BIOMASS CO-FIRING

1.0 System Description

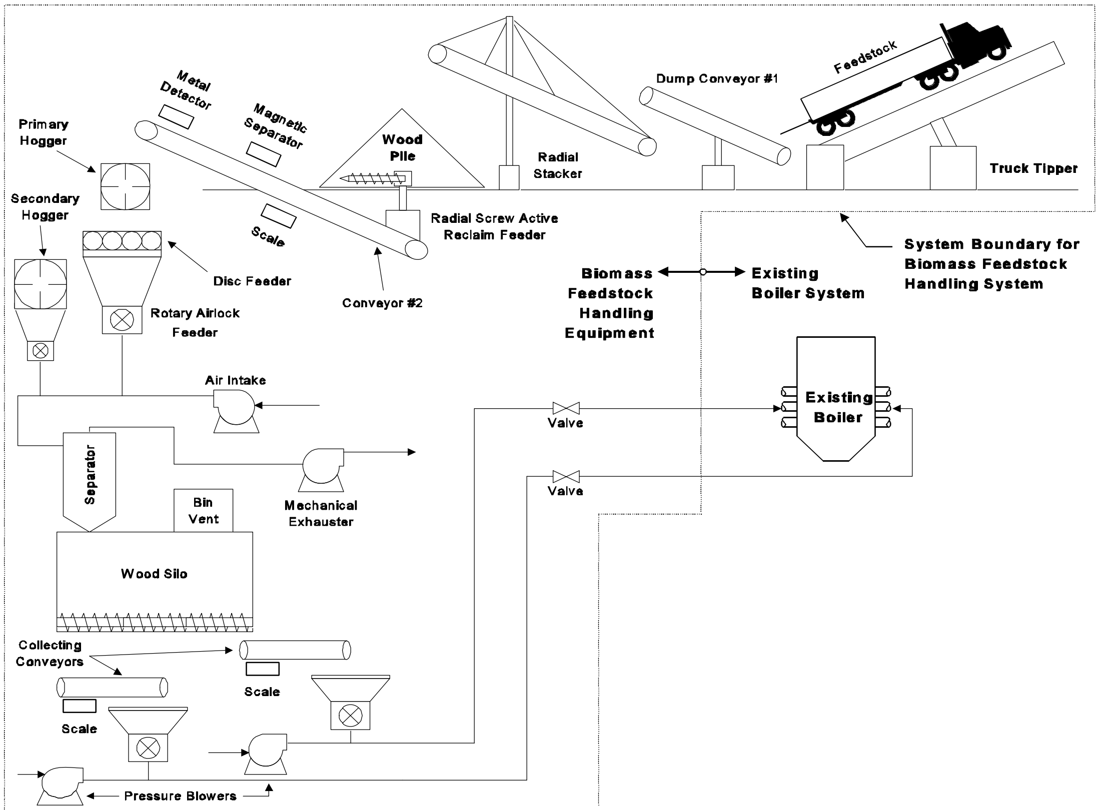

Figure 1. Biomass co-firing retrofit schematic for a pulverized coal boiler system.

Co-firing is the simultaneous combustion of different fuels in the same boiler. Many coal- and oil-fired boilers at power stations have been retrofitted to permit multi-fuel flexibility. Biomass is a well-suited resource for co-firing with coal as an acid rain and greenhouse gas emission control strategy. Co-firing is a fuel-substitution option for *existing* capacity, and is not a capacity *expansion* option. Co-firing utilizing biomass (see Figure 1) has been successfully demonstrated in the full range of coal boiler types, including pulverized coal boilers, cyclones, stokers, and bubbling and circulating fluidized beds [1]. The system described here is specifically for pulverized coal-fired boilers which represent the majority of the current fleet of utility boilers in the U.S.; however, there are also significant opportunities for co-firing with biomass in cyclones. Co-firing biomass in an existing pulverized coal boiler will generally require modifications or additions to fuel handling, storage and feed systems. An automated system capable of processing and storing sufficient biomass fuel in one shift for 24-hour use is needed to allow continuous co-firing while minimizing equipment operator expenses. Typical biomass fuel receiving equipment will include truck scales and hydraulic tippers, however tippers are not required if deliveries are made with self-unloading vans. Biomass supplies may be unloaded and stored in bulk in the coal yard, then reclaimed for processing and combustion. New automated reclaiming equipment may be added, or existing front-end loaders may be detailed for use to manage and reclaim biomass fuel. Conveyors will be added to transport fuel to the processing facility, with magnetic separators to remove spikes, nails, and tramp metal from the feedstock. Since biomass is the “flexible” fuel at these facilities, a 5-day stockpile should be sufficient and will allow avoidance of problems with long-term storage of biomass such as mold development, decomposition, moisture pick-up, freezing, etc. [2].

Fuel processing requirements are dictated by the expected fuel sources, with incoming feedstocks varying from green whole chips up to 5 cm (2 inches) in size (or even larger tree trimmings) to fine dry sawdust requiring no additional processing. In addition to woody residues and crops, biomass fuel sources could include alfalfa stems, switchgrass, rice hulls, rice straw, stone fruit pits, and other materials [3]. For suspension firing in pulverized coal boilers, biomass fuel feedstocks should be reduced to 6.4 mm (0.25 inches) or smaller particle size, with moisture levels under 25% MCW (moisture content, wet basis) when firing in the range of 5% to 15% biomass on a heat input basis [2,4]. Demonstrations have been conducted with feedstock moisture levels as high as 45%. Equipment such as hoggers, hammer mills, spike rolls, and disc screens are required to properly size the feedstock. Other boiler types (cyclones, stokers, and fluidized beds) are better suited to handle larger fuel particle sizes. There must also be a biomass buffer storage and a fuel feed and metering system. Biomass is pneumatically conveyed from the storage silo and introduced into the boiler through existing injection ports, typically using the lowest level of burners. Introducing the biomass at the lowest level of burners helps to ensure complete burnout through the scavenging effect of the upper-level burners and the increased residence time in the boiler. Discussions with boiler manufacturers indicate that generally no modifications are required to the burners if the biomass fuel is properly sized [1].

The system described here, and shown in Figure 1, is designed for moderate percentage co-firing (greater than 2% on a heat input basis) and, for that reason, requires a separate feed system for biomass which acts in parallel with the coal feed systems. Existing coal injection ports are modified to allow dedicated biomass injection during the co-firing mode of operation. For low percentage co-firing (less than 2% on a heat input basis), it may be possible to use existing coal pulverizers to process the biomass if spare pulverizer capacity exists. If existing pulverizers are used, the biomass is processed and conveyed to the boiler with the coal supply and introduced into the boiler through the same injection ports as the coal (i.e., the biomass and coal are blended prior to injection into the boiler). Using existing pulverizers could reduce capital costs by allowing the avoided purchase of dedicated biomass processing and handling equipment, but the level of co-firing on a percentage basis will be limited by pulverizer performance, biomass type, and excess pulverizer capacity. The suitability of existing pulverizers to process biomass with coal will vary depending on pulverizer type and biomass type. Atritta mills (pulverizers which operate much like fine hammermills), for example, have more capability to process biomass fuels [3].

Drying equipment has been evaluated by many designers, and recommended by some. Dryers are not included here for three reasons: (1) the benefit-to-cost ratio is almost always low, (2) the industrial fuel sources that supply most co-firing operations provide a moderately dry fuel (between 28% and 6% MCW), and (3) biomass is only a modest percentage of the fuel fired. Although drying equipment is not expected to be included initially, future designs may incorporate cost effective drying techniques (using boiler waste heat) to maintain plant efficiency while firing a broader range of feedstocks with higher moisture contents.

2.0 System Application, Benefits, and Impacts

The current fleet of low-cost, coal-fired, base load electricity generators are producing over 50% of the nation's power supply [5]. With the 1990 Clean Air Act Amendments (CAAA) requiring reductions in emissions of acid rain precursors such as sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from utility power plants, co-firing biomass at existing coal-fired power plants is viewed as one of many possible compliance options. In addition, co-firing using biomass fuels from sustainably grown, dedicated energy crops is viewed as a possible option for reducing net emissions of carbon dioxide (CO_2), a greenhouse gas that contributes to global warming. Coupled with the need of the industrial sector to dispose of biomass residues (generally clean wood byproducts or remnants), biomass co-firing offers the potential for solving multiple problems at potentially modest investment costs. These opportunities have caught the interest of power companies in recent years.

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Unlike coal, most forms of biomass contain very small amounts of sulfur. Hence, substitution of biomass for coal can result in significant reductions in sulfur dioxide (SO_2) emissions. The amount of SO_2 reduction depends on the percent of heat obtained from biomass and the sulfur content of the coal. Co-firing biomass with coal can allow power producers to earn SO_2 emission allowances under Section 404(f) of the CAAA [6]. An allowance is earned for each ton of SO_2 emissions reduced (1 allowance = 1 ton = 0.91 tonnes; 1 tonne = 1 metric ton). This section of the CAAA includes provisions for earning credits from SO_2 emissions avoided through energy conservation measures (i.e., demand side management or DSM) and renewable energy. In addition to any allowances which the producer earned by not emitting SO_2, two allowances can be given to the utility from an allowance reserve for every gigawatt-hour (10^6 kWh) produced by biomass in a co-fired boiler. These allowances may then be sold or traded to others who need them to remain in compliance with the CAAA. The value of an SO_2 allowance has ranged from \$135 in 1993 to a current value of about \$80.

As with fossil fuels, a result of burning biomass is the emission of CO_2. However, biomass *absorbs* about the same amount of carbon dioxide during its growing cycle as is emitted from a boiler when it is burned. Hence, when biomass production is undertaken on a sustainable or "closed-loop" basis by raising energy crops or by using the standard practice in the U.S. of growing at least as much forest as is being harvested, *net* CO_2 emissions on a complete fuel cycle basis (from growth to combustion) are considered to be nearly zero [7]. Therefore, biomass co-firing may be one of the most practical strategic options for complying with restrictions on generation of greenhouse gases. Fossil CO_2 reductions are currently being pursued voluntarily by utilities in the U.S. through the federal government's Climate Challenge program. These utilities may be able to receive early credit for their fossil CO_2 emission reductions for future use in the event that legislation is passed which creates market value for CO_2 reductions. Total estimated emissions of both SO_2 and CO_2 from power plants operating in coal-only modes and when co-firing with biomass are shown in Table 3 (Section 4.2).

In addition to these emissions reductions and being a *base load* renewable power option, biomass co-firing has other possible benefits. The use of biomass to produce electricity in a dedicated feedstock supply system, where biomass is grown specifically for the purpose of providing a fuel feedstock, will provide new revenue sources to the U.S. agriculture industry by providing a new market for farm production. These benefits will result in substantial positive economic effects on rural America. Using urban wood residues as a fuel reduces landfill material and subsequently extends landfill life. For industries served by the utilities, rising costs of tipping fees, restrictions on landfill use, and potential liabilities associated with landfill use represent opportunities for power companies to assist industrial customers while obtaining low-cost biomass residues for use as alternative fuels. These residues can be mixed with more expensive biomass from energy crops to reduce the overall cost of biomass feedstocks. Finally, firing biomass in boilers with pollution control can reduce burning of wood residues in uncontrolled furnaces or in open fields, and hence provides another means of reducing air emissions.

Potential negative impacts associated with co-firing biomass fuels include: (1) the possibility for increased slagging and fouling on boiler surfaces when firing high-alkali herbaceous biomass fuels such as switchgrass, and (2) the potential for reduced fly ash marketability due to concerns that commingled biomass and coal ash will not meet existing ASTM fly ash standards for concrete admixtures, a valuable fly ash market. These two issues are the subject of continued research and investigation. Two factors indicate that biomass co-firing (using sources of biomass such as energy crops or residues from untreated wood) will have a negligible effect on the physical properties of coal fly ash. First, the mass of biomass relative to coal is small for co-firing applications, since biomass provides 15% or less of the heat input to the boiler. Second, combustion of most forms of biomass results in only half as much ash when compared to coal. Despite these factors, significant efforts will be required to ensure that commingled biomass and coal ash will meet ASTM standards for concrete admixture applications. In the immediate future (three to five years), the ASTM standards that preclude the use of non-coal ash will probably remain unchanged. Estimated ash effluents are shown in Table 3 (Section 4.2) for power plants operating in the coal-only mode and when co-firing with biomass.

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3.0 Technology Assumptions and Issues

Biomass co-firing is a retrofit application, primarily for coal-fired power plants. Biomass co-firing is applicable to most coal-fired boilers used for power generation. A partial list of existing or planned utility applications is shown in Table 1. Retrofits to co-fire at 5% (by heat) or more for coal-fired cyclones, stokers, and fluidized bed boilers are potentially simpler and less expensive than for pulverized coal. However, pulverized coal boilers are the most widely used steam generating system for coal-fired power generation in the U.S., and they represent the majority of plants affected by 1990 Clean Air Act Amendment provisions for reducing the emissions of SO_2 and NO_x from electric generating units.

The power plants characterized in the following section are pulverized coal plants which co-fire from 10% to 15% biomass on a heat input basis. The co-firing rate is not projected to exceed 15% due to biomass resource limitations and requirements to maintain unit efficiency. System capital and operating costs are assumed to be representative of plants which receive biomass via self-unloading vans and can utilize existing front-end loaders for receiving and pile management. The facilities are assumed to be located in a region where medium- to high-sulfur coal (0.8% by weight and greater) is used as a utility boiler fuel and where biomass residues are available for relatively low costs ($0.47/GJ, or $0.50/MMBtu; 1 MMBtu = 10^6 Btu). Areas with these characteristics include portions of the Northeast, Southeast, mid-Atlantic, and Midwest regions.

As shown in Table 1, biomass co-firing with coal is currently practiced at a handful of utility-scale boilers (Northern States Power, Tacoma Public Utilities, New York State Electric and Gas, TVA). Co-firing has also been successfully demonstrated by GPU Genco, Madison Gas & Electric, Southern Company, and several others. Retrofits require commercially available fuel handling and boiler equipment. Optimized equipment for efficiently processing some biomass feedstocks (such as switchgrass and willow energy crops) to a size suitable for combustion in a pulverized coal boiler will require further development and demonstration. Engineering and design issues are well understood for most applications, but the optimum design for a given power plant will be site-specific and could vary depending on a number of key factors, including site layout, boiler type, biomass type and moisture content, level of co-firing, type of existing pulverizer, and pulverizer excess capacity. In general, capital costs for blended feed systems are low (about $50/biomass kW) and costs for separate feed systems are higher (about $200/biomass kW). The design shown in this technology characterization is a separate feed system. Separate feeding is needed for biomass heat contributions greater than 2% to 5% in a pulverized-coal boiler. At low co-firing levels in a pulverized-coal unit (<2%), or at mid-level (5% to 10%) in a cyclone, blended feed can be used.

Emissions of gaseous effluents other than CO_2 and SO_2 are not estimated in Section 4 because they are highly dependent on boiler operating conditions and design. However, NO_x emissions for a co-fired boiler could be lower than those for a 100% coal-fired boiler due to the lower nitrogen content of biomass and the lower flame temperatures associated with combustion of high-moisture-content biomass feedstocks. In addition, reburn technologies using biomass could provide additional NO_x reductions. Reburning involves a fuel-lean primary combustion stage, followed by the downstream injection of an additional fuel (natural gas, or micronized coal or biomass) in a fuel-rich secondary zone (the reburn zone) to reduce the NO_x formed in the primary stage. Additional air is injected downstream of the fuel-rich zone to complete combustion. Further research and development in the area of NO_x reduction, for both reburn and conventional co-firing arrangements, is required to better define the potential NO_x reduction benefits associated with biomass co-firing. If the NO_x reduction benefits using biomass are proven to be

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Table 1. Previous, existing, or planned biomass co-firing applications [1].

Utility, Plant Name, Location	Co-fired Fuels	Total (Net) Plant Size *	Boiler Technology
Northern States Power Allen S. King Station Minneapolis, Minnesota	Coal/wood residues (lumber)	560 MW_e	Cyclone
Otter Tail Power Co. Big Stone City, South Dakota	Coal/refuse-derived-fuel (RDF)/tires/waste oil/ag. refuse	440 MW_e	Cyclone
Tennessee Valley Authority Allen Fossil Plant Memphis, Tennessee	Coal/wood residues and coal/wood/tires	272 MW_e	Cyclone
I/S Midtkraft Energy Co. Grenaa Co-Generation Plant Grenaa, Denmark	Coal/straw	150 MW_e	Circulating Fluidized Bed
Tacoma Public Utilities -- Light Division Steam Plant No. 2 Tacoma, Washington	Coal/RDF/wood residues	2 x 25 MW_e	Bubbling Fluidized Bed
GPU Genco Shawville Station Johnstown, Pennsylvania	Coal/wood residues	130 MW_e and 190 MW_e	Pulverized Coal
IES Utilities Inc. Sixth Street (1) and Ottumwa (2) Stations Marshalltown, Iowa	(1) Coal/agricultural residues (2) Coal/switchgrass	(1) 3 Units, 6-15 MW_e (2) 714 Mw_e	(1) Pulverized Coal (2) Pulverized Coal
Madison Gas & Electric Blount Street Station Madison, Wisconsin	Coal/switchgrass	50 MW_e	Pulverized Coal
New York State Electric & Gas Greenidge Station Dresden, New York	Coal/wood residues and coal/energy crops (willow)	108 MW_e	Pulverized Coal
Niagara Mohawk Power Corp. Dunkirk Station Dunkirk, New York	Coal/wood residues and coal/energy crops (willow)	91 MW_e	Pulverized Coal
Tennessee Valley Authority (1) Kingston and (2) Colbert Fossil Plants (1) Kingston, TN and (2) Tuscumbia, AL	(1) Coal/wood residues (2) Coal/wood residues	(1) 190 MW_e (2) 190 MW_e	(1) Pulverized Coal (2) Pulverized Coal
EPON Centrale Gelderland Netherlands	Coal/wood residues (demolition)	602 MW_e	Pulverized Coal
I/S Midtkraft Energy Co. Studstrupvaeket, Denmark	Coal/straw	150 MW_e	Pulverized Coal
Uppsala Energi AB Uppsala, Sweden	Coal (peat)/ wood chips	200 MW_e and 320 MW_t	Pulverized Coal
New York State Electric & Gas Hickling (1) and Jennison (2) Stations Big Flats and Bainbridge, New York	Coal/wood residues and coal/tires	(1) 37.5 MW_e (2) 37.5 Mw_e	(1) Stoker (2) Stoker
Northern States Power Bay Front Station Ashland, Wisconsin	Coal/wood residues (forest)	2 x 17 MW_e	Stoker

Notes:
* The capacity supported by the supplementary (i.e., biomass) fuel will be a fraction of the total capacity shown in this table, normally in the range of 1 to 10% of the total capacity.

feasible for reducing the NO_x emissions control costs at existing cyclone and pulverized coal boilers, the resulting cost savings could be several times the fuel savings for co-firing [8]. The dollar value of NO_x reduction will be site-specific, depending on the cost of the alternative NO_x control action.

As mentioned in Section 2, two other issues needing additional research and development efforts are: (1) slagging and fouling on boiler surfaces caused by firing high alkali herbaceous biomass feedstocks such as switchgrass, and (2) the potential for reduced fly ash marketability due to concerns that commingled biomass and coal ash will not meet ASTM fly ash standards for concrete admixtures. Finally, due to high transportation costs, sufficiently inexpensive biomass residues and energy crops (relative to local coal prices) must exist within an 80 to 120 km (50 to 75 mile) radius to economically justify a co-firing operation [9]. Improved resource acquisition methods and energy crop development are needed to foster the widespread adoption of biomass co-firing.

4.0 Performance and Cost

Table 2 summarizes the performance and cost indicators for the biomass co-fired system being characterized in this report.

4.1 Evolution Overview

In the tables in this section, for each year from 1997 through 2030, the performance of two systems is estimated. One is a pulverized coal power plant using only coal. These cases represent the plant operation prior to a biomass co-firing retrofit. The other case shows the performance of the same power plant operating with biomass co-firing. The 1997 base case is a 100 MW plant which obtains 10% of its total heat input from biomass while in the co-firing mode, resulting in 10 MW of biomass-based power generation capacity. This is representative of the planned size and co-firing rates of two Northeast power plants that are presently participating in the DOE Salix Consortium demonstration project. The same size boiler is used for the year 2000 case, but the co-firing rate is increased from 10% to 15%, assuming that lessons learned during initial years will permit sustained operation in similar boilers at a 15% co-firing rate. This case results in 15 MW of biomass-based generation capacity. Co-firing rates as high as 15% have been demonstrated during preliminary testing. For the years 2005 through 2030, co-firing rates remain the same (15%), but boiler sizes are increased from year to year. This demonstrates the effect that improved biomass feedstock acquisition techniques and increased development of energy crops will have in allowing increasingly larger power plants to be co-fired near maximum levels of 15%.

4.2 Performance and Cost Discussion

The tools used for this analysis were based on EPRI's BIOPOWER co-firing model [10]. Input requirements for the model include ultimate analyses of the fuels (chemical composition of the fuels), capacity factor for the power plant, net station capacity, gross turbine heat rate, and percent excess air at which the plant operates. The technical input information used for the model was based on data from a representative Northeast power plant which intends to implement biomass co-firing [2]. For a given biomass co-firing rate, the model calculates thermal efficiency, change in net heat rate, coal and biomass consumption, and reduced SO_2 and CO_2 emissions.

The coal was assumed to contain 1.9% sulfur, compared to a 0.02% sulfur content for the biomass. Moisture contents were 7.2% for the coal and 21.5% for the biomass. Ash contents were assumed to be 8.8% for coal and 0.9% for

Table 2. Performance and cost indicators.

INDICATOR NAME	UNITS	Base Case 1997	+/- %	2000	+/- %	2005	+/- %	2010	+/- %	2020	+/- %	2030	+/- %
Plant Size	MW	100		100		150		200		300		400	
General Performance Indicators													
Capacity Factor	%	85		85		85		85		85		85	
Coal Moisture Content	%	7.2		7.2		7.2		7.2		7.2		7.2	
Biomass Moisture Content	%	21.5		21.5		21.5		21.5		21.5		21.5	
Annual Energy Delivery	GWh/yr	745		745		1,117		1,489		2,234		2,978	
Coal-only Performance Indicators													
Efficiency	%	32.9		32.9		32.9		32.9		32.9		32.9	
Net Heat Rate	kJ/kWh	10,929		10,929		10,929		10,929		10,929		10,929	
Net Power Capacity from Coal	MW	100		100		150		200		300		400	
Annual Electricity Delivery from Coal	GWh/yr	745		745		1,117		1,489		2,234		2,978	
Coal Consumption	tonnes/yr	276,175		276,175		414,262		552,350		828,525		1,104,699	
Annual Heat Input from Coal @ 31,751 kJ/kg	TJ/yr	8,138		8,138		12,206		16,275		24,413		32,550	
TOTAL Annual Heat Input	TJ/yr	8,138		8,138		12,206		16,275		24,413		32,550	
Biomass Co-firing Performance Indicators													
Co-firing Rate (Heat Input from Biomass)	%	10		15		15		15		15		15	
Thermal Efficiency	%	32.7		32.5		32.5		32.5		32.5		32.5	
Net Heat Rate	kJ/kWh	11,015		11,066		11,066		11,066		11,066		11,066	
Net Power Capacity from Coal	MW	90		85		128		170		255		340	
Net Power Capacity from Biomass	MW	10.0		15.0		22.5		30.0		45.0		60.0	
Annual Electricity Delivery from Coal	GWh/yr	670		633		949		1,266		1,899		2,532	
Annual Electricity Delivery from Biomass	GWh/yr	74		112		168		223		335		447	
Coal Consumption	tonnes/yr	250,525		237,695		356,542		475,389		713,084		950,778	
Biomass Consumption (dry)	tonnes/yr	42,933		64,695		97,043		129,391		194,086		258,781	
Annual Heat Input from Coal @ 31,751 kJ/kg	TJ/yr	7,382		7,004		10,506		14,007		21,011		28,015	
Annual Heat Input from Biomass @ 19,104 kJ/kg	TJ/yr	820		1,236		1,854		2,472		3,708		4,944	
TOTAL Annual Heat Input	TJ/yr	8,202		8,240		12,359		16,479		24,719		32,959	

NOTES:
1. The columns for "+/- %" refer to the uncertainty associated with a given estimate

Table 2. Performance and cost indicators.(cont.)

INDICATOR NAME	UNITS	Base Case 1997	+/- %	2000	+/- %	2005	+/- %	2010	+/- %	2020	+/- %	2030	+/- %
Plant Size	MW	100		100		150		200		300		400	
Capital Cost ($/kW of BIOMASS power capacity)													
Biomass Handling System Equipment	$/kW		25		25		25		25		25		25
Conveyor		12.9		12.1		11.4		10.9		10.3		9.9	
Separation Equipment, Conveyor		3.5		3.3		3.1		3.0		2.8		2.7	
Hogging Tower and Equipment		21.3		20.0		18.9		18.1		17.0		16.3	
Pneumatic Conveying System (Vacuum)		4.5		4.2		4.0		3.8		3.6		3.4	
Wood Silo with Live Bottom		5.5		5.2		4.9		4.7		4.4		4.2	
Collecting Conveyors		6.6		6.2		5.8		5.6		5.3		5.0	
Rotary Airlock Feeders		0.6		0.6		0.5		0.5		0.5		0.5	
Pneumatic Conveying System (Pressure)		17.0		16.0		15.1		14.4		13.6		13.0	
Controls		10.5		9.9		9.3		8.9		8.4		8.0	
Total Equipment		82.4		77.5		73.0		69.9		65.8		63.0	
Biomass Handling System Installation		51.2	25	48.2	25	45.3	25	43.4	25	40.9	25	39.1	25
Total Biomass Handling		133.6		125.7		118.3		113.3		106.6		102.1	
Civil Structural Work		36.9	25	34.7	25	32.7	25	31.3	25	29.4	25	28.2	25
Modifications at Burners		3.0	15	2.8	15	2.7	15	2.5	15	2.4	15	2.3	15
Electrical		16.4	25	15.4	25	14.5	25	13.9	25	13.1	25	12.5	25
Subtotal (A)		189.9		178.7		168.2		161.0		151.5		145.1	
Contingency @ 30%, 0.3 * (A)		57.0		53.6		50.4		48.3		45.5		43.6	
Total Direct Costs (B)		246.9		232.3		218.6		209.3		197.0		188.7	
Engineering @ 10%, 0.1 * (B)		24.7		23.2		21.9		20.9		19.7		18.9	
Total Capital Requirement		271.6		255.5		240.5		230.3		216.7		207.6	

NOTES:

1. The columns for "+/- %" refer to the uncertainty associated with a given estimate
2. Plant construction is assumed to require 1 year for a retrofit to an existing system

Table 2. Performance and cost indicators.(cont.)

INDICATOR NAME	UNITS	Base Case 1997	+/- %	2000	+/- %	2005	+/- %	2010	+/- %	2020	+/- %	2030	+/- %
Plant Size	MW	100		100		150		200		300		400	
Incremental Operation and Maintenance Costs; Incremental O&M = Biomass O&M - Coal O&M ; Values in ( ) indicate *negative* costs (i.e., revenues).													
Fuel Cost @ $9.14/dry tonne (biomass) *	¢/kWh	(.820)		(.817)		(.817)		(.817)		(.817)		(.817)	
Fuel Cost @ $51.48/dry tonne (biomass) *	¢/kWh	1.622		1.635		1.635		1.635		1.635		1.635	
Fuel Cost @ $9.14/dry tonne (biomass) †	¢/kWh	(.439)		(.437)		(.437)		(.437)		(.437)		(.437)	
Fuel Cost @ $51.48/dry tonne (biomass) †	¢/kWh	2.002		2.016		2.016		2.016		2.016		2.016	
Variable Costs	¢/kWh												
Consumables (incl. SO_2 credit revenue) ‡		(.163)		(.163)		(.163)		(.163)		(.163)		(.163)	
Fixed Costs	$/kW-yr												
Labor		5.00		5.00		5.00		5.00		5.00		5.00	
Maintenance		5.43		5.11		4.81		4.61		4.33		4.15	
Total Fixed Costs		10.43		10.11		9.81		9.61		9.33		9.15	
Total Operating Costs													
@ $9.14/dry tonne (biomass) *	¢/kWh	(.842)		(.844)		(.848)		(.851)		(.855)		(.857)	
@ $51.48/dry tonne (biomass) *	¢/kWh	1.599		1.608		1.604		1.601		1.598		1.595	
@ $9.14/dry tonne (biomass) †	¢/kWh	(.462)		(.464)		(.468)		(.470)		(.474)		(.477)	
@ $51.48/dry tonne (biomass) †	¢/kWh	1.980		1.989		1.985		1.982		1.978		1.976	

NOTES:
1. The columns for "+/- %" refer to the uncertainty associated with a given estimate
2. Plant construction is assumed to require 1 year for a retrofit to an existing system

* Coal cost is assumed to be $39.09/tonne

† Coal cost is assumed to be $28.05/tonne

‡ SO_2 credit revenues are calculated as follows, with SO_2 credits valued at $110/tonne SO_2 = $100/ton SO_2:
[(Coal-only - Co-firing) tonnes SO_2/yr * (1 allowance/tonne SO_2) + (2 allowances/GWh biomass power) * (GWh biomass power/yr)] * ($110/allowance) * (100 ¢/$) / (kWh biomass power/yr)
Projected annual SO_2 savings for each year from 1997 to 2030 are $121,100, $181,600, $272,500, $363,100, $544,700, and $726,300, respectively.

biomass. The coal heating value was 31,751 kJ/kg (13,680 Btu/lb) (dry), while that for the biomass was 19,104 kJ/kg (8,231 Btu/lb) (dry). These values for sulfur, moisture, ash, and heating value were taken directly from tests conducted on the fuel supplies for the representative power plant. They are typical for eastern bituminous coal and hardwood biomass [11,12]. According to plant records, the gross turbine heat rate is 9,118 kJ/kWh (8,643 Btu/kWh). A capacity factor of 85% was used, based on historical records at the plant and projected future needs. The resulting estimated net heat rate for coal-only operation is 10,929 kJ/kWh (10,359 Btu/kWh). This value is typical of high capacity factor coal boilers in the range from 100 MW to 400 MW, and was therefore assumed constant for all cases. Improvements in net plant heat rate for future coal plants were not considered in this analysis. The material and energy balances for the year 2000 case are shown in Figure 2.

All system capital costs are due to the retrofit of an existing pulverized coal boiler to co-fire biomass. Costs for the 1997 case are based on engineering specifications, including materials and sizing of major system components, from a feasibility study for a corresponding 10 MW (biomass power) biomass co-firing retrofit at an existing plant [2]. The unit costs for the co-firing retrofit are expressed in $/kW of biomass power capacity, not total power capacity. For each following year, unit costs for larger co-firing systems were scaled down based on the relationship [13]: $\text{Cost(B)} = \text{Cost(A)} * [\text{MW(B)} / \text{MW(A)}]^s$, where the scaling factor "s" was assumed to be 0.9. The effect of this scaling relationship is a 10% reduction in $/kW unit costs for a doubling in system capacity (MW). This corresponds to observed economies of scale for coal power plants [14]. Since the system components are already commercially available and no major technological advances are expected, the only reductions in unit capital costs assumed to occur are due to economies of scale, not technological advancements or increased equipment production volumes.

Capital costs include costs for new equipment (e.g., fuel handling), boiler modifications, controls, engineering fees (10% of total process capital), civil/structural work including foundations and roadways, and a 30% contingency [2]. Cost estimates for the example systems assume that front-end loaders and truck scales are already available at the plant for unloading and pile management. Costs also assume that live-bottom trucks are used for biomass delivery, allowing the avoidance of the purchase of a truck tipper. Land and substation (system interface) costs are zero because existing plant property and the existing substation will be utilized.

Operation and maintenance costs, including fuel costs, are presented in Table 2 on an *incremental* basis. That is, each O&M cost component listed there represents the *difference* in that cost component when comparing biomass co-firing operation to coal-only operation. Negative costs, surrounded by parentheses in the table, represent a cost saving in the co-firing operation relative to coal-only operation. Fixed operating costs are broken into two components, labor and maintenance. Estimates of both of these cost components are based on information obtained from plant management at an existing co-firing operation [2]. Fixed labor costs are estimated based on a requirement for one additional operator for each 10 MW of biomass capacity (0.1 operator/MW). The operator manages the biomass deliveries, handling and processing equipment, and is compensated at a loaded rate of $50,000 per year. Annual fixed maintenance costs are assumed to be 2% of the original capital cost of the co-firing retrofit [15]. Variable operation costs (consumables such as water, chemicals, etc.) are assumed to be the same for co-firing operation and coal-only operation, with the exception of the assumed value received for reduced SO_2 emissions. The assumed value of an SO_2 allowance is $100/ton SO_2 reduced ($110/tonne) and the value is assumed to remain constant throughout the analysis period. It is also assumed that fossil-based CO_2 emissions savings hold zero financial value; however, this is subject to change and could have a large impact on the economics of a co-firing application.

It should be recognized that co-firing retrofit costs are extremely site-specific and can range from $50 to $700/kW [2,4] depending on many factors, including boiler type, amount of biomass co-fired, site layout, existing receiving equipment at the plant, complexity of handling and processing system design, nature of the biomass feedstock, etc. The example used in the present analysis provides a payback period of about three to four years (a typical

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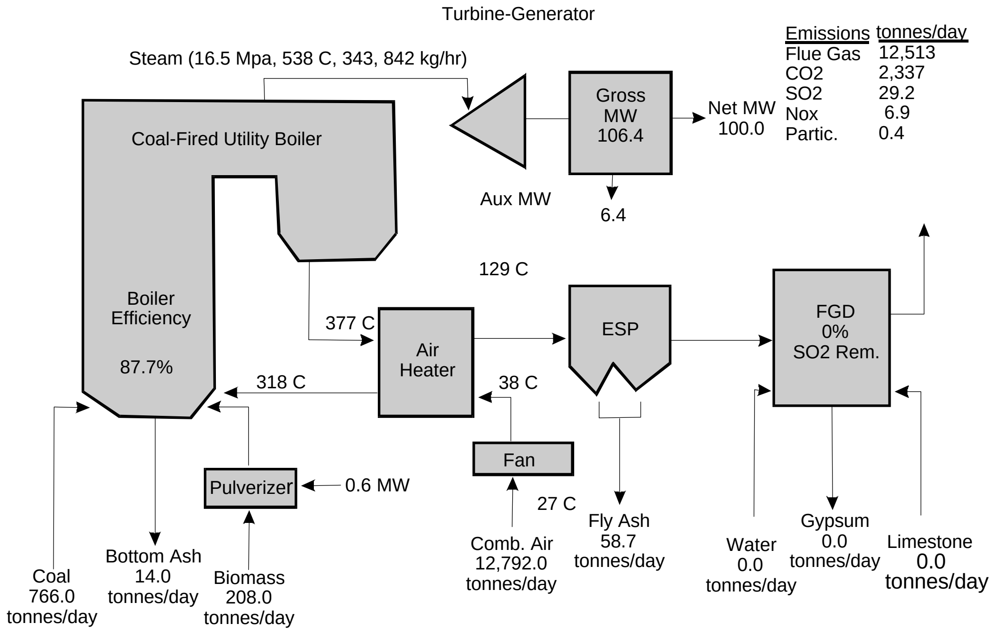

Energy Balance (GJ/hr)	Baseline Coal Only	Alt. Fuel Cofired
Heat In		
Coal	1092.9	940.6
Wood Blend	-------	166.0
Total	1092.9	1106.6
Heat Out		
Net steam turbine output	360.1	360.1
Auxiliary power use	23.0	23.0
Condenser	587.0	587.0
Stack gas losses	97.6	112.1
Boiler radiation losses	3.4	3.4
Unburned carbon losses	5.5	4.4
Unaccounted for boiler heat loss	16.4	16.6
Total	1092.9	1106.6
Plant Performance		
Net Capacity, MW	100.0	100.0
Boiler Efficiency, %	88.8	87.7
Net Heat Rate, kJ/kWh	10,929	11,066
Thermal Efficiency, %	32.9	32.5
Capacity Factor, %	85.0	85.0

Material Balance (Mg/hr)	Baseline Coal Only	Alt. Fuel Cofired
Mass In		
Coal	37.1	31.9
Residues		11.1
Limestone	0.0	0.0
FGD Water Makeup	0.0	0.0
Combustion air	525.3	533.0
Total	562.4	576.0
Mass Out		
Bottom ash	0.7	0.6
Fly ash	2.8	2.4
Gypsum	0.0	0.0
Flue gas	558.9	573.0
Total	562.4	576.0
Annual Performance		
Capacity Factor, %	85.0	85.0
Coal, 1000 tonnes/yr	276.2	237.7
Alt. Fuel, 1000 tonnes/yr		64.7

Figure 2. Material and energy balances for 100 MW (Nameplate) boiler at 15% biomass co-firing (see year 2000 case) [10]. Moisture contents were 7.2% for the coal and 21.5% for the biomass.

requirement for capital expenditures by plant managers)--i.e., it represents a realistic installation under present economic conditions--assuming a biomass residue supply is available for $9.14/dry tonne ($8.29/dry ton, $0.50/MMBtu) and coal costs at the plant are $39.09/tonne ($35.46/ton, $1.40/MMBtu). The economics are less favorable for coal costs less than $39.09/tonne, especially in areas of the Midwest where prices are as low as $28.05/tonne ($1.00/MMBtu). More expensive systems which do not provide a similar payback will likely not be implemented unless the capital expenditure decisions are heavily influenced by other factors such as providing service to a valuable customer, or achieving emissions reductions. To demonstrate the effect of various biomass and coal prices on overall *incremental* operation and maintenance costs, three more fuel price scenarios are shown in Table 2. The fuel price scenarios are:

1. $9.14/dry tonne ($8.29/dry ton, $0.50/MMBtu) biomass costs and $39.09/tonne ($35.46/ton, $1.40/MMBtu) coal costs--This represents an economic scenario where abundant sources of biomass residues are available at a cheap price, while coal prices are near the national average. The resulting simple payback periods range from 4.3 years for the 1997 base case to 3.3 years in 2030. Under these financial circumstances, a biomass co-firing retrofit is marginally economical with no additional environmental subsidies. An environmental credit equivalent to $3.31/tonne ($3.00/ton) of reduced fossil CO_2 emissions would result in a three year simple payback period for the year 2000 case.
2. $51.48/dry tonne ($46.70/dry ton, $2.84/MMBtu) biomass costs and $39.09/tonne ($35.46/ton, $1.40/MMBtu) coal costs--This represents an economic scenario where energy crops are the biomass fuel and coal prices are near the national average. Under these financial circumstances, a co-firing retrofit will not pay off without additional environmental subsidies. An environmental credit equivalent to $31.42/tonne ($28.50/ton) of reduced fossil CO_2 emissions would be necessary to obtain a three year simple payback period for the year 2000 case.
3. $9.14/dry tonne ($8.29/dry ton, $0.50/MMBtu) biomass costs and $28.05/tonne ($25.45/ton, $1.00/MMBtu) coal costs--This represents an economic scenario where abundant sources of biomass residues are available at a cheap price while coal prices are low. The resulting simple payback periods range from 7.9 years for the 1997 base case to 5.8 years in 2030. Under these financial circumstances, a co-firing retrofit will not pay off without additional environmental subsidies. An environmental credit equivalent to $7.72/tonne ($7.00/ton) of reduced fossil CO_2 emissions would be needed to achieve a three year simple payback period for the year 2000 case.
4. $51.48/dry tonne ($46.70/dry ton, $2.84/MMBtu) biomass costs and $28.05/tonne ($25.45/ton, $1.00/MMBtu) coal costs--This represents an economic scenario where energy crops are the biomass fuel and coal prices are low. Under these financial circumstances, a co-firing retrofit will not pay off without additional environmental subsidies. An environmental credit equivalent to $35.82/tonne ($32.50/ton) of reduced fossil CO_2 emissions would be needed to achieve a three year simple payback period for the year 2000 case.

It should be noted that cheaper alternatives for biomass co-firing exist. While high percentage co-firing in pulverized coal boilers represents a large potential market, it is also one of the most expensive co-firing arrangements. In the near term, less costly alternatives such as low percentage co-firing in pulverized coal boilers, low- or mid-percentage co-firing in cyclone boilers, or co-firing in stoker or fluidized bed boilers may be more attractive. Capital costs for these options could be less than $50/kW of biomass power capacity. At a capital cost of $100/kW of biomass power capacity, the fuel price scenarios described in cases 1 and 3 above would result in simple payback periods of 1.5 and 2.7 years, respectively, without additional environmental credits.

For each fuel cost scenario, biomass costs are assumed to remain constant (in 1997 dollars) in future years. The 100% residue scenario (#1 from above) is a likely one for the early years of a co-firing retrofit since, in the absence of greater monetary values for SO_2 (and CO_2) emissions reductions, a cheap source of residue fuel will be required to return the capital investment in an acceptable period of time (three years or less). A more dependable--but likely more expensive--feedstock in future years may be provided by dedicated energy crops. Once the capital costs have been paid off by fuel cost savings gained from using cheap residues in the initial years, feedstocks from dedicated energy crops may be combined with the remaining available cheap residues.

Coal costs are assumed to remain constant (in 1997 dollars) through future years based on projected stable coal prices [5]. The base year price of $39.09/tonne ($35.46/ton) is near or less than the 1995 average delivered coal price for the following census regions: New England, Middle Atlantic, East North Central, South Atlantic, West South Central, and Pacific Contiguous [16].

It should be recognized that, in a competitive restructured power industry, a major advantage of co-firing is fuel diversification. Plant management will use the fuel mix which will provide the overall lowest production costs once all fuel prices, O&M costs, environmental credits, and tax benefits are considered.

Effluent estimates (see Table 3) were derived using ultimate analyses and material balances (material and energy balances for the year 2000 case were provided in Figure 2). In Table 3, effluent estimates are shown for each year for coal-only operation, co-fired operation, and net reductions due to co-firing. Sulfur dioxide emissions, fossil fuel based carbon dioxide emissions, and ash discharges are all reduced by co-firing. Total estimated emissions of CO_2 from the stack show an increase when co-firing (due partially to the increased net heat rate when co-firing); however, if energy crops are used as the fuel source, the net CO_2 emissions on a full fuel cycle basis will be decreased due to the absorption of CO_2 from the atmosphere by the crops during their growth.

5.0 Land, Water, and Critical Materials Requirements

Resource requirements are shown in Table 4. It is important to note that in a typical co-firing application, no additional expenditures for land would be incurred. Available on-site coal storage areas can be managed to accommodate the biomass, and the space occupied by handling and processing equipment for biomass is easily provided on the existing property.

<u>Land</u>: The land area required for this co-firing example includes the area required for fuel storage plus the area needed to house the biomass processing and handling equipment. In a typical co-firing application, this newly required space can be found on the existing site of the power plant, and no additional land costs are incurred by the power producer. This is one example of the site-specific nature of a co-firing retrofit. The biomass storage, handling, and processing system will need to be designed to perform efficiently while also fitting within available space without negatively impacting existing operations at the facility. Additional land will be required for growing biomass to replace that used at the power plant. The estimated land requirements for growing biomass are also shown in Table 4, along with the average annual yields (dry tons/acre) used for the calculations for each year.

Because biomass has a lower energy density than coal, it will occupy a larger land area. The bulk volume (dry basis) of sawdust is about 6.2 m^3/MT (200 ft^3/ton) while an average value for bituminous coal is about 1.3 m^3/MT (42 ft^3/ton) [11]. Combined with the estimated heating values of the fuels, 19,104 kJ/kg (8,231 Btu/lb) for biomass and 31,751 kJ/kg (13,680 Btu/lb) for coal, biomass occupies 0.33 m^3/GJ (12 ft^3/MMBtu) while coal only occupies 0.04 m^3/GJ (1.5 ft^3/MMBtu); i.e, the biomass (sawdust) in this example occupies about eight times as much volume as coal for the same amount of heat. The resulting *additional* land area required for storage of biomass, assuming a 5-day supply is maintained on-site in a 6 m (20 ft) high pile, is shown in Table 4. This number assumes that biomass supplies will be handled in a similar manner to the present supply of coal at the facility; i.e., by bulldozers and front end loaders, placed in a single pile approximately 6 m (20 ft) high.

Table 3. Gaseous, liquid*, and solid effluents. (Values in this table, for each year, correspond to conditions described in Table 2.)

Indicator Name	Units	Base Year 1997	Future 2000	2005	2010	2020	2030
Plant Size	MW	100	100	150	200	300	400
Annual Electricity Generation	GWh/yr	745	745	1,117	1,489	2,234	2,978
Coal-Only System:							
Gaseous Emissions							
SO_2	tonnes/yr	10,500	10,500	15,700	21,000	31,500	41,900
Fossil CO_2	tonnes/yr	705,800	705,800	1,058,800	1,411,700	2,117,500	2,823,400
Solid Effluents							
Bottom Ash	tonnes/yr	4,900	4,900	7,300	9,700	14,600	19,400
Fly Ash	tonnes/yr	20,600	20,600	30,900	41,200	61,700	82,300
Co-Firing System:							
Co-Firing Rate (Heat obtained from biomass)	% of total	10	15	15	15	15	15
Gaseous Emissions							
SO_2	tonnes/yr	9,500	9,100	13,600	18,100	27,200	36,200
Stack CO_2 (Fossil + Biomass)	tonnes/yr	718,600	725,000	1,087,600	1,450,100	2,175,100	2,900,200
Fossil CO_2	tonnes/yr	640,300	607,500	911,300	1,215,000	1,822,500	2,430,000
Solid Effluents							
Bottom Ash	tonnes/yr	4,500	4,300	6,500	8,700	13,000	17,300
Fly Ash	tonnes/yr	18,900	18,200	27,400	36,500	54,700	72,900
Co-Firing System Savings vs. Coal-Only:							
Gaseous Emissions							
SO_2	tonnes/yr	950	1,400	2,100	2,900	4,300	5,700
Stack CO_2 (Fossil + Biomass)	tonnes/yr	(12,700)	(19,200)	(28,800)	(38,400)	(57,600)	(76,800)
Fossil CO_2	tonnes/yr	65,600	98,300	147,500	196,700	295,000	393,400
Solid Effluents							
Bottom Ash	tonnes/yr	350	500	790	1,100	1,600	2,100
Fly Ash	tonnes/yr	1,700	2,300	3,500	4,700	7,000	9,400

1. For this analysis, biomas sulfur content was 0.02% and ash content was 0.9%. Coal sulfur content was 1.9% and ash content was 8.8%

* Liquid effluents are negligible, and therefore not included here.

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Table 4. Resource requirements.

Indicator Name	Units	Base Year 1997	2000	2005	2010	2020	2030
Total Plant Capacity (net)	MW	100	100	150	200	300	400
Total Biomass Capacity (net)	MW	10.0	15.0	22.5	30.0	45.0	60.0
Land Required for Biomass Storage & Equipment*	m^2/MW	84	84	84	84	84	84
	ha	0.084	0.126	0.189	0.252	0.378	0.504
Land Required for Energy Crops†	ha/MW	470	404	351	311	253	253
	ha	4,732	6,057	7,907	9,333	11,386	15,182
Water	m^3	0.0	0.0	0.0	0.0	0.0	0.0

* The m^2/MW values are based on a biomass power capacity of 15 MW.

† The energy crop yields were assumed to increase linearly from 9.4 to 17 dry tonnes/ha/yr (4.1 to 7.5 dry tones/acre/yr) from years 1997 to 2020. Yields are assumed to remain constant between 2020 and 2030.

According to Parsons Power [2], based on equipment specifications and experience with similar systems, the storage and handling equipment for a 15 MW biomass system will require an area with dimensions of approximately 15 x 18 m (50 x 60 ft), or about 0.027 ha (0.067 acres). The total additional land requirements, including equipment and fuel storage areas, for a co-firing retrofit designed for supporting 15 MW of biomass power capacity would be about 0.126 ha (0.31 acres).

Water: Increases in water consumption at the plant are considered to be negligible compared to coal-only operation.

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