7. Representative Biomass CHP System Cost and Performance Profiles

A biomass-fueled CHP installation is an ***integrated power system*** that is comprised of the three main components described previously in this report:

- Biomass receiving and feedstock preparation (Chapter 4).
- Energy conversion (Chapter 5)—Conversion of the biomass into steam for direct combustion systems or into biogas for the gasification systems. This includes necessary environmental control equipment (cyclones, baghouses, acid gas removal, selective non-catalytic reduction, selective catalytic reduction, heat recovery, the boiler system or the biogas cooling, and cleanup section).
- Power and heat production (Chapter 6)—Conversion of the steam or syngas into electric power and process steam or hot water.

This chapter provides information about configurations, costs, and performance of typical biomass CHP systems, incorporating the information and data previously presented for each of the three primary components. Representative costs are developed for a series of typical biomass power generation systems and built up from the primary component costs developed in previous chapters of the report. System economics are presented on annual and net cost bases to generate power. The net cost to generate power is a function of the system cost and performance, the cost of biomass fuel, non-fuel O&M costs, the facility cost of capital, and the avoided cost of process steam for CHP configurations. Estimating the net cost to generate power is essentially a revenue requirements calculation. This methodology is typically used by utilities to calculate a required power price to achieve an allowed rate of return. This type of approach is useful in non-utility applications in that it estimates the cost of power from the system that would earn the owner/operator its cost of capital. In the calculation, the cost to generate power is the sum of the biomass fuel cost, non-fuel O&M cost, and a capital recovery cost, all on a per kWh-generated basis. In a CHP configuration, the unit also provides steam or thermal energy to the site that would have otherwise been generated by separate means, and displaces fuel that would have been consumed in generating this steam or thermal energy requirement. The ***net cost*** to generate power calculation credits that fuel savings against the other generating costs.

Key economic assumptions are listed in **Table 7-1.** Capital recovery costs are based on assumptions of the cost of capital and project economic life; a cost of capital of 8 percent and a project economic life of 20 years was used for this analysis. A 20-year annuity at an 8 percent cost of capital results in an annual capital recovery factor of 10.2 percent. The annual capital costs that must be recovered to earn the required cost of capital over the 20-year life is then equal to the initial capital cost of a project multiplied by the 10.2 percent capital recovery factor. The per kWh unit capital recovery cost is equal to the annual capital payment (as determined by the calculation just described) divided by the annual kWh generated by the system.

Table 7-1. Key Economic Assumptions

Key Economic Assumptions	Value
Biomass fuel cost ($/MMBtu)	$2.00
Displaced natural gas cost ($/MMBtu)	$6.00
Displaced retail average electricity cost ($/kWh)	$0.07
Biomass system availability (%)	90
Cost of capital (%)	8
System economic life (years)	20
Annual capital recovery factor (%)	10.2

7.1 Direct Firing of Biomass (Boilers With Steam Turbines)

Direct firing of solid fuel biomass in a boiler to raise high-pressure steam is the most common CHP configuration in use today. The steam generated in the boiler is used to power a steam turbine generator and, in turn, to serve process needs at lower pressure and temperature. Process steam can be provided by use of an extraction condensing steam turbine, with part of the steam output being extracted from the turbine at the pressure required by the process. This is accomplished through the use of a back-pressure turbine that exhausts all the steam at the pressure required by the process, or through a combination of back-pressure and condensing turbines. Power-only configurations (non-CHP) would send all of the steam through a condensing turbine. As described in Chapter 5, direct-fired systems rely primarily on two types of boilers—fixed bed stoker and variant type boilers and circulating fluidized bed boilers.

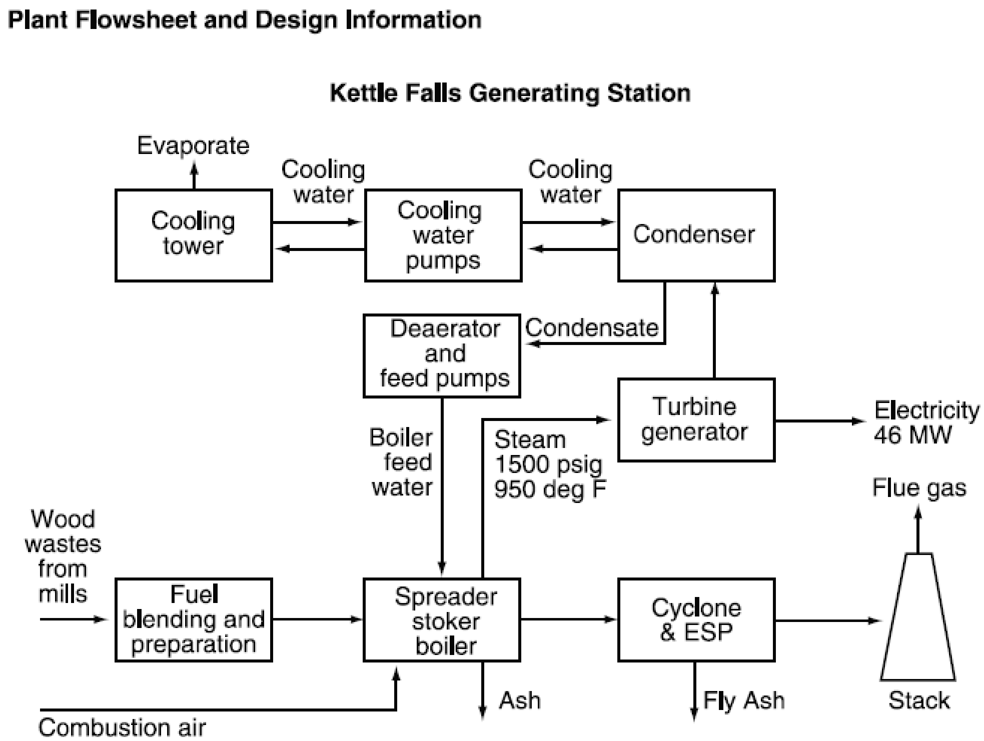
For illustrative purposes, **Table 7-2** provides a listing of recent biomass CHP and power-only plants using fixed and vibrating grate stoker boilers ranging in size from 46 to 74 MW. The plants are all primarily fueled by wood waste feedstock. Typical boiler output is 1,500 psig steam pressure and 950^{o}F steam temperature. Capital costs vary from $2,000 to $2,600/kW. The typical features of a biomass power plant are shown in **Figure 7-1,** representing a schematic of the 46 MW plant in Kettle Falls, Washington.

Table 7-2. Example of Biomass Power Plants and Costs

Biomass Power Plant	Year Installed	MW	Fuel	Technology	Heat Rate (Btu/kWh)	Total Cost ($ million)	Total Cost ($/kW)
Kettle Falls (power only)	1983	46.0	Mill wood waste	1 traveling grate stoker, 1,500 psig, 950°F	14,100	82.5	$1,940
Williams Lake Generating Station (power only)	1993	60.0	Mill wood waste	1 water-cooled vibrating grate, 1,500 psig, 950° F	11,700	125	$2,100
Snohomish Public Utility District (CHP)	1996	46.9	Mill, urban wood waste	1 sloping grate, 825 psig, 850° F	17,000	115	$2,452
Okeelanta (CHP)	1997	74.0	Bagasse, urban wood waste	3 water-cooled vibrating grate, 1525 psig, 950° F	13,000	194.5	$2,628

Source: NREL, 2000.

Figure 7-1. Kettle Falls Plant Schematic



Source: Appel Consultants, Inc., 2000.

The Kettle Falls schematic shows the configuration for a biomass-fueled power plant using a fixed bed stoker boiler and a condensing steam turbine for power production. The balance of plant includes the fuel prep-yard, cooling tower, pumps, condenser, de-aerator, cyclone and electrostatic precipitator, and the stack. A CHP configuration would include an extraction-condensing turbine with a steam extraction point for process steam or a back-pressure steam turbine. Power output is maximized with a condensing turbine. Maximum available process steam (with power production) would result from the use of a back-pressure turbine. Intermediate levels of power and steam can be achieved using an extraction-condensing turbine. In large CHP systems such as those used in pulp and paper mills, there might be more than one extraction point to serve the needs of different process requirements.

7.1.1 Fixed Bed Stoker Boiler CHP Configurations and Performance

Fixed bed stoker boilers represent a commonly used option for a direct-fired biomass CHP system. The energy requirements and outputs for three sizes of stoker boiler systems from 100 to 900 tons/day are shown in **Table 7-3.** The table provides biomass feedstock requirements, typical feedstock characteristics, boiler biomass conversion efficiency, boiler output steam conditions as developed in Chapter 5, and power and process steam outputs for various power generation and steam production configurations. The power and steam configurations range from back-pressure steam turbines, various extraction turbine configurations, and power-only condensing turbine configurations. For this analysis, all process steam for the CHP systems is assumed to be required at 150 psig (saturated), except for the small 100 tons/day system, which supplies 15 psig saturated steam to process.

Table 7-3. Biomass Stoker Boiler Power Generation System Input and Output Requirements

	Tons/Day (as received)		
Biomass Cases	**100**	**600**	**900**
Biomass Fuel Characteristics			
Energy content (dry) (Btu/lb)	8,500	8,500	8,500
Moisture content (%)	50	30	30
Energy content (as received) (Btu/lb)	4,250	5,950	5,950
Biomass Conversion			
Boiler efficiency (zero moisture) (%)	77	77	77
Boiler efficiency (moisture adjusted) (%)	63	71	71
Heat input to boiler (MMBtu/hr)	35.4	297.5	446.3
Heat to the steam (MMBtu/hr)	22.5	212.0	318.0
Plant capacity factor	0.9	0.9	0.9
Boiler Steam Conditions			
Boiler output pressure (psig)	275	750	750
Boiler output temperature (° F)	494	750	750
Nominal steam flow (lb/hr)	20,000	165,000	250,000
Steam Turbine Options			
CHP—Back-Pressure Turbine			
Electric output (MW)	0.5	5.6	8.4
Process steam conditions (psig [saturated])	15	150	150
Process steam flow (lb/hr)	19,400	173,000	260,000
CHP efficiency (%)	62.9	70.5	70.5
CHP—Extraction Turbine			
Process steam conditions (psig [saturated])	N/A	150	150
Electric output (MW) (150,000 lb/hr steam)	N/A	6.9	14.7
Electric output (MW) (100,000 lb/hr steam)	N/A	9.8	17.5
Electric output (MW) (50,000 lb/hr steam)	N/A	12.6	20.4
Power Only—Condensing Turbine			
Electric output (MW)	N/A	15.5	23.3
Electric efficiency (%)		17.8	17.8

The smaller, 100 tons/day boiler system is assumed to produce steam at relatively modest conditions—275 psig and 494° F. The larger plants are assumed to produce steam at 750 psig and 700° F. The higher the temperature and pressure of the steam produced, the greater the power production potential, though this higher production potential comes at the expense of greater capital cost for the boiler and increased fuel consumption to reach the higher steam energy levels.

The tradeoff between process steam and power production is shown in **Figure 7-2.** Power production for the 900 tons/day plant can be varied from 23.3 MW with a condensing turbine and no process steam to 8.4 MW and 270,000 lb/hr of 150 psig saturated steam with a full back-pressure turbine. As the figure shows, power output versus process steam output is a linear relationship.

Figure 7-2. Power to Steam Production Options for Boiler/Steam Turbine CHP System

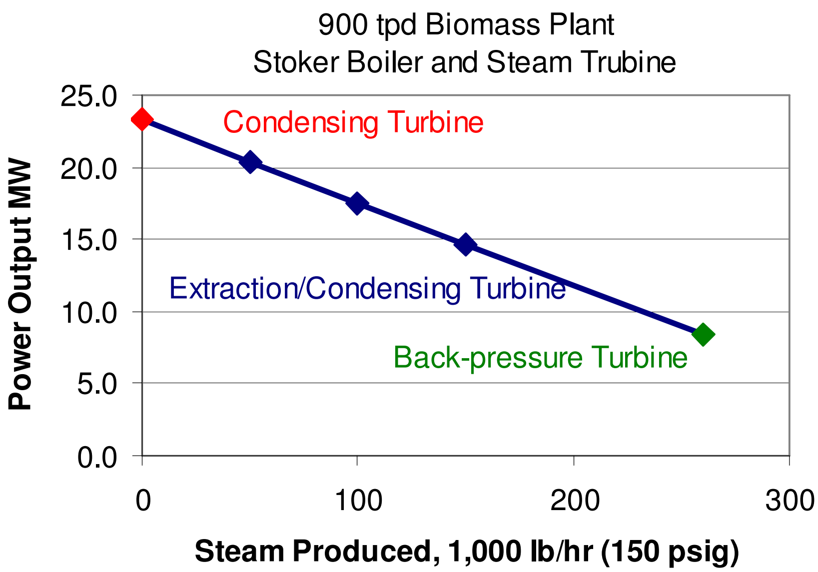


Table 7-4 presents the capital cost estimates for the three stoker boiler power systems. The capital requirements for the integrated power generation systems include:

Prep-yard

Steam boiler system

Steam turbine-generator

Building and site

Process controls

Construction and commissioning services

The cost estimates are based on a greenfield installation—there is no existing prep-yard, boiler, or generating equipment in place. There are no site preparation costs included in the estimates.

Table 7-4. Biomass Stoker Boiler Power Generation System Capital Cost Estimates

	Tons/Day (as received)		
Installed Capital Costs	**100**	**600**	**900**
Biomass prep-yard*	$2,639,660	$5,430,000	$7,110,000
Stoker boiler	$1,991,000	$18,000,000	$23,250,000
CHP—Back-Pressure (BP) Steam Turbine			
BP steam turbine capacity (MW)	0.5	5.6	8.4
BP steam turbine cost	$425,000	$2,500,000	$3,250,000
Total capital cost—CHP/back-pressure turbine	$4,630,660	$25,930,000	$33,610,000
Cost $/kW—CHP/back-pressure turbine	$9,260	$4,630	$4,000
Power Only—Condensing Steam Turbine			
Condensing steam turbine capacity (MW)	N/A	15.5	23.3
Condensing steam turbine cost	N/A	$5,425,000	$7,575,000
Total capital cost—condensing turbine	N/A	$28,855,000	$37,935,000
Cost $/kW—condensing turbine	N/A	$1,860	$1,630

*Prep-Yard costs are estimated based on the capital cost curve developed in section 4.1.5

The largest component of capital costs for the two larger systems is for the boiler itself and associated equipment—making up 60 to 70 percent of the total plant cost. For the 100 tons/day plant, the biomass prep-yard costs are much higher on a per unit basis due to the high economies of scale for prep-yard capital costs. The 600 and 900 tons/day plants have capital costs of $1,860/kW and $1,630/kW, respectively, for a condensing turbine (power-only system), and $4,630/kW and $4,000/kW for a back-pressure CHP system. The $/kW unit costs for the 100 tons/day plant are much higher (more than $9,000/kW) because this small back-pressure CHP plant generates a small amount of power relative to its process steam output.

Table 7-5 shows the estimated non-fuel O&M costs for each stoker boiler system. Labor costs are based on the assumption of 15 full-time staff for the two larger plants (one manager, three maintenance workers, eight shift workers, and four prep-yard workers) and six full-time staff for the 100 tons/day plant. Annual non-labor fixed O&M is assumed to be 2 percent of the capital cost. There is no labor portion of variable O&M, but the non-labor portion equals the cost of consumables such as chemicals, water, and electricity, needed to run the equipment at the prep-yard. These are assumed to collectively equal $0.001/kWh.

Table 7-5. Biomass Stoker Boiler Power Systems Non-Fuel O&M Cost Estimates

	Tons/Day (as received)		
O&M Cost Components	**100**	**600**	**900**
Prep-yard O&M	$400,000	$320,000	$320,000
Boiler section O&M	$160,000	$1,095,000	$1,110,000
Steam turbine O&M	$15,000	$177,000	$265,000
Total O&M	$575,000	$1,592,000	$1,695,000
Non-fuel O&M ($/kWh)/(back-pressure turbine)	$0.146	$0.036	$0.026
Non-fuel O&M ($/kWh) (condensing turbine)	N/A	$0.013	$0.009

Table 7-6 shows the annual operating and capital expenses and the net cost to generate power for each of the three biomass stoker boiler systems. As described earlier, the net cost to generate power is a function of the system cost and performance, the cost of biomass fuel, non-fuel O&M costs, the facility cost of capital, and the avoided cost of process steam. In the calculation, the cost to generate power is the sum of the biomass fuel cost, the non-fuel O&M cost, and a capital recovery cost, all on a per kWh-generated basis. As detailed in **Table 7-1**, the biomass fuel cost was assumed to be $2.00/MMbtu. The non-fuel O&M costs are detailed in **Table 7-5**. In CHP configuration, the unit also provides steam or thermal energy to the site that would have otherwise been generated by separate means, and displaces fuel that would have been consumed in generating this steam or thermal energy requirement. The ***net cost*** to generate power calculation credits that fuel savings against the other generating costs.

The net costs to generate power are estimated in **Table 7-6** for both a CHP configuration using back-pressure turbines, and for the power-only configuration using condensing turbines. The 100 tons/day plant is only shown in a back-pressure turbine configuration. The annual expenses are shown only for the back-pressure steam turbine CHP configuration. The net costs to generate are calculated for the CHP configuration in two ways: displacing steam that would have been generated with the same biomass fuel and boiler efficiencies and displacing steam that would have been generated with a natural gas boiler at 80 percent efficiency and at a gas price of $6.00/MMBtu. The 600 and 900 tons/day plants have net power costs in the condensing turbine (maximum power production) configuration of $0.076/kWh and $0.069/kWh, respectively. Using a back-pressure turbine to maximize steam production, the value of avoided natural gas fuel for steam generation is greater than the capital and operating costs of the two larger systems, resulting in a negative net power cost. The high capital cost and non-fuel O&M cost of the 100 tons/day system results in a high net power cost, even with a $0.309/kWh credit for avoided natural gas boiler fuel.

Annual operating costs assume that all of the power generated by the biomass CHP systems can be used on site and displace purchased electricity at an average cost of $0.07/kWh. These calculations provide an estimate of the annual cost of providing steam to the site and include a credit for displaced power purchases.

7.1.2 Circulating Fluidized Bed Boiler CHP Configurations and Performance

The circulating fluidized bed boiler CHP system configuration is similar to the stoker boiler configuration. Higher carbon conversion increases the boiler efficiency, allowing somewhat higher power and steam outputs. On the other hand, capital costs are higher. In the 100 tons/day plant, net power costs are much higher for the circulating fluidized bed case. For the two larger plants, net power costs are 4.5 percent higher even though the power outputs are 4 percent higher. The cost and performance for the integrated plant are summarized in the following tables.

Table 7-7 shows the energy requirements and outputs for three sizes of circulating fluidized bed generation systems from 100 to 900 tons/day of biomass feed. Similar to the stoker boiler systems, the table provides biomass feedstock requirements, typical feedstock characteristics, the boiler biomass conversion efficiency, and boiler output steam conditions as developed in Chapter 5 for circulating fluidized bed systems, and power and process steam outputs for various power generation and steam production configurations. The power and steam configurations range from back-pressure steam turbines to various extraction turbine configurations and power-only condensing turbine configurations.

Table 7-6. Biomass Stoker Boiler CHP Systems—Net Cost to Generate Power ($/kWh)

	Tons/Day (as received)		
Cost Components	**100**	**600**	**900**
Biomass fuel cost ($/MMBtu)	$2.00	$2.00	$2.00
Biomass boiler fuel use (MMBtu/hr)	35.4	297.5	446.3
Biomass boiler efficiency (%)	63	71	71
Natural gas cost ($/MMBtu)	$6.00	$6.00	$6.00
Natural gas boiler efficiency (%)	80	80	80
Displaced boiler biomass fuel cost ($/MMBtu of process steam)	$3.17	$2.82	$2.82
Displaced boiler natural gas cost ($/MMBtu of process steam)	$7.50	$7.50	$7.50
CHP—Back-Pressure Turbine			
Electric capacity (MW)	0.5	5.6	8.4
Annual electric generation (megawatt-hour [MWh])	3,942	44,150	66,226
Process steam (MMBtu/hr)	20.6	192.1	288.2
Annual process steam generation (MMBtu)	162,400	1,560,244	2,339,400
Annual Operating Expenses			
Biomass fuel costs	$558,187	$4,690,980	$7,037,258
Non-fuel O&M costs	$575,000	$1,592,000	$1,695,000
Annual capital recovery costs	$472,327	$2,644,860	$3,428,220
Displaced electricity purchases ($0.07/kWh)	($275,941)	($3,090,500)	($4,635,820)
Total Annual Operating Expenses	**$1,329,573**	**$5,837,340**	**$7,524,658**
Net Cost to Generate ($/kWh)			
Biomass fuel costs ($/kWh)	$0.142	$0.106	$0.106
Non-fuel O&M costs ($/kWh)	$0.146	$0.036	$0.026
Capital recovery ($/kWh)	$0.120	$0.060	$0.052
Cost to generate ($/kWh)	$0.407	$0.202	$0.184
Biomass boiler steam credit ($/kWh)	($0.131)	($0.097)	($0.097)
Net Power Costs ($/kWh)	**$0.277**	**$0.106**	**$0.087**
Natural gas boiler steam credit ($/kWh)	($0.309)	($0.257)	($0.257)
Net Power Costs ($/kWh)	**$0.098**	**($0.055)**	**($0.074)**
Power Only—Condensing Turbine			
Electric capacity (MW)	N/A	15.5	23.3
Annual electric generation (MWh)	N/A	122,200	183,300
Process steam (MMBtu/hr)	N/A	0	0
Net Cost to Generate ($/kWh)			
Biomass fuel costs ($/kWh)	N/A	$0.038	$0.038
Non-fuel O&M costs ($/kWh)	N/A	$0.013	$0.009
Capital recovery ($/kWh)	N/A	$0.024	$0.021
Net Power Costs ($/kWh)	**N/A**	**$0.076**	**$0.069**

Table 7-7. Biomass Circulating Fluidized Bed Power Generation System Input and Output Requirements

	Tons/Day (as received)		
Biomass Cases	**100**	**600**	**900**
Biomass Fuel Characteristics			
Energy content (dry) (Btu/lb)	8,500	8,500	8,500
Moisture content (%)	50	30	30
Energy content (as received) (Btu/lb)	4,250	5,950	5,950
Biomass Conversion			
Boiler efficiency (zero moisture) (%)	80	80	80
Boiler efficiency (moisture adjusted) (%)	67	75	75
Heat input to boiler (MMBtu/hr)	35.4	297.5	446.3
Heat to the steam (MMBtu/hr)	23.7	223.1	334.7
Plant capacity factor	0.9	0.9	0.9
Boiler Steam Conditions			
Boiler output pressure (psig)	275	750	750
Boiler output temperature (°F)	494	750	750
Nominal steam flow (lb/hr)	20,000	175,000	260,000
Steam Turbine Options			
CHP—Back-Pressure Turbine			
Electric output (MW)	0.5	5.9	8.8
Process steam conditions (psig [saturated])	15	150	150
Process steam flow (lb/hr)	20,300	181,100	271,600
CHP efficiency (%)	66.1	73.7	73.7
CHP—Extraction Turbine			
Process steam conditions (psig [saturated])	N/A	150	150
Electric output (MW) (150,000 lb/hr steam)	N/A	7.6	15.7
Electric output (MW) (100,000 lb/hr steam)	N/A	10.5	18.6
Electric output (MW) (50,000 lb/hr steam)	N/A	13.4	21.5
Power Only—Condensing Turbine			
Electric output (MW)	N/A	16.2	24.3
Electric efficiency (%)	N/A	18.6	18.6

Table 7-8 shows the estimated capital costs for the three circulating fluidized bed power systems. The capital requirements for the integrated system include the prep-yard, circulating fluidized bed boiler and supporting systems, and the steam turbine generator and supporting systems. Again, capital cost estimates are based on installing a greenfield system—there is no existing prep-yard, boiler, or generating equipment in place.

Capital cost for the circulating fluidized bed systems are significantly higher than the stoker power systems. Prep-yard costs are equal to the stoker prep-yard costs because they are a function of the amount of biomass handled, and steam turbine costs are only slightly higher than the stoker systems. As discussed in Chapter 5, the circulating fluidized bed costs are significantly higher than similarly sized stoker-boilers. Overall, the $/kW cost of the 100 tons/day CHP system has more than doubled to over $20,000/kW. The costs for the larger CHP systems have increased by about $900/kW, almost entirely due to the higher cost of the boiler.

Table 7-8. Biomass Circulating Fluidized Bed Power Generation System Capital Cost Estimates

	Tons/Day (as received)		
Installed Capital Costs	**100**	**600**	**900**
Biomass prep-yard	$2,639,660	$5,430,000	$7,110,000
Circulating fluidized bed boiler	$6,972,000	$24,500,000	$32,250,000
CHP—Back-Pressure Steam Turbine			
Back-pressure steam turbine capacity (MW)	0.5	5.9	8.8
Back-pressure steam turbine cost	$425,000	$2,625,000	$3,400,000
Total capital cost—CHP/back-pressure turbine	$10,036,660	$32,555,000	$42,760,000
Cost $/kW—CHP/BP turbine	$20,070	$5,515	$4,860
Power Only—Condensing Turbine			
Condensing steam turbine capacity (MW)	N/A	16.2	24.3
Condensing steam turbine cost	N/A	$5,675,000	$7,900,000
Total capital cost—condensing turbine	N/A	$35,605,000	$47,260,000
Cost $/kW—condensing turbine	N/A	$2,197	$1,945

Capital cost for the circulating fluidized bed systems are significantly higher than the stoker power systems. Prep-yard costs are equal to the stoker prep-yard costs because they are a function of the amount of biomass handled, and steam turbine costs are only slightly higher than the stoker systems. As discussed in Chapter 5, the circulating fluidized bed costs are significantly higher than similarly sized stoke-boilers. Overall, the $/kW cost of the 100 tons/day CHP system has more than doubled to over $20,000/kW. The costs for the larger CHP systems have increased by about $900/kW, almost entirely due to the higher cost of the boiler.

Table 7-9 shows estimates for O&M costs for the circulating fluidized bed direct-fired cases. Labor requirements and costs are identical to the corresponding stoker boiler cases and variable O&M costs are the same per unit of power generated. Fixed non-labor O&M is higher for the circulating fluidized bed cases, resulting in slightly higher total non-fuel O&M costs for these systems.

Table 7-9. Biomass Circulating Fluidized Bed System Non-Fuel O&M Cost Estimates

	Tons/Day (as received)		
O&M Cost Components	**100**	**600**	**900**
Prep-yard O&M	$400,000	$320,000	$320,000
Boiler section O&M	$260,000	$1,190,000	$1,205,000
Steam turbine O&M	$15,000	$185,000	$277,000
Total O&M	$675,000	$1,695,000	$1,802,000
Non-fuel O&M—back-pressure turbine ($/kWh)	$0.229	$0.036	$0.026
Non-fuel O&M—condensing turbine ($/kWh)	N/A	$0.013	$0.009

Table 7-10 shows the annual operating expenses and the net costs to generate power for the biomass circulating fluidized bed power generation systems. In the 100 tons/day case, the much higher cost for a small circulating fluidized bed boiler results in higher net power costs. The net power costs are comparable to the stoker boiler cases presented previously. The annual operating expenses are about 10 percent higher for the large systems, and 50 percent higher for the 100 tons/day system. However, circulating fluidized bed offers advantages in operational flexibility and reduced emissions as discussed in Chapter 5.

Table 7-10. Biomass Circulating Fluidized Bed Power Generation Systems—Net Cost to Generate Power ($/kWh)

	Tons/Day (as received)		
Cost Components	**100**	**600**	**900**
Biomass fuel cost ($/MMBtu)	$2.00	$2.00	$2.00
Biomass boiler fuel use (MMBtu/hr)	35.4	297.5	446.3
Biomass boiler efficiency (%)	67	75	75
Natural gas cost ($/MMBtu)	$6.00	$6.00	$6.00
Natural gas boiler efficiency (%)	80	80	80
Displaced boiler biomass fuel cost ($/MMBtu of process steam)	$2.99	$2.67	$2.67
Displaced boiler natural gas cost ($/MMBtu of process steam)	$7.50	$7.50	$7.50
CHP—Back-Pressure Turbine			
Electric capacity (MW)	0.5	5.9	8.8
Annual electric generation (MWh)	3,942	46,516	69,379
Process steam (MMBtu/hr)	22.0	203.0	304.7
Annual process steam generation (MMBtu)	162,400	1,560,244	2,339,400
Annual Operating Expenses			
Biomass fuel costs	$558,187	$4,690,980	$7,037,258
Non-fuel O&M costs	$675,000	$1,695,000	$1,802,000
Annual capital recovery costs	$1,023,739	$3,320,610	$4,361,520
Displaced electricity purchases ($0.07/kWh)	($275,941)	($3,256,120)	($4,856,530)
Total Annual Operating Expenses	**$1,980,985**	**$6,360,470**	**$8,344,248**
Net Cost to Generate ($/kWh)			
Biomass fuel costs ($/kWh)	$0.142	$0.101	$0.101
Non-fuel O&M costs ($/kWh)	$0.146	$0.034	$0.024
Capital recovery ($/kWh)	$0.120	$0.057	$0.049
Cost to generate ($/kWh)	$0.407	$0.192	$0.175
Biomass boiler steam credit ($/kWh)	($0.131)	($0.092)	($0.092)
Net Power Costs ($/kWh)	**$0.276**	**$0.100**	**$0.083**
Natural gas boiler steam credit ($/kWh)	($0.330)	($0.258)	($0.260)
Net Power Costs ($/kWh)	**$0.077**	**($0.066)**	**($0.084)**
Power Only—Condensing Turbine			
Electric capacity (MW)	N/A	16.2	24.3
Annual electric generation (MWh)	N/A	127,721	191,581
Process steam (MMBtu/hr)	N/A	0	0
Net Cost to Generate ($/kWh)			
Biomass fuel costs ($/kWh)	N/A	$0.037	$0.037
Non-fuel O&M costs ($/kWh)	N/A	$0.012	$0.009
Capital recovery ($/kWh)	N/A	$0.023	$0.020
Net Power Costs ($/kWh)	**N/A**	**$0.072**	**$0.066**

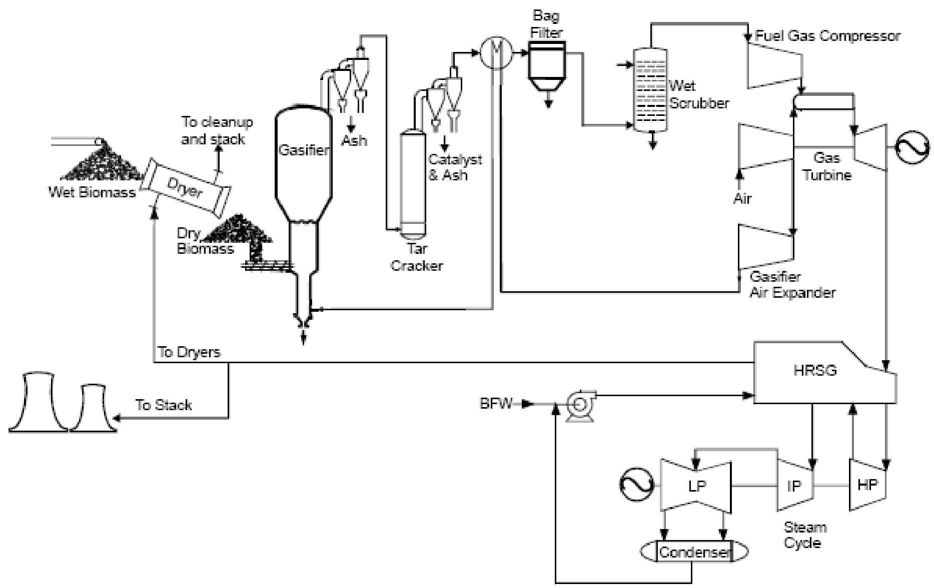
7.2 Biomass Gasification Systems

Gasification systems are more complicated than direct combustion, but they allow the use of more efficient power production. Gasification systems can use combined-cycle power plants based on gas turbines and also steam turbines that use recovered heat from the gas turbine exhaust in the form of steam.

Four gasification systems of varying sizes are compared in this section:

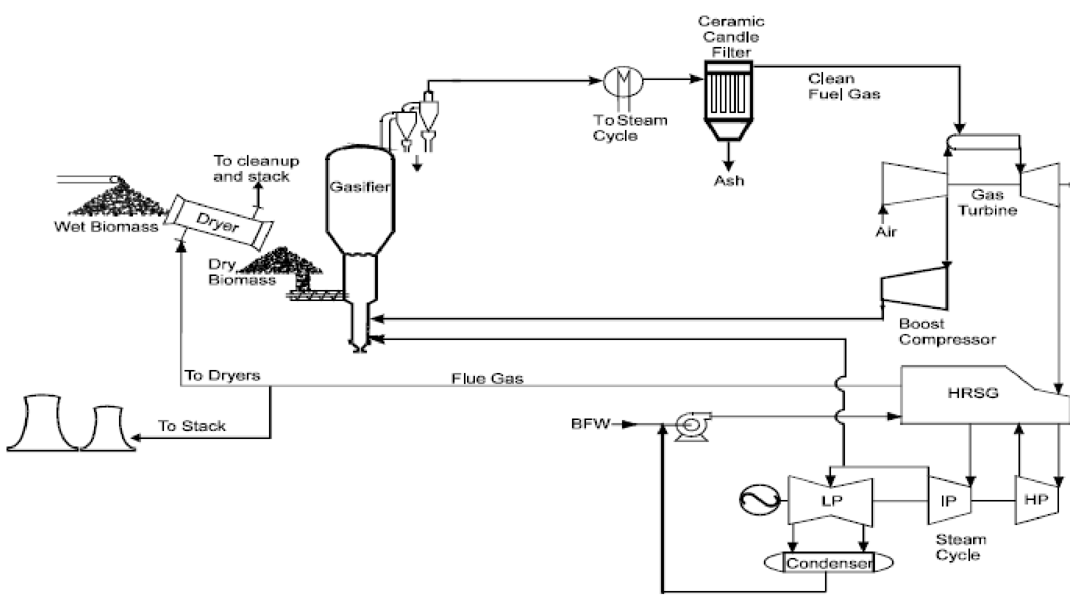
- A 100-tons/day atmospheric gasification system that uses efficient reciprocating IC engines to generate power and hot water. At this size range, engines are more efficient than small gas turbines and are preferable if the thermal energy can be utilized as hot water or low-pressure steam. In addition, the engines are capable of using the low-pressure syngas with additional compression.
- 250 and 452 tons/day atmospheric gasification systems producing power and steam in a gas turbine combined-cycle configuration. Significant energy is required to compress the low-pressure syngas. In addition, standard gas turbines are designed to compress a larger quantity of air than is needed for this low-Btu application. **Figure 7-3** shows a schematic representation of a direct-fired atmospheric gasification system. The combined-cycle system is based on the Solar Turbines Steam Turbine Assisted Cogeneration configuration in which the gas turbine and the steam turbine are at opposite ends of the same drive shaft powering a single generator.
- A 1,215-tons/day pressurized gasification system with an aeroderivative gas turbine in combined-cycle configuration—the pressurized gasifier eliminates the need for syngas compression before introduction into the gas turbine. Air extracted from the gas turbine compression stage is used to compress the air introduced into the gasifier for partial oxidation. **Figure 7-4** shows a schematic of this type of system.

Figure 7-3. Atmospheric Pressure Biomass Gasification Combined-Cycle



Source: Craig, 1996.

Figure 7-4. High-Pressure Biomass Gasification Combined-Cycle



Source: Craig, 1996.

Table 7-11 shows the capacities and performance estimates for the gasification cases analyzed. Electric efficiencies are higher for gasification than for the direct combustion cases. Power and steam output can be varied between maximum power output using a condensing steam turbine and higher levels of process steam production through use of a back-pressure steam turbine.

Table 7-11. Biomass Gasification Power Generation System Input and Output Requirements

Biomass Cases	Atmospheric Gasification	Atmospheric Gasification	Atmospheric Gasification	High-Pressure Gasifier
Tons/day (as received)	100	258	452	1,215
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/ high-pressure
Feedstock Characteristics*				
Energy content (dry) (Btu/lb)	8,500	8,500	8,500	8,476
Moisture content (%)	30	30	30	38
Energy content (as received) (Btu/lb)	5,950	5,950	5,950	5,255
Biomass Conversion				
Gasifier efficiency, moisture adjusted	71	71	71	72
Biomass fuel value to gasifier (MMBtu/hr)	49.6	127.9	224.1	531.9
Fuel produced (MMBtu/hr)	35.2	90.8	159.1	382.6
Heating value (Btu/scf) (HHV)	110.0	110.0	110.0	128.8
Fuel pressure (psig)	Atmospheric	Atmospheric	Atmospheric	Pressurized
Plant capacity factor (%)	90	90	90	90
Prime Mover Performance				
Power train	IC Engine/ Hot Water	Gas Turbine/ Steam Turbine	Gas Turbine/ Steam Turbine	Gas Turbine/ Steam Turbine
Gross electric capacity (MW)	4.0	8.2	14.3	36.3
Parasitic load (MW)		3.3	5.8	3.79
Prime mover thermal efficiency (%)(HHV)	38.3	30.7	30.7	32.4
Heat Recovery	**Hot Water**	**Steam**	**Steam**	**Steam**
Heat recovery steam generator steam production (thousand pounds [Mlb]/hr)		34.9	61.0	123.0
Pressure (psig)		400	400	755
Temperature		500	515	740
Hot water (MMBtu/hr)	21.8			
Simple Cycle—Maximum Thermal Energy Production				
Net electric power output (MW)	4.0	4.9	8.6	32.6
Process thermal energy (MMBtu/hr)	21.8	40.1	70.0	170.5
Electric efficiency from biomass (%)	27.2	13.0	13.0	20.9
Heat rate (Btu/kWh)	12,551	26,249	26,172	16,338
CHP efficiency (%)	71.2	44.3	44.3	52.9
Combined Cycle—Maximum Power Production				
Gas turbine output (MW)		4.9	8.6	32.6
Condensing steam turbine output (MW)		1.7	3.0	6.4
Net plant output (MW)		6.6	11.6	39.0
Process thermal energy (MMBtu/hr)		0.0	0.0	0.0
Electric efficiency from biomass (%)		17.6	17.6	25.0
Heat rate (Btu/kWh)		19,431	19,426	13,650
Combined Cycle/Back-Pressure Turbine				
Gas turbine output (MW)		8.2	14.3	36.3
Back-pressure turbine output (MW)		0.4	0.7	2.3
Net plant output (MW)		5.3	9.2	34.9
Process thermal energy (MMBtu/hr)		38.6	67.7	139.4
Electric efficiency from biomass (%)		14.0	14.1	22.4
Heat rate (Btu/kWh)		24,307	24,236	15,261
CHP efficiency (%)		44.3	44.2	48.9

*Assumptions for feedstock characteristics in the atmospheric and high pressure gasifier cases are slightly different because the reference sources for the underlying data did not provide enough information to allow conversion to a consistent energy and moisture content across all cases.

Table 7-12 shows the estimated capital costs for the biomass gasification power systems. The capital requirements for the integrated systems include the prep-yard, gasifier and supporting systems, and the prime movers (reciprocating engine, gas turbine, and steam turbine generators) and supporting systems. Costs for the prep-yard, gasifier, and gas cleanup are a function of the quantity of biomass processed. The fuel gas compressor costs are a function of the size of the gas turbine. The turbine section contains various combinations and sizes of gas turbines, heat recovery steam generators, steam turbines, and supplementary firing. The costs were assumed to vary as a function of the total generating capacity. Unit costs ($/kW) are based on the net power output only.

Table 7-12. Biomass Gasification Power Generation System Capital Cost Estimates

Biomass Cases	Atmospheric Gasification	Atmospheric Gasification	Atmospheric Gasification	High-Pressure Gasifier
Tons/day (as received)	100	258	452	1,215
Biomass prep-yard	$2,639,700	$3,947,400	$4,972,000	$9,685,800
Gasification section	$1,837,000	$15,074,000	$22,736,000	$52,020,000
CHP—Maximum Thermal				
Generation/heat recovery equipment	$4,740,650	$6,400,000	$8,800,000	$24,440,000
Total capital cost	$9,217,350	$25,421,400	$36,508,000	$86,145,000
Cost ($/kW)	$2,333	$5,188	$4,245	$2,291
Power Only—No Thermal				
Generation/heat recovery equipment	N/A	$7,920,000	$11,750,000	$28,638,000
Total capital cost	N/A	$26,941,400	$39,458,000	$90,343,800
Cost ($/kW)	N/A	$4,082	$3,400	$2,319

Non-fuel O&M cost estimates are shown in **Table 7-13** for each of the four gasification power generation systems. The level of O&M costs for the prep-yard is similar to the direct-fired cases and is a function of daily throughput. Gasifier O&M costs include operating and maintenance labor, supervisory labor, water, ash removal, insurance, and other operating materials. Generator O&M costs ranged from $0.0075/kWh for the largest system to $0.0175/kWh for the 4 MW reciprocating engine systems.

Table 7-13. Biomass Gasification Power Generation Non-Fuel O&M Cost Estimates

Biomass Cases	Atmospheric Gasification	Atmospheric Gasification	Atmospheric Gasification	High-Pressure Gasifier
Tons/day (as received)	100	258	452	1,215
Prep-yard O&M	$400,000	$320,000	$320,000	$400,000
Gasifier O&M	$502,000	$634,000	$789,500	$2,235,800
Generator/heat recovery O&M	$475,000	$750,000	$1,145,000	$2,225,000
Total annual O&M	$1,377,000	$1,704,000	$2,254,500	$4,860,800
Non-fuel O&M—CHP/max thermal ($/kWh)	$0.044	$0.044	$0.033	$0.019
Non-fuel O&M—power only ($/kWh)	N/A	$0.037	$0.028	$0.018

The annual operating costs and net costs to generate power are shown in **Table 7-14** for the four biomass gasification power generation system options. As shown, biomass gasification has comparable net costs to generate power to the biomass boiler generation options. Because all the gasification options generate more power than similar-sized boiler systems, the annual operating expenses for gasification are lower on a relative basis, assuming the power can displace retail electric rates. However, it should be remembered that the technology cost, performance, and availability of biomass gasification systems are far more speculative than the direct-fired options considered.

7.3 Modular Biomass Systems

The cost and performance for a representative modular biomass system is shown in **Table 7-15**. As discussed in Chapter 5, modular systems are developmental and vary widely in size, technology, and performance. (Additional information about modular system suppliers is available in Appendix D.) Installations can be found in the United States, but they have all been subsidized with research, development, and demonstration funding from DOE, USDA, and other federal and state sources. Therefore, the costs and performance estimates included in the table should be considered speculative. A 50 kW modular system was evaluated, consisting of a packaged gasifier and internal combustion engine generator with heat recovery. Total installed capital costs for a 50-kW modular gasification system are estimated at $6,450/kW. The very low power to thermal ratio means that there is a very high percentage of thermal energy that is available compared to the system's electric output. If all of this thermal energy can be utilized effectively, the overall CHP efficiency of the system is 67.8 percent, and the net power costs are $0.10/kWh, assuming the thermal energy is displacing high priced natural gas or fuel oil.

Table 7-14. Biomass Gasification Power Generation Systems—Net Cost to Generate Power ($/kWh)

Biomass Cases	Atmospheric Gasification	Atmospheric Gasification	Atmospheric Gasification	High-Pressure Gasifier
Tons/day (as received)	100	258	452	1,215
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/ high-pressure
Gasifier efficiency (%)	71	71	71	72
Biomass fuel to gasifier (MMBtu/hr)	49.6	127.9	224.1	531.9
Fuel produced (MMBtu/hr)	35.2	90.8	159.1	382.6
Natural gas cost ($/MMBtu)	$6.00	$6.00	$6.00	$6.00
Natural gas boiler efficiency (%)	80%	80%	80%	80%
Displaced boiler biomass fuel ($/MMBtu of process steam)	$2.82	$2.82	$2.82	$2.82
Displaced boiler natural gas ($/MMBtu of process steam)	$7.50	$7.50	$7.50	$7.50
CHP—Maximum Thermal				
Electric capacity (MW)	4.0	4.9	8.6	32.6
Annual electric generation (MWh)	31,536	38,632	67,802	257,018
Process steam (MMBtu/hr)	21.8	40.1	70.0	170.5
Annual process steam generation (MMBtu)	171,871	316,148	551,880	1,344,222
Annual Operating Expenses				
Biomass fuel costs	$695,194	$1,792,646	$3,140,985	$7,455,110
Non-fuel O&M costs	$1,377,000	$1,704,000	$2,254,000	$4,860,000
Annual capital recovery costs	$940,134	$2,592,983	$3,723,816	$8,786,790
Displaced electricity purchases ($0.07/kWh)	($2,207,520)	($2,704,240)	($4,746,140)	($17,991,260)
Total Annual Operating Expenses	**$804,808**	**$3,385,389**	**$4,372,661**	**$3,110,640**
Net Cost to Generate ($/kWh)				
Biomass fuel costs ($/kWh)	$0.022	$0.046	$0.046	$0.029
Non-fuel O&M costs ($/kWh)	$0.044	$0.044	$0.033	$0.019
Capital recovery ($/kWh)	$0.030	$0.067	$0.055	$0.034
Cost to generate ($/kWh)	$0.096	$0.158	$0.134	$0.082
Biomass boiler steam credit ($/kWh)	($0.015)	($0.022)	($0.022)	($0.014)
Net Power Costs ($/kWh)	**$0.081**	**$0.136**	**$0.113**	**$0.068**
Natural gas boiler steam credit ($/kWh)	($0.041)	($0.061)	($0.061)	($0.039)
Net Power Costs ($/kWh)	**$0.055**	**$0.096**	**$0.073**	**$0.043**
Power Only—Condensing Turbine				
Electric capacity (MW)	N/A	6.6	11.6	39.0
Annual electric generation (MWh)	N/A	46,253	81,293	273,312
Process steam (MMBtu/hr)	N/A	0	0	0
Net Cost to Generate ($/kWh)				
Boiler fuel costs ($/kWh)	N/A	$0.039	$0.039	$0.027
Non-fuel O&M costs ($/kWh)	N/A	$0.037	$0.028	$0.018
Capital recovery ($/kWh)	N/A	$0.059	$0.050	$0.034
Net Power Costs ($/kWh)	N/A	**$0.135**	**$0.116**	**$0.079**

Table 7-15. Modular Biomass System Cost and Performance Estimates

System Characteristic	Performance Value
Equipment type	Downdraft gasifier, gas cleanup, IC engine prime mover
Commercialization status	Several field demonstrations in the United States and internationally No commercial installations
Equipment size (kW)	50
Modular system capital cost ($/kW)	$3,500
Biomass storage/handling ($/kW)	$800
Installation ($/kW)	$2,150
Total capital costs ($/kW)	$6,450
Thermal output (Btu/hr)	600,000
Power to heat ratio	0.28
Biomass fuel use (MMBtu/hr)	0.098
Electric efficiency (est.) (%)	15
CHP efficiency (%)	67.70
Biomass fuel cost ($/MMBtu) Natural gas/diesel cost ($/MMBtu) Plant operating factor	$2.00 $8.00 80
Annual Operating Expenses	
Biomass fuel costs	$15,941
Non-fuel O&M costs	$10,512
Annual capital recovery costs*	$42,248
Displaced electricity purchases ($.07/kWh)	($24,528)
Total Annual Operating Expenses	**$44,173**
Net Cost to Generate ($/kWh)	
Biomass fuel costs ($/kWh)	$0.05
O&M costs (est.) ($/kWh)	$0.03
Capital recovery (15 years) ($/kWh)	$0.12
Cost to generate ($/kWh)	$0.20
Biomass boiler thermal credit ($/kWh)	($0.03)
Net Power Cost ($/kWh)	**$0.17**
Natural gas/oil boiler fuel cost ($/kWh)	($0.10)
Net Power Cost ($/kWh)	**$0.10**

* Capital recovery factor for the modular system was based on 15-year economic life and 10 percent cost of capital; annual recovery factor = 13.1 percent.