

# GASIFICATION-BASED BIOMASS

## 1.0 System Description

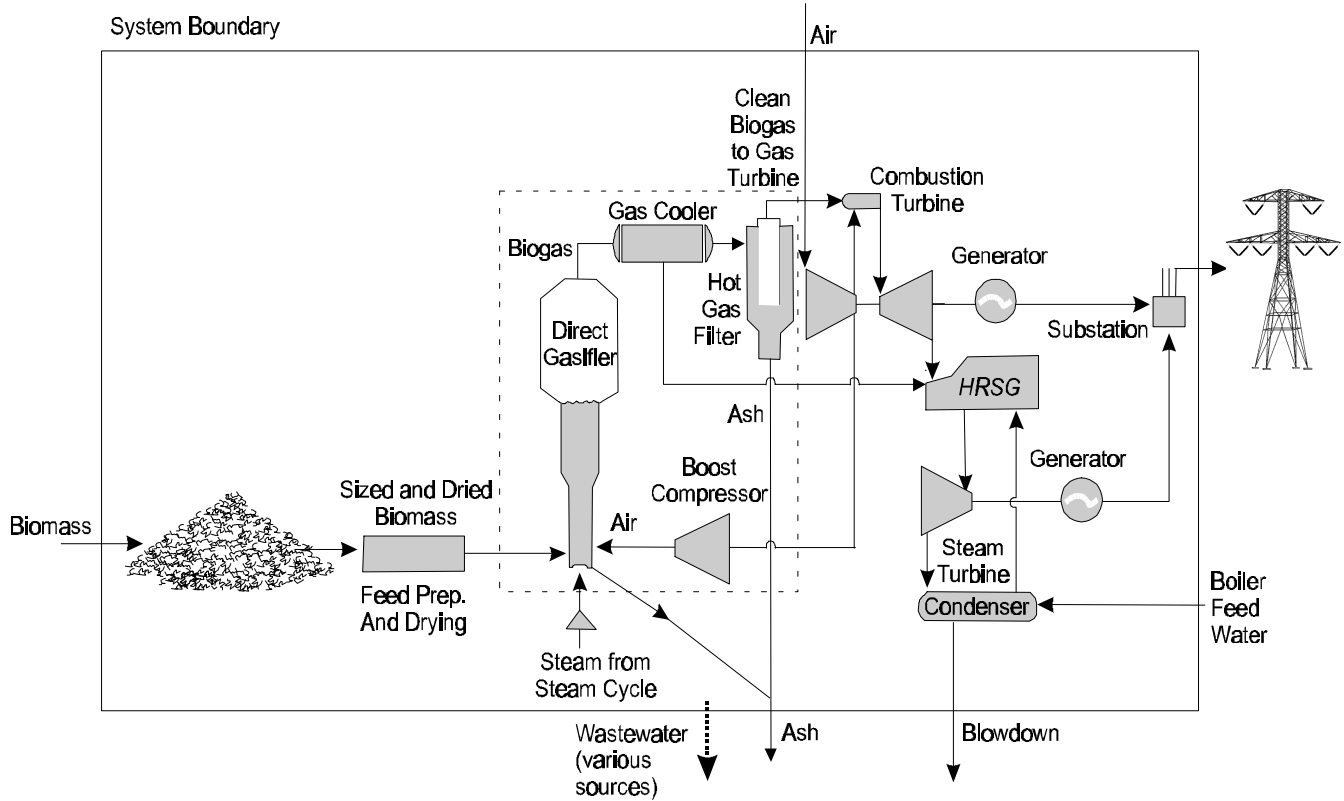


Figure 1. Biomass gasification combined cycle (BGCC) system schematic.

The conversion of biomass to a low- or medium-heating-value gaseous fuel (biomass gasification) generally involves two processes. The first process, pyrolysis, releases the volatile components of the fuel at temperatures below 600°C (1,112°F) via a set of complex reactions. Included in these volatile vapors are hydrocarbon gases, hydrogen, carbon monoxide, carbon dioxide, tars, and water vapor. Because biomass fuels tend to have more volatile components (70-86% on a dry basis) than coal (30%), pyrolysis plays a proportionally larger role in biomass gasification than in coal gasification. The by-products of pyrolysis that are not vaporized are referred to as char and consist mainly of fixed carbon and ash. In the second gasification process, char conversion, the carbon remaining after pyrolysis undergoes the classic gasification reaction (i.e. steam + carbon) and/or combustion (carbon + oxygen). It is this latter combustion reaction that provides the heat energy required to drive the pyrolysis and char gasification reactions. Due to its high reactivity (as compared to coal and other solid fuels), all of the biomass feed, including char, is normally converted to gasification products in a single pass through a gasifier system.

This report characterizes a biomass gasification combined cycle (BGCC) system as depicted in Figure 1. A high pressure, direct gasifier shown inside the dashed line within Figure 1 is considered here. Several other gasifier options are possible, specifically low pressure direct gasifiers (Figure 2) and indirect gasifiers (Figure 3). Depending on the type of gasifier used, the above reactions can take place in a single reactor vessel or be separated into different vessels. In the case of direct gasifiers, pyrolysis, gasification, and combustion take place in one vessel, while in indirect gasifiers, pyrolysis and gasification occur in one vessel, and combustion in a separate vessel. In direct gasification, air

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and sometimes steam are introduced directly to the single gasifier vessel (Figures 1 and 2). In indirect gasification, an inert heat transfer medium such as sand carries heat generated in the combustor to the gasifier to drive the pyrolysis and char gasification reactions.

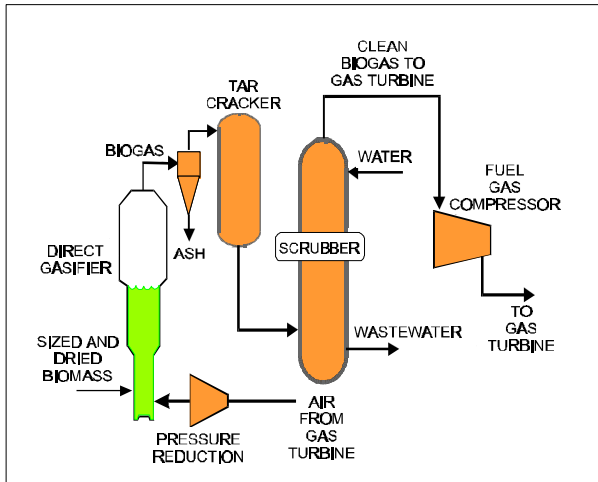


Figure 2. Low-pressure direct gasifier.

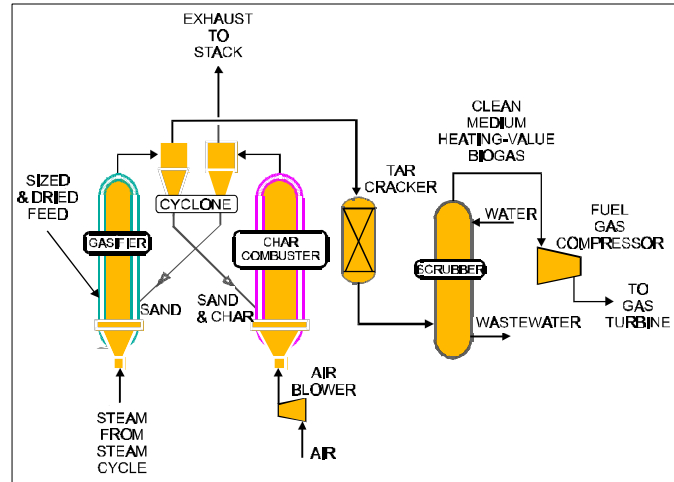


Figure 3. Indirect gasifier.

Currently, indirect gasification systems operate near atmospheric pressure. Direct gasification systems have been demonstrated at both elevated and atmospheric pressures. Any one of the gasifier systems can be utilized in the larger system diagrammed above and have been utilized in at least one recent system design study [1-4].

There are several practical implications of each gasifier type. Due to the diluent effect of the nitrogen in air, fuel gas from a direct gasifier is of low heating value (5.6-7.5 MJ/Nm<sup>3</sup>). This low heat content in turn requires an increased fuel flow to the gas turbine. Consequently, in order to maintain the total (fuel + air) mass flow through the turbine within design limits, an air bleed is usually taken from the gas turbine compressor and used in the gasifier. This bleed air is either boosted slightly in pressure or expanded to near atmospheric pressure depending on the operating pressure of the direct gasifier.

Since the fuel-producing reactions in an indirect gasifier take place in a separate vessel, the resulting fuel gas is free of nitrogen diluent and is of medium heating value (13-18.7 MJ/Nm<sup>3</sup>). This heat content is sufficiently close to that of natural gas (approx. 38 MJ/Nm<sup>3</sup>) that fuel gas from an indirect gasifier can be used in an unmodified gas turbine without air bleed.

Gasifier operating pressure affects not only equipment cost and size, but also the interfaces to the rest of the power plant including the necessary cleanup systems. Since gas turbines operate at elevated pressures, the fuel gas generated by low pressure gasifiers must be compressed. This favors low temperature gas cleaning since the fuel gas must be cooled prior to compression in any case. Air for a low pressure gasifier can be extracted from the gas turbine and reduced in pressure (direct, low pressure gasifier) or supplied independently (indirect gasifier). High pressure gasification favors hot, pressurized cleanup of the fuel gas and supply to the gas turbine combustor at high temperature (~ 538°C or 1,000°F) and sufficiently high pressure for flow control and combustor pressure drop. Air for a high pressure, direct gasifier is extracted from the gas turbine and boosted in pressure prior to introduction to the gasifier.

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Cooling, cold cleanup, and fuel gas compression add equipment to an indirect gasifier system and reduce its efficiency by up to 10% [3,5]. Gasifier and gas cleanup vessels rated for high pressure operation and more elaborate feed systems, however, add cost and complexity to high pressure gasification systems despite their higher efficiency. Results from several recent studies [1-3,5] indicate that, at the current, preliminary grade of estimates (as defined by EPRI TAG [6]) being performed, there is little discernable difference in cost of electricity (COE) between systems employing high and low pressure gasification.

As stated earlier, for the purposes of this analysis, a high-pressure, direct gasification system was selected. The resulting system is very similar to that evaluated in a pre-feasibility study conducted by Northern States Power for NREL and EPRI, reported in NREL/TP-430-20517, and referenced here as "DeLong"[1]. This study examined a 75 MW<sub>e</sub> power plant that would gasify alfalfa stems to provide electricity to the Northern States Power Company and sell the leaf co-product for animal feed. A departure from the DeLong study is the use here of wood as the biomass feedstock. Wood feedstock allows for a more generic plant representation. Alfalfa separation and leaf meal processing steps in the original DeLong study would have added complexity and cost to the plant and have complicated the economic analysis.

Following receipt of wood chips at the plant, they are screened and hogged to a proper size consistency, and dried in a rotary drum dryer. Dried wood is conveyed to storage silos adjacent to the gasifier building. It is then weighed and transferred to a lockhopper/screw feeder system and is fed into the fluidized bed gasifier. The gasifier vendor selected for the DeLong study was Tampella Power Systems (now Carbona) who have developed a commercial version of the IGT RENUGAS™ gasifier. A dolomite feed system is also provided to maintain the inventory of inert material in the bed. In the gasifier, the biomass is gasified at temperatures between 843°C (1550°F) and 954°C (1750°F). The fluidizing and gasifying medium is a mixture of air and steam. Air is extracted from the compressor section of the gas turbine and fed into the gasifier through a boost compressor. Gasification steam is extracted from the steam cycle. The gasifier operates as a so-called spouted bed with intensive circulation of solids from top to bottom which guarantees rapid gasification and maximizes tar cracking.

Fuel gases exiting the gasifier are cooled in the product gas cooler to approximately 538°C (1,000°F). In addition to protecting the fuel flow control valve, this cooling causes the vapor-phase alkali species present in the fuel gas, which could damage the gas turbine, to condense, congeal, and deposit on the fine particulate matter carried over from the gasifier. The combined particulate matter and alkali species are next removed in a Westinghouse hot ceramic candle filter unit to levels within gas turbine tolerances. Since biomass in general and wood in particular are very low in sulfur, a sulfur removal step is not necessary prior to combustion in the gas turbine. Hot cleanup of the fuel gas also minimizes waste water generation from this step of gas processing.

The fuel gas is combusted in a Westinghouse "ECONOPAC" 251B12 gas turbine, producing electric power and a high temperature exhaust stream. A heat recovery steam generator (HRSG) is employed to recover this heat to generate high temperature, high pressure steam that is then expanded in a steam turbine to produce additional power. Steam for the gasifier is extracted from the steam cycle. Finally, electricity for the plant is sent to a substation for voltage step-up. As noted above, the total net electricity output from this system is 75 MW<sub>e</sub>. The cost and performance estimates in Section 4 are based on the evolution of this technology through an "nth" plant and eventually to incorporation of turbines resulting from the DOE Advanced Turbine Systems (ATS) Program.

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As mentioned earlier, several gasifier configurations could have been considered. Converting solid biomass into a gaseous fuel with suitable heating value creates the opportunity to integrate biomass gasifiers with the gas turbine cycles such as the combined gas and steam cycle depicted above. Close coupling of gasification and the power system increases overall conversion efficiency by utilizing both the thermal and chemical energy of hot product gases to fuel the power cycle. Combined cycles, with their high efficiency and low emission characteristics, are a prime choice for biomass gasification systems.

### 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 electricity supply system. A near-term application for biomass gasification is with industrial-scale turbines for repowering of the pulp and paper and sugar cane industries. It has been estimated that roughly 70% of the power houses in the U.S. pulp and paper industry (which represents more than 30% of the world's capacity) will need to be replaced within the next 10-15 years [7]. A similar situation exists in the sugarcane industry. Repowering these plants with modern, efficient, gas turbine technology will substantially improve efficiency, reduce emissions, and provide additional electrical power that can offset purchases or be exported to the surrounding area. A recent study [2] examined a variety of options for mill repowering and found BGCC to be the most economically attractive option. Use of BGCC in the sugarcane industry worldwide could increase the power available for export to the surrounding community by an order of magnitude [8]. This is a significant benefit because many sugar mills are located in developing regions with burgeoning electric power needs. It is worth noting that rapid developments are also being made in smaller turbine sizes as well, and the industrial and cogeneration markets (10-50 MW<sub>e</sub> output) should not be ignored.

As discussed in the Overview of Biomass Technologies, there is approximately 7 GW of grid-connected biomass generating capacity in the U.S. [9], much of it associated with the wood and wood products industry, which obtains more than half its electricity and thermal energy from biomass. In comparison, coal-fired electric units account for 297 GW of capacity, or about 43% of total generating capacity. In 1994, U.S. biomass consumption was approximately 3 EJ, and represented about 3.2% of the 94 EJ of total primary energy consumption [9]. Electricity from biomass represents about 1% of the total U.S. demand. The amount of electricity derived from this quantity of biomass could be roughly doubled if gasification/turbine based power systems were employed (average efficiency of existing capacity = 20%, efficiency of biomass/turbine systems = 35-40%).

Biomass-to-electricity systems based on gasification have a number of potential advantages. Projected process efficiencies are much higher than the direct combustion systems in commercial use today. Process efficiencies are comparable to high efficiency coal-based systems, but can be achieved at a smaller scale of operation. Thus, not only does biomass close the carbon cycle, but gasification based systems, due to their high efficiency, reduce CO<sub>2</sub> emissions per megawatt of power generated over conventional biomass power plants. Biomass is also lower in sulfur than is most U.S. coal. A typical biomass contains 0.05 to 0.20 weight % sulfur on a dry basis and has a higher heating value of about 29.8 MJ/kg (8500 Btu/lb). This compares with coal at up to 2-3 dry weight %. The biomass sulfur content translates to about 51 to 214 mg SO<sub>2</sub>/MJ (0.12 to 0.50 lb SO<sub>2</sub>/MMBtu). The higher sulfur level is still less than the regulated limit set in the current New Source Performance Standards (NSPS). Controlled NO<sub>x</sub> levels from biomass plants will also be less than the NSPS standards.

Since gasifiers operate at much lower temperatures than combustors, gasification allows a wider variety of feedstocks, such as high alkali fuels, than may be technically feasible for direct combustion systems. High alkali fuels such as switchgrass, straws, and other agricultural residues often cause severe corrosion, erosion, and deposition problems on

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heat transfer surfaces in conventional combustion boilers [10]. Gasification systems can easily remove the alkali species from the fuel gas before it is combusted.

Future technology, such as gasification/fuel cell systems, holds the promise of efficiencies well above 50% even at relatively small scales. Gasifier development potentially benefits other technology areas such as fuels and chemicals through development of gasifier technology which can also be used to generate syngas for chemical synthesis.

The emission data shown in Table 1 are taken from DeLong [1], and are based on alfalfa feed. These data were used rather than estimates generated by the BIOPOWER model [4], since data in the DeLong study were provided by equipment vendors, and the BIOPOWER model is more generic. Since wood is lower in nitrogen than alfalfa, it is expected that the estimate of NO<sub>x</sub> emissions listed here is higher than actual. The ash produced is based on yearly plant feed, assuming biomass is 1.2% ash, as is common for wood. Essentially the same turbine technology is used for the systems through 2010, so the emissions are assumed to be constant. Since advanced turbine systems have not yet been built, emission estimates for later systems were not made. The details of the steam-injected gas turbines (STIG) used in the 2020-2030 cases are not available so boiler blowdown estimates were not made; however, a worst case scenario would have amounts the same as the 2005 case. Future plants will need to meet applicable Federal, state, and local emission requirements.

Table 1. Emissions from a high-pressure, direct gasification system.

Indicator Name	Units	Base Year					
		1997	2000	2005	2010	2020	2030
Particulates (PM10)	g/Nm <sup>3</sup>	0.007	0.007	0.007	0.007		
Nitrogen Oxides@15% O <sub>2</sub>	g/GJ	64.5	64.5	64.5	64.5		
Carbon Monoxide	g/GJ	20.6	20.6	20.6	20.6		
Non-CH <sub>4</sub> Hydrocarbons	g/GJ	9.6	9.6	9.6	9.6		
Sulfur Dioxide	g/GJ	81.8	81.8	81.8	81.8		
Ash	Mg/yr	2,912	2,912	3,883	3,883	4,271	4,271
Boiler blowdown	Mg/yr	6,989	6,989	9,319	9,319		

### 3.0 Technology Assumptions and Issues

The system described is assumed to be in the contiguous U.S., and to have adequate feedstock supply available within a 80.5 km (50 mile) radius. Other assumptions include adequate highway infrastructure, and ready electricity transmission access. The site for the primary reference study [1] is southwestern Minnesota (FERC Region 5). This technology provides a service similar to base load fossil electric generation and cogeneration plants.

It is expected that biomass gasification systems of the type discussed here will be commercially available in the next five years, with the near-term application assumed to be in industrial scale turbines for repowering of pulp/paper and sugar cane industries. Gasifiers have been developed in the U.S. and Europe to produce low- and medium-heating-value gases from biomass. In Europe, gasifier systems include fixed-bed gasifiers such as the Bioneer gasifier [11], high pressure gasifiers such as the High Temperature Winkler [12], and circulating fluid bed gasifiers such as the Studsvik [13], Gotaverken [14], Ahlstrom [15] and Lurgi [16].

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In the U.S., gasifiers are being developed by the Institute of Gas Technology(IGT) [17], Battelle Columbus Laboratory (BCL) [18], the University of Missouri at Rolla [19], and Manufacturing and Technology Conversion International [20]. The IGT system is an air/oxygen-blown fluidized bed gasifier while others are indirectly heated gasifiers, using either entrained-flow or fluidized bed reactors. In a jointly funded program, a modified Lurgi-type fixed-bed gasifier using wood chips has been operated. In addition, commercial-scale gasifiers have been operated in the U.S. to produce low-heating-value gas for use as a plant fuel. The status of these systems range from the level of research and development to commercially available for generating low calorific gas. A number of advanced systems, such as the Ahlstrom, TPS/Studsvik, and Institute of Gas Technology and Battelle Columbus Laboratory gasifiers, are considered to be near commercial for generating electricity in combination with commercial gas turbine technology.

The IGT technology is being demonstrated in Hawaii at the 90 Mg/day scale on sugarcane bagasse fuel. The gasifier has run for over 100 hours and is being prepared for a 1500 hour test during late summer 1997 to verify the readiness of the gasification technology as well as the suitability of hot gas filter material for commercial application with biomass fuel. The BCL technology is the subject of a scale-up to 180 Mg/day at the McNeil Generating Station in Burlington, Vermont. These demonstration tests will be fueled by wood chips and the resulting synthesis gas fired in the existing McNeil boiler. Subsequent phases of this project call for installation and testing of a gas turbine of approximately 10 MW<sub>e</sub> capacity. Successful completion of these tests will provide the final data and technology confidence required for scale-up to commercial projects and for obtaining financing for such projects.

The hot gas particulate filter technology used in this characterization was developed by Westinghouse and has been demonstrated in numerous applications from pressurized fluidized bed coal combustion at the Tidd demonstration project through large scale coal gasification at the Sierra Pacific Pinon Pine Clean Coal demonstration project. The filter size used at Tidd has been deemed adequate for biomass gasification applications in the 50-75 MW<sub>e</sub> range. A number of filter elements were tested at the IGT 9 Mg/day pilot gasifier in Chicago, Illinois [21]. This test established the appropriate filter face velocity for use with biomass derived gases and ability of the filters to be cleaned and recover a stable pressure drop across the filter vessel. The results from this test also indicated that sufficient particulate removal was achieved for subsequent use of the gas in a gas turbine. Alkali levels in the exit gas were acceptably low with the exception of sodium. Subsequent analysis of the filter material indicated that long term durability of the filter was a potential issue. For this reason, long-term (1,500 hour) durability tests are being performed at the Hawaii gasification facility to select a more appropriate filter material from those commercially available and to determine whether the sodium levels measured in the pilot plant testing are indicative of actual behavior or an anomaly. These tests should settle any final technical issues surrounding use of hot particulate and alkali removal from biomass synthesis gases.

In addition to efficient technology, 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.

### 4.0 Performance and Cost

Table 2 summarizes the performance and cost indicators for the high pressure, direct gasification combined cycle system being characterized in this report.

Table 2. Performance and cost indicators.

INDICATOR NAME	UNITS	Base Case 1997		2000		2005		2010		2020		2030	
			+/- %		+/- %		+/- %		+/- %		+/- %		+/- %
Plant Size	MW <sub>e</sub>	75		75		100		100		110		110	
General Performance Indicators													
Capacity Factor	%	80		80		80		80		80		80	
Efficiency	%	36.0		36.0		37.0		37.0		41.5		45.0	
Net Heat Rate	kJ/kWh	10,000		10,000		9,730		9,730		8,670		8,000	
Annual Energy Delivery	GWh/yr	526		526		701		701		771		771	
Capital Cost													
	\$/kW		15		20		20		20		30		30
Fuel Preparation		113		113		101		101		94		86	
Gasifier		519		450		377		346		319		293	
Gas Turbine		216		216		216		198		176		160	
Steam Turbine		48		48		48		44		0		0	
Balance of Plant		311		248		197		147		118		85	
Control System		9		9		9		8		8		7	
Hot Gas Cleanup		43		39		34		31		31		28	
Installation		208		191		157		132		112		99	
Turbine Building		6		6		6		6		6		5	
Waste Pond etc.		2		2		2		2		2		1	
General Plant Facilities		147		132		115		102		87		77	
Engineering Fee		162		145		126		112		95		84	
Proj./Process Contingency		243		218		189		168		143		126	
Startup Costs		56		56		56		51		51		46	
Inventory Capital		10		10		10		9		9		8	
Land @ \$16,060/ha		9		9		7		7		7		6	
<b>Total Capital Requirement</b>		<b>2,102</b>	<b>15</b>	<b>1,892</b>	<b>20</b>	<b>1,650</b>	<b>20</b>	<b>1,464</b>	<b>20</b>	<b>1,258</b>	<b>30</b>	<b>1,111</b>	<b>30</b>

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 <sub>e</sub>	75		75		100		100		110		110	
Operations 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		15		20		25		30		30		30
Operating		22.96		7.13		7.13		7.13		7.13		7.13	
Supervision and Clerical		9.24		5.8		5.8		5.8		5.8		5.8	
Maintenance Labor and Material Costs		36.5		30.47		30.47		30.47		30.47		30.47	
Total Fixed Costs		68.7		43.4		43.4		43.4		43.4		43.4	
Variable Operating Costs	¢/kWh		15		20		25		30		30		30
Labor		0.34		0.34		0.34		0.34		0.34		0.34	
Maintenance Labor and Material Costs		0.06		0.06		0.06		0.06		0.06		0.06	
Total Variable Costs		0.40		0.40		0.40		0.40		0.40		0.40	
Variable Consumables Cost	¢/kWh		15		20		25		30		30		30
Chemicals		0.04		0.04		0.04		0.04		0.04		0.04	
Water		0.06		0.06		0.06		0.06		0.06		0.06	
Ash/Solids Disposal		0.03		0.03		0.03		0.03		0.03		0.03	
Total Consumables		0.12		0.12		0.12		0.12		0.12		0.12	
Total Operating Costs		3.98		3.62		3.55		3.55		3.29		3.12	

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 variable operating costs.
3. Totals may be slightly off due to rounding.



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### 4.1 Evolution Overview

The 1997 case describes on a high pressure, direct-fired fluidized bed gasifier utilizing hot particulate removal. The system is coupled to a combined cycle power system based on the Westinghouse 251B12 gas turbine with a firing temperature of 1,150°C (2,100°F) and pressure ratio of 15.3. This turbine is available with multi-annular swirl burners (for NO<sub>x</sub> control) designed for natural gas or low heating value synthesis gas. The overall process efficiency for this system is reported as 38.3% in DeLong [1]. The EPRI BIOPOWER model [4] reports the efficiency as 36.0%; however, it was not possible to precisely duplicate all aspects of the system in the BIOPOWER model.

The "power island" (gas turbine and steam cycle) utilized in the base case through the 2010 case is mature, commercially available technology, although minor technical improvements are expected to occur over this time frame. Of particular note are the improvements that will occur in the gasification and hot gas cleanup portions of the plant. The size range of the gas turbines used are available and have been widely demonstrated on natural gas and synthesis gas derived from gasification of coal, residual oil, and petroleum coke. For gas turbine applications, these latter fuels are all more problematic than biomass from a contaminant standpoint. Additionally, an unmodified small gas turbine has been operated directly on fuel gas from the Battelle Columbus Laboratory process development scale gasifier with no difficulties.

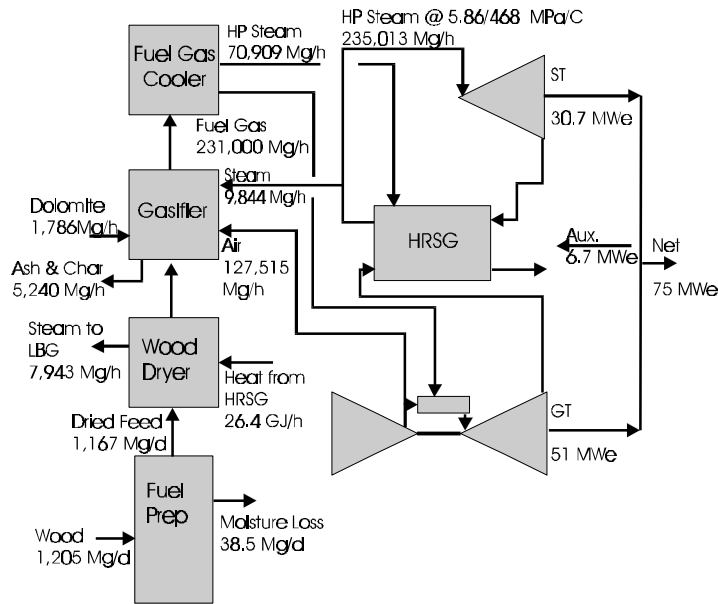
Further improvements occur in the 2020 and 2030 cases when ATS-based turbines are employed. These will result from efforts such as DOE's Advanced Turbine Systems Program (ATS) and the industry-lead Collaborative Advanced Gas Turbine (CAGT) development program. These turbines are assumed to have firing temperatures in excess of 1,250°C (2,282°F) and, for the purposes of this study, utilize steam injection for power generation. Such turbines are expected to be available for natural gas use around 2005, thus allowing an additional 15 years for any required research and demonstration of any combustor modifications or turbine "ruggedization" that may be required for synthesis gas use. It should be noted that research on technology required for use of these turbines with coal and biomass is an integral part of the turbine development programs.

### 4.2 Performance and Cost Discussion

The output from the EPRI BIOPOWER model are used for the 1997 base case in Table 2. Heat and material balance data are detailed in Figure 4. The principal departure from the DeLong case is that DeLong uses heat from the combined cycle for alfalfa processing and the alfalfa arrives at the plant with a moisture content of roughly 15% due to in-field drying. The current case assumes that this same amount of heat is instead utilized for wood drying. The heat available is sufficient to reduce wood of approximately 24% moisture to the feed moisture content of 10%. Each additional 10% of feed moisture (i.e. 34% instead of 24%) carries a performance penalty of roughly 1.5 basis points. The feed moisture utilized will result in an average efficiency; proper management of herbaceous crops and some wood wastes can yield lower delivered feed moisture, while some wood feedstocks can be appreciably higher. The steam cycle conditions in BIOPOWER are also somewhat more moderate than those employed in the DeLong study.

Plant availability is based on data in the EPRI TAG [6]. These data are derived from a number of plants currently in operation. For coal gasification combined cycle plants that utilize essentially the same power island technology, availability is 85.7%. For biomass based wood-fired stoker plants (direct combustion steam boiler), the availability is listed as 85%. The equipment in the power island characteristically has availability in excess of 89% in base load operations. Biomass gasification is, in many ways including the severity of process conditions, much simpler than coal gasification. Therefore, it seems that an 85% availability estimate for the entire biomass power plant is

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### Energy Balance (GJ/hr)

#### Heat In

Wood to dryer	750.731
C.T. compressor air	23.243
Boiler feed water	-0.493
Dolomite	-3.152
Auxiliary power- MBG compressor	10.237
Other	25.218
Total	805.784

#### Heat Out

Ash and char from gasifier	1.97
Air sep plant effluent	0.698
Solids from hot gas filter	0.026
Combustion turbine power	183.51
Flue gas from combustion turbine	181.231
Steam turbine power output	110.68
Condenser loss	262.506
Blowdown loss	5.208
Generator losses	6.004
Heat losses	53.951
Total	805.784

### Material Balance (Mg/hr)

#### Mass In

Wood to plant	50.245
C.T. Compressor air	680.653
Boiler feed water	9.659
Dolomite	0.893
Total	741.451

#### Mass Out

Fuel prep moisture losses	1.607
Fuel prep fines	0
Fuel prep ferrous metal	0
Ash and char from gasifier	2.620
Air sep plant effluent	16.472
Solids from hot gas filter	0.026
Flue gas from combustion turbine	715.990
Blowdown	4.737
Total	741.451

### Performance Summary

Annual capacity factor, %	80%
Net kJ/kWh	10000
Thermal Efficiency, %	36.0%

Figure 4. Material and energy balance for the 1997 base case.

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reasonable. DeLong [1] also estimates availability to be between 82% and 88% based on experience with the Tampella gasification pilot facility. Based on these data, a plant capacity factor of 80% is assumed.

The cost and performance for the 1997 case are expected to be those for a first plant. All costs are expressed in constant 1997 dollars. A 30-year project life is assumed, after a two year construction period. The electrical substation is part of the general plant facilities, and is not separated out in the factor analysis. The convention followed is that used in the EPRI TAG [6], specifically "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."

Cost reductions and performance improvements through 2010 are expected to be largely the result of replication of, and minor technical improvements to, the 1997 case plant. The largest cost reductions occur in the least commercially mature plant sections, i.e. gasification and hot gas cleanup. The first plant costs for these sections normally include very substantial process contingencies and reflects an aggressive equipment "sparing" strategy to guarantee high on-stream factors. As experience is gained with these processes, design details will improve and appropriate maintenance schedules will be developed that minimize the need for large contingencies and spare equipment. Cost reductions also occur in the balance of plant equipment (BOP). In the base, first-of-a-kind case, the BOP cost, taken as a percentage of the other equipment cost, is a very high 35% which again reflects the uncertainties involved in pioneer plants. This is gradually reduced to a more common value of 21% in the mature 2010 case. Overall, these capital costs are reduced by roughly 30% during progression from pioneer plant to mature technology. A similar progression is represented in the EPRI TAG [6] (p. 8-5). Operating labor costs are similarly reduced as more activities can be brought under automated control and operating labor is reduced to a practical minimum.

The gasifier technology is assumed to be largely mature by the 2010 time frame. The fully mature (2010) system costs correlate well with mature plant costs projected by those demonstrating coal gasification combined cycle at a large scale. For example, the \$2,400/kW first plant cost for the Demkolec plant is projected to be \$1,500/kW on a mature technology basis [22]. Similarly, the \$1,646/kW cost for the Puertollano plant declines to \$1,000/kW for the nth plant [22]. The 2010 cost is also consistent with cost data on natural gas fired combined cycle systems. Gas Turbine World [23] reports a turnkey price for a natural gas fired combined cycle plant using the 251B12 turbine of \$713/kW. Adding to this the cost for biomass feed handling and gasification yields a capital cost of approximately \$1,200/kW. This is the lower bound of the nth plant cost posited in Turnure et al. [24] Additional cost reductions beyond 2010 are largely due to improvements in system efficiency which reduce the amount of biomass required (and therefore equipment size) for each megawatt of power generated.

Performance increases from 2000-2010 are the result of gradual improvements to the technology and, in the 2005 case, adoption of more advanced turbine technology using higher firing temperatures (1,288°C, or 2,350°F) and improved steam cycle conditions. The efficiency gains in the 2000 case are assumed to result from improved system integration and the continuing improvement of gas turbine technology. Gas turbines in this size range have increased output and efficiency by 2-4% since 1991 [23].

The ATS program is a \$700 million effort funded by DOE and gas turbine manufacturers that has a target of 60% efficiency (LHV basis) for utility gas turbine combined cycle plants by the year 2000. The industrial turbine portion of the program targets efficiency improvements of at least 15% (from 29 to at least 34% simple cycle efficiency) in the same time period. The ATS program includes in its goals the criteria that the turbines developed be suitable for coal or biomass fuels. It is assumed that this technology will have penetrated the biomass market after the 2010 time frame. As an upper limit, the 60% combined cycle efficiency (LHV basis) goal on natural gas fuel translates into roughly 50% efficiency (HHV basis) on biomass fuel. The higher firing temperatures being utilized by these advanced turbines (up to 1,426°C or 2,600°F) can result in up to 5 basis points improvements in turbine efficiencies. Additional benefits from

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advanced turbines include the use of STIG technology. STIG turbines are commercially available today for natural gas fuels up to approximately 50 MW<sub>e</sub> output at FOB costs of approximately \$280/kW. Increased efficiency, and therefore power output should reduce this cost on a dollar per kilowatt basis. These turbines further reduce system cost by eliminating the need for a steam cycle while still maintaining high specific power output. The 2010 and beyond systems assume that this innovation is available for advanced turbine systems. The 2020-2030 cases utilize cost and efficiency data from Turnure et al. (1995) for early and mature gas turbines utilizing ATS and CAGT technology.

Feed costs in this characterization are expressed in 1997 dollars and represent an update of the DOE feedstock goal for dedicated feedstocks of \$2.50/GJ. If residue feeds are used instead, then feed costs are approximately \$18.7/tonne (\$0.95/GJ; \$1/MMBtu). Depending on the particular application, the use of residue cannot be ruled out even for systems as large as 75 MW<sub>e</sub>. Some pulp and paper and sugarcane mills produce residues within the range of feedstock requirements for systems of this scale. Utilities and others are also examining the use of residues for power production as a service to their customers in need of residue disposal options. 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.

### 5.0 Land, Water, and Critical Materials Requirements

Table 3 provides an overview of the resources required for the biomass gasification systems described here.

Table 3. Resource requirements.

Indicator Name	Units	Base Year					
		1997	2000	2005	2010	2020	2030
Plant Size	MW <sub>e</sub>	75	75	100	100	100	110
Land Plant	ha/MW	0.54	0.54	0.41	0.41	0.41	0.37
	ha	40.5	40.5	40.5	40.5	40.5	40.5
Crops	ha/MW	318	318	207	207	138	138
	ha	23,850	23,850	20,700	20,700	13,800	15,180
Growth rate	Mg/ha/yr	11.20	11.20	16.80	16.80	22.40	22.40
Water (Boiler Feed Water)	Mm <sup>3</sup> /yr	0.07	0.07	0.08	0.08		
Energy: Biomass	PJ/yr	2.26	2.26	2.94	2.94	2.62	2.62
Feedstock: Biomass (dry)	Tg/yr	0.267	0.267	0.346	0.346	0.308	0.308

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Land requirements for the plant proper are assumed to be 40.5 ha@ \$16,060/ha (100 acres@ \$6,500/acre). Feedstock requirements are based on biomass at 19.77 GJ/MT (8,500 Btu/lb), and the capacity factors from Section 4.2. Water requirements are based on results from the BIOPOWER model. Since the details of the steam injected gas turbine technology used in the 2020-2030 cases are not known at this point, a projection for the water requirement was not made. However, it can be expected to be significantly higher since steam injected into a gas turbine is not re-captured as it is in a steam cycle.

Large-scale dedicated feedstock supply systems to supply biomass to biomass power plants are not commercially available in the U.S. today. The U.S. DOE recognizes this fact, and therefore a large part of its commercial demonstration program addresses dedicated feedstock issues. Projects in several locations around the country are developing commercial varieties of woody and herbaceous feedstocks. Development of feedstocks (e.g., hybrid poplar and switchgrass) and resource assessments are also underway at Oak Ridge National Laboratory.

In the forest products (e.g., pulp and paper) and agriculture industries (e.g., sugar) there are many examples that demonstrate the sustainable utilization of biomass residues for power and energy production. Consequently, evidence exists that the agriculture, harvest, transport, and management technologies are capable of supporting power plants of the sizes discussed in this technology characterization.

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