DIRECT-FIRED BIOMASS

1.0 System Description

The technologies for the conversion of biomass for electricity production are direct combustion, gasification, and pyrolysis. As shown in Figure 1, direct combustion involves the oxidation of biomass with excess air, producing hot flue gases which in turn produce steam in the heat exchange sections of boilers. The steam is used to generate electricity in a Rankine cycle; usually, only electricity is produced in a condensing steam cycle, while electricity and steam are cogenerated in an extracting steam cycle. Today's biomass-fired steam cycle plants typically use single-pass steam turbines. However, in the past decade, efficiencies and more complex design features, characteristic previously of only large scale steam turbine generators (> 200 MW), have been transferred to smaller capacity units. Today's biomass designs include reheat and regenerative steam cycles as well as supercritical steam turbines. The two common boiler configurations used for steam generation with biomass are stationary- and traveling-grate combustors (stokers) and atmospheric fluid-bed combustors.

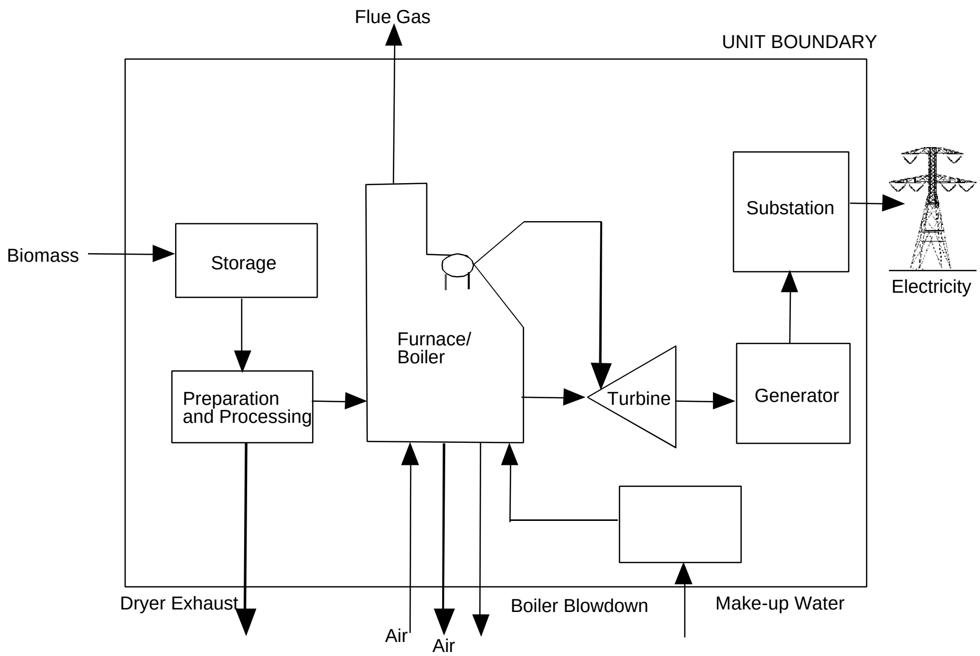

Figure 1. Direct-fired biomass electricity generating system schematic.

All biomass combustion systems require feedstock storage and handling systems. The 50 MW McNeil station, located in Burlington, Vermont, uses a spreader-stoker boiler for steam generation, and has a typical feed system for wood chips [1]. Whole tree chips are delivered to the plant gate by either truck or rail. Fuel chips are stored in open piles (about a 30 day supply on about 3.25 ha of land), fed by conveyor belt through an electromagnet and disc screen, then fed to surge bins above the boiler by belt conveyors. From the surge bins, the fuel is metered into the boiler's pneumatic stokers by augers.

The base case technology is a commercially available, utility operated, stoker-grate biomass plant constructed in the mid-1980's [2], and is representative of modern biomass plants with an efficiency of about 23%. Plant efficiency of the stoker plant increases to 27.7% in the year 2000 through the use of a dryer, and in 2020 plant efficiency is increased to 33.9% due to larger scale plants which permit more severe steam turbine cycle conditions, e.g. higher pressure, higher temperature and reheat.

DIRECT-FIRED BIOMASS

Direct Fire Technologies

Pile burners represent the historic industrial method [3] of wood combustion and typically consist of a two-stage combustion chamber with a separate furnace and boiler located above the secondary combustion chamber. The combustion chamber is separated into a lower pile section for primary combustion and an upper secondary-combustion section. Wood is piled about 3.3 m (10 ft) deep on a grate in the bottom section and combustion air is fed upwards through the grate and inwards from the walls; combustion is completed in a secondary combustion zone using overfire air. The wood fuel is introduced either on top of the pile or through an underfeed arrangement using an auger. The underfeed arrangement gives better combustion control by introducing feed underneath the active combustion zone, but it increases system complexity and lowers reliability. Ash is removed by isolating the combustion chamber from the furnace and manually dumping the ash from the grate after the ash is cooled. Pile burners typically have low efficiencies (50% to 60%), have cyclic operating characteristics because of the ash removal, and have combustion cycles that are erratic and difficult to control. Because of the slow response time of the system and the cyclic nature of operation, pile burners are not considered for load-following operations. The advantage of the pile burner is its simplicity and ability to handle wet, dirty fuels.

Stoker combustors [3] improve on operation of the pile burners by providing a moving grate which permits continuous ash collection, thus eliminating the cyclic operation characteristic of traditional pile burners. In addition, the fuel is spread more evenly, normally by a pneumatic stoker, and in a thinner layer in the combustion zone, giving more efficient combustion. Stoker-fired boilers were first introduced in the 1920's for coal, and in the late 1940's the Detroit Stoker Company installed the first traveling grate spreader stoker boiler for wood. In the basic stoker design, the bottom of the furnace is a moving grate which is cooled by underfire air. The underfire air rate defines the maximum temperature of the grate and thus the allowable feed moisture content. More modern designs include the Kabliz grate, a sloping reciprocating water-cooled grate. Reciprocating grates are attractive because of simplicity and low fly ash carryover. Combustion is completed by the use of overfire air. Furnace wall configurations include straight and bull nose water walls. Vendors include Zurn, Foster Wheeler, and Babcock and Wilcox.

In a gas-solid fluidized-bed, a stream of gas passes upward through a bed of free-flowing granular materials. The gas velocity is high enough that the solid particles are widely separated and circulate freely, creating a “fluidized-bed” that looks like a boiling liquid and has the physical properties of a fluid. During circulation of the bed, transient streams of gas flow upwards in channels containing few solids, and clumps or masses of solids flow downwards [4]. In fluidized-bed combustion of biomass, the gas is air and the bed is usually sand or limestone. The air acts both as the fluidizing medium and as the oxidant for biomass combustion. A fluidized-bed combustor is a vessel with dimensions such that the superficial velocity of the gas maintains the bed in a fluidized condition at the bottom of the vessel. The cross-sectional area changes above the bed and lowers the superficial gas velocity below fluidization velocity to maintain bed inventory and act as a disengaging zone. Overfire air is normally introduced in the disengaging zone. To obtain the total desired gas-phase residence time for complete combustion and heat transfer to the boiler walls, the larger cross-sectional area zone is extended and is usually referred to as the freeboard. A cyclone is used to either return fines to the bed or to remove ash-rich fines from the system. The bed is fluidized by a gas distribution manifold or series of sparge tubes [5].

If the air flow of a bubbling fluid bed is increased, the air bubbles become larger, forming large voids in the bed and entraining substantial amounts of solids . This type of bed is referred to as a turbulent fluid bed [6]. In a circulating fluid bed, the turbulent bed solids are collected, separated from the gas, and returned to the bed, forming a solids circulation loop. A circulating fluid bed can be differentiated from a bubbling fluid bed in that there is no distinct separation between the dense solids zone and the dilute solids zone. The residence time of the solids in a circulating fluid bed is determined by the solids circulation rate, the attritibility of the solids, and the collection efficiency of the solids separation device. As with bubbling fluid beds, emissions are the primary driving force behind the development of circulating fluid beds in the U.S. The uniform, low combustion temperatures yield low NO_x emissions. In a circulating fluid bed, with its need for introduction of solids to maintain bed inventory, it is easy to introduce a sorbent solid, such as limestone or dolomite, to control SO_2 emissions without the need for back-end sulfur removal equipment. Circulating fluid bed temperatures are maintained at about 870°C (1,598°F), which help to optimize the limestone-sulfur reactions [7]. The major manufacturers of circulating fluid bed boilers for biomass are Combustion Engineering (CE-Lurgi), B&W-Studsvik, Ahlstrom Pyropower (Foster Wheeler) and Gotaverken. A number of plants have been built in the 25 MW size range, primarily in California.

The suspension burning of pulverized wood in dedicated biomass boilers is a fairly recent development and is practiced in relatively few installations. Suspension burning has also been accomplished in lime kilns [8] and is being investigated by the utility industry for co-firing applications [9]. Successful suspension firing requires a feed moisture content of less than 15% [3] and a particle size less than 0.15 cm [8]. These requirements give higher boiler efficiencies (up to 80%) than stoker grate or fluid bed systems (65% efficiency), which fire wet wood chips (50-55% moisture). The higher efficiency of suspension burners results in smaller furnace size. Offsetting the higher efficiency is the cost and power consumption of drying and comminution. In addition, special burners (i.e. scroll cyclonic burners and vertical-cylindrical burners) are required [3]. Installations include the 27 MW Oxford Energy facility at Williams, California [3]; the ASSI Lövholmen Linerboard Mill in Piteå, Finland [10]; the Klabin do Parana mill in Monte Alegre, Brazil [8]; and the E.B. Eddy Mill in Espanola Ontario [8].

The Whole Tree Energy™ Process is being developed by Energy Performance Systems, Minneapolis, Minnesota [11], as an integrated wood-conversion process encompassing feedstock production, harvesting, transportation, and conversion to electricity. Elements of the process have been tested, but the system has not been run as an integrated process. The concept involves transporting whole trees to the conversion facility where drying will be accomplished over a 30-day period using low temperature heat from the power island. Trees will be transported to the power island where they will be cut to the desired length and introduced into the primary combustion chamber through a ram charger door. The primary combustion chamber is envisioned as a deep bed operated as a substoichiometric combustor to produce a mixture of combustion products and volatilized organics. The gases leaving the primary combustion chamber will be burned with overfire air under excess air conditions to complete the combustion process. The boiler will be a standard design with superheater and economizer. The steam turbine cycle will be comparable to modern cycles utilizing 16.54 MPa, 538°C (1000°F) steam. The potential advantages of the Whole Tree Energy™ process are reduced operating costs achieved by elimination of wood chipping, and increased efficiency by almost complete use of waste heat in the condensing heat exchange system.

2.0 System Application, Benefits, and Impacts

Electricity production from biomass is being used, and is expected to continue to be used, as base load power in the existing electrical distribution system. As discussed in the Overview of Biomass Technologies, there are approximately 7 GW of grid-connected biomass generating capacity in the U.S. [12]. Much of this is associated with the wood and wood products industries that obtain over half of their electricity and thermal energy from biomass. All of today's capacity is direct combustion/Rankine cycle technology. Biomass consumption in 1994 reached approximately 3 EJ, representing about 3.2% of the total U.S. primary energy consumption (94 EJ) [12].

There are a number of benefits of using biomass-derived electricity. Biomass is lower in sulfur than most U.S. coals. A typical biomass contains 0.05 to 0.20 weight % sulfur and has a higher heating value of about 19.77 MJ/kg. This sulfur content translates to about 51 to 214 mg SO_2/MJ. The higher level is still less than the regulated limit set out in the current New Source Performance Standards (NSPS) for coal: 517 mg/MJ for coal-fired plants that have achieved a 90% reduction in emissions since 1985 and 259 mg/MJ for coal-fired plants that have achieved a 70% reduction in emissions since 1985 [13]. Controlled NO_x levels from biomass plants will also be less than the NSPS standards. Biomass is a renewable resource that consumes carbon dioxide during its growing cycle. Therefore, it contributes no net carbon dioxide to the atmosphere when biomass is produced and consumed on a sustainable basis as part of a dedicated feedstock supply system/energy production system. The use of biomass to produce electricity in a dedicated feedstock supply system/electricity-generation system will provide new revenue sources to the U.S. agriculture system by providing a new market for farm production. The gaseous and particulate emissions shown in Table 1 are performance guarantees for existing biomass power plants in California [3]. The ash produced is based on yearly plant feed, assuming biomass with 0.69% ash. Since advanced direct combustion systems have not been built, emission estimates have not been made. Future plants will need to meet applicable Federal, state, and local emission requirements.

Table 1. Biomass power plant gaseous and particulate emissions.

Indicator Name	Units	Base Year 1997	2000	2005	2010	2020	2030
Unit Size	MW	50	60	100	150	184	184
Traveling Grate							
Particulates (@ 12% CO_2)	g/Nm^3	0.054					
Nitrogen Oxides	g/GJ	4.30					
Carbon Monoxide	g/GJ	129					
Non-CH_4 Hydrocarbons	g/GJ	17.2					
Sulfur Dioxide	g/GJ	Not specified					
Ash	Gg/yr	2.042	2.042	3.393	5.088	5.088	5.088

3.0 Technology Assumptions and Issues

The base technology is assumed to be located in New England (FERC Region 1), which is considered a representative region. The use of biomass power could be widespread, and is excluded only from desert regions. In 1994, of the 3 EJ of biomass energy consumed in the U.S., 1.055 EJ were used to produce power [12]. These values include biomass residues, municipal solid waste, and landfill gas. Although biomass is being used to produce power in many locations across the U.S., biomass electricity production is currently concentrated in New England, the South Atlantic, and the West (FERC Regions 1, 4, and 9, respectively).

An abundant and reliable supply of low-cost biomass feedstock is critical for significant growth to occur in the biomass power industry. The use of biomass residues, about 35 Tg/yr today, is expected to expand throughout the period, reaching about 50 Tg/yr. A key premise of the U.S. National Biomass Power Program is that a dramatic expansion in future availability of dedicated feedstocks will occur in the 2005-2020 time frame, growing to about 90 Tg/yr by 2020. For purposes of this analysis, the use of dedicated feedstock is assumed.

Direct-fired biomass technology will provide base-loaded electricity and is operated in a way similar to fossil and nuclear plants. Direct-fired biomass technology is commercial technology. All of the assumed advances in performance involve the incorporation of proven commercial technology. Therefore, there are no R&D issues involved in the power station technology. However, there is R&D required to determine additives and boiler modifications to permit the combustion of high-alkali biomass, such as wheat straw, without fouling of boiler heat exchange surfaces.

4.0 Performance and Cost

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

4.1 Evolution Overview

The base case is based on the McNeil Station located in Burlington, Vermont, as described by Wiltsee and Hughes [1]. Feed composition is given in Table 3. Wood heating values are about 10 MJ/kg on a wet basis and 20 MJ/ kg on a dry basis; these values are about 40% and 80% of coal (24.78 MJ/kg [12]), respectively.

Table 3. Feedstock composition.

Component	Pine 5%M	Pine 50%M	Oak 5%M	Oak 50%M
C, wt%	50.45	26.55	47.65	25.08
H	5.74	3.02	5.72	3.01
N	0.16	0.09	0.09	0.05
O	37.34	19.66	41.17	21.65
S	0.02	0.01	0.01	0.01
Cl	0.03	0.01	0.01	0.01
Moisture	5.00	50.00	5.00	50.00
Ash	1.26	0.67	0.35	0.19
MJ/kg (wet)	19.72	10.38	18.92	9.96
MJ/kg (dry)	20.76	20.76	19.92	19.92

Representative material and energy balances for the 1996 and 2000 cases are given by Figures 2 and 3. The nameplate efficiency of the McNeil Station is 25%, while the Biopower model [14] from which Figure 2 was derived, gives 23.0% efficiency.

As indicated in Figure 3, the plant efficiency is increased to 27.7% in the year 2000 (EPRI 1995) through the use of a dryer. This increase in efficiency comes from an increase in boiler efficiency that occurs when dry feed is substituted for wet feed. For example, for a wood-fired stoker boiler, boiler efficiency is estimated at 70% for a 50% moisture content fuel and 83% for a 10% moisture content fuel, assuming 30% excess air, 19.96 MJ/kg dry feed, and a flue gas exit temperature of 177°C (351°F) [1]. The McNeil Station boiler efficiency is 70% for a 50% moisture fuel and its process efficiency is 23%. Wiltsee states “The boiler efficiency, multiplied by the higher heating value of the fuel burned in the boiler, determines the amount of energy that ends up in the steam, available for driving the steam turbine generator. The boiler efficiency also determines the gross station efficiency when it is multiplied by the gross turbine efficiency. Boiler efficiency is a function of the amount of moisture in the fuel, the amount of

Table 2. Performance and cost indicators.

INDICATOR NAME	UNITS	Base Case 1997	+/- %	2000	+/- %	2005	+/- %	2010	+/- %	2020	+/- %	2030	+/- %
Plant Size	MW	50		60		100		150		184		184	
General Performance Indicators													
Capacity Factor	%	80		80		80		80		80		80	
Efficiency	%	23.0		27.7		27.7		27.7		33.9		33.9	
Net Heat Rate	kJ/kWh	15,280		13,000		13,000		13,000		10,620		10,620	
Annual Energy Delivery	GWh/yr	350		420		700		1,050		1,290		1,290	
Capital Cost													
Fuel Preparation	$/kW	181	20	150	20	129	20	114	20	93	20	93	20
Dryer		0		79		68		60		49		49	
Boiler		444	25	369	25	317	25	281	25	229	25	229	25
Baghouse & Cooling Tower		29		24		21		18		15		15	
Boiler feed water/deaerator		56	25	46	25	40	25	35	25	29	25	29	25
Steam turbine/gen		148		123		106		94		76		76	
Cooling water system		66		55		47		42		34		34	
Balance of Plant		273	15	227	15	195	15	172	15	141	15	141	15
Subtotal (A)		1,197		1,073		922		816		667		667	
General Plant Facilities (B)		310		257		221		196		160		160	
Engineering Fee, 0.1*(A+B)		1,513		133		114		101		83		83	
Project /Process Contingency		2,269		200		171		152		124		124	
Total Plant Cost		1,884		1,664		1,429		1,265		1,034		1,034	
Prepaid Royalties		0		0		0		0		0		0	
Init Cat & Chemical Inventory		2.21		2.21		2.21		2.21		2.21		2.21	
Startup Costs		53.06		53.06		53.06		53.06		53.06		53.06	
Inventory Capital		11.19		11.19		11.19		11.19		11.19		11.19	
Land, @$16,060/hectare		14.49		14.49		14.49		14.49		14.49		14.49	
Total Capital Requirement	$/kW	1,965		1,745		1,510		1,346		1,115		1,115	

Notes:

1. The columns for "+/- %" refer to the uncertainty associated with a given estimate.
2. Plant construction is assumed to require two years.
3. Totals may be slightly off due to rounding

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

INDICATOR NAME	UNITS	Base Case 1997	+/- %	2000	+/- %	2005	+/- %	2010	+/- %	2020	+/- %	2030	+/- %
Plant Size	MW	50		60		100		150		184		184	
Operation and Maintenance Cost													
Feed Cost	$/GJ	2.50	60	2.50	60	2.50	60	2.50	60	2.50	60	2.50	60
Fixed Operating Costs	$/kW-yr	73	15	60	15	60	15	60	15	49	15	49	15
Variable Operating Costs	¢/kWh												
Labor		0.37	15	0.30	15	0.30	15	0.30	15	0.25	15	0.25	15
Maintenance		0.21		0.17		0.17		0.17		0.14		0.14	
Consumables		0.27		0.23		0.23		0.23		0.18		0.18	
Total Variable Costs		0.85		0.70		0.70		0.70		0.57		0.57	
Total Operating Costs	¢/kWh	5.50		4.74		4.74		4.74		3.87		3.87	

Notes:

1. The columns for "+/- %" refer to the uncertainty associated with a given estimate.
2. Total operating costs include feed costs, as well as fixed and vaiable operating costs.
3. Totals may be slightly off due to rounding

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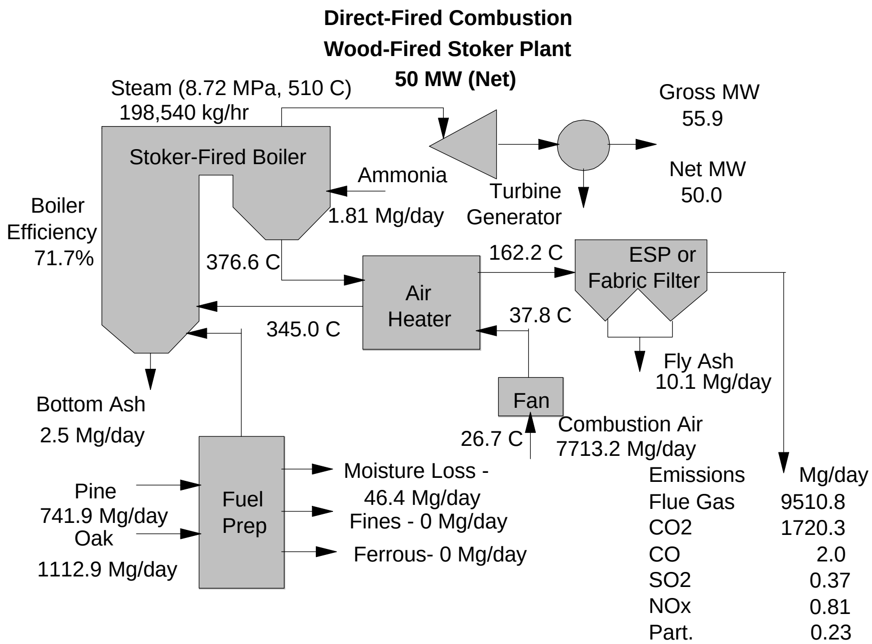


Energy Balance (GJ/hr)		**Material Balance (Mg/hr)**	
<u>Heat In</u>		<u>Mass In</u>	
Fuel (as fired)	782.5	Fuel (as received)	77.3
	----------	Ammonia	0.1
Total	782.5	Combustion Air	321.4

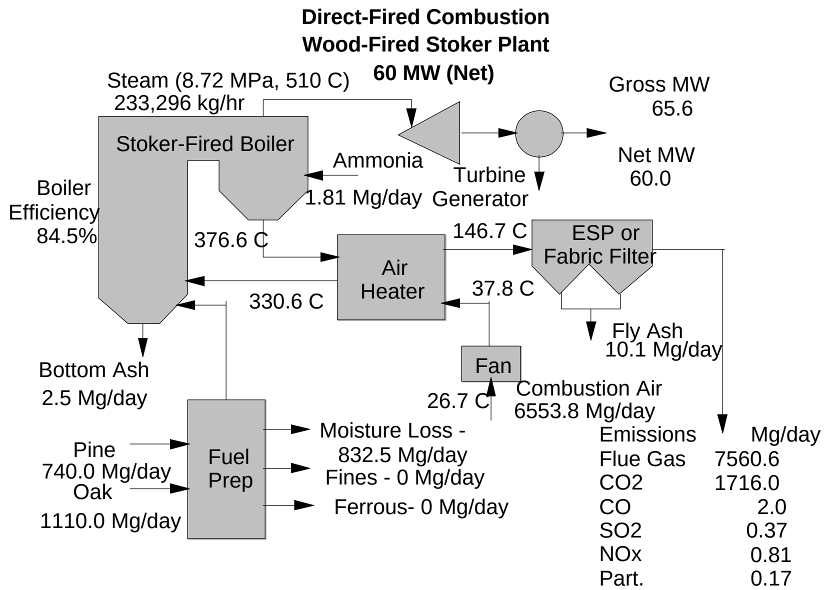
<u>Heat Out</u>		Total	398.7
Net stream turbine output	180.1	<u>Mass Out</u>	
Auxiliary turbine use	21.1	Fuel prep moisture losses	1.9
Condenser	360.3	Fines	0.0
Stack gas losses	199.5	Ferrous metal	0.0
Boiler radiation losses	2.0	Bottom ash	0.3
Unaccounted carbon loss	7.8	Fly ash	1.0
Unaccounted boiler heat loss	11.7	Flue gas	396.3
	----------		----------
Total	782.5	Total	398.7

Performance Summary

Annual capacity factor, %	80%
Net KJ/kWh	15,650
Thermal Efficiency, %	23.0%

Figure 2. Material and energy balance for the 1997 base case.

DIRECT-FIRED BIOMASS



Energy Balance (GJ/hr)

<u>Heat In</u>	
Fuel (as fired)	782.5

Total	782.5
<u>Heat Out</u>	
Net stream turbine output	216.1
Auxiliary turbine use	20.4
Condenser	423.3
Stack gas losses	99.4
Boiler radiation loses	1.9
Unaccounted carbon loss	7.8
Unaccounted boiler heat loss	11.7

Total	780.5

Material Balance (Mg/hr)

<u>Mass In</u>	
Fuel (as received)	77.1
Ammonia	0.1
Combustion Air	273.1

Total	350.3
<u>Mass Out</u>	
Fuel prep moisture losses	34.6
Fines	0.0
Ferrous metal	0.0
Bottom ash	0.1
Fly ash	0.5
Flue gas	315.0

Total	350.3

Performance Summary

Annual capacity factor	80%
Net KJ/kWh	13,008
Thermal Efficiency	27.7%

Figure 3. Material and energy balance for the year 2000 case.

excess air used in the combustion process, and the amount of heat lost in the heat transfer process, which is largely a function of boiler design." If we multiply the McNeil Station design efficiency by 83/70, we get 27.3% efficiency.

In 2020, plant efficiency is increased to 33.9% [1] through more severe steam turbine cycle conditions possible at larger scale, e.g., higher pressure, higher temperature, and reheat. For example, Wiltsee and Hughes [1] provide an example of a 50 MW stoker plant, compared to a 100 MW WTE™ plant and state "As shown, the WTE™ steam turbine (7,874 Btu/kWh) is much more efficient than the stoker power plant's steam turbine (9,700 Btu/kWh). This is because of the WTE™ steam turbine's larger size (106 vs. 59 gross MW), and higher steam conditions (2,520 psig and 1,000^{o}F with 1,000^{o}F reheat, vs. 1,250 psig and 950^{o}F, with no reheat)." If one multiplies the 27.7% efficiency case by the ratio 9,700/7,864, one gets 34.1%, which is comparable to the Biopower model results of 33.9%.

4.2 Performance and Cost Discussion

The base case capital and operating costs [1] were updated to 1996 dollars using the Marshall and Swift Index [15]. In the year 2000, plant costs were adjusted by adding a dryer [16]. Capital and operating costs in later years were scaled from the 2000 values using a 0.7 scaling factor. Peters and Timmerhaus [17] state "It is often necessary to estimate the cost of a piece of equipment when no cost data are available for the particular size of operational capacity involved. Good results can be obtained by using the logarithmic relationship known as the 'six-tenths-factor rule,' if the new piece of equipment is similar to one of another capacity for which cost data are available. According to this rule, if the cost of a given unit at one capacity is known, the cost of a similar unit with X times the capacity of the first is approximately $(X)^{0.6}$ times the cost of the initial unit." Valle-Riesta [18] states "A logical consequence of the 'sixth-tenths-factor' rule for characterizing the relationship between equipment capacity and cost is that a similar relationship should hold for the direct fixed capital of specific plants.....In point of fact, the capacity exponent for plants, on the average, turns out to be closer to 0.7." The exception to this rule happens when plant capacity is increased by change in efficiency, not change in equipment size. In this case, capital cost in dollars remains constant, and capital cost in $/kW decreases in proportion to efficiency increase. For example, the change in capital costs between 1996 and 2000 reflects an efficiency increase, while the change between 2000 and 2005 reflects equipment scale change.

The electrical substation is part of the general plant facilities, and is not separated out in the factor analysis. The convention follows that used in the EPRI Technical Assessment Guide [12], as follows "It also includes the high-voltage bushing of the generation step-up transformer but not the switchyard and associated transmission lines. The transmission lines are generally influenced by transmission system-specific conditions and hence are not included in the cost estimate."

Feedstock for biomass plants can be residues or dedicated crops or a mixture of the two. For purposes of this analysis, dedicated feedstock is assumed. The Overview of Biomass Technologies provides a discussion of the sustainability of dedicated feedstock supplies which are assumed to be used in the systems characterized here. Fuel from dedicated feedstock supply systems is projected to cost as little as $1/GJ and as much as $4/GJ, depending on species and conditions [1]. For this analysis, an average cost of $2.50/GJ is used, which represents an update of the DOE goal for dedicated feedstocks.

5.0 Land, Water, and Critical Materials Requirements

Storage requirements are included in both the station and cropland area estimates shown in Table 4. About one week of storage at the plant site is assumed. Transfer stations are included in land estimates. Feedstock requirements are based on biomass at 19.77 GJ/MT (8,500 Btu/lb), and the capacity factors from Table 2.

As discussed in the Overview of Biomass Technologies, large-scale dedicated feedstock supply systems to supply biomass to biomass power plants do not exist in the U.S. today. Because the U.S. DOE has recognized this fact, a large share of its commercial demonstration program directly addresses dedicated feedstock supply. Projects in New York, Iowa, and Minnesota are developing commercial feedstocks of both woody and herbaceous varieties. Feedstock development (e.g., hybrid poplar and switchgrass) and resource assessment are also underway at Oak Ridge National Laboratory.

Furthermore, many examples in the forest products industries (e.g., pulp and paper) and agriculture industries (e.g., sugar) demonstrate sustainable utilization of biomass residues for power and energy production. In the U.S. and abroad, numerous examples demonstrate that the agriculture, harvest, transport, and management technologies exist to support power plants of the proportions discussed in this technology characterization.

Table 4. Resource requirements.

Indicator Name	Units	Base Year 1996	2000	2005	2010	2020	2030
Plant Size	MW	50	60	100	150	184	184
Land							
Plant	ha/MW	0.902	0.902	0.902	0.902	0.902	0.902
	ha	45.1	54.1	90.2	135.3	166.0	166.0
Crops	ha/MW	487	401	268	268	164	164
	ha	24,350	24,060	26,800	40,200	30,176	30,176
Crop Growth Rate	Mg/ha/yr	11.2	11.2	16.8	16.8	22.4	22.4
Power Plant Water	Mm^3/yr	0.808	0.808	1.341	2.012	2.426	2.426
Energy: Biomass	PJ/yr	5.35	5.35	8.90	13.34	13.34	13.34
Feedstocks: Biomass	Tg/yr	0.271	0.271	0.450	0.675	0.675	0.675
Labor							
Farm (261 ha/FTE)	FTE	95	95	101	152	114	114
Station	FTE	22	22	22	30	35	35

Note: FTE refers to full-time equivalent.

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6.0 References

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