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TECHNICAL REPORT

Near-Term Opportunities for Integrating Biomass into the U.S. Electricity Supply

Technical Considerations

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Summary

In light of potential regulatory limits on GHG emissions, mandates for renewable-energy use in emerging legislation, and potentially higher prices for some conventional fossil fuels, biomass could become an increasingly important source of fuel for generating electricity and heat and for manufacturing liquid fuels. Biomass energy resources are organic matter, typically trees or plants, grown and harvested for the purpose of producing energy. Examples of biomass resources include the uncollected tops and branches from forestry operations, agricultural residues, and crops specifically grown for the purpose of producing energy, such as switchgrass. In general, because plants convert carbon dioxide (CO_2) in the air into carbon-containing compounds that form the plant, the life-cycle GHG emissions of biomass are significantly less than those of fossil fuels.

In 2008, approximately 14 million tons of biomass were burned in dedicated or cofired facilities to generate approximately 28 billion kilowatt-hours (kWh) of electricity, 1.3 percent of total electricity generation in the United States (Energy Information Administration [EIA], 2009). If biomass is to significantly reduce GHG emissions that result from generating electricity, biomass use will need to increase substantially.

The U.S. Department of Energy's (DOE's) NETL requested that RAND characterize the technical and logistical constraints to using biomass, and potential solutions to overcome them, in the current U.S. energy system. RAND was asked to focus on plants that could easily use biomass resources, the technical issues associated with cofiring biomass, constraints that could arise in transporting and processing the biomass, and the conditions under which broader markets for biomass resources could develop.

This is the fourth study for NETL by RAND specifically focused on biomass resources. The first study analyzed biomass as a potential supplementary feedstock for the production of liquid fuels and supported a larger effort (NETL, 2009c). The second characterized the life-cycle GHG emissions from producing biomass (Curtright et al., 2010). The third study characterized the cost, quantity, and land used when producing biomass on agricultural lands for a single plant (LaTourrette et al., 2011).

Analytical Goals and Methodology

In this report, we posed four analytical questions:

- What are the technical constraints and costs of cofiring at the plant site? Biomass is a different fuel from coal and needs distinct handling and processing steps, requiring addi-

tional capital equipment and increasing operating expenses at the plant. The viability of biomass as a means of reducing GHG emissions from coal-fired power plants depends critically on these costs.
- What are the characteristics and costs of biomass supply systems, and what is their effect on delivered prices of biomass energy resources? In general, biomass is a low-density resource requiring a large area to supply commercial quantities of fuels. Are there opportunities for densifying biomass to reduce transportation costs and improve commercial viability?
- What GHG savings can cofiring provide and at what cost? Because the current motivation for using biomass resources to produce electricity is to reduce GHG emissions, a quantitative analysis of these emissions is needed.
- What are the current characteristics of markets for biomass energy resources, and what are likely paths to development? Under what conditions could this immature market develop to a more formal market with standard grades of biomass and more-formal supply contracts?

Because biomass has low levels of sulfur and is more reactive than coal, cofiring biomass can reduce the emissions of criteria pollutants from coal-fired power plants. The DOE carried out a number of cofire tests in collaboration with the Electric Power Research Institute (EPRI) demonstrating the viability of this approach (Tillman, 2001). In interviews, several generating companies were able to give us more-current insights into how they source biomass, plant-site requirements for cofiring and dedicated facilities, and the key factors underlying firm-level decisionmaking about using biomass. Using the information gleaned from these interviews, we formulated three distinct supply scenarios to analyze the costs of alternative approaches to sourcing biomass resources:

- biomass supplied from the local area, i.e., the contiguous area surrounding the plant
- biomass supplied from the local area augmented with densified biomass imported from another region
- densified biomass supplied entirely from a distant region.

The three supply scenarios differentiate themselves along the types of biomass supplied and the delivered cost of biomass. Table S.1 lists the results of this logistical analysis. To make the logistical analysis representative of current biomass sourcing and potential near-term alternatives, local biomass supplies are assumed to be clean greenwood.

Table S.1
Estimated Cost of Delivered Biomass for Three Logistical Scenarios

Scenario	Characteristics	Type(s) of Biomass	Cost of Delivered Biomass ($/GJ)	Cost of Delivered Biomass ($/metric ton)
1	Local sourcing of biomass	Woody biomass	2.1	40
2	Local sourcing, augmented with external deliveries via rail	Woody biomass and woody pellets	3.3	62
3	External deliveries via barge	Herbaceous pellets	6.9	120

NOTE: GJ = gigajoule (10^9 joules).

To determine the life-cycle GHG emissions from sourcing, processing, and burning biomass, we apply the Calculating Uncertainty in Biomass Emissions (CUBE) model (Curtright et al., 2010). By coupling the GHG analysis with the biomass costs derived for the supply scenarios and the plant-site costs, we are then able to determine the cost of avoiding a given amount of GHG emissions. Using information provided during the interviews, we then considered key factors in the development of biomass markets and the potential benefits of such markets.

Key Findings

Plant Operators' Experiences Cofiring Biomass

The Principal Challenge with Respect to Cofiring Biomass Is Maintaining a Consistent Fuel Supply. Plant operators reported that cofiring with biomass at up to 10 percent of total fuel energy had little effect on the performance of the boiler or on installed emission-control equipment. The lower energy content and increased moisture content of biomass relative to coal can result in a reduction in plant generating capacity, but plant operators did not cite this as a significant concern. These results are consistent with reported experience in Europe (Van Loo and Koppejan, 2008) and the United States (Tillman, 2001; Antares Group, 2009). However, most domestic experience to date concerning cofiring biomass with coal is recent, consisting of test fires or a year or two of cofiring. The potential effects that long-term cofiring (i.e., greater than five years) could have on plant components are still unknown.

One potential technical improvement that was identified, especially for boilers that burn pulverized coal (PC), is the development of a burner specifically designed to fire biomass or mixtures of biomass and coal. Biomass storage, handling, and processing can be challenging; plant operators reported that programs that facilitate the sharing of lessons learned and best practices could be a benefit.

The most significant concern cited by the majority of interviewees was the challenge of securing a consistent supply of biomass. Suppliers tend to be small, so plants find that it is necessary to maintain relationships with several dozen suppliers to meet the fuel requirements for the plant. We did speak with one aggregator who maintains a database of biomass fuel suppliers and will charge a premium to guarantee a consistent supply of biomass.

The Choice to Cofire Biomass Depends on a Confluence of Technical and Regulatory Factors. In the absence of regulation of GHG emissions, the decision to convert a plant to cofire depends more on regulatory and policy factors than on technical factors:

- The plant operator must be able to recover the additional costs of cofiring through renewable-energy credits (RECs) or increases in rates.
- The ability to burn biomass must be included in the existing air permit for the plant.

Surprisingly, we did not find that the type of boiler factored significantly into the decision about whether to cofire biomass with coal: Appropriate handling and processing methods have been devised and tested to allow biomass to be used with any type of boiler. It is the aggregate of the plant's technical characteristics, cost to implement, policy, and regulatory factors that currently lead plant operators to choose to cofire biomass with coal.

Plant-Site Costs of Cofiring

Cofiring Biomass Results in Increased Capital and Operating Costs and Lost Revenues. We built a model to estimate the plant-site costs of cofiring biomass and coal at low cofire fractions (i.e., below approximately 10 percent biomass by energy content). At current prices for woody biomass (approximately $40 per dry metric ton), the additional costs associated with cofiring at 5 percent by energy are approximately $0.021 per kilowatt-hour. These costs include $0.007 per kilowatt-hour each for increased capital and nonfuel operating costs, $0.001 per kilowatt-hour for biomass fuel, and $0.005 per kilowatt-hour of lost revenue. The lost revenue is due to two factors: The plant is slightly less efficient when cofiring biomass, and the biomass requires additional parasitic electricity to process—electricity that could be sold. The costs rise linearly with the price of biomass, rising $0.006 per kilowatt-hour for each $10 increase in biomass prices: At prices for wood chips of $120 per dry metric ton, the cost of cofiring is an additional $0.069 per kilowatt-hour.

Densification of Biomass Does Not Result in Plant-Site Cost Savings. Because densified biomass (i.e., pellets) requires fewer plant-site modifications and can be commingled with coal, densification might result in significant plant-site cost savings over other biomass forms. As mentioned earlier, the additional costs of cofiring wood chips are $0.021 per kilowatt-hour at current prices of $40 per dry ton. Our analysis indicates that the delivered cost of herbaceous pellets would be $120 per dry metric ton. At that cost of biomass, the cost of cofiring at 5 percent is an additional $0.069 per kilowatt-hour.

Fixed-Price Renewable-Energy Credits Might Not Be an Effective Tool to Encourage Cofiring. Another interpretation of the cost of cofiring is the required price of a REC to recover costs associated with cofiring. For current woody biomass prices of $40 per dry metric ton, the implied price of a REC (at 5-percent cofiring) for a bus-bar electricity price of $0.0444 per kilowatt-hour is approximately $0.021 per kilowatt-hour. However, as the price of biomass rises, so does the required price of a REC. At biomass supply prices of $62 per dry metric ton, the implied price of a REC is $0.032 per kilowatt-hour, at $120 per dry metric ton, the implied price of a REC is $0.069 per kilowatt-hour. One of the plant operators we interviewed reported that he was able to receive a REC of $0.045 per kilowatt-hour, which covers costs of cofiring and associated revenue losses up to a biomass price of approximately $80 per dry metric ton. The implication of these results is that, because of the inherently varying nature of the costs, a fixed-price REC might not be an appropriate means to encourage cofiring and might be more applicable to other renewable-energy sources, such as wind, where most costs are fixed rather than variable.

Potential Biomass Demand and Logistics

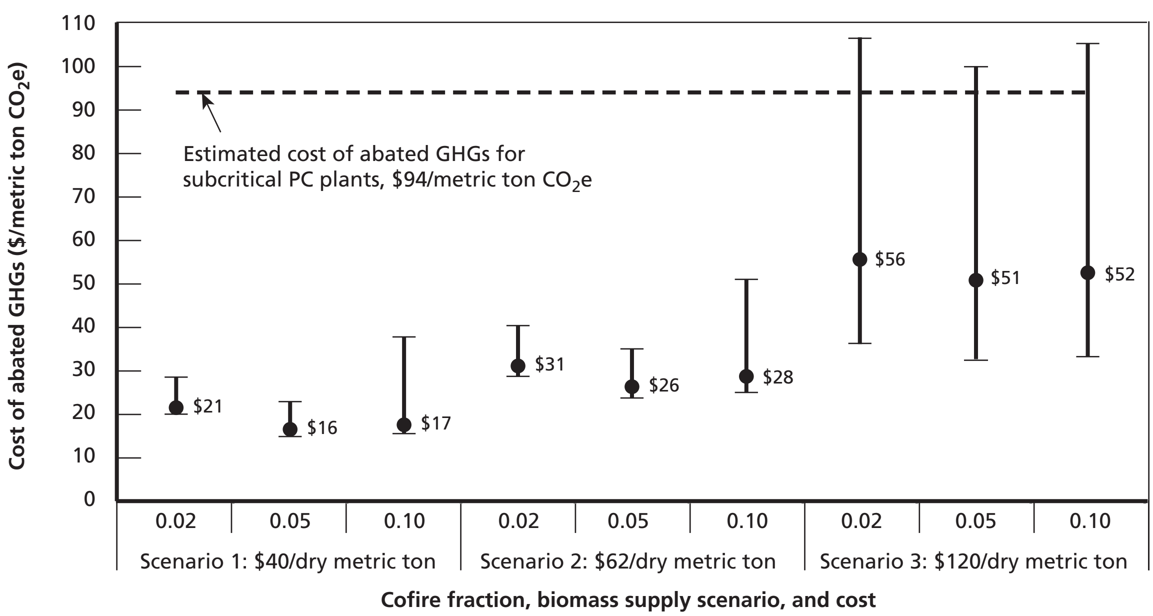
The Appalachia and Northeast Regions Are Potential Biomass Importers, and the Pacific and Lake States Regions Are Potential Suppliers. Cofiring replaces a fraction of coal with biomass. If there were a widespread movement toward cofiring, regions in which a significant amount of the installed generating capacity is currently coal based could exhaust locally available resources. Conversely, a surplus of resources might exist in regions in which there was relatively little installed coal-fired electricity generating capacity. Our analysis indicates that the U.S. Department of Agriculture (USDA) Appalachia, Southern Plains, Northeast, and Mountain regions would likely exhaust local biomass resources under scenarios with significant development of cofiring, whereas the Pacific, Delta, Northern Plains, and Lake States regions could potentially be biomass suppliers.

Densification of Biomass Is Cost-Effective at Distances Greater Than 200 Miles. Densifying biomass adds between $16 and $34 per dry metric ton to the cost of biomass. However, pellets have a high bulk density and low moisture content and are easier to handle than other forms of biomass. As a result, the benefit of densification can be realized when transporting biomass long distances. Our analysis indicates that, when shipping by rail, the minimum distance at which the savings in transportation costs offsets pelletization costs is approximately 225 miles for wood chips and about 200 miles for herbaceous bales. When shipping by barge, the minimum distances are 230 miles for wood chips and 160 miles for bales. Although densification provides a cost savings over raw biomass at these transportation distances, additional transportation costs are still incurred. In our examples, these additional costs were $50 per dry metric ton for wood pellets transported from Minneapolis, Minnesota, to Pittsburgh, Pennsylvania, by rail and $15 per dry metric ton for herbaceous pellets transported from Paducah, Kentucky, to southern Ohio by barge.

Greenhouse-Gas Reductions from Cofiring

Cofiring Is a Cost-Effective Means of Reducing Greenhouse-Gas Emissions. The primary current motivation for cofiring biomass with coal is to reduce the life-cycle GHG emissions associated with producing electricity. We assess cofiring biomass at input-energy fractions of 2, 5, and 10 percent of total input energy because experience to date indicates that major plant modifications are not required to cofire biomass at or below these percentages. For the three supply scenarios that we considered, these results are summarized in Figure S.1; included in

Figure S.1
Cost of Abating Greenhouse Gases Through Cofiring Biomass with Coal



SOURCE: NETL (2010, Chapter Five and Appendixes B and E).
NOTE: CO_2e = CO_2 equivalent. Woody biomass is the source for scenarios 1 and 2, and herbaceous pellets are supplied in scenario 3. The price indicated on the figure represents the best estimate; error bars represent high and low estimates.
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Figure S.1 is a reference line for the current estimated cost of abating a ton of CO_2 by carbon capture and storage (CCS) at a subcritical PC power plant (NETL, 2010).

Our analysis shows that the cost of abating GHG emissions is \$21 per metric ton CO_2e at a cofire fraction of 2 percent and a biomass price of \$40 per dry metric ton. The abatement costs drop as the cofire fraction increases: \$16 per metric ton CO_2e for a cofire fraction of 5 percent. The cost of abating GHGs drops as the cofire fraction increases because it enables a higher utilization of the equipment installed to cofire biomass. The cost of abating GHGs rises for cofire fractions of 10 percent because additional electrical load is required to process the biomass, increasing processing costs. At a biomass supply cost of \$120 per dry metric ton, approximately three times the current price of wood chips, the best estimate of the cost of abating GHGs is \$51 per metric ton CO_2e when cofiring at 5 percent. These figures are compared with an estimated cost of abatement of \$94 per metric ton CO_2e when retrofitting subcritical PC plants for carbon capture and sequestration (NETL, 2010). However, there is considerable uncertainty regarding the life-cycle GHG emissions of agricultural residues, resulting in estimated costs of abatement ranging from \$33 to \$100 per metric ton CO_2e.

Developing Biomass Markets

Biomass Markets for Electricity Generation Currently Cannot Support Densified Fuels. Currently, biomass energy markets in the United States comprise many small suppliers and are regionally diverse. Densified biomass could promote standardization and the integration of markets by (1) reducing plant-site costs for cofiring, (2) reducing transportation costs, and (3) increasing fuel flexibility and insulation from supply shocks. We found that propositions 1 and 2 are valid in certain circumstances and that 3 is questionable. It is true that biomass feed systems are less expensive for pellets than they are for raw biomass. For torrefied biomass, which is processed such that it has properties similar to those of coal, additional plant-site costs can be minimal. However, these differences in the costs of cofiring between densified and raw biomass are similar after taking into account the additional costs of producing a biomass pellet. Although transporting pellets long distances is less expensive than transporting raw biomass, the extra cost of manufacturing pellets results in a much higher total cost than that of using local raw biomass. Finally, the benefits of fuel flexibility do not exist in current biomass markets, which are characterized by an abundance of suppliers and an oversupply of biomass. In the absence of legislative requirements to use biomass, we expect such a situation to continue. If there were a requirement to use biomass, either as part of a state renewable portfolio standard or as a means of reducing life-cycle GHG emissions, that significantly increased delivered prices for local biomass, then pellets, and other densified forms of biomass, might become attractive.