Economic Impacts Resulting from Co-firing Biomass Feedstocks in Southeastern United States Coal-Fired Plants

Burton C. English, Kim Jensen, Jamey Menard, Marie Walsh, Daniel De La Torre Ugarte, Craig Brandt, Jim Van Dyke, and Stanton Hadley

Burton English (benglish@utk.edu) and Kim Jensen are Professors, Jamey Menard is a Research Associate, Marie Walsh is an Adjunct Professor, and Daniel De La Torre Ugarte is a Research Associate Professor in the Department of Agricultural Economics, University of Tennessee, 2621 Morgan Circle, Knoxville, TN 37996-4518, Phone: (865) 974-3716, Fax: (865) 974-4829

Craig Brandt and Jim Van Dyke work in the Environmental Sciences Division, Oak Ridge National Laboratory, P.O. Box 2008, Oak Ridge, TN 37831-6038; Stanton Hadley works in the Engineering Science and Technology Division, Oak Ridge National Laboratory, P.O. Box 2008, Oak Ridge, TN 37831-6070

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Abstract: *Economic impacts of using biomass in Southeast United States coal-fired plants are estimated using a county-level biomass database; ORCED, a dynamic electricity distribution model that estimates feedstock value; ORIBAS, a GIS model that estimates feedstock transportation costs; and IMPLAN, an input-output model that determines the impacts of co-firing on economic activity.*

Background

Electricity from coal-firing provides over 50 percent of the electricity generated in the United States. For the Southeast United States, 60 percent of the electricity demand depends on coal (Department of Energy, 2001b). Although coal-fired plants are important sources of electricity in the United States, negative environmental impacts are associated with this type of electricity generation. About two-thirds of sulfur dioxide (SO_2), one-third of carbon dioxide (CO_2), and one-fourth of nitrogen oxide (NO_x) emissions are produced by burning coal. Particulate matter is also emitted when coal is converted to electricity. The Southeastern Region of the U.S. leads in CO_2 emissions and ranks second in emissions of SO_2 and NO_2 (Department of Energy, 1999).

When compared with coal, biomass feedstocks (agriculture residues, dedicated energy crops, forest residues, urban wood waste, and wood mill wastes) have lower emission levels of sulfur or sulfur compounds and can potentially reduce nitrogen oxide emissions. In a system where biomass crops are raised for the purposes of energy production, the system is considered carbon neutral since crops absorb carbon during their growth process. Thus, the net emissions of the CO_2 are much lower compared with coal-firing (Haq).

The credits for offsetting SO_x emissions, currently priced at $100 per ton, provide an incentive for co-firing biomass with coal (Comer, Gray, and Packney). Costs of conversion of power plants for co-firing are relatively modest at the lower levels of percent biomass in the mix. Power companies also have the potential in the future, to obtain marketable value through offsetting CO_2 for greenhouse gas mitigation. Replacing coal with biomass offers a means for achieving CO_2 reductions while maintaining operational coal generating capacity (Comer, Gray, and Packney). Co-firing as compared with 100 percent biomass use is not reliant on a continuous supply of biomass because of a ready supply of coal (Demirbas).

In 2002, the Bush Administration announced legislation to implement the Clear Skies Initiative. The legislation proposes to cap SO_2, NO_x, and mercury emissions from power plants in the next two decades. The caps are at higher levels than required under the Clean Air Act (Environmental Protection Agency). A summary of the projected reductions with the caps is displayed in Table 1.

Table 1. Year 2000 Estimates Versus Projected 2020 Estimates under the Clear Skies Initiative.

	SO_2 (1000 tons)		NOx (1000 tons)		Mercury (tons)	
State/Region	2000	2020	2000	2020	2000	2020
Alabama	500	75	182	31	2.53	0.38
Georgia	508	66	185	37	1.47	0.25
Kentucky	588	194	244	44	1.78	0.32
Mississippi	129	9	65	11	0.24	0.04
North Carolina	459	133	161	45	1.52	0.67
South Carolina	200	64	87	26	0.53	0.19
Tennessee	425	119	156	39	1.12	0.38
Virginia	213	81	82	32	0.64	0.3
Regional Total	3,021	741	1,162	265	9.82	2.53
United States	11,818	3,900	4,595	1,700	67	18

Source: Environmental Protection Agency, Office of Air and Radiation, Clear Skies, 2003.

For the Southeast, the Initiative would potentially result in a reduction of 75 percent in SO_2 emissions, 57 percent in NO_x emissions, and 77 percent in mercury emissions (Environmental Protection Agency).

This study examines the economic impacts of co-firing biomass feedstocks (forest residues, primary mill residues, agricultural residues, dedicated energy crops-switchgrass, and urban wood wastes) with coal in coal-fired plants in the Southeastern United States (Alabama, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia). The impacts of using each type of feedstock are evaluated for three emission credit and two co-firing level scenarios. The potential economic impacts (total industry output, employment, value added) for producing/collecting/transporting the feedstock, retrofitting the coal-fired utilities for burning the feedstock, operating co-fired utilities, and the coal displaced from burning the feedstock are estimated.

Prior Studies

Mann and Spath use a life cycle assessment, where all processes are examined cradle-to-grave. They found both life cycle and plant emissions are reduced with co-firing from a closed-loop biomass system (biomass production dedicated for energy use) compared with coal-based electricity generation. Reductions in emissions include CO, particulates, SO_2, and NO_x. Their results showed that at rates of 5% and 15% by heat input, co-firing reduces greenhouse gas emissions on a CO_2-equivalent basis by 5.4% and 18.2%, respectively.

Morris notes that use of certain types of biomass may provide valuable waste disposal services. Morris examines the benefits from biomass use accruing from changes in air pollutants and greenhouse gases, landfill capacity use, forest and watershed improvement, rural employment, economic development, and energy diversity and security. The study found that loss of the biomass industry would result in a loss of 12,000 rural jobs and would result in an additional 4.6 million tons of residues returning into the waste stream.

Haq examined issues affecting uses of biomass for electricity generation in the United States. Estimates of about 590 million wet tons of biomass are available on an annual basis, with 20 million wet tons available at prices of $1.25 per million Btu or less, while the average price of coal to electric utilities was $1.23 per million Btu. Therefore, for the majority of biomass production, cost competitiveness with coal is an issue. Under a 20% non-hydroelectric renewables portfolio standard (20% RPS), about 9.6 to 14.4 million acres of land would be devoted to energy crops by 2020.

Walsh et al. found that if producers were paid $44/dry metric ton for switchgrass, nearly 17 million hectares (41.9 million acres) of agricultural cropland in the U.S. could produce bioenergy crops at a profit greater than existing agricultural uses. Also, farm income could increase by nearly $6 billion as a result of bioenergy crop production. Total annual biomass production is estimated at 171 million dry metric tons (188 dry tons), equivalent to $3.07*10^{12}$ MJ (2.91 Quads) of primary energy, potentially displacing about 253 million barrels of oil or supplying 7.3 percent of U.S. electricity needs.

Graham and Walsh note that the community level job creation potential increases with larger biomass facilities as labor, farmer participation, input use, and transportation and product distribution needs increase. Direct job creation associated with the conversion facility can be measured by determining the number of people (people per unit of output generally decrease in the plant operation) needed to build and operate the facility. Jobs may be created in associated supply and support industries. Increased employment will have a multiplier effect throughout the community. However, jobs may be lost if a new biomass facility displaces conversion facilities using conventional technologies. Demands (and thus costs) on local infrastructure facilities might also increase as facility size increases.

Methodology

Study Area

The power plants studied for this analysis were associated with the Southeastern Electric Reliability Council (SERC), the regional organization for the coordination of the operation and planning of the bulk power electric systems in the southeastern United States. This region includes areas in eight states – Alabama, Georgia, Kentucky, Mississippi, North Carolina, South Carolina, Tennessee, and Virginia. Power plants in each of these states were identified and incorporated into the analysis. In order to conduct the regional economic impact analysis, trading regions within the eight states were identified. These regions were based on the Bureau of Economic Analysis Trading Areas (referred as Economic Trading Areas (ETA) in this study).

The analysis uses the Oak Ridge County-Level Biomass Supply Database (ORCBS) and three additional models – Oak Ridge Integrated Bioenergy Analysis System (ORIBAS), Oak Ridge Competitive Electricity Dispatch (ORCED), and Impact Analysis for Planning (IMPLAN). The ORCBS Database provides county biomass quantities available at several price levels for multiple feedstock categories (forest, agricultural, and mill residues; dedicated energy crops; urban wood wastes) and sub-categories (e.g., spring and winter wheat straw; corn stover for agricultural residues) for the United States. The Oak Ridge Integrated Bioenergy Analysis System is a GIS-based transportation model used to estimate the delivered costs of biomass to power plant facilities (Graham et al., Noon et al.). The Oak Ridge Competitive Electricity Dispatch model is a dynamic electricity distribution model that estimates the price utilities can pay for biomass feedstocks. ORCED models the electrical system for a region by matching the supplies and demands for two seasons of a single year. The IMPLAN model uses input-output analysis to derive estimated economic impacts for constructing and operating the power plants, the transporting of the bio-based feedstocks, and the growing/collecting of wastes, residues, and dedicated crops in the eight states. Input-output analysis creates a picture of a regional economy to describe flows of goods and services to and from industries and institutions.

For each power generating location, ORIBAS provides the delivered cost of the bio-based feedstock, the cost of transporting the feedstock from collection point to the demand center, the value paid to the original owner of the feedstock, and the location of the feedstock and the power plant. The value to be paid is pre-specified and must be greater than or equal to the cost of growing, collecting, loading, and unloading the feedstock.

The delivered value that the power facilities are willing to pay per MMBtu is estimated by ORCED and that information is supplied to ORIBAS. Once ORIBAS is solved, the number of plants that can get sufficient quantities of biomass delivered at the pre-specified price is estimated along with the location, quantity, and value of the biomass supplies. This information is then converted into direct economic impact estimates and used by IMPLAN.

Economic or direct impacts occur when changes in policies or other actions stimulate changes in final demand for a sector's product. Indirect impacts measure the change in inter-industry purchases due to the change in final demand from the industry directly affected. In addition, induced impacts measure the changes in the incomes of households and other institutions and the resulting increases/decreases in spending power as a result of the change in final demand.

Impacts are estimated for four economic sectors. A one-time only impact in the construction sector is estimated. Annual impacts are estimated for electrical generation, growing/collecting of the bio-based feedstock, and transportation sectors. In addition, the difference between the amount the power plant is assumed to pay for the residue and the cost of growing/collecting that residue is estimated. This amount is assumed to go to the original owner of the feedstock as a change in proprietary income. In areas that produce coal that is being replaced by residue within the Southeast, a negative impact from the reduction of coal mining is estimated.

Co-Firing Scenarios Analyzed

Two levels of co-firing are examined in the analysis – 2 percent or 15 percent (by weight) of the coal replaced by bio-based feedstocks. In addition, three levels of carbon taxes are assumed – $0 (Base), $70 (Low Carbon), and $120 (High Carbon) per ton of pollutant emitted. Further, each ton of SO_x produced has a negative value of $142. In the positive carbon tax scenarios, each ton of NO_x pollutant generates -$2,374 (Table 2) (Department of Energy, 2001a). This results in a total of five scenarios to be estimated – Base Case 2%, Low Carbon 2%, Low Carbon 15%, High Carbon 2%, and High-Carbon 15%. A 15% co-fire under the Base Case was evaluated; however, power plants could not attain a sufficient supply of residues, at prices less than they could afford to pay, to meet the 15% demand level.

Table 2. Value of Pollutants in the Three Scenarios Analyzed.

Scenario	Carbon Value	NO_x Value	SO_x Value
		$/ton	
Base	0	0	142
Low Carbon	70	2,374	142
High Carbon	120	2,374	142

Source: Department of Energy, Energy Information Administration. 2001. "Analysis of Strategies for Reducing Multiple Emissions from Power Plants: Sulfur Dioxide, Nitrogen Oxides, and Carbon Dioxide."

Total Project Investment (Plant Construction)

The costs of converting power plants to co-firing differed depending on whether a 2- or 15-percent co-fire was assumed. If a 2 percent co-fire is assumed, the costs of conversion are estimated to equal $50/kw (Van Dyke). Likewise, for the 15% co-fire scenario, the investment cost was estimated to be $200/kw (Van Dyke). Each power plant was rated with a plant capacity and a capacity factor (Van Dyke). When these two values are multiplied, the number of kilowatts produced is determined. The kilowatts produced multiplied by the co-fire level assumed (2% or 15%) multiplied by either the $50 or $200 investment cost provides an estimate of the total investment required ($\mathrm{INVEST}_{p,m}$ where p is the power plant and m is the percent co-fire assumed) (Van Dyke).

Based on information provided by Van Dyke, a million dollar investment was proportioned through the economy and assigned to the appropriate IMPLAN industry sectors. Each ETA was then impacted with a million dollar investment for both the 2% and 15% co-firing scenarios. The impact of this million dollar investment was then divided by the direct impact to develop a multiplier ($\mathrm{MULT}_{ETA,m}$ where ETA is a prespecified trading area and m is the percent co-fire assumed).

To determine the impact of the investment stage within an ETA, the total investment required for all power plants within the ETA expressed in millions of dollars was multiplied by the multipliers for TIO, employment, and value added. This can be represented as:

$$\mathrm{IMPACT}_{ETA,m} = \mathrm{MULT}_{ETA,m} * \sum_{p=1}^{n} \mathrm{INVEST}_{p,m}$$

where p is the number of plants in the ETA.

Annual Operating Costs

The IMPLAN sector representing electricity production was modified to reflect an increase in annual machinery repair expenditures. Employment compensation was increased to reflect the additional labor requirements. Assuming a $1 million change, employment compensation was increased by $750,000 and machinery by $250,000 (Van Dyke). Using IMPLAN results, operating multipliers were estimated for total industry output, number of jobs, and value-added (Olson and Lindall). To estimate the increased amount spent per year to operate the power plant, the amount of coal replaced by biomass was multiplied by 22, the amount of mmBtu's in coal, and then by $0.09. The $0.09 is the estimated operating cost per mmBtu (Van Dyke). The total impact on the economy in terms of output, jobs, and value-added is estimated by multiplying the amount spent per year with the appropriate multiplier.

Bio-based Feedstock Costs

Each of the six types of bio-based feedstocks considered in the analysis had a different cost structure. The distribution of expenditures across input sectors is displayed in Table 3. These distributions were then multiplied times a million dollars and assigned the appropriate IMPLAN sector. The non-labor costs were used to adjust the current production function of the sector most likely to provide the output.

A new economic impact model was created for each bio-based feedstock with adjusted production function coefficients reflecting the new activity in the economy. Total industry output, employment, and value-added multipliers were then generated for each bio-based feedstock. These multipliers were multiplied by the cost of producing/collecting the feedstock that ORIBAS indicated would be used by the power plant. The economic impact that co-firing would have in the areas where the feedstock originated was then estimated.

Proprietary Income Impacts

The value paid for the bio-based feedstock determined by ORIBAS for each scenario was subtracted from the per acre cost to estimate impacts on proprietary income. An impact analysis on proprietary income was conducted in each ETA and the multiplier generated multiplied by the total change in proprietary income served as an estimate of the impacts that would occur as a result of an increase in profit within the region.

Table 3. Expenditures by IMPLAN Sector Per Million Dollars of Gross Expenditures by Feedstock Type.

		Residues					
IMPLAN Sector	Description	Ag*	Forest*	Switchgrass*	Poplar*	Mill	Urban Waste
		$1,000 dollars per million dollars of expenditure					
20	Seeds	0	0	30	100	0	0
26	Miscellaneous	160	90	40	50	0	0
26	Operating Costs	0	0	20	100	0	0
202	Fertilizer	0	0	310	40	0	0
204	Chemicals	0	0	10	110	0	0
451	Fuel/Lube	70	60	80	40	360	310
456	Depreciation	240	280	220	110	140	180
456	Capital	70	60	10	30	10	10
460	Insurance	0	10	20	10	10	10
482	Repair	330	170	110	110	130	160
	Labor	130	330	150	300	350	330
	Total	1,000	1,000	1,000	1,000	1,000	1,000

*Ag—costs for agriculture residues include round baling and moving to edge of field and stacking.
*Forest—costs for forest residues include felling-bunching/skidding to field edge/chipping at field edge and blowing into van.
*Switchgrass—costs for switchgrass include production costs and harvest costs of round baling, moving to edge of field, and stacking.
*Poplar—costs for poplar include production costs and harvest costs of felling/bunching, skidding, chipping and blowing into chip van.

Transportation Sector Impacts

Total transportation sector impacts were determined by summing costs of the biomass transported to the power generating facility over all trips and residue types. The result was a change in total industry output. Input-output multipliers for the ETA's in which the power plants are located were then used to estimate the impact on the economy, employment, and value-added.

Results

Consumption of Residues by Scenario

In each of the scenarios evaluated some residues were projected to replace coal as a fuel. Under the Base Case (Table 2), a 2% co-fire scenario generates a demand of 0.51 million metric tons of residue. The residue demanded consists of mill and urban wastes, plus forest residue. Agricultural residues or dedicated crops cannot compete with coal prices, and therefore, are not demanded. In the Base Case, feedstock owners are projected to receive slightly over $16/ton for urban waste to nearly $21/ton for forest residue. At these prices, no dedicated crop or agricultural residues are purchased by the power plants. Over 510,000 metric tons of residues are used producing 8.4 trillion Btu's or 2,478 Kwh of electricity[1]. Demand for residue occurs in seven of the eight states with concentrations near urban areas and near power generating facilities.

In the other four scenarios, as percent co-fire increases so does the amount of residue demanded, and as the amount the utility is willing to pay for residue increases the demand for residues increases. However, this increase is not uniform among all units as competition among units for placing electricity on the grid changes as the cost of generating electricity changes. Indeed, as the system moves from a low carbon to a high carbon tax, less total residue is demanded in the 2% co-fire solution. In the High Carbon 15% co-fire scenario, 29 million metric dry tons of biomass is used in the generation of 137,054 Kwh of electricity.

In both the 2- and 15-percent co-fire solutions, dedicated crops play a large role in the mix of residues, wastes, and dedicated crops. Nearly 40 percent of the bio-based feedstock used in the co-fire comes from dedicated crops in both co-fire solutions. Dedicated crops increase from a low of 0 tons of use in the Base to 1.6 million metric dry tons in the 2% co-fire scenario

[1] Conversion factor of 293 Kwh per million Btu's is used.

and 11.0 million metric dry tons in the 15% co-fire scenario. Total biomass use increases to 4 million metric dry tons in the 2 percent co-fire scenarios and 22 and 29 million dry tons in the low and high carbon, 15% co-fire scenarios, respectively. Geographic locations producing the bio-based feedstocks expand as the amount of bio-based feedstock produced increases.

The value of the residues to the power plant increases as the value of coal decreases. In the Base Case, the price paid by power plant averages $23-$24 per ton. In the High Carbon 15% scenario, this value increases to $55 per ton with the residue "farm gate" price ranging from a low of $18.40 for urban waste to $45.75 for agricultural residues.

Impacts to the Coal Industry

Using biomass instead of coal to generate electricity will result in a decrease in coal demand within the region. The amount of decrease depends on the amount of coal that would have been purchased within the region had the substitution of bio-based feedstocks not occurred. This study estimated the amount of decrease by the BEA study regions based on state proportion of coal purchases estimated to be replaced.

In the Base solution, 355 thousand tons of coal is replaced by biomass (Table 4). A decrease of 3,344 tons of sulfur emissions along with a decline of $8.4 million dollars in coal purchases within the region is estimated. This decrease in coal purchases reduces economic activity within the region by $15.5 million dollars and 127 jobs are reduced as a result of the decreased purchases (Table 5). These impacts increase as demand for coal declines.

Table 4. Characteristics of Coal Replaced by Bio-Based Feedstocks for Alternative Scenarios.

	Coal Replaced	% Sulfur	Coal Value	Sulfur Replaced
	tons	percent	dollars	tons
Base-2% co-fire	355,412	0.94	$12,487,292	3,344
Low Carbon, 2% co-fire	3,251,073	1.33	$91,389,091	43,160
Low Carbon, 15%co-fire	18,198,976	1.24	$525,177,225	225,992

Total Impacts Resulting from Co-firing Bio-Residues

The bio-based feedstock sectors gain $10.3 million annually (forest residues—$0.6 million, mill waste—$4.2 million, and urban waste—$5.5 million) for producing, harvesting, and collecting the feedstock. In addition, $1.4 million is paid toward the transportation of the feedstock to the power generating facilities. An estimated $0.7 million in operating costs occur annually with an additional $4.6 million in investment required to convert the exclusive coal burning system to co-fire. Proprietors within the region are estimated to earn over $1.3 million.

Incorporating the decrease in coal demand that would occur with the substitution of biomass of $8.4 million, the region's annual increase in direct economic activity in the Base Case, 2% Co-fire scenario is estimated at $5.5 million and nearly 100 additional jobs (Table 5). The direct, indirect, and induced impacts yield a total impact of $7.4 million annually with an additional one time impact of $7.5 million as a result of increased investment for converting the facilities into co-fire units.

In the 2% co-fire scenarios, as the Carbon Tax increases, economic activity first increases and then slightly declines. A comparison of the Base with the Low Carbon scenarios shows total economic activity impacts as measured by total industry output increases from $47.3 million to $260.5 million. This occurs despite a decrease in economic activity as a result of replacing coal of $110 million. An additional $6.5 million is spent operating the power plants and $14.6 million is spent transporting the bio-based feedstocks. These impacts increase total economic activity by $9.2 and $29.9 million for operation and transportation sectors, respectively. Job increases within the region are projected to exceed 3,800 in both the low and high carbon 2% scenarios.

In the 15 % co-fire scenarios, the impacts are much larger. Unlike the Base scenario, in which the power plants are required to use 15% co-fire if they decide to co-fire, many plants do select the co-fire alternative as their optimum method of producing electricity. In the Low Carbon scenario, nearly $1 billion is spent on the production, harvest, and/or collection of the bio-based feedstocks. This amount increases to nearly $1.6 billion under the high carbon tax situation. Adding the indirect and induced impacts to the direct impacts resulted in an estimated $1.5 and $2.4 billion annual total industry output impact to the region's economy. An additional impact of $430 million and $533 million occurs as a result of increased transportation of bio-based feedstocks in the Low Carbon and High Carbon tax scenarios, respectively. Operating costs in the power facility increases $36 to $47 million. With the added impacts that occur as a result of these expenditures, an estimated increase in the economy of $52 and $68 million is projected for the Low Carbon and High Carbon tax scenarios, respectively. Finally, for both the Low Carbon and High Carbon tax scenarios, less coal is purchased from the region and this decrease in economic activity resulted in an estimated $600 or $800 million reduction, respectively.

The number of jobs within the region will increase overall. A decrease in jobs caused by a decrease in coal demand (-6,500 in the High Carbon, 15% Co-fire solution) is offset by the increase in employment of 6,000 as a result of changes in the transportation industry, 500 jobs in the power industry, and 32,000 jobs in the supply of biomass industries. Impacts are similar for all the co-fire scenarios.

Conclusions

Co-firing does appear economically competitive under the current market conditions except in certain agricultural situations and under low co-fire levels. Very small amounts of residue (2%) are economically feasible for co-fire in the Base Case. Under the two percent co-fire, some plants do find residue at lower costs than coal plus sulfur emissions costs. However, using a 15% co-fire, the analysis indicates paying the sulfur emissions cost is more economical than burning residue. The analysis does indicate that there are areas now that would benefit from generating electricity using forest residues, mill waste, and urban waste. In fact, nearly 2,500-kilowatt hours of electricity could be produced using these residues replacing 355,000 tons of coal. Each state, with the exception of Kentucky, consumes some residue.

There is little difference between the Low Carbon and High Carbon tax scenarios under the two percent co-fire level. There is a slight change in the mix of the residues. However, the power plants using the residues do not change between the two scenarios. Total Industry Output within the region increases by 170 million dollars including a reduction in the demand for coal of $60 million. Analysis indicates that an estimated 270 jobs would be created.

While in the Base Case, increases in percent co-fire from 2 to 15% resulted in no additional residue demand, in both the Low Carbon and High Carbon emissions cost scenarios, the amount of residues consumed will significantly increase from 4 million metric dry tons to 23 (Low Carbon) and 29 (High Carbon) million metric dry tons. This expansion in residue demand resulted in significant increases in regional economic impacts. There is an estimated $1.4 to $2.2 billion dollar impact that occurs to the Southeast Region under the high co-fire levels with Low Carbon and High Carbon emission cost scenarios, respectively. Concurrent with this increase in economic activity is an estimated increase of 25,000 jobs.

Discussion

The cost data for conversion of the boilers to accept residues is extrapolated from a study of a single power plant (Van Dyke; Antares Group and Parsons Power). It is expected that these costs would vary between power plants and in fact between units within power plants. The costs of producing, collecting, and/or harvesting the bio-based feedstocks are estimated costs and as such will vary depending on the locations and infrastructure available in the region.

More residues might be demanded than indicated in the analysis. The model used in determining whether electricity could be generated from bio-based feedstocks in a competitive environment assumed that the entire power generating facility would be co-fired at the 2 and 15 percent levels. If the amount of residue required for each level was not available at a competitive price, the entire facility would continue burning 100 percent coal. However, each facility consists of multiple units and co-firing could occur at the individual unit level rather than the entire facility level. Lower unit demand levels result in lower delivered feedstock costs compared with total facility demand, resulting in the potential for more co-firing than is estimated in the analysis.

Finally, the analysis provides a first cut at estimating the economic benefits of substituting bio-based feedstocks for coal in the generation of electricity. As conducted, the analysis estimates the amount of benefits that occurred within a trading area (BEA region). Some of the leakages that occur from a transaction within the region would likely occur in the eight state area. Thus, the actual economic impacts for the eight state region might be greater than those presented in this analysis.

No attempts are made to evaluate the overall U.S. impacts nor is the impact of increased feedstock costs as a result of the employment of environmental taxes incorporated into the analysis. Furthermore, the authors recognize that additional economic impacts that are not captured would occur to the rail industry (transportation of coal) and other forward linked sectors to the coal industry. Finally, estimation of the long-term economic benefits accruing to the region as a result of a cleaner environment is beyond the scope of this study.

Table 5. Estimated Total Impact on the Economy as a Result of Increased Demand for Bio-Based Feedstocks using Total Industry Output, Employment, and Total Value-Added Indicators by Carbon Tax and Co-fire Percent Scenario.

	Base Case 2%		Low Carbon 2%		Low Carbon 15%		High Carbon 2%		High Carbon 15%	
Estimated TIO Impacts	Direct	Total	Direct	Total	Direct	Total	Direct	Total	Direct	Total
					$1,000 dollars					
Transportation	$1,455	$2,995	$14,569	$29,862	$215,291	$432,973	$13,431	$27,559	$257,456	$533,618
Operating	$704	$1,011	$6,437	$9,231	$36,034	$51,556	$6,437	$9,231	$47,495	$68,154
Coal Replacement	-$8,368	-$15,512	-$60,117	-$110,063	-$325,295	-$596,173	-$60,117	-$110,063	-$439,634	-$805,137
Bio-based Feedstocks	$11,663	$18,854	$218,340	$331,425	$975,436	$1,516,413	$217,815	$330,239	$1,594,662	$2,458,748
Total Annual Impact	$5,453	$7,349	$179,229	$260,455	$901,465	$1,404,770	$177,566	$256,967	$1,459,979	$2,255,383
Investment (Non-annual)	$4,655	$7,577	$43,533	$71,204	$1,080,693	$1,830,102	$43,533	$71,204	$1,382,542	$2,367,249

Estimated Job Impacts (Number created)

	Base Case 2%		Low Carbon 2%		Low Carbon 15%		High Carbon 2%		High Carbon 15%	
	Direct	Total	Direct	Total	Direct	Total	Direct	Total	Direct	Total
Transportation	14.3	34.9	142.8	342.1	2,120.5	5,042.9	131.6	315.7	2,520.8	6,095.9
Operating	3.6	8.0	33.0	71.7	187.0	407.4	33.0	71.7	243.8	530.5
Coal Replacement	-34.4	-126.9	-249.4	-899.6	-1,348.3	-4,881.9	-249.4	-899.6	-1,823.0	-6,586.5
Bio-based Feedstocks	79.8	180.8	2,771.6	4,368.1	12,540.5	20,195.4	2,774.5	4,368.9	20,309.2	32,570.6
Total Annual Jobs	63.3	96.8	2,698.0	3,882.3	13,499.7	20,763.8	2,689.7	3,856.7	21,250.8	32,610.5
Investment (Non-annual)	29.8	67.8	275.0	631.0	8,720.9	19,210.4	275.0	631.0	11,057.8	24,559.1

Estimated Total Value Added Impacts

	Base Case 2%		Low Carbon 2%		Low Carbon 15%		High Carbon 2%		High Carbon 15%	
	Direct	Total	Direct	Total	Direct	Total	Direct	Total	Direct	Total
					$1,000 dollars					
Transportation	$605	$1,514	$6,066	$15,042	$89,170	$216,183	$5,595	$13,886	$107,336	$269,693
Operating	$277	$467	$2,538	$4,237	$14,185	$23,632	$2,538	$4,237	$18,722	$31,298
Coal Replacement	-$3,741	-$7,980	-$26,689	-$56,193	-$144,528	-$304,500	-$26,689	-$56,193	-$195,253	-$411,191
Bio-based Feedstocks	$4,586	$9,031	$60,066	$127,288	$277,665	$595,140	$59,934	$126,773	$397,658	$941,027
Total Annual Impact	$1,727	$3,032	$41,981	$90,375	$236,492	$530,456	$41,378	$88,704	$328,463	$830,826
Investment (Non-annual)	$1,570	$3,344	$15,547	$32,248	$508,477	$962,418	$15,547	$32,248	$652,288	$1,249,153

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