, the lignin residues from a 25 million gallon per year ethanol facility would provide enough fuel to generate 19 megawatts of electricity when cofired in a coal-fired power plant, assuming the coal plant operates at a 35% conversion efficiency. (Note that this is another advantage of cofiring; larger coal plants typically have higher conversion efficiencies than smaller stand-alone biomass power plants achieve.) At 19 megawatts, the fuel input from lignin would be 10% of a 190 megawatt coal plant – 10% is a typical range anticipated for viable biomass/coal cofiring approaches.

COGENERATION ISSUES

Assuming separate ownership of the ethanol facility and power plant, how much can the ethanol facility afford to pay for the steam provided by the power plant? Conversely, how much would the power plant need to be paid for steam delivered to the ethanol plant for process heat? The quality of the steam would be a significant factor. High pressure/temperature steam would have a high value for the power plant operation since it could be used to make electricity. Lower grade steam (at lower pressures and temperatures) would be less valuable to the power plant. Most of the steam needed for hydrolysis-based ethanol facilities is lower grade steam. One possible approach would be to establish a streamlined trading agreement between the ethanol producer and the coal-based power plant. The lignin could essentially be traded to the power plant in exchange for the process steam and electricity needed for the ethanol process, with no monetary payments made between the ethanol plant and power plant. However, it may be difficult to reach such an agreement, given the different values for fuel and energy which would "cross the fence" between the two operations. However, this idea has enough merit to warrant further consideration.

THE "VISION 21 ENERGYPLEX" CONCEPT

The DOE Office of Fossil Energy has a major new "Vision 21 EnergyPlex" initiative underway.[11] The goal of this initiative is to integrate advanced concepts for high-efficiency power generation and pollution control into a new class of fuel-flexible facilities. These facilities would be capable of co-producing electric power, process heat and high value fuels (such as ethanol) and chemicals. The goal is to achieve "environmentally friendly" facilities that produce virtually no emissions/pollutants. The energyplex concept envisions modular generation facilities that will mix traditional and next-generation technologies (including the use of waste stream "opportunity fuels" such as biomass). The future core technologies anticipated with this concept include coal gasifiers coupled to fuel cells. Coal conversion with greater than 50 percent efficiencies and very low emissions are envisioned. Some form of permanent carbon dioxide storage is being explored with the concept, such as carbon dioxide injection/storage in unmineable coal seams. The Vision 21 concept has been endorsed by the President's Committee of Advisors on Science and Technology (PCAST). The co-production of ethanol from cellulosic biomass at existing coal-fired power plants is consistent with, and complementary to, the Vision 21 concept – where multiple feedstocks would be processed at a site for the production of multiple products, with increased overall feedstock conversion efficiencies, and reduced greenhouse gas emissions.

COFIRING STATUS AND ISSUES

There are five utilities currently cofiring biomass in existing coal-fired power plants.[12] There have also been many trial test runs of biomass cofiring at utilities across the U.S. that provide a basis of experience upon which to draw. With assistance from the Federal Energy Technology Center (FETC), the Electric Power Research Institute (EPRI) and the DOE Biomass Power Program are collaborating in efforts to foster increased cofiring by the electric power industry.

With respect to cofiring opportunities, one of the biggest concerns for operators of coal-fired power plants would be procuring biomass fuel. One advantage of the ethanol co-location approach would be the option of having the ethanol facility operator deal with biomass supply contracting (in the same way that biomass-based independent power producers currently operate). In this case, the ethanol facility could offer long-term contracts to the power plant for lignin fuel delivery, dramatically simplifying the fuel procurement process for biomass cofiring.

Marketing Issues Regarding Coal Ash from Biomass Cofiring

Some concerns have been raised regarding the marketing of ash from coal-based power plants when biomass material is cofired with coal. ASTM Standard C-618 narrowly defines acceptable coal ash for cement applications as ash that is exclusively derived from burning coal. Efforts are underway to modify this standard to make it similar to one used in Canada. There, the acceptability of coal ash for cement applications is based on the chemical and physical characteristics of the ash, rather than the fuel/feedstocks that are used for combustion.

MONETIZATION OF GREENHOUSE GAS BENEFITS

If an economic value can be established for reduced greenhouse gas emissions, this will significantly enhance the attractiveness of ethanol co-production at coal-fired power plants. A number of early pilot efforts are underway to establish markets for tradable emissions credits associated with reduced GHG emissions. The success of the sulfur dioxide allowance trading program in the U.S. is considered a potentially attractive model for a trading program that establishes allowances for greenhouse gas emissions reductions.[13] The most significant progress to date in building a framework that could evolve toward this type of a trading program is in voluntary international greenhouse gas emissions trading. The International Utility Efficiency Partnerships (IUEP) is one of the organizations involved in international greenhouse gas (GHG) reduction efforts. The Edison Electric Institute sponsors IUEP. A key activity of IUEP is to facilitate United States International Joint Implementation (JI) projects for greenhouse-gas credits. Under this structure, electric utilities receive offsets for domestic carbon dioxide emissions by sponsoring projects in developing countries that result in carbon sequestration or reductions in GHG emissions. Efforts are currently underway to set up an "International Offsets Facility" that will operate as a bank for GHG offsets. Initially it was anticipated that GHG credits would be valued in the range of $1.50 per ton, but their value has already gone as high as $3 to $4 per ton of carbon equivalent offset. Procedures are being established for registering, transferring and processing "clean development mechanisms" (CDMs) in order to certify carbon trading offsets (CTOs).[14]

Renewable portfolio standards are being implemented by a number of states and are also being considered at the federal level. These standards require that a minimum portion of future electric generating capacity in a state be derived from renewable energy sources. Biomass cofiring offers the most attractive option to utilities for meeting these standards, since it is the lowest-cost renewable option.[12] Thus renewable portfolio standards could be another means of recognizing the GHG benefits of biomass cofiring and ethanol co-production. Implementation of these standards at the state or federal level may open significant opportunities for cofiring (and ethanol co-production) projects in the near- to mid-term.

SUMMARY

From the point of view of a hydrolysis-based ethanol facility, it appears likely that co-locating near a coal-fired power plant would be beneficial. The main uncertainty is the extent to which co-locating will be beneficial for coal-fired power plants. Key questions that need to be answered to determine the attractiveness of ethanol co-locating to coal-fired power plants (and electric utilities) include the following:

- What will be the price of the lignin?
- Will lignin cause boiler tube fouling?
- Will lignin cofiring impact coal ash marketing for cement applications?
- What are the characteristics of the lignin when it is delivered to the coal boiler (e.g., slurry, powder, moisture content, etc.)?

- What quality steam would an ethanol facility need and how much would the ethanol facility be willing to pay for the steam delivered from a coal-fired power plant?
- What would be the revenue for electricity sales to the ethanol plant?
- What are the regulatory or market drivers for reducing greenhouse gas emissions?

For electric utilities, the attractiveness of the ethanol co-location approach would be significantly enhanced if they could receive financial credit for the reduced GHG emissions provided by this approach. While monetization of avoided GHG emissions or, conversely, savings from avoided carbon taxes, are not currently available for U.S. domestic projects, renewable portfolio standards could play an analogous role. These standards are being implemented by a number of states in recognition of the environmental benefits offered by renewables and could play a significant role in fostering cofiring, including the co-production of ethanol at coal-fired power plants.

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Figure 1. Integrated production of ethanol at a coal-fired power plant.