Biomass Combined Heat and Power Catalog of Technologies

U. S. Environmental Protection Agency
Combined Heat and Power Partnership

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Foreword

The U.S. Environmental Protection Agency (EPA) Combined Heat and Power (CHP) Partnership is a voluntary program that seeks to reduce the environmental impact of power generation by promoting the use of CHP. CHP is an efficient, clean, and reliable approach to generating power and thermal energy from a single fuel source. CHP can increase operational efficiency and decrease energy costs, while reducing the emissions of greenhouse gases, which contribute to global climate change. The CHP Partnership works closely with energy users, the CHP industry, state and local governments, and other stakeholders to support the development of new projects and promote their energy, environmental, and economic benefits.

The partnership provides resources about CHP technologies, incentives, emission profiles, and other information on its Web site at www.epa.gov/chp. For more information, contact:

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Acronyms & Abbreviations

AC alternating current
Btu   British thermal unit(s)
C&D construction   and demolition
CCAR   California Climate Action Registry
CDM clean   development mechanism
CHP   combined heat and power
cfm   cubic feet per minute
CI co   mpression ignition
CIBO   Council of Industrial Boiler Owners
CO carbon   monoxide
CO_2 carbon dioxide
DOE   U.S. Department of Energy
EPA   U.S. Environmental Protection Agency
EPRI   Electric Power Research Institute
ft^3 cubic foot
GHG greenhouse   gases
HHV   high heating value
hr hour(s)
Hz Hertz
IC internal   combustion
IGCC   integrated gasification combined cycle
IPCC   Intergovernmental Panel on Climate Change
kW kilowatt(s)
kWh kilowatt-hour   (s)
lb poun   d(s)
LFG landfill   gas
LMOP   Landfill Methane Outreach Program
MCFC   molten carbonate fuel cell
Mlb thousand   pounds
MMBtu   million British thermal units
MSW   municipal solid waste
MW megawatt(s)
MWh megawatt-hour(s)
N_2O nitrous   oxide
NO_X nitrogen   oxides
NRCS   Natural Resource Conservation Service
O&M   operations and maintenance
ORC   organic Rankine cycle
PAFC   phosphoric acid fuel cell
PEMFC   proton exchange membrane fuel cell
PM particulate   matter
ppm parts   per million
psig   pounds per square inch gauge
scf   standard cubic foot
SI spark   ignition
SO_2 sulfur   dioxide
SOFC   solid oxide fuel cell

UNFCCC	United Nations Framework Convention on Climate Change
USDA	U.S. Department of Agriculture
WWTF	wastewater treatment facility

1. Introduction and Overview

1.1 Biomass for Power and Heat Generation

As part of its efforts to reduce the environmental impacts of energy production and use, the U.S. Environmental Protection Agency (EPA) has engaged in outreach and technical assistance to broadly increase understanding and use of highly efficient combined heat and power (CHP) applications through the efforts of the CHP Partnership program. Over the past three years, market and policy forces have driven strong interest and early implementation of new biomass-fueled CHP projects by Partners and other clean energy stakeholders. In the interest of continuing the trend toward greater utilization of biomass fuels to power clean, efficient electricity and thermal energy generation, this document provides resource owners, facility managers, developers, policymakers, and other interested parties with a detailed technology characterization of biomass CHP systems. The report reviews the technical and economic characterization of biomass resources, biomass preparation, energy conversion technologies, power production systems, and complete integrated systems.

There are many potential advantages to using biomass instead of fossil fuels for meeting energy needs. Specific benefits depend upon the intended use and fuel source, but often include: greenhouse gas (particularly carbon dioxide [CO_2]) and other air pollutant reductions, energy cost savings, local economic development, waste reduction, and the security of a domestic fuel supply. (Specific information about the climate change benefits of biomass CHP can be found in Appendix A.) In addition, biomass is more flexible (e.g., can generate both power and heat) and reliable (as a non-intermittent resource) as an energy option than many other sources of renewable energy.

Biomass fuels are typically used most efficiently and beneficially when generating both power and heat through CHP. CHP, also known as cogeneration, is the simultaneous production of electricity and heat from a single fuel source, such as biomass/biogas, natural gas, coal, or oil. CHP provides:

- **Distributed generation** of electrical and/or mechanical power.

- **Waste-heat recovery** for heating, cooling, or process applications.

- **Seamless system integration** for a variety of technologies, thermal applications, and fuel types into existing building infrastructure.

CHP is not a single technology, but an integrated energy system that can be modified depending on the needs of the energy end user. The hallmark of all well-designed CHP systems is an increase in the efficiency of fuel use. By using waste heat recovery technology to capture a significant proportion of heat created as a byproduct in electricity generation, CHP systems typically achieve total system efficiencies of 60 to 80 percent for producing electricity and thermal energy. These efficiency gains improve the economics of using biomass fuels, as well as produce other environmental benefits. More than 60 percent of current biomass-powered electricity generation in the United States is in the form of CHP.[1]

The industrial sector currently produces both steam or hot water and electricity from biomass in CHP facilities in the paper, chemical, wood products, and food-processing industries. These industries are major users of biomass fuels; utilizing the heat and steam in their processes can improve energy efficiency by more than 35 percent. The biggest industrial user of bioenergy is the forest products

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[1] Energy and Environmental Analysis, Inc., 2006.

industry, which consumes 85 percent of all wood waste used for energy in the United States. Manufacturing plants that utilize forest products can typically generate more than half of their own energy from woody waste products and other renewable sources of fuel (e.g., wood chips, black liquor).

Most of the electricity, heat, and steam produced by industrial facilities are consumed on site; however, some manufacturers that produce more electricity than they need on site sell excess power to the grid. Wider use of biomass resources will directly benefit many companies that generate more residues (e.g., wood or processing wastes) than they can use internally. New markets for these excess materials may support business expansion as the residues are purchased for energy generation purposes or new profit centers of renewable energy production may diversify and support the core business of these companies.

1.2 Biomass Feedstocks

The success of any biomass-fueled CHP project is heavily dependent on the availability of a suitable biomass feedstock. Biomass feedstocks are widely available in both rural and urban settings and can include:

Rural Resources:
- Forest residues and wood wastes
- Crop residues
- Energy crops
- Manure biogas

Urban Resources:
- Urban wood waste
- Wastewater treatment biogas
- Municipal solid waste (MSW) and landfill gas (LFG)
- Food processing residue

Feedstocks vary widely in their sources and fuel characteristics and therefore vary in typical considerations for their utilization. Various biomass resources can require different approaches to collection, storage, and transportation, as well as different considerations regarding the conversion process and power generation technology that they would most effectively fuel.

Of the 9,709 megawatts (MW) of biomass electric capacity in the United States in 2004, about 5,891 MW were from wood and wood wastes; 3,319 MW of generating capacity was from MSW and LFG; and 499 MW of capacity was attributable to other biomass, such as agricultural residues, sludge, anaerobic digester gas, and other sources.[2]

1.3 Biomass Conversion

Biomass can be used in its solid form or gasified for heating applications or electricity generation, or it can be converted into liquid or gaseous fuels. Biomass conversion refers to the process of converting biomass feedstocks into energy that will then be used to generate electricity and/or heat.

Multiple commercial, proven and cost effective technologies for converting biomass feedstocks to electricity and heat are currently available in the United States (see **Table 1-1**). These technologies include anaerobic digesters for animal waste or wastewater, and three types of direct-fired boiler systems that have been used for decades for converting woody biomass: fixed bed boilers, fluidized bed boilers, and cofiring applications. Some of these boiler technologies are extremely clean and can result in

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[2] Energy Information Administration, 2006.

electricity production of up to 50 megawatts (MW)—enough electricity to power 50,000 homes.[3]

Additionally, an emerging class of biomass conversion technologies is becoming available that converts woody biomass feedstocks to useable fuel through gasification processes. These technologies, called fixed bed gasifiers and fluidized bed gasifiers, are becoming commercialized and are currently in limited use producing syngas for power and heat. Rapid commercialization may be seen in the near future as these gasification technologies are expected to be used in integrated gasification combined cycle (IGCC) coal plants and within some of the thermochemical (cellulosic) biorefineries built in the United States in the next two to ten years (see **Table 1-1**). Modular versions—smaller than 5 MW—of both direct-fired boiler and gasification technologies are also being developed, though they are at earlier stages of commercialization.

1.4   Report Layout

The report is organized into the following chapters:

Chapter 2:   **Basic First Steps and Considerations**—This chapter provides an overview of basic considerations that need to be taken into account when beginning to evaluate the viability of biomass-fueled electricity and thermal energy generation.

Chapter 3:   **Biomass Resources**—This chapter presents a discussion of the various types of biomass resources, locations, characteristics, resource potential, and costs.

Chapter 4:   **Biomass Preparation**—This chapter describes the receiving, processing, and treatment systems required for preparing biomass feedstocks and biogas for use as a power generation fuel. Equipment configurations and capital and operating costs are outlined.

Chapter 5:   **Biomass Conversion Technologies**—This chapter describes configurations, cost, and performance for the two basic biomass conversion approaches: combustion and gasification. In addition, a brief discussion of small modular biomass conversion technologies is presented.

Chapter 6:   **Power Generation Technologies**—This chapter provides basic cost and performance information for power generation technologies with heat recovery, and special considerations for selecting and operating these technologies on biomass or biogas fuels.

Chapter 7:   **Representative Biomass CHP System Cost and Performance Profiles**—This chapter provides an integration of resource, preparation, conversion, and power and heat production system costs into integrated biomass-fueled CHP facilities. Capital costs, operating costs, fuel costs, and typical energy balances, including power and heat production options, are described. This chapter provides a starting point for conducting a preliminary economic screening of possible biomass energy production options.

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[3] In contrast, coal-fired power plants are generally sized in the 100 MW to 1,000 MW range.

Additional biomass-related resources and tools created by the EPA CHP Partnership are listed in Appendix B.

Table 1-1. Commercialization Status of Biomass Conversion Systems for Power and Heat Generation
This table identifies the major biomass conversion technologies and associated prime mover technologies for CHP applications. The commercial status of each technology for biomass applications is described.

Energy Conversion Technology	Conversion Technology Commercialization Status	Integrated CHP Technology (Prime Mover)	Prime Mover Commercialization Status
Anaerobic Digestion			
Anaerobic digester (from animal feeding operations or wastewater treatment facilities)	Commercial technology	Internal combustion engine	Commercial technology
		Microturbine	Commercial technology
		Gas turbine	Commercial technology
		Fuel cell	Commercial introduction
		Stirling engine	Emerging
Direct Combustion—Boilers			
Fixed bed boilers (stoker)	Commercial technology – Stoker boilers have long been a standard technology for biomass as well as coal, and are offered by a number of manufacturers.	Steam turbine	Commercial technology
Fluidized bed boilers	Commercial technology – Until recently fluidized bed boiler use has been more widespread in Europe than the United States. Fluidized bed boilers are a newer technology, but are commercially available through a number of manufacturers, many of whom are European-based.		
Cofiring	Commercial technology – Cofiring biomass with coal has been successful in a wide range of boiler types including cyclone, stoker, pulverized coal, and bubbling and circulating fluidized bed boilers.		
Modular* direct combustion technology	Commercial technology – Small boiler systems commercially available for space heating. A small number of demonstration projects in CHP configuration.	Small steam turbine	Commercial technology
		Organic Rankine cycle	Emerging technology – Some "commercial" products available.
		"Entropic" cycle	Research and development (R&D) status
		Hot air turbine	R&D status

*Small, packaged, pre-engineered systems (smaller than 5 MW).

Energy Conversion Technology	Conversion Technology Commercialization Status	Integrated CHP Technology (Prime Mover)	Prime Mover Commercialization Status
Gasification			
Fixed bed gasifiers	Emerging technology – The actual number of biomass gasification systems in operation worldwide is unknown, but is estimated to be below 25.	Gas turbines – simple cycle	Prime movers have been commercially proven with natural gas and some medium heating value biogas.
Fluidized bed gasifiers	A review of gasifier manufacturers in Europe, USA, and Canada identified 50 manufacturers offering commercial gasification plants from which 75 percent of the designs were fixed bed; 20 percent of the designs were fluidized bed systems.	Gas turbines – combined cycle	Operation on low heating value biogas and the effects of impurities on prime mover reliability and longevity need to be demonstrated.
		Large internal combustion (IC) engines	
Modular* gasification technology	Emerging technology – A small number of demonstration projects supported with research, design, and development funding.	IC engine	Commercial technology – But operation on very low heating value biogas needs to be demonstrated.
		Microturbine	
		Fuel cell	Commercial introduction
		Stirling engine	Emerging technology
Modular* hybrid gasification/combustion	Emerging technology – Limited commercial demonstration.	Small steam turbine	Commercial technology – But integrated system emerging.

*Small, packaged, pre-engineered systems (smaller than 5 MW).

2. Basic First Steps and Considerations

Biomass is any organic matter, typically plant-based matter, that is available on a renewable or recurring basis. Biomass resources include forest and mill residues, agricultural crops and wastes, wood and wood wastes, animal wastes, livestock operation residues, aquatic plants, fast-growing trees and plants, and municipal and industrial wastes. Biomass can be used in its solid form or gasified for heating applications or electricity generation, or it can be converted into liquid or gaseous fuels. The use of biomass to produce heat and power can be environmentally beneficial because biomass is a renewable resource and its combustion does not contribute additional greenhouse gases to the atmosphere.[4]

In almost all cases, the production of electricity from biomass resources is most economic when the resulting waste heat is also captured and used as useful thermal energy—known as CHP. The lowest cost forms of biomass for generating electricity are residues. Residues are the organic byproducts of food, fiber, and forest production, such as sawdust, rice husks, wheat straw, corn stalks, and bagasse (the residue remaining after juice has been extracted from sugar cane). Wood is the most commonly used biomass fuel for heat and power. The most economic sources of wood fuels are wood residues from manufacturing, discarded wood products diverted from landfills, and non-hazardous wood debris from construction and demolition activities. Generating energy with these materials can recoup the energy value in the material and avoid the environmental and monetary costs of disposal or open burning.

Biomass is plentiful in various forms across the country. Certain forms of biomass are more plentiful in specific regions where climate conditions are more favorable for their growth. The biomass feedstocks discussed in this report vary widely in their sources and fuel characteristics and therefore vary in typical considerations for their utilization. The various biomass resources can require different approaches to collection, storage, and transportation, as well as different considerations regarding the power generation technology that they would most effectively fuel.

The U.S. Energy Information Administration (EIA) estimates that 590 million wet tons (equivalent to 413 million dry tons) of biomass resources are available in the United States on an annual basis. EIA forecasts that biomass will generate 76.5 billion kilowatt-hours (kWh) of electricity, or 1.7 percent of the United States' forecasted total generation, in 2010.[5]

To turn a biomass resource into productive heat and/or electricity requires a number of steps and considerations, most notably evaluating the availability of suitable biomass resources; determining the economics of collection, storage, and transportation; and evaluating available technology options for converting biomass into useful heat or electricity.

2.1 Survey Availability of Local Resources

The availability of biomass feedstocks in close proximity to a biomass power project is a critical factor in their efficient utilization. An in-depth evaluation of the available quantity of a given resource should be conducted to determine initial feasibility of a project, as well as subsequent fuel availability issues. The primary reasons for failure of biomass power projects are changes in fuel supply or demand (wrongly assumed during the planning stage) and changes in fuel quality.[6] Fuel considerations that should be analyzed in a preliminary evaluation include:

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[4] The combustion of biomass merely returns the CO_2 that was absorbed during the growth of the biomass, resulting in a zero net contribution of greenhouse gases.

[5] Energy Information Administration, 2006.

[6] Schmidt and Pinapati, 2000.

- Typical moisture content (including the effects of storage options)
- Typical yield
- Seasonality of the resource
- Proximity to the power generation site
- Alternative uses of the resource that could affect future availability or price
- Range of fuel quality (i.e., contaminants that could effect power generation equipment)
- Weather-related issues
- For agricultural residues: percentage of farmers contracted to sell residues

An introduction to the typical characteristics and regional availability of a variety of rural and urban feedstocks is included in Chapter 3.

It is important to be as accurate as possible when making fuel availability assumptions because miscalculations can greatly impact the successful operation of biomass power projects. When fuel availability is known to be an issue in the planning stage, a power generation technology that can handle varying degrees of moisture content and particle size can be selected. Technologies that can handle several fuels in a broad category, such as agricultural residues, provide security in operation without adversely affecting combustion efficiency, operations and maintenance costs, emissions levels, and reliability. Information on fuel flexibility is included in the technology characterizations in Chapter 5 of this report.

2.2   Cost Considerations

Collection Method

The amount of a biomass resource that can be collected at a given time depends on a variety of factors. For agricultural residues and energy crops, these considerations include the type and sequence of collection operations, the efficiency of collection equipment, tillage and crop management practices, and environmental restrictions, such as the need to control erosion, maintain soil productivity, and maintain soil carbon levels.[7] The collection mechanism used for agricultural residues and switchgrass is similar to what is currently used to collect hay. Different systems have varying collection efficiencies, driving the cost of collection to approximately 20 to 25 percent of total delivered cost, typically $5 to $7/ton.

For wood resources, the cost of collection is one of the largest costs of delivered wood fuel. Forest residues can be collected easily by equipment that is already in the forest collecting timber, whereas forest thinnings can be more difficult to harvest due to site accessibility issues.

For gaseous biomass fuels, such as LFG and wastewater treatment gas, regulatory requirements might have already mandated the collection of methane generated by these applications. Therefore the collection cost does not factor into a power generation project because it is a sunk cost that would be present regardless. However, as outlined in Table 4-3, collection costs for an LFG energy project can be significant (close to $1 million per 500 cubic feet per minute [cfm]) and should be factored into the economic evaluation of a potential project that is not required due to regulations.

Resource Cost

Some biomass resources do not involve compensating an owner for removal. However, payment (a "farmer premium") may have to be made to a farmer for agricultural residues and some energy crops,

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[7] Perlack and Turhollow, 2002.

like switchgrass, if collected from an individual's land. The amount of the payment varies, but is designed to compensate the farmer for the value of the removed nutrients and compensate for potential soil compaction and decreased surface organic matter. Structuring payment based on distance from the plant is common, with farmer premiums of up to $15/ton for haul distances within 15 miles or $7/ton or less for distances around 50 miles.

Transportation

Biomass transportation costs are site specific and depend on the distance from the plant as well as the amount of biomass to be transported. Recent data are not readily available; however, in 2002, transportation costs for agricultural crops typically ranged from $7 to $10/dry ton for conventional bales and between $4 to $7/dry ton for compacted bales.[8] For wood feedstocks, costs between $8 and $15/ton were typical.[9] As a comparison, average trucking costs for coal in 2001 were approximately $11.70/ton for a 50-mile haul.[10]

Storage

There are three common storage options for biomass feedstocks, each with its own benefits and challenges:

1. Feedstock is hauled directly to the plant with no storage at the production site.
2. Feedstock is stored at the production site and then transported to the plant as needed.
3. Feedstock is stored at a collective storage facility and then transported to the plant from the intermediate storage location.

The type of storage system used at the production site, intermediate site, or plant can greatly affect the cost and the quality of the fuel. Storage systems that maintain high fuel quality also cost the most. Typical storage systems, ranked from highest cost to lowest cost, include:

- Enclosed structure with crushed rock floor ($10 to $15/ton)
- Open structure with crushed rock floor ($6 to $8/ton)
- Reusable tarp on crushed rock ($3/ton)
- Outside unprotected on crushed rock ($1/ton)
- Outside unprotected on ground ($0/ton)[11]

Chapter 4 of this report provides an overview of storage area requirements at a biomass conversion facility. For example, wood burning facilities typically store up to a month of fuel supply on site to carry the plant through possible supply shortages in the spring or winter seasons. Depending on the size of the facility, this storage could require a significant amount of space. For other feedstocks such as agricultural residues that have harvesting seasons of little more than two months, a large amount of storage is required. For these fuels, it is typical to have intermediate storage facilities that are either at the farm of origin or in staging areas off site. The land requirements for a storage facility depend on the size of the plant as well as the storage density of the feedstock. For a 2,000 ton/day plant, 50 storage areas of 8 acres each for round bales or 3 acres each for compacted bales would be needed.[12]

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[8] Perlack and Turhollow, 2002.
[9] Resource Dynamics Corporation, 2004.
[10] Energy Information Administration, 2004.
[11] Iowa State University, 2002.
[12] Perlack and Turhollow, 2002.

Facility Size

As biomass power projects increase in size, economies of scale are partially offset by increased transportation costs associated with hauling biomass feedstocks farther distances. When assuming a circular collection area around a plant, the average feedstock haul distance increases by about 41 percent with every doubling of facility size.[13] The subsequent increase in hauling costs is not linear because the collection area increases exponentially as distance increases.

Government Support and Incentives

Many incentives are available for using biomass feedstocks in power generation applications, which can substantially help the economics of using biomass as a fuel source. A good resource for information on biomass incentives is the EPA CHP Web site (www.epa.gov/chp/funding/bio.html), where almost 100 incentives are listed by state, along with information on how to qualify and apply for each incentive.

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[13] Perlack and Turhollow, 2002.

3.   Biomass Resources

Detailed and specific information about local biomass resources available for fueling a project are essential before seriously considering a biomass power installation. For example, typical moisture content (including the effects of storage options), typical yield, seasonality of the resource, proximity to the power generation site, issues that could affect future availability, fuel quality, and weather are all factors to consider when selecting a biomass fuel and determining the feasibility of a project.

For background and use in narrowing the range of options, this chapter provides an overview of typical characteristics of the most common biomass fuels. In this report, feedstocks are classified into two general categories: rural resources and urban resources. Within these categories, the following biomass feedstocks are discussed:

Rural Resources: Urban Resources:
      Forest residues and wood wastes   Urban wood waste
      Crop residues   LFG
      Energy crops   Wastewater treatment biogas
      Manure biogas   Food processing residue

The following sections provide descriptions of these biomass feedstocks in the United States, including information about the resource base, current utilization, potential availability, typical energy content (in British thermal units [Btu]), typical cost, and the advantages and disadvantages of utilizing the feedstock. All resource availability figures in this analysis are defined as resources not currently destined for other productive uses.[14]

3.1   Rural Resources

3.1.1   Forest Residues and Wood Wastes

Forest residues and wood wastes represent a large potential resource for energy production and include forest residues, forest thinnings, and primary mill residues. Even though the costs for these fuels are usually greater than coal, they reduce fuel price risk by diversifying the fuel supply; result in significantly lower greenhouse gas, sulfur dioxide (SO_2), and nitrogen oxide (NO_X) emissions than coal; and can easily be cofired.[15]

Forest Residues

Forest residues are defined as the biomass material remaining in forests that have been harvested for timber, and are almost identical in composition to forest thinnings. Because only timber of a certain quality can be used in lumber mills and other processing facilities, biomass material—forest residue—is left in forests by harvesting operations. Forestry residues include logging residues, excess small pole trees, and rough or rotten dead wood. These residues could be collected after a timber harvest and used for energy purposes. Typically, forest residues are either left in the forest or disposed of via open burning through forest management programs. The primary advantage of using forest residues for power generation is that an existing collection infrastructure is already set up to harvest wood in many areas. Companies that harvest wood already own equipment and transportation options that could be extended to gathering forest residues. A report evaluating forest residues in the eastern United States estimated that

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[14] The resource analysis in this section is based on previous work done by Oak Ridge National Laboratory, Antares Group, Inc., the U. S. Department of Agriculture (USDA), and Energy and Environmental Analysis (EEA), as noted.
[15] DOE, 2004; Robinson, et al., 2003.

2.3 tons are available for every 1,000 cubic feet of harvested timber.[16] **Figure 3-1** shows the potential

capacity for power generation fueled by forest residues in each state. Potential capacity is concentrated in the western and southeastern regions of the United States.

Figure 3-1. Forest Residue Potential

Forest residues typically have an energy content of 5,140 Btu/pound (lb) (wet) and 8,570 Btu/lb (dry). The cost items for obtaining recoverable forest wood residues include collecting, harvesting, chipping, loading, transportation, and unloading; a stumpage fee; and a return for profit and risk. The cost of forest residue

□ <50 MW
□ 50-250 MW
■ 250-500 MW
■ >500 MW

Based on data from Antares Group, Inc., 2003.

can be as low as $15 to $25 per ton, or between $1.46 and $2.43/million Btu (MMBtu); however, the average price in most parts of the country is roughly $30/ton, or $2.92/MMBtu.[17,18]

Forest Thinnings

Forest thinnings are defined as underbrush and saplings smaller than 2 inches in diameter, as well as fallen or dead trees. These substances are sometimes known as "ladder fuels" because they can accelerate a forest fire's vertical spread. Large volumes of forest biomass should be available from implementation of U.S. Department of the Interior, the U.S. Department of Agriculture (USDA)/U.S. Forest Service, and Bureau of Land Management joint initiatives to reduce fire risk in national forests; however, the actual business of harvesting, collecting, processing, and transporting loose forest thinnings is costly and presents an economic barrier to their recovery and utilization for energy. Typically, the wood waste from forest thinnings is disposed of through controlled burning due to the expense of transporting it to a power generation facility. In areas that are not already used for wood harvesting, there is no existing infrastructure to extract forest thinnings. A study for the Colorado Office of Energy Management and Conservation found that the delivered cost of forest thinnings was nearly $100 per dry ton, making it hard to compete with other fuels at a cost of $5.83 to $9.73/MMBtu.[19]

Forest thinnings typically have an energy content of 5,140 Btu/lb (wet) and 8,570 Btu/lb (dry). The use of forest thinnings for power generation is concentrated in the western United States. **Figure 3-2** shows that Nevada, Arizona, Idaho, and New Mexico have the greatest potential to generate power from forest thinnings.

Figure 3-2. Forest Thinning Generation Potential From National Forests and Bureau of Land Management Property
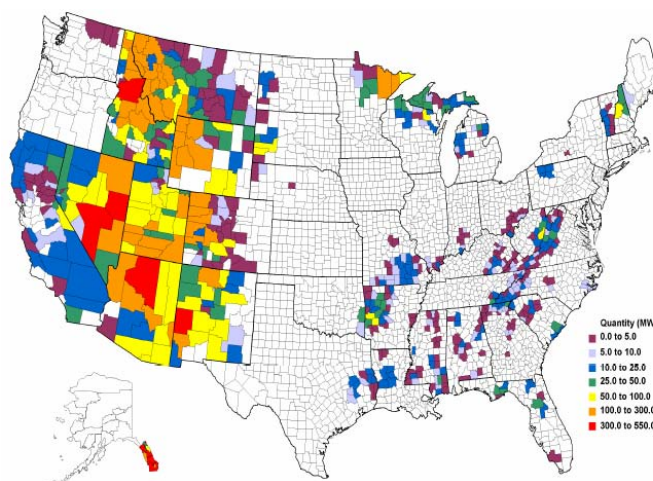
Primary Mill Residues

Primary mill residues are waste wood from manufacturing operations that would otherwise be sent to a landfill.

Quantity (MW)
■ 0.0 to 5.0
■ 5.0 to 10.0
■ 10.0 to 25.0
■ 25.0 to 50.0
■ 50.0 to 100.0
■ 100.0 to 300.0
■ 300.0 to 550.0

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[16] C.T. Donovan Associates, 1994.

[17] Walsh, et al., 1999.

[18] Curtis, et al, 2003.

[19] Colorado Governor's Energy Office, n.d.

Source: Antares Group, Inc., 2003.

Manufacturing operations that produce mill residues usually include sawmills, pulp and paper companies, and other millwork companies involved in producing lumber, pulp, veneers, and other composite wood fiber materials. Primary mill residues are usually in the form of bark, chips, sander dust, edgings, sawdust, or slabs. Due to the fact that primary mill residues are relatively homogeneous and concentrated at one source, nearly 98 percent of all residues generated in the United States are currently used as fuel or to produce other fiber products. Of the 21.6 million dry tons of bark produced in the United States, 76.6 percent is used for fuel and 20.6 percent is used for other purposes such as mulch, bedding, and charcoal. Overall, USDA estimates that 2 to 3 percent of primary mill residues are available as an additional fuel resource because they are not being used for other purposes. **Figure 3-3** shows that the largest concentrations of primary mill residues are in the western and southeastern regions of the United States.

Figure 3-3. Primary Mill Residue Potential

Based on data from Antares Group, Inc., 2003.
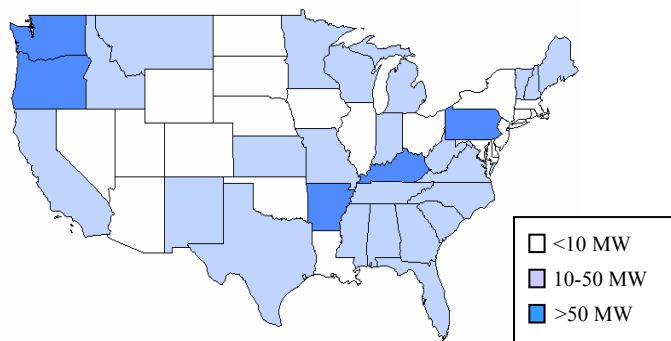
Because most primary mill residues are fairly dry after they have been through a manufacturing process, they fall at the upper level of the energy content range for wood (8,570 Btu/lb). Producing power from primary mill residues is highly advantageous in the wood products industries because they have a "free" (i.e., no additional cost) source of fuel with no transportation costs and a secure supply that they control. The cost of these residues is actually negative to most wood products industries because if the residues are not used on site, companies have to pay for disposal. When purchasing mill residues, the price can vary considerably from $8 to $50 per oven dry ton, corresponding to a cost of $0.46 to $2.92/MMBtu.[20] This high variability occurs on a site by site basis depending on whether the site is already using the residues.

3.1.2 Crop Residues

Agriculture is a major economic activity in the United States with approximately 302 million acres of harvested cropland currently being used for agricultural production.[21] According to the most recent USDA Census (2004), the most frequently planted crops (in terms of average total acres planted) are corn, wheat, soybeans, hay, cotton, grain sorghum, barley, oats, and rice.[21] Following the harvest of many traditional agricultural crops such as corn and wheat, residues such as crop stalks, leaves, and cobs, referred to as corn stover and wheat straw, are left in the field. A segment of these residues could potentially be collected and combusted to produce energy. Only slightly more than one-fifth of the more than 100 million tons of agricultural waste generated in the United States is currently used each year.[22]

Corn stover[23] and wheat straw are the primary agricultural residues used in energy production. **Figures 3-4** and **3-5** show the location and MW potential for corn stover and wheat straw that can be delivered at less than $50/dry ton. Although more states produce wheat than corn, the country's total MW-generation potential is significantly less from wheat straw than from corn stover because wheat straw has a lower energy content than corn stover and fewer tons of wheat straw can be collected per acre

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[20] Walsh, et al., 1999.
[21] USDA, 2004.
[22] DOE/USDA, 2005.
[23] Corn stover is the stalks, leaves, and cobs that are left in the field after harvesting.

Figure 3-4. Available Corn Stover Residues at Less Than $50/Dry Ton
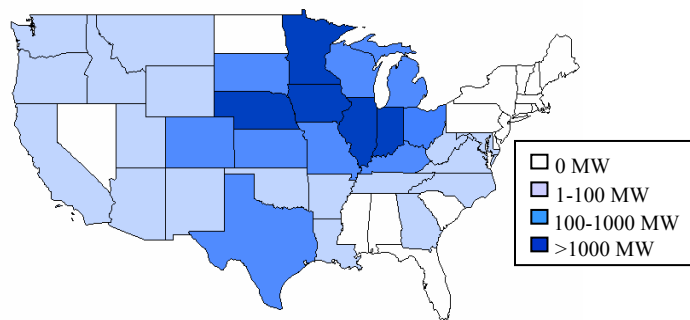
Based on data from Antares Group, Inc., 2003.

Figure 3-5. Available Wheat Straw Residues at Less Than $50/Dry Ton

Based on data from Antares Group, Inc., 2003.

than corn stover. Corn stover has an energy content of 5,290 Btu/lb (wet) and 7,560 Btu/lb (dry). Wheat straw has an energy content of 5,470 Btu/lb (wet) and 6,840 Btu/lb (dry).

The estimated prices of corn stover and wheat straw include the cost of collecting the residues, the premium paid to farmers for participation in a collection program, and transportation costs. The cost of corn stover ranges from $20 to $40 per ton and the cost of wheat straw is approximately $50 per ton. Consequently, corn stover typically costs between $1.89 to $3.78/MMBtu, and wheat straw costs approximately $4.57/MMBtu.[24,25]

The primary drivers for converting agricultural residues into electricity are avoided fossil fuel purchases and the environmental improvements due to avoided decomposition and open burning practices. The disadvantages to using these residues are crop seasonality, which creates an unsteady and unreliable fuel supply, and competing uses for the residue. For example, corn stover is normally used for animal feed or compost, and wheat straw is used for feed or animal bedding—all of which are established markets.

3.1.3 Energy Crops

Energy crops are perennial grasses and trees grown through traditional agricultural practices that are produced primarily to be used as feedstocks for energy generation. The Bioenergy Feedstock Development Program at Oak Ridge National Laboratory (ORNL) has identified hybrid poplars, hybrid willows, and switchgrass as having the greatest potential for dedicated energy use over a wide geographic range. Currently, energy crops are not being grown commercially in the United States, but this situation could change if they could be sold at prices that ensure producers a profit that is comparable to using the land for alternate purposes. Demonstration programs are underway with Department of Energy (DOE) funding in Iowa and New York, but DOE assumes that energy crops will not become commercially available until 2010 or beyond. DOE estimates that about 190 million acres of land in the United States could be used to produce energy crops.[26]

Table 3-1 presents the energy content and typical costs for common energy crops. Harvesting costs for switchgrass are similar to most forage crops because switchgrass can be cut and baled with conventional mowers and balers, which make this energy crop the easiest and cheapest to harvest.

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[24] Hag, 2002.
[25] Curtis, et al, 2003.
[26] Antares, 2003.

Table 3-1. Energy and Cost Characteristics of Energy Crops

Energy Crop	Energy Content Wet (Btu/lb)	Energy Content Dry (Btu/lb)	Cost Range (per ton)	Cost/MMBtu
Hybrid Poplar	4,100	8,200	$39 to $60	$4.76 to $7.32
Hybrid Willow	4,100	8,200	$39 to $60	$4.76 to $7.32
Switchgrass	6,060	8,670	$35 to $50	$2.89 to $4.13

Source: State of Oregon, n.d.; Walsh et al., 1999

As an example of energy crop generation potential, **Figure 3-6** shows the amount of generation capacity that could be achieved by using switchgrass. Several states throughout the Midwest and South could provide more than 1,000 MW of power fueled by switchgrass.

If developed, energy crops could represent significant additional farm income. The advantages of using crops specifically grown for energy production is consistency in moisture content, heat content, and processing characteristics. Disadvantages include relatively higher overall costs than many fossil fuels, higher-value alternative land uses that further drive up costs, added expenses associated with harvesting and processing, and farmers' and power plant owners' unfamiliarity with energy crops.

Figure 3-6. Available Switchgrass at Less Than $50/Dry Ton

Legend:
- ☐ <50 MW
- ☐ 50-500 MW
- ☐ 500-1000 MW
- ■ >1000 MW
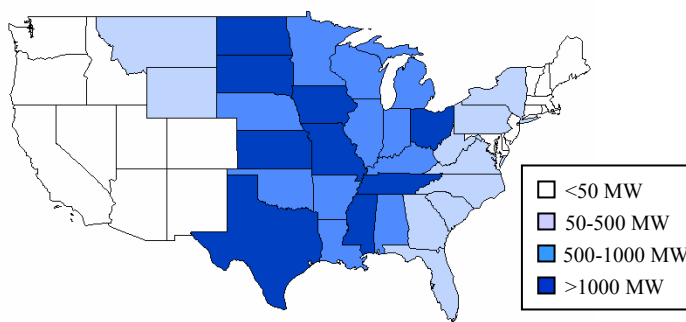
Based on data from Antares Group, Inc., 2003.

3.1.4 Manure Biogas

Manure digester biogas is produced at animal production operations when manure decomposes anaerobically (without oxygen) in a digester. Animal production operations use anaerobic digestion to reduce odor and pathogens and to effectively separate the solid and liquid portions of the sludge for application to cropland as fertilizer or irrigation water, respectively. Energy-recovery digesters are specially designed digesters that optimize the production of biogas from the decomposition of manure. Biogas from a manure digester typically contains 60 to 80 percent methane, depending on the type of animal and the manure collection system, resulting in an energy content of approximately 600 to 800 Btu per standard cubic foot (scf). The balance of the biogas is composed of CO_2 and trace amounts of hydrogen sulfide.

The use of manure biogas to produce energy is limited to farms that have the animals and manure management to accommodate anaerobic digestion. Farms that produce electricity from biogas might sell the electricity back to the grid, making this energy available to consumers outside of the farm. Selling electricity back to the grid, however, has not typically been an economically viable option for these operations. Furthermore, animal operations with anaerobic digesters currently represent a small fraction of the total number of animal operations. The USDA 2002 Census of Agriculture data showed a total of 91,989 dairy operations and 78,895 swine operations in the United States.[27] Out of these operations, only 65 dairy operations and 40 swine operations used anaerobic digesters.

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[27] USDA, 2004

The EPA AgSTAR Program has identified the most viable candidates for anaerobic digestion as dairy operations with greater than 500 head and swine operations with more than 2,000 head. Also, the potential for generating biogas from manure is greatest for manure management systems that collect and store manure as a liquid, slurry, or semi-solid (lagoon, liquid/slurry, or deep pit). Considering these parameters, approximately 2,290 dairy operations and 6,440 swine operations are potential candidates for anaerobic digestion and manure biogas production.[28]

Assuming an anaerobic digester is in place, there are no additional costs associated with obtaining the biogas. Therefore, manure biogas for energy use is considered an opportunity—or free—fuel. Capital costs, operation and maintenance (O&M) costs, and costs associated with collection and gas treatment will be a factor, however, in evaluating the suitability for a biogas power project. These costs are discussed in Chapter 4.

3.2   Urban Resources

3.2.1   Urban Wood Waste

Urban wood wastes include yard trimmings; wood construction and demolition (C&D) waste; site clearing wastes; and pallets, wood packaging, furniture, and other miscellaneous commercial and household wood wastes that are generally disposed at MSW landfills or C&D landfills. Urban wood wastes are available across the United States, but they are mainly concentrated in populous areas.

Woody yard trimmings are an abundant source of wood sent to landfills. In 1996, yard trimmings were the second largest component of the MSW stream at 29.3 million tons.[29] Yard trimmings can be generated from residential landscaping and right-of-way trimming near roads, railways, and utility systems such as power lines. Yard trimmings comprise about 14 percent of the MSW stream; because approximately 36 percent of yard trimmings are recoverable, roughly 5 percent of the total MSW stream for each state is available yard trimming residue.

C&D waste is woody material generated from C&D activity. Wood debris makes up around 26 percent of the total C&D stream, or approximately 35.1 million tons.[30] Approximately 30 percent of that debris, about 10.5 million tons/year, is uncontaminated by chemical treatment and available for recovery.[31]

Other wood wastes include discarded consumer wood products and wood residues from non-primary mill manufacturers, such as discarded wooden furniture, cabinets, pallets and containers, and scrap lumber. Approximately 7 percent of the entire MSW stream is other wood residue; of this, 44 percent is generally available. **Figure 3-7** shows the states with the highest concentrations and potential capacity for generating

Figure 3-7. Urban Wood Waste Potential Including Yard Trimmings, C&D Waste, and Other Wood Wastes

☐ <50 MW
☐ 50-200 MW
☐ 200-500 MW
☐ >500 MW
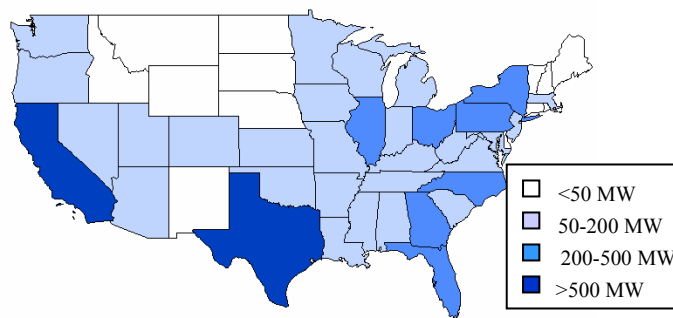
Based on data from Antares Group, Inc., 2003.

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[28] Additional information about manure biogas and anaerobic digester potential at animal production operations is available at <www.epa.gov/agstar>.
[29] McKeever, 1998.
[30] Sandler, 2003.
[31] Antares Group, Inc., 2003.

power from urban wood wastes.

Wood waste costs can be lower than other forms of biomass because wood waste that is burned for energy generation purposes is usually offsetting disposal costs from otherwise being landfilled. Therefore, some urban wood wastes can actually be collected at a negative cost. Typically, urban wood waste costs range from $3 to $24/ton. The energy content of urban wood waste is 4,600 Btu/lb (wet) and 6,150 Btu/lb (dry), or between $0.33 and $2.61/MMBtu.[32, 33]

One drawback to using urban wood waste for energy generation is that wood used for construction and consumer wooden goods can contain high levels of impurities caused by chemical treatments to extend the wood's useful life. These impurities can cause emission problems when burned and might require wood waste boilers to have extra filtration and control equipment to curb contaminants or would require effective separation of the contaminated items prior to burning.

3.2.2   Landfill Gas

LFG is generated through the decomposition of organic waste in anaerobic (oxygen-deprived) conditions at MSW disposal facilities, commonly known as landfills. Of all anthropogenic sources of methane emissions in the United States, landfills are estimated to account for the most generation from a single source category—25 percent of the total in 2004.[34] The amount of methane generated by a landfill over its lifetime is dependent on the composition of the waste, the quantity and moisture content of the waste, and the design and management practices of the facility. Landfills with more waste deposited in them typically produce more gas over time than those with less waste. Other factors aside, landfills in drier regions do not produce as much gas as those in areas that receive greater precipitation, as moisture is a necessary component in decomposition. The gas generation potential of a landfill is a function of the facility's size (waste in place), the climate in which it is located, and other site-specific attributes. Significant generation of LFG generally begins about one to two years after disposal of a mass of waste and continues evolving from that mass at an exponentially declining rate for 10 to 60 years, depending on landfill conditions.

On a dry basis, LFG is basically composed of 50 percent methane and 50 percent CO_2, resulting in a heating value of approximately 500 Btu/scf. Minute amounts of nitrogen, oxygen, and hydrogen, and trace amounts of inorganic compounds such as hydrogen sulfide (which has a strong odor), are also found in LFG.[35] Due to varying compositions of LFG at different sites (primarily variations in the relative amounts of methane and CO_2), measured heating values can range from 350 to 600 Btu/scf.[36]

The EPA Landfill Methane Outreach Program (LMOP) estimates that, in addition to the approximately 410 landfills already collecting LFG for energy recovery, 570 additional landfills are good candidates for LFG energy recovery. The majority of these landfills have more than 1 million tons of waste in place and either are still accepting waste or have been closed for five or fewer years.[37] These candidate landfills have the potential to generate approximately 1,370 MW of electricity. **Figure 3-8** shows the number of landfill energy recovery systems currently in place in each state as well as the number of candidate landfills.[38]

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[32] Antares Group, Inc., 2003.
[33] Walsh, et al., 1999.
[34] EPA, 2006a.
[35] EPA, 2006b.
[36] Perry, 1963.
[37] EPA, 2006c.
[38] Additional information about LFG and the feasibility of collecting it at landfills across the United States is available at <www.epa.gov/lmop>.

Figure 3-8. Operational LFG Energy Projects and Candidate Landfills
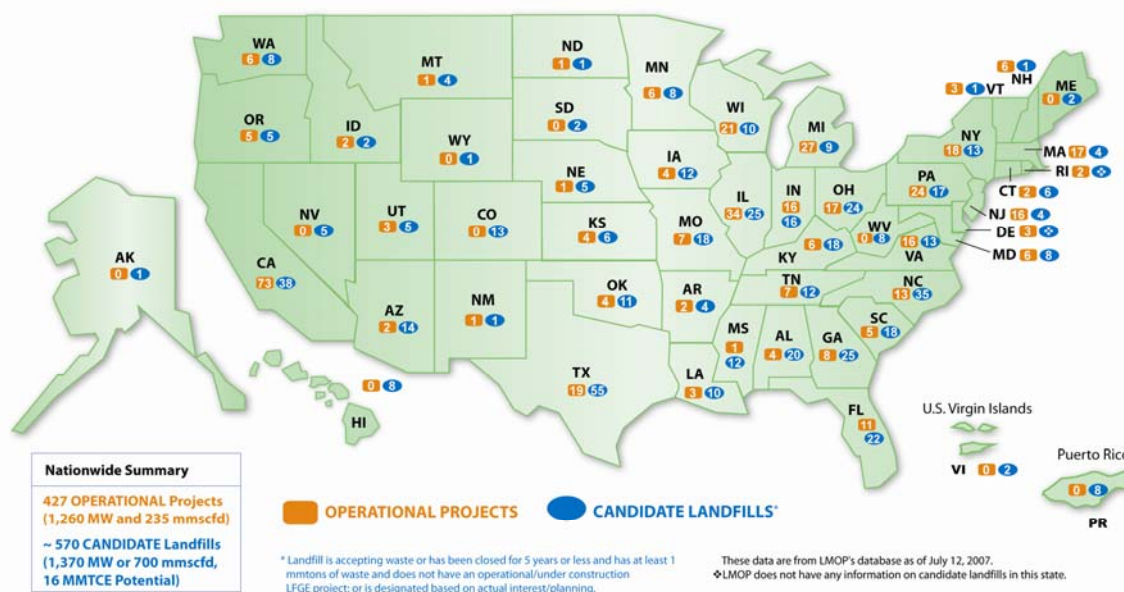
Source: EPA, 2006d.

A LFG energy recovery project developer typically pays between $1.00 and $3.00/MMBtu for raw LFG.[39] In addition to these royalties paid for raw LFG, there are often costs associated with gas collection and treatment, which are discussed in Chapter 4. In certain cases, a landfill will already have a gas collection system in place to comply with regulations but is burning the gas in a flare. A number of federal and state financial incentives and programs, including tax credits and state renewable portfolio standards, are available to help make LFG energy projects economically feasible. Appendix B provides information about an online funding guide that tracks LFG-related programs and incentives.

3.2.3 Wastewater Treatment Biogas

Wastewater treatment biogas is produced from the anaerobic digestion of domestic/industrial wastewater sludge. During the wastewater treatment process, solids from primary and secondary treatment are collected and further processed, via digestion, to stabilize and reduce the volume of the sludge. The digestion is performed either aerobically (in the presence of oxygen) or anaerobically (without oxygen) to produce biogas. Anaerobic digestion and wastewater treatment take place in a closed or covered tank to exclude air or oxygen from the waste. Anaerobic treatment has been historically used to biologically stabilize high-strength wastes at a low cost. In many cases, the biogas has not been used as an energy resource but has been burned in a flare and discharged to the atmosphere. Biogas is also generated from other anaerobic wastewater treatment processes, including anaerobic lagoons and facultative lagoons.

Wastewater treatment biogas consists of approximately 55 to 65 percent methane, 30 percent CO_2, and other inert gases such as nitrogen. This composition results in a heating value of approximately

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[39] Brian Guzzone, Landfill Methane Outreach Program (August 29, 2007).

550 to 650 Btu/scf.[40] Today, most wastewater treatment plants that employ anaerobic digestion collect and use their biogas on site. If used on site, the biogas created during the anaerobic digestion process is typically collected and used, often without pretreatment, in boilers that generate steam for space and digester heating and in reciprocating engines that drive air compressors and/or electric generators. Any excess biogas that cannot be used on site is generally flared.

According to the 2004 Clean Watersheds Needs Survey,[41] there are more than 16,000 municipal wastewater treatment facilities operating in the United States. An analysis completed by the CHP Partnership found that if all 544 wastewater treatment facilities with influent flow rates greater than 5 million gallons per day that operate anaerobic digesters were to install CHP, approximately 340 MW of electricity could be generated.[42] **Figure 3-9** shows the number of wastewater treatment facilities in each state greater than 5 million gallons per day, and the potential electric capacity estimated by the EPA CHP Partnership.

Figure 3-9. Wastewater Treatment Facilities Greater Than 5 Million Gallons Per Day and Electric Generating Potential
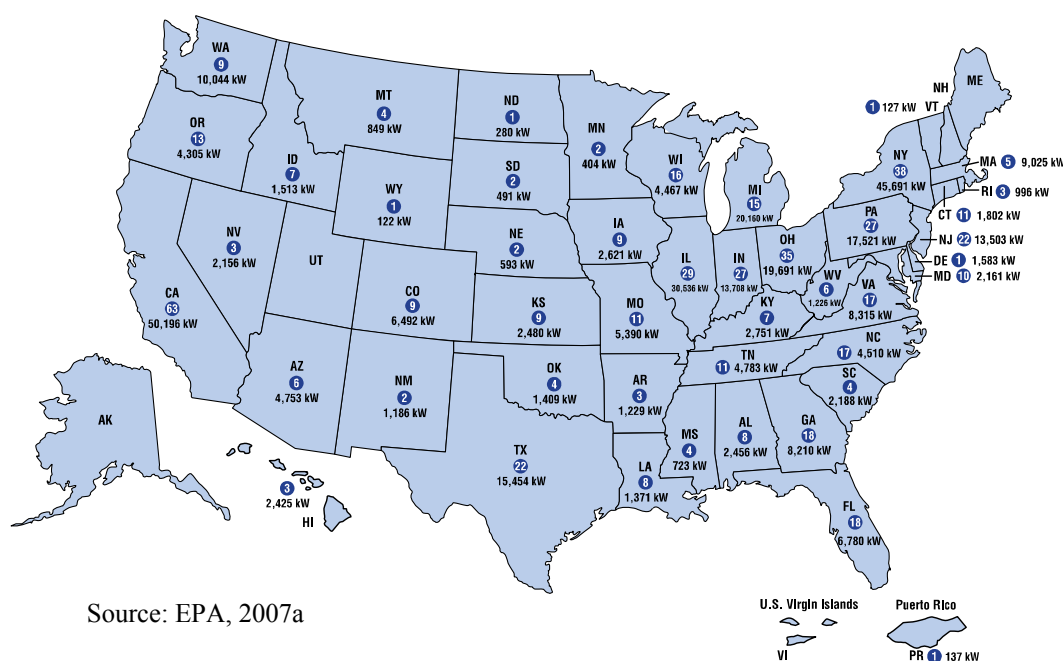
Source: EPA, 2007a

Like manure biogas and LFG, wastewater treatment biogas is an opportunity fuel, meaning there is no cost associated with generating the gas if the anaerobic digester used to produce the gas is already in place. Despite being an opportunity fuel, there are costs associated with collection, gas treatment, and O&M, which are discussed in Chapter 4. The cost of the collection system piping and the blower for moving the gas through the piping is relatively insignificant in comparison to the cost of the gas utilization systems discussed in subsequent sections.

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[40] Metcalf and Eddy, 2003.
[41] EPA, 2004a
[42] EPA, 2007a

3.2.4   Food Processing Waste

Food processing wastes are being used throughout the country as biomass feedstocks for energy generation. These wastes include:

Nut shells	Rice hulls	Meat processing residues
Fruit pits	Cotton gin trash	Cheese whey

Food processing wastes can be difficult to utilize as a fuel source due to the varying characteristics and properties of different waste streams. As such, most food wastes are currently disposed of as industrial wastewater and discharged to a local treatment plant. Work is underway in the food processing industry, however, to evaluate the energy resource these wastes represent, and to develop collection and processing methods that would allow for more effective utilization of this biomass resource. For example, dry solids production of shells, pits, hulls, and cotton gin trash exceeds 1 million dry tons per year in California, with at least three of these feedstocks currently being used for power generation in a few applications—almond shells, walnut shells, and rice hulls.[43]

In addition, utilities are taking advantage of these low-cost fuel sources. For example, peanut processors must dispose of large amounts of peanut hulls every month that cannot be used for such things as mulch, cat litter, or fire logs. Georgia Power has worked with firms to cofire peanut hulls with a mixture of coal at the Plant Mitchell Generating Station. Georgia Power estimates that every truckload of peanut hulls fired saves the company approximately $400 in fuel costs.[44] In southwest Louisiana, electric power generated from rice hulls powers a rice processing plant. Most of the power is used to operate the rice mill from which the hulls come, while any extra power is sold to Entergy, the regional electrical utility.

Researchers at the University of Georgia have done considerable research into the costs of using food processing wastes in power production. They have found that every bale of ginned cotton produces 200 pounds of gin trash,[45] which can be sold at prices ranging from $10 to $12 per ginned bale (i.e., per 200 pounds of gin trash).[46] Some resources indicate that large peanut and pecan shellers offer the hulls of these nuts at no cost if picked up and transported off their properties. Food processing wastes can produce a high-quality and clean-burning fuel that is cost competitive with coal on a Btu basis ($1.25 to $2.50/MMBtu) when sold as a solid. Potential waste sources are hard to generalize, however, and must be evaluated on a case-by-case basis.

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[43] California Energy Commission, 2004.
[44] National Food and Energy Council, n.d.
[45] Gin trash is a light material that cattle farmers currently utilize as a supplemental feed source.
[46] Curtis, 2003.

4.   Biomass Preparation

Biomass feedstocks have to be prepared, stored, and transported to the energy conversion process before they can be used to generate power or produce steam. This chapter describes the requirements and costs of preparing solid biomass fuel and biogas fuel for power generation.

4.1   Solid Biomass Fuel Preparation

The steps of preparation, storage, and transportation of a biomass feedstock comprise the ***preparation yard*** (prep-yard). The major requirements of a standard prep-yard can be divided into four categories:[47]

1.   Receiving: truck tipper, conveyor, and radial stacker

2.   Processing: reclaim feeder, conveyor, metal separator, dryer, screener, and grinder

3.   Buffer storage: storage bin (24 hours)

4.   Fuel metering conveyors, meters, and pneumatic transport

Two typical prep-yard configurations are shown in **Figures 4-1** and **4-2**. Figure 4-1 includes manual feedstock handling steps that reduce capital costs but increase labor requirements. The manual approach to feedstock handling would be primarily used for smaller facilities. Figure 4-2 shows a fully automated prep-yard, which is more capital intensive but requires less labor. An automated system is only cost-effective for large biomass conversion systems. Both of these configurations are based on woody biomass feedstock. The discussions throughout this chapter are based on three systems:

- 100 tons/day system based on manual biomass handling

- 450 tons/day system based on automatic handling

- 680 tons/day system based on automatic handling

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[47] The costs and schematics for this section are based on Antares Group, Inc., 2003.

Figure 4-1. Manual Biomass Receiving and Preparation System
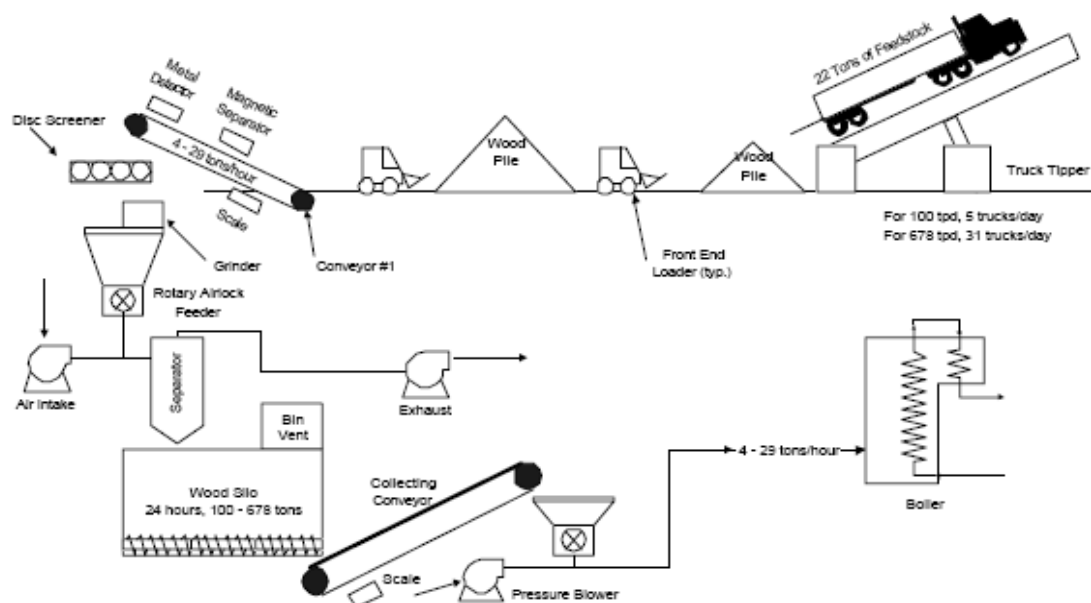
Source: Antares Group, Inc., 2003.

Figure 4-2. Automatic Biomass Receiving and Preparation System
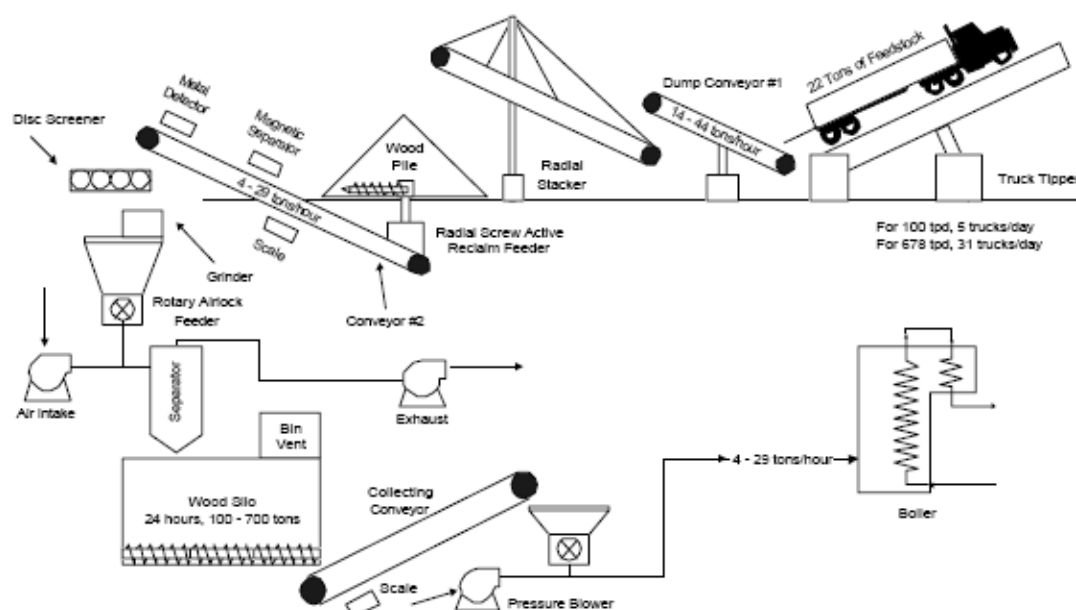
Source: Antares Group, Inc., 2003.

4.1.1   Receiving System

With the exception of residues generated in-house, virtually all woody biomass is delivered by truck to industrial users. Three types of trucks are commonly used for delivery of wood fuels: 1) dump trucks, 2) live-bottom (self-unloading) semi-trailer vans, and 3) standard semi-trailer vans. The choice of truck is dependent on the quantity of the biomass purchased and the equipment available for unloading. Dump trucks and live-bottom trucks have the advantage of being able to unload themselves directly onto storage piles. Standard semi-trailer vans require truck dumpers to unload. Smaller and less expensive dump systems only raise the trailer van for dumping, a process that requires decoupling the tractor and semi-trailer and is therefore more time intensive. Larger dump units can tilt the whole truck and unload in a manner of minutes, or approximately one-half the time of a trailer-only dumper. Minimizing unloading times is important because haulers can impose financial penalties for excessive unloading times.

A set of drive-on scales is used to determine how much biomass is on the truck. Although mechanical or electronic scales can be used, maintenance costs are generally lower for mechanical scales so those are more commonly used. Sometimes conveyor belt scales are used for determining weights, but these systems are less accurate, more time consuming, and more expensive to operate.

Biomass delivery and receiving methods depend on the size of the installation:

- **Very small installations** of a few tons per day use small dump trucks or standard semi-trailer vans for biomass delivery. Dump trucks drop the load at the site where it is then moved to storage by small front-end loaders. Where standard semi-trailer vans are used, a ramp or loading dock is required so that front-end loaders can remove the load—a process that takes about an hour per load.

- **Small-scale users,** 10 to 50 tons/day, typically use self-unloading semi-trailer vans. These trailers have a live-floor system that walks the load from the van, allowing a single person to unload a van in 10 minutes. The trailers are 30 to 45 feet in length and can carry 20 to 30 tons of biomass.

- **Intermediate-scale installations** 50 to 100 tons/day might add a light-duty frame-tilt hydraulic dumper for unloading fuel. For these systems, the trailer must first be disconnected from the tractor. Front-end loaders or bulldozers move the fuel from the concrete pad and stack the biomass on the storage pile. A system sized for 100 tons/day would handle about four to five trucks per day.

- **Large-scale installations** of greater than 100 tons/day typically use standard semi-trailers and hydraulic dumpers that can lift and tilt the whole truck up to an angle of 75°, emptying the entire load in a matter of minutes. The system includes a live-bottom receiving hopper. From the concrete pad, the fuel is conveyed to a woodpile. An automated storage radial stacker is used to stack the fuel on the pile for future processing needs. A system sized for 400 tons/day capacity would handle about 20 trucks per day.

The storage area for the options considered in this section is sized for a 30-day supply of biomass. This quantity of biomass can carry the plant through possible supply shortages in the spring or winter seasons. This amount of biomass storage requires an area between 12,500 and 93,750 square feet (for the 100 tons/day and 680 tons/day systems, respectively), assuming the wood has an average density of 40 lb/cubic foot and an average storage height of 12 feet. The larger area is greater than two football fields, so a significant area would be needed on site for a large biomass processing facility.

4.1.2   Processing System

The processing system treats the biomass prior to charging the energy conversion process. Common steps in processing include separation, sizing, removal of metals and other noncombustible materials, and grinding or other size reduction methods. An automated system conveys the correct amount of biomass required by the energy conversion process. In a manual system, a front-end loader will perform this function.

The sizing equipment separates oversized pieces and sizes them to meet boiler specifications. The disc screener separates the oversized particles and bypasses the undersized feedstock. The oversized particles are sent to a tub grinder to be properly sized. The tub grinder is adequate for wood chips and bark, but urban wood waste needs a hammer hog (hogger) because metal objects in this waste stream would damage a tub grinder. From the grinder or hogger, the material is conveyed into a wood silo to be stored until the boiler needs the fuel. Stoker and fluidized bed boilers can charge material up to about two to three inches in size.

Biomass might also have to undergo drying. If needed, this step occurs immediately after sizing. Of the technologies studied in this report, only gasification requires biomass drying. For all biomass conversion technologies, the lower the as-fired moisture content of the biomass feedstock, the higher the energy efficiency of the conversion process. If part of the fuel, moisture must be heated and vaporized and this energy is lost in the stack. In direct-fired conversion processes described in Chapter 5, each additional 10 percent of moisture in the fuel lowers the conversion (or boiler) efficiency by about 2 percentage points. Therefore, as-received biomass with moisture contents of 30 to 50 percent result in process efficiencies of 6 to 10 percentage points lower than bone dry feedstock. Efficiency reductions due to moisture contained in the biomass also occur in cofiring, but the effect is considerably reduced because the biomass is only a small part of the total fuel used. Typical practice in direct-fired and cofired applications, however, is not to dry the feedstock before charging in the boiler. In a well designed boiler, most of the available stack heat is already being extracted in steam production and other energy recovery options. Therefore, diverting stack heat from the process for drying would reduce what is available for steam generation. Gasification processes, on the other hand, typically require biomass feedstock drying for proper process function and control. Feedstock drying is an integral part of most gasification designs. Therefore, costs of drying are only considered in the section on biomass gasification.

4.1.3   Buffer Storage

A biomass silo serves as storage buffer in the 100 to 680 tons/day cases outlined here. The silo has a live bottom that moves the fuel to collector conveyors. The silo's capacity varies by fuel consumption rate. Prep-yard costs can be reduced by lowering the buffer size.

4.1.4   Fuel Metering

Fuel metering consists of the controlled delivery of the required amount of biomass to the energy conversion process. In the systems considered here, the biomass is metered as it is discharged from the silo to the collecting conveyor. An auger at the base of the silo feeds a conveyor, which then feeds a surge bin. From the surge bin, the fuel is metered into the boiler or other energy conversion device, passing through a rotary airlock. The metering rate is controlled by the boiler control room. The fuel is pneumatically transferred to the boiler after passing the airlock.

4.1.5   Prep-Yard Capital Costs

This section summarizes installed capital costs for biomass prep-yards of 100, 450, and 680 tons/day. The 100-tons/day plant utilizes a manual feedstock handling system. The two larger plants use an automatic system.

Table 4-1 shows installed capital costs, including the major equipment components described in the preceding sections. Installation costs, controls, civil/structural work, electrical work, engineering fees, and contingency costs are also shown. Prep-yard capital costs decline sharply on a per ton basis as the plant gets larger.

Table 4-1. Installed Capital Costs for Solid Biomass Receiving and Preparation

Component	Tons/Day Fuel (as received)		
	100	450	680
Receiving System			
Truck tipper	$230,000	$230,000	$230,000
Conveyor to wood pile		$40,000	$45,000
Radial stacker, adder		$190,000	$205,000
Front end loaders, adder	$100,000		
Receiving Equipment Subtotal	**$330,000**	**$460,000**	**$480,000**
Processing System			
Reclaim feeder		$230,000	$230,000
Conveyor		$149,000	$160,000
Metal separator	$40,000	$40,000	$40,000
Screener	$150,000	$220,000	$250,000
Grinder	$250,000	$400,000	$600,000
Processing Equipment Subtotal	**$440,000**	**$1,039,000**	**$1,280,000**
Buffer storage	$60,000	$98,000	$135,000
Fuel metering	$252,000	$313,000	$364,000
Controls	$115,000	$166,000	$196,000
Equipment Subtotal	**$1,197,000**	**$2,076,000**	**$2,455,000**
Equipment installation	$500,000	$1,093,000	$1,220,000
Civil/structural work	$370,000	$787,000	$877,000
Electrical work	$170,000	$275,000	$305,000
Direct Cost Subtotal	**$2,237,000**	**$4,231,000**	**$4,857,000**
Engineering (10% of direct cost)	$223,700	$423,100	$485,700
Contingency (8% of direct cost)	$178,960	$338,480	$388,560
Indirect Costs Subtotal	**$402,660**	**$761,580**	**$874,260**
Total Prep-Yard Cost	**$2,639,660**	**$4,992,580**	**$5,731,260**
Prep-Yard Unit Cost ($/tons/day)	**$26,397**	**$11,046**	**$8,453**

Source: Based on Antares Group, 2003.

These three plant sizes were used to develop a capital cost curve as a function of plant biomass throughput, as shown in **Figure 4-3**. Above 680 tons/day, the biomass prep-yard costs were assumed to increase as a function of a 0.85 power factor of the ratio of prep yard throughput.

Figure 4-3. Estimated Unit Prep-Yard Capital Cost As a Function of Throughput
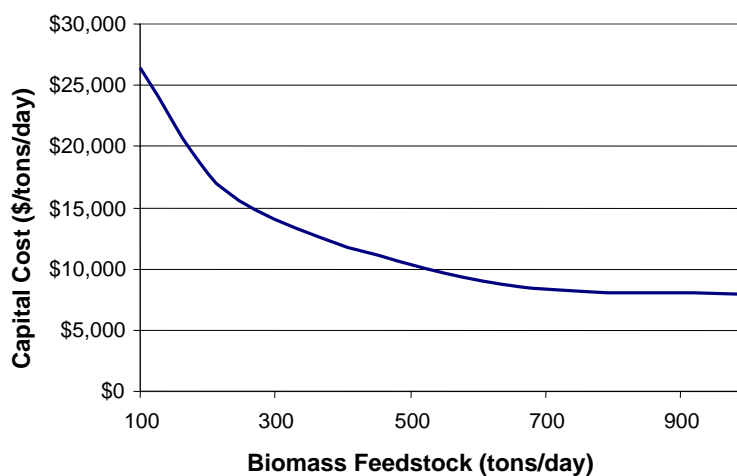
4.1.6   Labor for Operating the Prep-Yard

There are also labor costs associated with operating the receiving and processing portions of the prep-yard. The amount of labor needed for the three options is based on baseline firing rates of 100, 452, and 678 tons/day. The labor requirements are shown in **Table 4-2.** Each employee is assumed to have a loaded compensation rate of $80,000/year. Each plant requires a delivery coordinator; larger plants need an additional person for this function. The manual handling system of the 100-tons/day plant requires three people to operate the front-end loaders, including a supervisor. The automatic operation of the larger plants eliminates this requirement. For the larger plants, two operators can manage the handling and processing equipment; for the 100-tons/day plant, only one is required. Overall, the 100-tons/day plant requires five people, and the two larger automatic prep-yards require four people.

Table 4-2. Labor Requirements

	Tons/Day Fuel (as received)		
Employee Position	**100**	**450**	**680**
Delivery Coordinator	1	1	1
Assistant Coordinator		1	1
Employee Supervisor	1		
Front End Loader Operator	2		
Operators	1	2	2
Total Employees	**5**	**4**	**4**

These labor estimates contribute to the O&M cost estimates presented in Chapter 6.

4.2   Biogas Fuel Preparation

Biogas fuel is generated from the anaerobic decomposition of organic material and is typically composed of about half methane, half CO_2, and small amounts of non-methane organic compounds and

other contaminants. Like solid biomass, biogas fuel must be collected and treated for use in power generation. The following discussion reviews the preparation requirements and associated capital and operating costs for biogas fuel generated at wastewater treatment facilities, farms, and landfills.

4.2.1   Gas Collection Systems

Both wastewater treatment biogas and manure biogas are generated in anaerobic digesters. (Anaerobic digester physical descriptions vary by digester type; see Appendix C for information about different types of anaerobic digesters.) The biogas produced by the anaerobic digesters is collected from the gas space between the organic material (wastewater treatment sludge for wastewater treatment facilities and manure for farms) and the digester cover using a low-pressure blower. The biogas typically goes through a free water knockout vessel before being conveyed to the combustion device.

For LFG, collection typically begins after a portion of a landfill (called a cell) is closed. In 1996, EPA promulgated rules requiring the collection and destruction of LFG under New Source Performance Standards and Emissions Guidelines. If a landfill's non-methane organic compound emissions are greater than or equal to about 50 metric tons (megagrams) per year, the landfill rule requires the installation of a gas collection and control system. Sources must collect the LFG and destroy it at 98 percent efficiency. Two collection system configurations are generally used: vertical wells or horizontal trenches. Vertical wells are by far the most common type of well used for gas collection. Trenches might be appropriate for deeper landfills and can be used in areas of active filling. In a conventional vertical well system, vertical wells of approximately 2 to 3 feet in diameter are drilled into the waste at a typical spacing of one well per acre. Perforated polyvinyl chloride pipe approximately 6 inches in diameter is inserted into the well, and the hole is filled with gravel and capped with an impervious material. Each wellhead is connected to lateral piping, which transports the gas to a main collection header. Each wellhead is fitted with valves and a pressure tap so that the operator can monitor and adjust the gas flow from each well, as necessary. A blower is necessary to pull the gas from the collection wells into the collection header and convey the gas to the treatment system. The size, type, and number of blowers needed depend on the gas flow rate and the resistance in the collection system.

An important part of any LFG collection system is the condensate collection and treatment system. Condensate forms when warm, humid gas from the landfill cools as it travels through the collection system. If condensate is not removed, it can block the collection system and disrupt the energy recovery process. Condensate control typically begins in the field collection system, where sloping pipes and headers are used to allow drainage into collecting ("knockout") tanks or traps. These systems are typically augmented by post-collection condensate removal as well.

Another device that is part of LFG energy recovery systems is a flare. A flare is simply a device for igniting and burning the LFG. Flares are considered a component of each energy recovery option to dispose of gas during system start-up and downtime. In some cases, it might be most cost-effective to gradually increase the size of the energy recovery system and to flare excess gas between system upgrades (e.g., before adding another engine). Flare designs include open (or candlestick) flares and enclosed flares. Enclosed flares are more expensive but might be preferable (or required) because they allow for stack testing and can achieve slightly higher combustion efficiencies. In addition, enclosed flares could reduce noise and light nuisances.

4.2.2   Gas Treatment Systems

Some minimal amount of gas cleaning is required for almost any application using biogas. Both anaerobically digested wastewater treatment biogas and LFG contain methane and CO_2, but also contain contaminants including hydrogen sulfide, other sulfur compounds, and a variety of other corrosive gases

that evolve from chemical products in the waste. LFG also contains water, particulates, hazardous air pollutants, and chemicals called siloxanes, which are silica-based compounds that derive from various consumer products in the waste stream.

Wellhead natural gas contains a variety of contaminants, inert gases, moisture, and particulates. All of these are removed in processing so that pipeline natural gas is a very clean fuel with consistent combustion characteristics. Waste and byproduct biogases are similar in many ways to raw, wellhead natural gas, which creates a variety of challenges to their direct use. Specifically, the contaminants in the gas cause erosion and corrosion of generation equipment.

Some of the specific components of waste and byproduct fuels and their operational problems include:

- **Solids** can cause erosion of critical surfaces or plugging of orifices.

- **Water** retards combustion and can cause erosion, corrosion, or catastrophic damage to critical surfaces or components.

- **Non-methane fuel components** (butane, propane, carbon monoxide [CO], hydrogen) can change combustion characteristics; if present in liquid form can cause physical damage.

- **Sulfur and sulfur compounds** can cause corrosion in engines, increase maintenance requirements (more frequent overhauls and oil changes), and poison catalyst materials.

- **CO_2** reduces heating value and combustibility.

- **Siloxanes** create a glassy deposition on high-temperature surfaces; particles can break off and damage working parts.

After biogas has been collected, and before it is used in an energy project, typical treatments remove moisture that is not captured in the knockout tanks, as well as particulates and other impurities. For small systems, however, particularly at farms, gas cleanup beyond removing moisture from the initial free water knockout vessel is not typically performed due to the high cost of cleanup.

Treatment requirements depend on the end use application. Minimal treatment is required for direct use of gas in boilers and reciprocating engines. This treatment typically includes dehumidification to drop the gas dew-point below winter temperatures, particle filters to remove particulates that could damage engine components, and compression to meet the fuel pressure requirements of the energy application.

For biogas generated at landfills and wastewater treatment facilities, some reciprocating engine applications and many gas turbine applications also require siloxane removal if the level of siloxanes is high.[48] Siloxane removal is typically accomplished with adsorption beds situated after the dehumidification process. Recently, additional cleanup technologies have been introduced for the production of a high-Btu LFG, which could also be used for other types of biogas. These technologies remove CO_2, organic, and sulfur compounds using a variety of gas separation technologies, including: adsorption, absorption, chilling, and membrane separation. The separated CO_2 can be either vented to the atmosphere or cleaned and used in CO_2 applications. The sulfur is often adsorbed onto a medium that can be returned to the landfill or can be recovered for chemical sale. More information about siloxanes and siloxane removal is available through LMOP (see Appendix B).

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[48] Siloxanes are a class of compounds present in a number of consumer products. Siloxanes form hard ceramic-like deposits on combustion. These deposits can shorten the life of engines or gas turbines and also require more frequent oil changes.

4.2.3 Collection and Treatment System Capital and O&M Costs

Wastewater Treatment Biogas

As mentioned in Section 3.2.2, minimal gas treatment is required for direct use of biogas in boilers or small-scale reciprocating engines. Treatment might be required, however, in other applications. Based on analyses completed by the EPA CHP Partnership, fuel treatment costs can range from approximately $194,000 for a 300-kilowatt (kW) fuel cell CHP system ($650/kW) to approximately $369,000 for a 1-MW internal combustion engine CHP system ($370/kW).[49]

Manure Biogas

As mentioned earlier, manure biogas systems are typically too small for gas treatment to be economical.

Landfill Gas

Total collection system costs vary widely, based on a number of site-specific factors. If the landfill is deep, collection costs tend to be higher due to the fact that well depths will need to increase. Collection costs also increase with the number of wells installed.

Table 4-3 presents estimated capital and O&M costs for typical collection and treatment systems at typical landfills generating 500 cfm, 1,000 cfm, and 2,000 cfm of LFG. The capital costs for these systems include installation of the gas wells, gas collection system, emergency flare, and gas treatment system (dehydration, filtration, and compression), along with start-up costs. The annual O&M costs include all labor, materials, electricity, and administrative costs required to operate the equipment described previously. This operation includes the monthly optimization of gas collection at each wellhead.

Table 4-3. Summary of Representative Collection and Treatment Costs ($2006)

Estimated Gas Flow (cfm)	Capital Costs	Annual O&M Costs
500	$1.2 million	$0.23 million
1,000	$2.1 million	$0.45 million
2,000	$4.1 million	$0.90 million

Source: EPA, n.d.

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[49] EPA, 2007a.

5. Biomass Conversion Technologies

In the context of this document, biomass conversion refers to the process of converting biomass into energy that will in turn be used to generate electricity and/or heat. The principal categories of biomass conversion technologies for power and heat production are ***direct-fired*** and ***gasification*** systems. Within the direct-fired category, specific technologies include stoker boilers, fluidized bed boilers, and cofiring. Within the gasification category, specific technologies include fixed bed gasifiers and fluidized bed gasifiers. Anaerobic digesters are also considered a biomass conversion technology; however, extensive information about digesters is readily available from EPA's AgSTAR Program <www.epa.gov/agstar> and therefore, will not be discussed within this chapter.

Biomass power systems are typically below 50 MW in size, compared to coal-fired plants, which are in the 100- to 1,000-MW range. Most of today's biomass power plants are ***direct-fired systems.*** The biomass fuel is burned in a boiler to produce high-pressure steam that is used to power a steam turbine-driven power generator. In many applications, steam is extracted from the turbine at medium pressures and temperatures and is used for process heat, space heating, or space cooling. ***Cofiring*** involves substituting biomass for a portion of the coal in an existing power plant boiler. It is the most economic near-term option for introducing new biomass power generation. Because much of the existing power plant equipment can be used without major modifications, cofiring is far less expensive than building a new biomass power plant. Compared to the coal it replaces, biomass reduces SO_2, NO_X, CO_2, and other air emissions.

Biomass ***gasification*** systems operate by heating biomass in an environment where the solid biomass breaks down to form a flammable gas. The gas produced—synthesis gas, or syngas—can be cleaned, filtered, and then burned in a gas turbine in simple or combined-cycle mode, comparable to LFG or biogas produced from an anaerobic digester. In smaller systems, the syngas can be fired in reciprocating engines, microturbines, Stirling engines, or fuel cells. Gasification technologies using biomass byproducts are popular in the pulp and paper industry where they improve chemical recovery and generate process steam and electricity at higher efficiencies and with lower capital costs than conventional technologies. Pulp and paper industry byproducts that can be gasified include hogged wood, bark, and spent black liquor.

Table 5-1 provides a summary of biomass conversion technologies for producing heat and power.

Table 5-1. Summary of Biomass CHP Conversion Technologies

Biomass Conversion Technology	Common Fuel Types	Feed Size	Moisture Content	Capacity Range
Stoker grate, underfire stoker boilers	Sawdust, bark, chips, hog fuel, shavings, end cuts, sander dust	0.25–2 in.	10–50%	4 to 300 MW (many in the 20 to 50 MW range)
Fluidized bed boiler	Wood residue, peat, wide variety of fuels	< 2 in.	< 60%	Up to 300 MW (many in the 20 to 25 MW range)
Cofiring—pulverized coal boilers	Sawdust, bark, shavings, sander dust	< 0.25 in.	< 25%	Up to 1000 MW
Cofiring—stoker, fluidized bed boilers	Sawdust, bark, shavings, hog fuel	< 2 in.	10–50%	Up to 300 MW
Fixed bed gasifier	Chipped wood or hog fuel, rice hulls, shells, sewage sludge	0.25–4 in.	< 20%	Up to 50 MW
Fluidized bed gasifier	Most wood and agriculture residues	0.25–2 in.	15–30%	Up to 25 MW

Source: Based on Wright, 2006.

Modular systems employ some of the same technologies mentioned above, but on a smaller scale that is more applicable to farms, institutional buildings, and small industry. A number of modular systems are now under development and could be most useful in remote areas where biomass is abundant and electricity is scarce.

5.1   Direct-Fired Systems

The most common utilization of solid fuel biomass is direct combustion with the resulting hot flue gases producing steam in a boiler—a technology that goes back to the 19th century. Boilers today burn a variety of fuels and continue to play a major role in industrial process heating, commercial and institutional heating, and electricity generation. Boilers are differentiated by their configuration, size, and the quality of the steam or hot water produced. Boiler size is most often measured by the fuel input in MMBtu per hour (MMBtu/hr), but it may also be measured by output in pounds of steam per hour. Because large boilers are often used to generate electricity, it can also be useful to relate boiler size to power output in electric generating applications. Using typical boiler and steam turbine generating efficiencies, 100 MMBtu/hr heat input provides about 10 MW electric output.

The two most commonly used types of boilers for biomass firing are stoker boilers and fluidized bed boilers. Either of these can be fueled entirely by biomass fuel or cofired with a combination of biomass and coal. The efficiency, availability, operating issues, equipment and installed costs, O&M requirements and costs, and commercial status of each of these options are discussed below.

5.1.1   Boilers

Characterization

Stoker Boilers

Stoker boilers employ direct fire combustion of solid fuels with excess air, producing hot flue gases, which then produce steam in the heat exchange section of the boiler. The steam is used directly for heating purposes or passed through a steam turbine generator to produce electric power. Stoker-fired boilers were first introduced in the 1920s for coal; in the late 1940s the Detroit Stoker Company installed the first traveling grate spreader stoker boiler for wood. Mechanical stokers are the traditional technology that has been used to automatically supply solid fuels to a boiler. All stokers are designed to feed fuel onto a grate where it burns with air passing up through it. The stoker is located within the furnace section of the boiler and is designed to remove the ash residue after combustion. Stoker units use mechanical means to shift and add fuel to the fire that burns on and above the grate located near the base of the boiler. Heat is transferred from the fire and combustion gases to water tubes on the walls of the boiler.

Modern mechanical stokers consist of four elements, 1) a fuel admission system, 2) a stationary or moving grate assembly that supports the burning fuel and provides a pathway for the primary combustion air, 3) an overfire air system that supplies additional air to complete combustion and minimize atmospheric emissions, and 4) an ash discharge system. **Figure 5-1** illustrates the different sections of a stoker boiler.

A successful stoker installation requires selecting the correct size and type of stoker for the fuel being used and for the load conditions and capacity being served. Stoker boilers are typically described by their method of adding and distributing fuel. There are two general types of systems—*underfeed* and *overfeed*. Underfeed stokers supply both the fuel and air from under the grate, while overfeed stokers supply fuel from above the grate and air from below. Overfeed stokers are further divided into two types—*mass feed* and *spreader*. In the mass feed stoker, fuel is continuously fed onto one end of the grate

surface and travels horizontally across the grate as it burns. The residual ash is discharged from the opposite end. Combustion air is introduced from below the grate and moves up through the burning bed of fuel. In the spreader stoker, the most common type of stoker boiler, combustion air is again introduced primarily from below the grate but the fuel is thrown or spread uniformly across the grate area. The finer particles of fuel combust in suspension as they fall against the upward moving air. The remaining heavier pieces fall and burn on the grate surface, with any residual ash removed from the discharge end of the grate. Chain grate, traveling grate, and water-cooled vibrating grate stokers are other less common configurations that use various means to maintain an even, thin bed of burning fuel on the grate. Other specialized stoker boilers include balanced draft, cyclone-fired, fixed bed, shaker hearth, tangential-fired, and wall-fired. Practical considerations limit stoker size and, consequently, the maximum steam generation rates. For coal firing, this maximum is about 350,000 pounds per hour (lb/hr); for wood or other biomass firing it is about 700,000 lb/hr.

Figure 5-1. Cut-Away View of a Traveling Grate Stoker Boiler
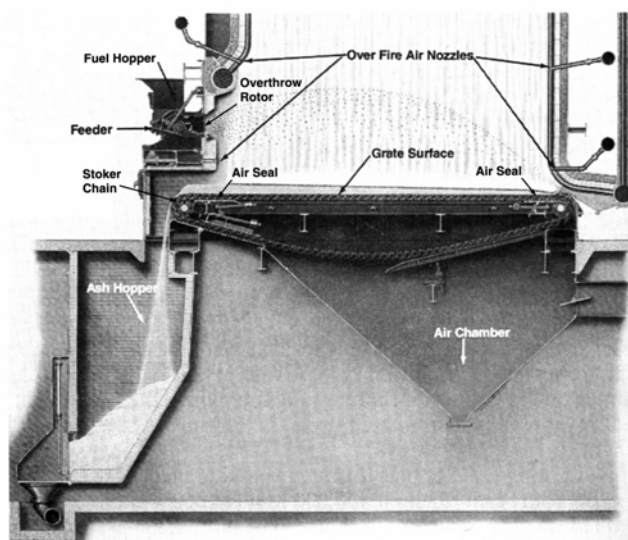
Source: ORNL, 2002.

Underfeed Stokers

Underfeed stokers supply both fuel and primary combustion air from beneath the grate so that the top of the fuel pile is not cooled by cold and moist fuel or cold air. The fuel is moved into a hopper and onto the grate by either a screw- or ram-driven mechanism. Underfeed stokers push the fuel into the bottom of the bed of fuel while heat causes volatilization and complete combustion of the fuel by the time it rises to the top of the bed as ash and is discharged. As the fuel moves out over the grate where it is exposed to air and radiant heat, it begins to burn and transfer heat to the water tubes. As with any combustion process, ash accumulates as the fuel, is burned. The two basic types of underfeed stokers are: 1) the horizontal-feed, side-ash discharge type and 2) the gravity-feed, rear-ash discharge type. A cross-section of an underfeed, side-ash discharge stoker is shown in **Figure 5-2**. The demand for underfeed stokers has diminished due to cost and environmental considerations. Underfeed stokers are best suited for relatively dry fuel (under 40 to 45 percent moisture.)

Figure 5-2. Cross Section of Underfeed, Side-Ash Discharge Stoker
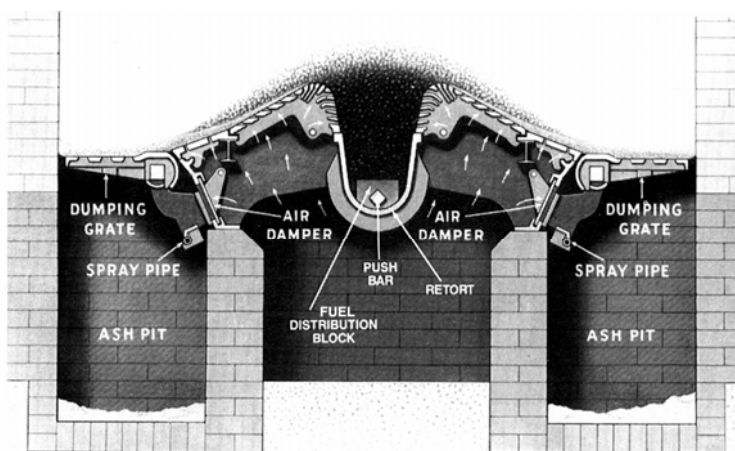
Source: ORNL, 2002.

Overfeed Stokers

Overfeed stokers are generally classified by the way the fuel is distributed and burned within the boiler. The primary designations are mass-feed or spreader stokers. Mass-feed stokers introduce fuel continuously at one end of a grate. As the fuel moves into the boiler, it falls onto the grate by gravity. To control the amount of fuel that enters the boiler, a gate can be moved up or down, or the speed at which the fuel moves beneath the gate can be adjusted. Inside the boiler, the fuel burns as it travels along the grate. Primary combustion air flows upward from beneath the grate and through the burning bed of fuel, allowing for complete combustion. Any ash that remains on the grate is then discharged at the opposite end of the system. The two primary mass-feed stokers are 1) water-cooled vibrating grate and 2) moving (chain and traveling) grate stokers. A cross-section of an overfeed, water-cooled vibrating grate mass-fed stoker is presented in **Figure 5-3.**

Figure 5-3. Cross Section of Overfeed, Water-Cooled, Vibrating-Grate, Mass-Feed Stoker
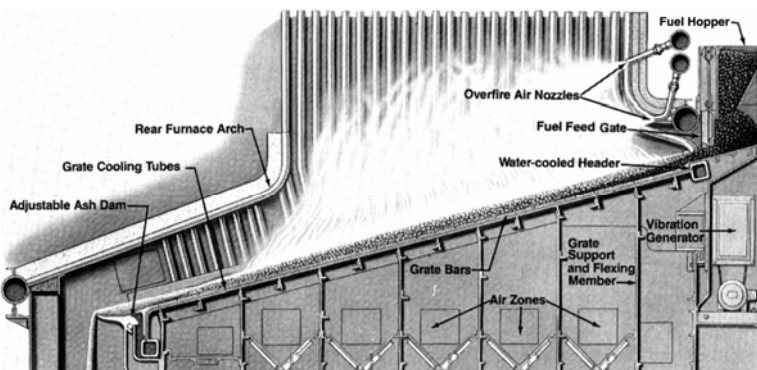
Source: ORNL, 2002.

Spreader Stokers

Spreader stokers are the most commonly used stokers because of their versatility. They are capable of distributing fuel evenly and to a uniform depth over the entire grate surface by using a device that propels the individual fuel particles into the air above the grate. Methods used to propel the fuel particles include air injection and underthrow and overthrow rotors. As the fuel is thrown into the boiler, fine particles ignite and burn while suspended in the combustion air. Due to suspension burning, response times of spreader stokers are better than for mass feed or underfeed stokers. The coarser particles that fall onto the grate end up burning in a thin bed of fuel on the grate. Primary combustion air is supplied from beneath the grate. Because the fuel is evenly distributed across the active grate area, the combustion air is uniformly distributed under and through the grate. A portion of the total combustion air is admitted through ports above the grate as overfire air, completing the combustion process. Grates for spreader stokers are generally designed to move rather than remain stationary. Therefore, traveling grates, air-cooled vibrating grates, and water-cooled vibrating grates are designs that have been used effectively. Modern boilers with spreader stokers incorporate:

- Equipment that distributes fuel uniformly over the grate.

- Specially designed air-metering grates.

- Dust collection and reinjection equipment.

- Forced draft fans for both undergrate and overfire air.

- Combustion controls to coordinate fuel and air supply with steam demand.[50]

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[50] ORNL, 2002.

Along with the fuel feed system and furnace section geometry, air system design plays an important role in efficient and complete combustion of biomass fuels in stoker boilers. Excess air for bark, wood, and most biomass fuels is set at 25 percent or above for stoker firing. Because biomass fuels are typically highly volatile on a dry basis, are heterogeneous in size, and more often burn in suspension compared to coal, biomass combustion air systems are designed to provide more overfire air than those used for coal. Modern designs use undergrate and overfire quantities of 40 and 60 percent, respectively.

Fluidized Bed Boilers

Fluidized bed boilers are the most recent type of boiler developed for solid fuel combustion. The primary driving force for development of fluidized bed combustion is reduced SO_2 and NO_x emissions from coal combustion. As the technology developed, it became apparent that the process could efficiently burn biomass and other low-grade fuels that are difficult or impractical to burn with conventional methods.

In this method of combustion, fuel is burned in a bed of hot inert, or incombustible, particles suspended by an upward flow of combustion air that is injected from the bottom of the combustor to keep the bed in a floating or "fluidized" state. The scrubbing action of the bed material on the fuel enhances the combustion process by stripping away the CO_2 and solids residue (char) that normally forms around the fuel particles. This process allows oxygen to reach the combustible material more readily and increases the rate and efficiency of the combustion process. One advantage of mixing in the fluidized bed is that it allows a more compact design than in conventional water tube boiler designs. Natural gas or fuel oil can also be used as a start-up fuel to preheat the fluidized bed or as an auxiliary fuel when additional heat is required. The effective mixing of the bed makes fluidized bed boilers well-suited to burn solid refuse, wood waste, waste coals, and other non-standard fuels. **Figure 5-4** shows the components of a fluidized bed combustion boiler.

Figure 5-4. Cut-Away View of a Fluidized Bed Combustion Boiler
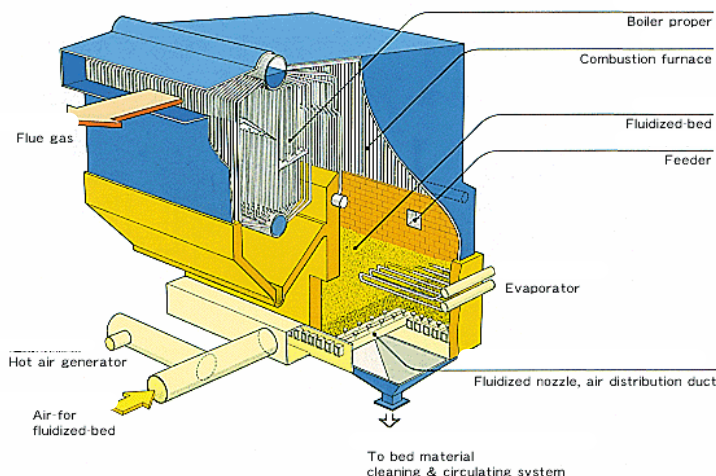
Source: Babcock & Wilcox, 2005.

The fluidized bed combustion process provides a means for efficiently mixing fuel with air for combustion. When fuel is introduced to the bed, it is quickly heated above its ignition temperature, ignites, and becomes part of the burning mass. The flow of air and fuel to the dense bed is controlled so that the desired amount of heat is released to the furnace section on a continuous basis. Typically, biomass is burned with 20 percent or higher excess air. Only a small fraction of the bed is combustible material; the remainder is comprised of inert material, such as sand. This inert material provides a large inventory of heat in the furnace section, dampening the effect of brief fluctuations in fuel supply or heating value on boiler steam output.

Fuels that contain a high concentration of ash, sulfur, and nitrogen can be burned efficiently in fluidized bed boilers while meeting stringent emission limitations. Due to long residence time and high intensity of mass transfer, fuel can be efficiently burned in a fluidized bed combustor at temperatures

considerably lower than in conventional combustion processes (1,400 to 1,600° F compared to 2,200° F for a spreader stoker boiler). The lower temperatures produce less NO_x, a significant benefit with high nitrogen-content wood and biomass fuels. SO_2 emissions from wood waste and biomass are generally insignificant, but where sulfur contamination of the fuel is an issue, limestone can be added to the fluid bed to achieve a high degree of sulfur capture. Fuels that are typically contaminated with sulfur include construction debris and some paper mill sludges.

Fluidized bed boilers are categorized as either atmospheric or pressurized units. Atmospheric fluidized bed boilers are further divided into bubbling-bed and circulating-bed units; the fundamental difference between bubbling-bed and circulating-bed boilers is the fluidization velocity (higher for circulating). Circulating fluidized bed boilers separate and capture fuel solids entrained in the high-velocity exhaust gas and return them to the bed for complete combustion. Atmospheric-pressure bubbling fluidized bed boilers are most commonly used with biomass fuels. The type of fluid bed selected is a function of the as-specified heating value of the biomass fuel. Bubbling bed technology is generally selected for fuels with lower heating values. The circulating bed is most suitable for fuels of higher heating values.

In a pressurized fluidized bed boiler, the entire fluidized bed combustor is encased inside a large pressure vessel. Burning solid fuels in a pressurized fluidized bed boiler produces a high-pressure stream of combustion gases. After the combustion gases pass through a hot gas cleanup system, they are fed into a gas turbine to make electricity, and the heat in the hot exhaust gas stream can be recovered to boil water for a steam turbine. Therefore, a pressurized fluidized bed boiler is more efficient, but also more complicated and expensive. Capital costs of pressurized fluidized bed combustion technology are higher than atmospheric fluidized beds.

Efficiency

Boiler efficiency is defined as the percentage of the fuel energy that is converted to steam energy. Major efficiency factors in biomass combustion are moisture content of the fuel, excess air introduced into the boiler, and the percentage of uncombusted or partially combusted fuel. According to the Council of Industrial Boiler Owners (CIBO), the general efficiency range of stoker and fluidized bed boilers is between 65 and 85 percent efficient.[51] Fuel type and availability have a major effect on efficiency because fuels with high heating values and low moisture content can yield efficiencies up to 25 percent higher than fuels having low heating values and high-moisture contents.

Biomass boilers are typically run with a considerable amount of excess air so that they can achieve complete combustion, but this has a negative impact on efficiency. A CIBO rule of thumb indicates that boiler efficiency can be increased 1 percent for each 15 percent reduction in excess air.[52]

Table 5-2 compares the efficiency of a biomass stoker and a fluidized bed boiler that are operated with 50 percent excess air with a final flue gas exit temperature of 350° F. The efficiencies are estimated based on the heat-loss method, which is a way of determining boiler efficiency by measuring the individual heat losses (expressed as a percent of heat input) and subtracting them from 100 percent. As can be seen in the table, the largest energy loss in a boiler is the heat that leaves the stack. This loss could amount to as much as 30 to 35 percent of the fuel input in older, poorly maintained boilers. The table shows that decreasing fuel moisture content from 30 to 0 percent increases thermal efficiency by about 6 percentage points. This estimate assumes that the air-fuel ratio is maintained by adjusting air input based on the input moisture content. If the quantity of air is not reduced when wetter fuel enters the boiler then efficiency will drop even more as fuel moisture is increased.

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[51] Council of Industrial Boiler Owners, 1997.
[52] ORNL, 2002.

The primary difference in efficiency between a stoker boiler and a fluidized bed boiler is the amount of fuel that remains unburned. As shown in **Table 5-2**, the efficiency of fluidized bed boilers compares favorably with stoker boilers due to lower combustion losses. Stoker boilers can have 30 to 40 percent carbon in the ash and additional volatiles and CO in the flue gases, while fluidized bed boiler systems typically achieve nearly 100 percent fuel combustion. The turbulence in the combustor combined with the thermal inertia of the bed material provide for complete, controlled, and uniform combustion. These factors are key to maximizing the thermal efficiency, minimizing char, and controlling emissions.

Table 5-2. Biomass Boiler Efficiency as a Function of Input Fuel and Combustion Characteristics

Characteristics	Biomass Stoker		Biomass Fluidized Bed	
	Dry	**As Received**	**Dry**	**As Received**
Excess air (%)	50	50	50	50
Dry flue gas (lb/lb fuel)	15.25	10.675	15.25	10.675
Final exhaust temp (°F)	350	350	350	350
High heating value (HHV) of the fuel (Btu/lb)	8,500	5,950	8,500	5,950
Moisture content of fuel (%)	0	30	0	30
Hydrogen percent in the fuel (%)	4.59	3.21	4.59	3.21
Efficiency Losses				
Dry flue gas losses (%)	11.63	11.63	11.63	11.63
Moisture in fuel (%)	0.00	5.90	0.00	5.90
Latent heat (%)	5.69	5.69	5.69	5.69
Unburned fuel (%) (1)	3.50	3.50	0.25	0.25
Radiation and miscellaneous (%) (2)	2.03	2.03	2.03	2.03
Total Combustion Losses (%)	**22.85**	**28.74**	**19.60**	**25.49**
Boiler Efficiency HHV Basis (%)	**77.15**	**71.26**	**80.40**	**74.51**

(1) Estimated
(2) Includes radiation, moisture in air, and other miscellaneous issues.

When considering factors that influence boiler performance, it should be noted that efficiency is not constant throughout the entire operating range of a boiler. Peak efficiency generally occurs at a particular boiler output that is determined by design characteristics. Whenever boiler operations deviate from this output, the resulting performance is usually below peak efficiency. Operating continuously at peak efficiency is not practical due to seasonal demands, load variations and fuel property variations; however, operating at a steady load and avoiding cyclic or on-off operation can improve efficiency.

Operating Availability[53]

Typically, both stoker and fluidized boilers are designed for continuous operation, and design performance is in the 90+ percent availability range. Seasonal variability in fuel availability and/or quality can affect the plant availability, but this is a feedstock issue, not an issue of boiler performance. A well

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[53] The availability of a power generation system is the percentage of time that the system can operate, or is "available" to operate. Both planned maintenance and unplanned outages have a negative effect upon system availability. Therefore an availability of 100% would represent a system that never broke down or needed maintenance (impossible to achieve in real operation).

designed biomass steam system has a reasonable expectation of operating in the 92 to 98 percent availability range.[54]

Operating Advantages and Disadvantages

Stoker and fluidized bed boilers have specific operating advantages and disadvantages with biomass fuels depending on the fuel characteristics and site requirements. Biomass fuels are extremely variable in terms of heating value, moisture content, and other factors that affect combustion. Wood and most other biomass fuels are composed primarily of cellulose and moisture. As discussed previously, the high proportion of moisture is significant because it acts as a heat sink during the combustion process. The latent heat of evaporation depresses flame temperature, taking heat energy away from steam production, and contributing to the difficulty of efficiently burning biomass fuels. Cellulose, in addition to containing the chemical energy released in combustion, contains fuel-bound oxygen. This oxygen decreases the theoretical air requirements for combustion and, accordingly, the amount of nitrogen included in the products of combustion. A few general guidelines for direct firing of wood and biomass in boilers include:

- Maintain stable combustion, which can be achieved in most water-cooled boilers with fuel moisture contents as high as 65 percent by weight, as received.

- Use of preheated combustion air reduces the time required for fuel drying prior to ignition and is essential to spreader stoker combustion systems. Design air temperatures will vary directly with moisture content.

- A high proportion of the combustible content of wood and other biomass fuels burns in the form of volatile compounds. A large proportion of the combustion air requirement, therefore, is added above the fuel in stoker and other conventional combustion boilers as overfire air.

- Solid chars produced in the initial stages of combustion of biomass fuels are of very low density. Conservative selection of furnace section size is used to reduce gas velocity and keep char entrainment into the flue gases and possibly out the stack at acceptable levels.

To ensure smooth fuel feeding, biomass fuels have to be carefully sized and processed. As discussed above, the moisture content of wood and other biomass waste can vary over a wide range, from 10 percent to more than 60 percent. To ensure steady heat input into the boiler using volumetric feeders, efficient homogenization of fuel with different moisture contents at the fuel yard is a necessity.

Biomass-based fuels can increase the risk of slagging and fouling of heat transfer surfaces and, in some cases, the risk of fireside corrosion as well. Potassium ash content is relatively high in fresh wood, green particles, and fast-growing biomass, which causes the ash to melt at low temperatures and leads to a tendency for fouling and slagging. Additionally, biomass fuels can contain chlorine, which, together with alkalis, can induce aggressive corrosion.

Table 5-3 provides a comparison of combustion characteristics and fuel issues for stoker and fluidized bed boilers. Stoker boilers have been around for a long time and are a relatively basic technology, whereas fluidized bed technology is newer and more complex, but offers more flexibility and operating control. Fluidized bed systems offer significant operating flexibility because they can operate under a wide range of load conditions. The thermal inertia of the bed material allows it to withstand changes in moisture and heating content of the fuel without negative impacts. Additionally, the low fuel

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[54] Energy Products of Idaho, a company that provides fluidized bed boilers, has reported operating availabilities of 98 percent for their units, <www.energyproducts.com/fluidized_bed_combustors.htm>.

inventory present in the unit makes it responsive to variable loads. Another advantage is that the fluidized bed can also maintain efficiency during system turn-down. Fluidized bed manufacturers have reported that the operating flexibility of their units has allowed their customers to take advantage of utility incentive programs for generation that follows electric demand.[55]

Table 5-3. Comparison of Stoker and Fluidized Bed Boilers

Feature	Boiler Type	
	Stoker	**Fluidized Bed**
Combustion Mechanism		
Flow of solid fuel	Transported on stoker	Fluidized by combustion air and circulated through the combustion chamber and cyclone
Combustion zone	On the stoker	Entire area of the combustion furnace
Mass transfer	Slow	Active vertical movement-mass and heat transfer
Combustion Control		
Responsiveness	Slow response	Quick response
Excess air control	Difficult	Possible
Fuel Issues		
Applicability to various fuels	Fair	High
Fuel pretreatment	Generally not necessary	Lumps must be crushed
Environmental Factors		
Low sulfur oxide (SO_x) combustion	In-furnace desulfurization not possible	High rate of in-furnace desulfurization
Low NO_x combustion	Difficult	Inherently low NO_x
Appropriate facility size	Small	Medium to large

Equipment and Installed Costs

A biomass boiler system is a complex installation with many interrelated subsystems. An integrated steam system will include the fuel prep-yard and handling equipment, the boiler itself, induced and forced air fans, controls, and water treatment systems. Varying levels of emission control equipment will normally be needed as well. Most installations will include cyclone separators to capture large fly ash, a baghouse for fine particulate matter (PM), and a dry scrubber system. NO_x emissions control in stoker boilers is provided by a selective non-catalytic reduction system using urea or ammonia that is installed in the top of the boiler. Other control equipment includes acid gas removal system, stack, ash handling, and continuous emissions monitoring equipment if required.

Table 5-4 provides total capital cost estimates (equipment and installation) for both stoker and circulating fluidized bed steam systems for three biomass fuel feed rates: 100 tons/day, 600 tons/day and 900 tons/day. These feed rates are comparable to steam systems producing 20,000; 150,000 to 185,000; and 250,000 to 275,000 lb/hr of steam, respectively, depending on steam temperature and pressure. Installed costs can vary significantly depending on the scope of the equipment included, output steam conditions, geographical area, competitive market conditions, site requirements, emission control requirements, and prevailing labor rates. The estimates presented in the table are budgetary estimates based on published data and discussions with equipment suppliers and developers. The estimates are

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[55] Energy Product of Idaho, n.d.

based on steam conditions that might be typical for a process heating-only application in the small 100 tons/day biomass unit (250 pounds per square inch gauge [psig] saturated steam), and higher steam pressures (750 psig) for a steam turbine CHP configuration in the larger units. The range of expected cost variations can be as high as +/- 35 percent depending on the site and system variables listed above. Steam conditions also have a significant impact on boiler cost; higher temperatures and pressures require thicker tubes and more expensive materials (see **Table 5-5**).

Table 5-4. Estimated Installed Capital Costs for a Biomass-Fueled Steam Plant

	Biomass Fuel Feed (tons/day)		
Characteristics	**100**	**600**	**900**
Biomass heat input (MMBtu/hr)	35.4	297.5	446.3
Steam pressure (psig)	275	750	750
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
Stoker boiler equipment cost	$1,195,000	$7,980,000	$10,790,000
Other equipment and installation	$795,000	$10,020,000	$12,460,000
Total Installed Boiler System Cost	$1,990,000	$18,000,000	$23,250,000
Total Installed Biomass Prep-Yard*	$2,640,000	$5,430,000	$7,110,000
Total Installed Steam Plant Cost	**$4,630,000**	**$23,430,000**	**$30,360,000**
Unit Cost ($/lb steam)	$232	$142	$121
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
Fluidized bed boiler equipment cost	$6,175,000	$14,490,000	$19,790,000
Other equipment and installation	$795,000	$10,020,000	$12,460,000
Total Installed Boiler System Cost	$6,970,000	$24,510,000	$32,250,000
Total Installed Biomass Prep-Yard*	$2,640,000	$5,430,000	$7,110,000
Total Installed Steam Plant Cost	**$9,610,000**	**$29,940,000**	**$39,360,000**
Unit Cost ($/lb steam)	$480	$171	$151

*Prep-Yard costs are estimated based on the capital cost curve developed in section 4.1.5
Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

As shown in **Table 5-4**, the prep-yard and fuel handling system represents a significant portion of the total steam system costs, ranging from 15 to 25 percent of the total steam system costs for the larger sized units and 25 to 50 percent of the total cost of the 100 tons/day steam system. Fluidized bed boiler equipment costs are higher than the simpler stoker technology; the fluidized bed boiler itself is more than three times as expensive as a stoker boiler in the smallest size shown; in the larger sizes, the fluidized bed boiler is 35 to 40 percent more expensive. The unit capital costs ($/lb steam) for a biomass-fueled steam plant, including the prep-yard costs, are 20 to 25 percent more expensive for the larger fluidized bed systems. A portion of the higher capital cost is offset by the higher output due to higher efficiency.

The cost of the boiler is also a function of the steam output conditions as shown in **Table 5-5.** Generating higher pressure and temperature steam requires special and more expensive alloys and thicker water tubes. Boilers producing very high pressure steam can be more than twice as expensive as boilers generating low pressure steam.

Table 5-5. Effect of Steam Output Conditions on Boiler Capital Costs

Steam Conditions	Boiler Cost Factor
150–250 psig	1.0
600–750 psig	1.15–1.25
1,250–1,500 psig	1.5–2.0

Source: Matches, 2003.

O&M Costs

Estimated non-fuel O&M costs for stoker and fluidized bed boiler systems are provided in **Table 5-6** for the three steam system sizes, based on published data and discussion with manufacturers. The O&M costs are evaluated within the context of an integrated plant. Total O&M costs include the labor for the prep-yard, and labor, materials, and parts for the boiler system itself. Boiler system O&M estimates were based on an annual non-labor component for spare parts and maintenance equipment assumed to be 2 percent of boiler capital costs. Variable costs for chemicals, water, and electricity needed to run blowers and auxiliary equipment were assumed to be approximately $0.20 to $0.25 per thousand pounds of steam output.

Table 5-6. Annual O&M Costs for a Biomass-Fueled Steam Plant

	Biomass Fuel Feed (tons/day)		
Characteristics	**100**	**600**	**900**
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
Prep-yard labor	$400,000	$320,000	$320,000
Boiler section O&M	$160,000	$1,095,000	$1,110,000
Total Annual O&M	**$560,000**	**$1,415,000**	**$1,430,000**
Total Annual O&M ($/1,000 lb Steam)*	**$3.55**	**$1.09**	**$0.73**
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
Prep-yard labor	$400,000	$320,000	$320,000
Boiler section O&M	$260,000	$1,190,000	$1,205,000
Total Annual O&M	**$660,000**	**$1,510,000**	**$1,525,000**
Total Annual O&M, ($/1,000 lb Steam)*	**$4.19**	**$1.09**	**$0.74**

*Based on 90 to 95 percent steam system capacity factor.
Source: Based on data from Antares Group, Inc., 2003; discussions with developers.

As shown in **Table 5-6**, the two boiler types are assumed to have the identical prep-yard labor requirement for the same output. The 100 tons/day plant uses a less automated system, so the labor requirement is higher than for the larger plants using an automated prep-yard. On a unit cost basis, O&M costs are higher for the fluidized bed boiler in the 100 tons/day size, but equal to the stoker boiler O&M costs for the two larger sizes.

Commercialization Status

Stoker boilers have long been a standard technology for biomass as well as coal, and are offered

by a number of manufacturers. Fluidized bed boilers are a more recent technology, but are also commercially available through a number of manufacturers. Until recently, however, fluidized bed boiler use has been more widespread in Europe than the United States, and many of the suppliers are European-based.

As shown in **Table 5-6,** when evaluated within the context of an integrated plant on a unit cost basis, O&M costs are higher for a smaller circulating fluidized bed processing 100 tons/day, but lower than the stoker boiler for the two larger sizes evaluated in this study.

Overall Cost and Performance Characteristics

A summary of the cost and performance of typical biomass steam systems is shown in **Table 5-7**.

Table 5-7. Summary of Biomass Combustion Boiler System Cost and Performance

	Biomass Fuel Feed (tons/day)		
System	**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
Stoker Boiler Integrated Steam Plant			
Steam output (lb/hr)	20,000	165,000	250,000
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 input to steam (MMBtu/hr)	22.5	212.0	318.0
Capacity factor (%)	95	95	95
Cost Factors			
Total installed boiler costs	$1,990,000	$18,000,000	$23,250,000
Total installed steam system costs	$4,630,000	$23,430,000	$30,360,000
Unit capital cost ($/lb steam)	$232	$142	$121
Non-fuel O&M cost ($/1,000 lb steam)	$3.55	$1.09	$0.73
Fluidized Bed Integrated Steam Plant			
Steam output (lb/hr)	20,000	175,000	260,000
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 input to steam (MMBtu/hr)	23.6	221.7	332.5
Capacity factor (%)	95	95	95
Cost Factors			
Total installed boiler costs	$6,970,000	$24,510,000	$32,250,000
Total installed steam system costs	$9,610,000	$29,940,000	$39,360,000
Unit capital cost ($/lb steam)	$480	$171	$151
Non-fuel O&M cost ($/1,000 lb steam)	$4.19	$1.09	$0.74

Source: NREL, 2003.

5.1.2   Cofiring

One of the most cost effective and easily implemented biomass energy technologies is cofiring with coal in existing coal-fired boilers. Cofiring refers to the practice of mixing biomass with a fossil fuel in high-efficiency boilers as a supplementary energy source. In biomass cofiring, biomass can substitute for up to 20 percent of the coal used in the boiler. Cofiring is typically used when either the supply of biomass is intermittent or when the moisture content of the biomass is high. At large plants, biomass is cofired with coal, and more coal is typically used than biomass. At small plants, biomass is cofired with natural gas, and more biomass is typically used than natural gas because the natural gas is used to stabilize combustion when biomass with high-moisture content is fed into the boiler.

Characterization

Figure 5-5 shows a process diagram for a standard coal-based cofiring plant. Biomass has been cofired with coal economically in commercial plants, which is principally viewed as a fuel cost reduction strategy. In certain situations, cofiring has provided opportunities for utilities to get fuel from wood manufacturing and other businesses at zero or negative cost. Overall production cost savings can also be achieved by replacing coal with inexpensive biomass fuel sources such as wood waste and waste paper. Typically, biomass fuel supplies should cost at least 20 percent less, on a thermal basis, than coal supplies before a cofiring project can be economically attractive.

Figure 5-5. Biomass Cofiring in Coal Power Plant
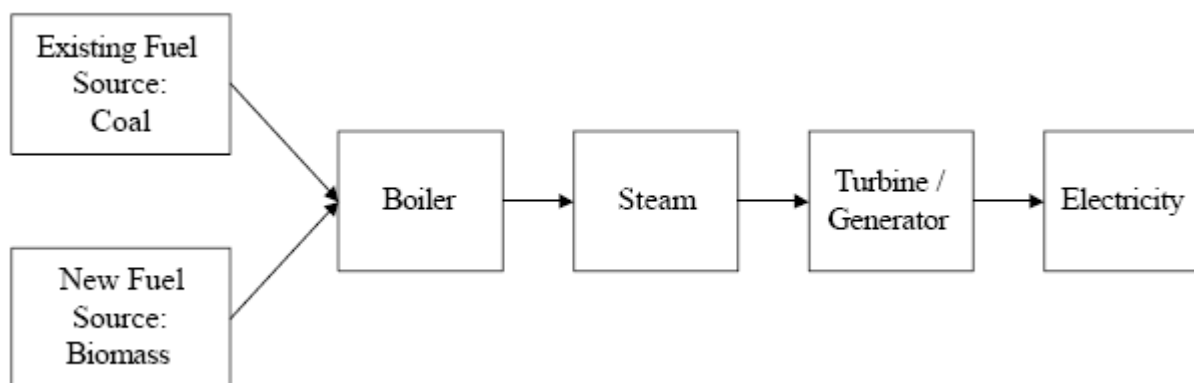
Source: Antares Group, Inc., 2003.

Biomass cofiring is mainly a retrofit application. A basic principle of cofiring is that significant changes to the boiler are not required beyond some minor burner modifications or additions necessary to introduce and burn the supplemental fuel. To meet this objective, cofiring biomass fuels is usually done on a limited basis, with the amount of biomass ranging from 5 to 15 percent of the total heat input to the boiler.[56] Biomass fuels that have been successfully cofired include wood and pelletized waste paper. Interest is growing in cofiring biomass among electric utilities and other users of coal boilers, chiefly due to the need to improve air emissions from coal-burning facilities, as well as to diversify fuel supplies.

Table 5-8 gives a sense of the size of typical utility cofiring power plants, the percentage of biomass fuel used (generally about 10 percent, but up to 50 percent), and the types of biomass feedstock used (wood, wood waste, wood residues, and sawdust).

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[56] Fehrs and Donovan, 1999.

Table 5-8. Utility Cofiring Biomass With Coal (Continuous Operation)

Plant Name	Location	Biomass Feedstock	Total Plant (MW)	Biomass (MW)	Boiler Type
6th Street—Alliant Energy	Cedar Rapids, IA	Agricultural and wood waste	85	6.5	Fluidized bed
Bay Front—Northern States	Ashland, WI	Wood residues	34	5.0	Stoker
Colbert—Tennessee Valley Authority	Tuscumbia, AL	Wood residues	190	3.0	Pulverized coal
Greenridge—AES Corporation	Dresden, NY	Wood residues	108	10.0	Pulverized coal
King—Northern States Power	Bayport, MN	Sawdust	560	10.0	Cyclone
Tacoma Steam Plant #2	Tacoma, WA	Wood	25	12.5	Fluidized bed
Willow Island—Allegheny Energy	Pleasants, WV	Sawdust, tire-derived fuel	188	2.3	Cyclone
Yates—Southern Co./Georgia Power	Newnan, GA	Wood residues	150	2.0	Pulverized coal

Source: Antares Group, 2003

Efficiency

Usually, no major changes in boiler efficiency result from cofiring. However, some design and operational changes might be needed to maximize boiler efficiency while maintaining acceptable opacity, baghouse performance, and other operating requirements. Without these adjustments, boiler efficiency and performance can decrease. For example, at a biomass heat input level of 10 percent, boiler efficiency losses of 2 percent were measured during cofiring tests at a facility with a pulverized coal boiler when no adjustments were made.[57] Numerous cofiring projects have demonstrated that efficiency and performance losses can be minimized with proper awareness of operational issues.

Operating Availability

The availability of biomass and coal cofired boilers is similar to that of regular coal boilers, if proper modifications are made to the system. If some of the potential operating issues mentioned in the next section manifest, then availability might be negatively affected.

Operating Advantages and Disadvantages

Typically, cofiring biomass in an existing coal boiler requires modifications or additions to fuel handling, processing, storage, and feed systems. Slight modifications to existing operational procedures, such as increasing overfire air, might also be necessary, as well as increasing fuel feeder rates to compensate for the lower density and heating value of biomass.

As covered in Chapter 4, fuel characteristics and processing can greatly affect the ability to use biomass as a fuel in boilers. Wood chips are preferable to mulch-like material for cofiring with coal in stoker boilers because the chips are similar to stoker coal in terms of size and flow characteristics. This

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[57] Tillman, 2000.

similarity minimizes problems with existing coal handling systems. When using a mulch-like material or a biomass supply with a high fraction of fine particles (sawdust size or smaller), periodic blockage of fuel flow openings in various areas of the conveying, storage, and feed systems can occur. These blockages can cause significant maintenance increases and operational problems; therefore, fuel should be processed to avoid difficulties with existing fuel feeding systems.

Another fuel consideration when dealing with biomass is the potential for problems with slagging, fouling, and corrosion. Some biomass fuels have high alkali (principally potassium) or chlorine content that can lead to unmanageable ash deposition problems on heat exchange and ash-handling surfaces. Chlorine in combustion gases, particularly at high temperatures, can cause accelerated corrosion of combustion system and flue gas cleanup components. These problems can be minimized or avoided by screening fuel supplies for materials high in chlorine and alkalis, limiting the biomass contribution to boiler heat input to 15 percent or less, using fuel additives, or increasing soot-blowing. The most troublesome biomass resource tends to be agricultural residues, including grasses and straws, which have high alkali and chlorine contents. In contrast, most woody materials and waste papers are relatively low in alkali and chlorine and should not present this problem.

Currently, about 25 percent of the fly ash from coal-fired power plants is used as a feedstock for cement and concrete production, while another 15 percent is used as a feedstock in other applications.[58] According to current industry standards,[59] only fly ash from coal combustion qualifies for use in cement/concrete applications. Cofiring biomass in a coal power plant would keep the fly ash from meeting the current standard. Similarly, coal fly ash will sometimes not meet the current standard when certain emissions control techniques are used, such as ammonia injection. Though these restrictions can impact the economics of biomass cofiring, the value of finding a productive use for fly ash and other coal combustion products is primarily the avoidance of a roughly $20/ton landfill fee. For coal with 10 percent ash content, this value would be worth about $2/ton of the input fuel cost. While the current restrictions are a barrier to considering cofiring in some applications, other uses of fly ash are not affected, and researchers are currently studying the impact of using fly ash from biomass and biomass/coal cofiring on concrete characteristics. Early results show that biomass and cofired fuels do not adversely affect the usefulness of fly ash in cement and concrete, and in fact might have some advantages.[60] It is likely that this work will eventually lead to a reevaluation of the standard and inclusion of fly ash from cofiring as an acceptable cement/concrete feedstock as has already happened in Europe.[61]

Equipment and Installed Costs

Cofiring typically does not involve added investment for the boiler equipment that is already in place for the coal-fired plant. There are additional costs for new fuel handling and processing equipment, boiler modifications, controls, engineering fees, and contingency. For blended fuel input systems, in which the biomass is added upstream of the coal fuel preparation equipment, the costs for the added feed preparation are on the order of 15 to 30 percent of the costs shown in the previous section in Table 5.4 for a dedicated biomass system. For systems using a separate fuel feed system, the costs are comparable to the costs ($/ton of biomass feed) for a dedicated biomass plant.

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[58] American Coal Ash Association, n.d.

[59] ASTM C-618.

[60] Wang, 2007.

[61] In 2004, European Standard EN 450 dealing with fly ash specifications for use in concrete was approved for modification to include fly ash from a wide range of cofired biomass and waste feedstocks. These changes are in the process of being adopted by the European Union member countries.

O&M Issues

As discussed under capital costs, additional O&M to the boiler section attributable to the addition of biomass for cofiring is minimal. Maintenance requirements for boilers cofiring biomass and coal are similar to those for coal-only boilers. However, slight changes to previous operational procedures, such as increasing overfire air and fuel feeder speeds, might be needed. Increases in O&M costs for biomass cofiring with coal are almost entirely for the biomass receiving and feed preparation. For a blended system, the adjustments to feed preparation O&M are also on the order of 15 to 30 percent of the cost of a dedicated biomass plant.

Commercialization Status

Organizations such as electric utilities, DOE, and the Electric Power Research Institute (EPRI), have conducted research and field tests on biomass cofiring in small- and large-scale utility boilers for a number of years. These tests have shown that cofiring with biomass has been successfully accomplished in a wide range of boiler types, including cyclone, stoker, pulverized coal, and bubbling and circulating fluidized bed boilers. According to the Federal Energy Management Program, at least 182 separate boilers and organizations in the United States have cofired biomass with fossil fuels although this number is not comprehensive. Of the 182 cofiring operations, 114 (or 63 percent) have been at industrial facilities, 32 at utility-owned power plants, 18 at municipal boilers, 10 at educational institutions, and eight at federal facilities[62].

5.2   Gasification Technologies

Biomass gasification for power production involves heating solid biomass in an oxygen-starved environment to produce a low or medium calorific gas. Depending on the carbon and hydrogen content of the biomass and the gasifier's properties, the heating value of the syngas, can range anywhere from 100 to 500 Btu/cubic foot (10 to 50 percent that of natural gas). The heating value of syngas generally comes from CO and hydrogen produced by the gasification process. The remaining constituents are primarily CO_2 and other incombustible gases. Biomass gasification offers certain advantages over directly burning the biomass because the gas can be cleaned and filtered to remove problem chemical compounds before it is burned. Gasification can also be accomplished using chemicals or biologic action (e.g., anaerobic digestion); however, thermal gasification is currently the only commercial or near commercial option.

The fuel output from the gasification process is generally called *syngas,* though in common usage it might be called *wood gas*, *producer gas,* or *biogas*. Syngas can be produced through direct heating in an oxygen-starved environment, partial oxidation, or indirect heating in the absence of oxygen. Most gasification processes include several steps. The primary conversion process, called pyrolysis, is the thermal decomposition of solid biomass (in an oxygen-starved environment) to produce gases, liquids (tar), and char. Pyrolysis releases the volatile components of the biomass feed at around 1,100° F through a series of complex reactions. Biomass fuels are an ideal choice for pyrolysis because they have so many volatile components (70 to 85 percent on dry basis, compared to 30 percent for coal). The next step involves a further gasification process that converts the leftover tars and char into CO using steam and/or partial combustion. In coal gasification, pure oxygen or oxygen-enriched air is preferred as the oxidant because the resulting syngas produced has a higher heating value, and the process is more efficient. In biomass gasification, oxygen is generally not used because biomass ash has a lower melting point than coal ash, and because the scale of the plants is generally smaller.

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[62] DOE, 2004.

Very high temperature processes involving passing the biomass through a plasma arc have been developed and tested primarily for waste remediation, contaminated wastes, and MSW. Plasma processes are not discussed in this report.

Compared with direct-fired biomass systems, gasification is not yet an established commercial technology. There is great interest, however, in the development and demonstration of biomass gasification for a number of reasons:

A gaseous fuel is more versatile than a solid fuel. It can be used in boilers, process heaters, turbines, engines and fuel cells, distributed in pipelines, and blended with natural gas or other gaseous fuels.

Gasification can remove fuel contaminants and reduce emissions compared to direct-fired systems.

Gasification can be designed to handle a wide range of biomass feedstocks, from woody residues to agricultural residues to dedicated crops, without major changes in the basic process.

Gasification can be used to process waste fuels, providing safe removal of biohazards and entrainment of heavy metals in non-reactive slag.

A gaseous fuel can be used in a high-efficiency power generation system, such as a gas turbine-combined cycle or fuel cells, provided it is cleaned of contaminants. When equipment is added to recover the heat from the turbine exhaust, system efficiencies can increase to 80 percent.

Like the direct combustion processes described in the previous section, two principal types of gasifiers have emerged: fixed bed and fluidized bed. Fixed bed gasifiers are typically simpler, less expensive, and produce a lower heat content syngas. Fluidized bed gasifiers are more complicated, more expensive, and produce a syngas with a higher heating value.

5.2.1   Gasifiers

Characterization

Fixed Bed Gasifiers

Fixed bed gasifiers typically have a fixed grate inside a refractory-lined shaft. The fresh biomass fuel is typically placed on top of the pile of fuel, char, and ash inside the gasifier. A further distinction is based on the direction of air (or oxygen) flow: downdraft (air flows down through the bed and leaves as biogas under the grate), updraft (air flows up through the grate and biogas is collected above the bed), or crossflow (air flows across the bed, exiting as biogas). Schematics of the primary section of the fixed bed gasifier types are shown in **Figure 5-6**.

Figure 5-6. Fixed Bed Gasifier Types
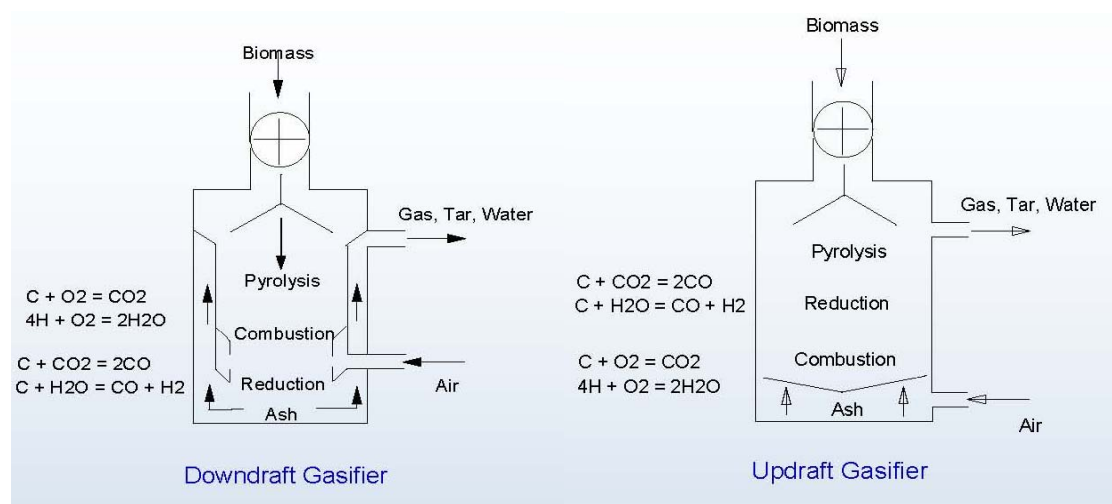
Source: Bain, 2006.

       Table 5-9 compares fixed bed gasifier types. **Table 5-10** provides typical physical characteristics of a fixed bed gasifier. Fixed bed gasifiers are usually limited in capacity, typically used for generation systems that are able to produce less than 5 MW. The physics of the refractory-lined shaft reactor vessel limits the diameter and thus the throughput. Developers have identified a good match between fixed bed gasifiers and small-scale distributed power generation equipment. However, the variable economics of biomass collection and feeding, coupled with the gasifier's low efficiency, make the economic viability of the technology particularly site-specific.

Table 5-9. Comparison of Fixed Bed Gasification Technologies

	Type of Gasifier		
	Downdraft	**Updraft**	**Crossflow**
Operation	Biomass is introduced from the top and moves downward. Oxidizer (air) is introduced at the top and flows downward. Syngas is extracted at the bottom at grate level.	Biomass is introduced from the top and moves downward. Oxidizer is introduced at the bottom and flows upward. Some drying occurs. Syngas is extracted at the top.	Biomass is introduced from the top and moves downward. Oxidizer is introduced at the bottom and flows across the bed. Syngas is extracted opposite the air nozzle at the grate.
Advantages	Tars and particulate in the syngas are lower, allowing direct use in some engines without cleanup. The grate is not exposed to high temperatures.	Can handle higher-moisture biomass. Higher temperatures can destroy some toxins and slag minerals and metal. Higher tar content adds to heating value.	Simplest of designs. Stronger circulation in the hot zone. Lower temperatures allow the use of less expensive construction materials.
Disadvantages	Biomass must be very dry (<20 percent moisture content). The syngas is hot and must be cooled if compression or extensive cleanup is required. About 4 to 7 percent of the carbon is unconverted and remains in the ash.	Higher tar content can foul engines or compressors. The grate is exposed to high temperatures and must be cooled or otherwise protected.	More complicated to operate. Reported issues with slagging. High levels of carbon (33%) in the ash.

Table 5-10. Typical Characteristics of a Fixed Bed Gasifier

Parameter	Fixed Bed, Downdraft
Fuel size (inches)	0.4-4
Fuel ash content (% weight)	<6
Operating temperature (°F)	1450-2550
Control	Simple
Turn-down ratio	4:1
Construction material	Mild steel + refractory
Capacity (MW$_{thermal}$) (tons biomass/day)	<5 (<30)
Start-up time	Minutes
Operator attention	Low
Tar content (lb/MMBtu product gas)	<1.2
Heating value (Btu/scf) HHV	130

Source: GasNet, n.d.

Fluidized Bed Gasifiers

Fluidized bed gasifiers utilize the same gasification processes and offer higher performance than fixed bed systems, but with greater complexity and cost. Similar to fluidized bed boilers, the primary gasification process takes place in a bed of hot inert materials suspended by an upward motion of oxygen-deprived gas (**Figure 5-7**). As the amount of gas is augmented to achieve greater throughput, the bed will begin to levitate and become "fluidized." Sand or alumina is often used to further improve the heat transfer. Notable benefits of fluidized bed devices are their high productivity (per area of bed) and flexibility. Fluidized bed gasifiers can also handle a wider range of biomass feedstocks with moisture contents up to 30 percent on average.

Figure 5-7. Fluidized Bed Gasifier
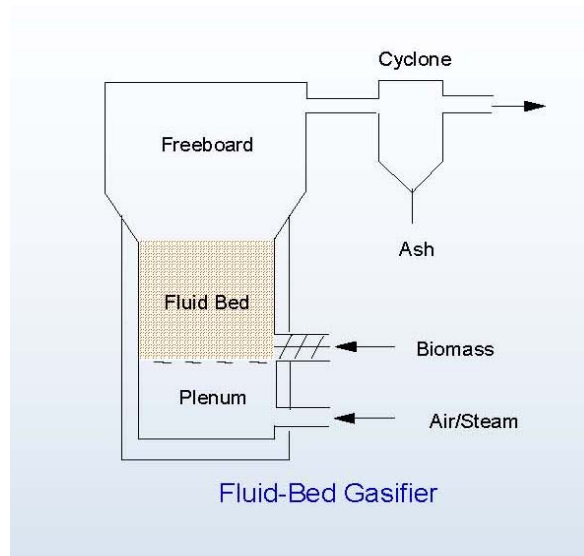
Source: Bain, 2006.

There are three stages of fluidization that can occur on the gasifier depending on the design: bubbling, recirculating, and entrained flow. At the lower end of fluidization, the bed expands and begins to act as a fluid. As the velocity is increased, the bed will begin to "bubble." With a further increase in airflow, the bed material begins to lift off the bed. This material is typically separated in a cyclone and "recirculated" to the bed. With still higher velocities, the bed material is entrained (i.e., picked up and carried off in the airflow).

Fluidized bed gasifiers can be designed to use a portion of the pyrolysis gases to generate the heat to drive the process, or they can be externally fired. Operating the gasifier at higher pressures increases the throughput; however, this also increases the gasifier's complexity and cost. In these units, the biomass is fully converted after going through the pyrolysis and char conversion processes.

By reducing the quantity of air and process temperature, it is possible to operate fluidized bed boilers as gasifiers. In this operating mode, the gasifiers produce a gas with a heating value of slightly more than 100 Btu/cubic foot (ft^3). This gas is burned above the bed as additional air supply is injected upstream of the boiler tube section.

Table 5-11 provides typical physical characteristics of a fluidized bed gasifier. A number of advanced-concept fluidized bed gasifiers aiming to produce a syngas with a heating value between 250 and 400 Btu/ft^3 are under development. This type of syngas would be more appropriate for use in gas

turbines, fuel cells, and reciprocating internal combustion engines; however, these advanced concept gasifiers have not reached the point where they are proven in commercial operation.

Table 5-11. Typical Characteristics of a Fluidized Bed Gasifier

Parameter	Fluidized Bed
Fuel size (inches)	0-0.8
Fuel ash content (% weight)	<25
Operating temperature (°F)	1,350-1,750
Control	Average
Turn-down ratio	3
Construction material	Heat-resistant steel
Capacity (MW$_{thermal}$) (biomass tons/day)	5 and up (> 30)
Start-up time	Hours
Operator attention	Average
Tar content (lb/MMBtu product gas)	<2
Heating value (Btu/scf) HHV	150

Source: GasNet, n.d.

Efficiency

Both fixed and fluidized bed biomass gasification uses similar types of equipment as direct combustion. The biomass fuel is fed into a combustion/reaction vessel with either a fixed, fluidized, or moving bed. The thermodynamics of heat loss are similar, but gasification conditions are different from direct combustion. In direct combustion, 10 to 14 times the weight of the fuel is introduced as air. In gasification, the air entering the reactor, if any, is only one to two times the weight of the fuel. This difference reduces heat losses from the reaction zone. On the other hand, the syngas exits the gasification reactor at very high temperatures (1,200 to 1,500° F); some of this heat loss can be recovered either directly through the use of heat exchangers in the gas cooling section, or indirectly through the use of heat recovery from the combustion of the syngas in the power generation section. To the extent that heat is used to preheat incoming air, introduce high-temperature steam, or dry the incoming biomass, the efficiency of biomass to syngas conversion will be increased. Heat that is recovered from the hot gas cooling section can also be added to the CHP heat recovery. In this case, the intermediate efficiency value of syngas conversion is not increased but the overall CHP efficiency is. These differences combine to produce biomass to syngas efficiencies (heating value of the syngas divided by the heating value of the biomass) of 60 to 80 percent. In integrated configurations, however, additional steam can be generated from cooling the hot syngas exiting the reactor prior to cleanup.

Operating Availability

Due to the fact that commercialization of biomass gasification plants is in its early stages, no facility survey information was found on their availability or reliability. Plants are designed for continuous operation, and design performance is in the 90+ percent range. Actual experience with emerging technology tends to result in lower availability than is experienced during broad commercial use, as materials handling problems, control issues, and component failures cause more frequent unplanned outages than are seen after accumulating additional operating experience. With a newly established support infrastructure, outages also tend to last longer before being fixed or solved. A well

designed system, however, has a reasonable expectation of operating in the 85 to 95 percent availability range.
Operating Issues

As discussed above, moisture content, gas cleanup, and operating pressure can all affect operation of a gasifier. There are a number of operating issues common to the different types of gasification systems.

Moisture Content

Green biomass, defined as freshly harvested plant material, can contain a significant amount of water by weight (up to 60 percent). This water does not contribute to the heat content of the syngas while consuming a significant amount of energy in gasification. Even though water cannot be burned (oxidized) at elevated temperatures, it will dissociate into its elemental components—hydrogen and oxygen. The hydrogen will contribute to the calorific value of the syngas. This reaction is very temperature-sensitive, and the hydrogen and oxygen will usually recombine into water vapor as the syngas cools. Therefore, the moisture content of biomass must be strictly limited. If there is excess moisture, the gasification process cannot sustain itself without an external source of heat. As the moisture content of the biomass increases, the net energy available in the syngas decreases. Fixed bed gasifiers that use internal combustion of the syngas typically utilize biomass with less than 20 percent moisture content. Fluidized bed gasifiers typically require less than 30 percent moisture content.

Green biomass is the most readily available and inexpensive biomass product. The drying process requires a considerable additional capital investment and increases the O&M costs. Unfortunately, the cost of the drying equipment (equipment cost and O&M cost) seldom covers the cost savings of using green biomass.

Gas Cleanup

As syngas leaves the gasifier, it contains several types of contaminants that are harmful to downstream equipment, ash handling, and emissions. The degree of gas cleanup must be appropriately matched to its intended use. For use in reciprocating engines, gas turbines, and especially fuel cells, a very clean gas is required. As discussed in **Table 5-12**, the primary contaminants in syngas are tars, particles, alkali compounds, and ammonia. The types of contaminants that are observed depend on the biomass feedstock and the gasification process used.

Table 5-12. Gas Cleanup Issues

Contaminant	Description	Treatment
Tar	Tars (creosote) are complex hydrocarbons that persist as condensable vapors.	Wet scrubbers, electrostatic precipitators, barrier filters, catalysts, or combustion.
Particles	Particles are very small, solid materials that typically include ash and unconverted biomass.	Cyclone separators, fabric filters, electrostatic precipitators, and wet scrubbers.
Alkali compounds	Potassium, alkali salts, and condensed alkali vapors are part of the chemical composition of biomass.	First, cool syngas below 1,200º F, causing the alkali vapors to condense. Second, use cyclone separators, fine fabric filters, electrostatic precipitators, and wet scrubbers.
Ammonia	Ammonia is formed from nitrogen (fuel-bound and in air) and hydrogen (in fuel and in moisture content). When syngas is burned, ammonia is converted to NO_x.	Catalysts, hydrocarbon reforming, or wet scrubbing.

Because gasification occurs at an elevated temperature, syngas can have as much as a third of its total energy in sensible heat. Cleaning the gas while it is hot would be advantageous from an energy use perspective, but this task is currently difficult to accomplish. Research is ongoing regarding hot gas filters, which can be applied in coal gasification, as well as other high-temperature processes. Wet scrubbers are currently one of the most reliable and least expensive options for gas cleanup, even though they sacrifice a large portion of the sensible heat of the syngas. Cooling the hot syngas can provide a source of steam for the cleaning process, power generation, or end-use.

Operating Pressure

Gasifiers can be operated at either atmospheric or elevated pressures. Air-blown, atmospheric gasifiers produce a very low Btu gas 110 to 170 Btu/scf. To introduce this gas into a gas turbine in the power generation section of the plant requires considerable compression energy, up to a third of the turbine's output. Therefore, it would be advantageous to produce the syngas at a high pressure so that it can be introduced directly into the combustion section of a gas turbine without additional compression. Pressurized reactors, however, do need to compress any combustion air or oxygen that is introduced into the reactor and maintain a pressure seal on the biomass input and ash removal systems.

Advantages and Disadvantages

Fixed bed and fluidized bed gasifiers have specific operating advantages and disadvantages with biomass fuels depending on the biomass characteristics and site requirements. **Table 5-13** provides a qualitative comparison of gasifier characteristics and operating issues for fixed bed and fluidized bed systems.

Table 5-13. Relative Advantages/Disadvantages of Gasifier Types

Gasifier	Advantages	Disadvantages
Updraft fixed bed	Mature for heat Small-scale applications Can handle high moisture No carbon in ash	Feed size limits High tar yields Scale limitations Low Btu gas Slagging potential
Downdraft fixed bed	Small-scale applications Low particulates Low tar	Feed size limits Scale limitations Low Btu gas Moisture-sensitive
Bubbling fluid bed	Large-scale applications Feed characteristics Direct/indirect heating Can produce higher Btu gas	Medium tar yield Higher particle loading
Circulating fluid bed	Large-scale applications Feed characteristics Can produce higher Btu gas	Medium tar yield Higher particle loading
Entrained flow fluid bed	Can be scaled Potential for low tar Potential for low methane Can produce higher Btu gas	Large amount of carrier gas Higher particle loading Particle size limits

Equipment and Installed Costs

The main cost for the gasification train is the primary gasification reactor itself. Supplementary processing can occur in a tar cracker. Indirect gasifiers have separate char combustors to supply heat. The next major part is the gas cleanup section, which includes ash removal, quench, bag filter, wet scrubber, and heat exchangers to cool the syngas and provide heat to other parts of the process or to contribute to the CHP heat utilization. Capital costs for the gasification section and for a biomass-to-syngas plant are shown in **Table 5-14**. These costs are estimated based on published estimates (Antares Group, Inc., 2003) and discussions with equipment suppliers. The unit costs do not show a uniform declining trend as a function of size, but instead vary depending on the process considered.

Table 5-14. Biomass Gasification Capital Costs to Produce Syngas

	Gasifier Cases			
	Atmospheric Gasification	**Atmospheric Gasification**	**Atmospheric Gasification**	**High-Pressure Gasifier**
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/ high-pressure
Tons/day (as received)	100	260	450	1,200
Gasifier equipment	$1,225,000	$10,050,000	$15,158,000	$34,682,000
Installation	$612,000	$5,024,000	$7,578,000	$17,338,000
Total Installed Gasification	**$1,837,000**	**$15,074,000**	**$22,736,000**	**$52,020,000**
Biomass Prep Yard*	$2,639,700	$3,947,400	$4,972,000	$9,685,766
Total Installed Capital Cost	**$4,476,700**	**$19,021,400**	**$27,708,000**	**$61,705,766**
Unit Cost ($/MMBtu/hr) (syngas)	$127,164	$209,425	$174,130	$161,270

*Prep-Yard costs are estimated based on the capital cost curve developed in section 4.1.5
Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

O&M Costs

Non-fuel O&M costs for gasification include O&M labor, supervisory labor, water, ash removal, insurance, taxes, royalties, and other operating materials. These costs are estimated in **Table 5-15** based on published estimates and discussions with equipment suppliers.[63]

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[63] Antares Group Inc., 2003

Table 5-15. Gasification O&M Cost Estimates for Syngas Production

	Gasifier Cases			
	Atmospheric Gasification	**Atmospheric Gasification**	**Atmospheric Gasification**	**High-Pressure Gasifier**
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/ high-pressure
Tons/day (as received)	100	260	450	1,200
Net capacity, MMBtu/hr	35.2	90.8	159.1	382.6
Prep-yard labor costs	$400,000	$320,000	$320,000	$400,000
Gasifier section O&M	$502,000	$634,500	$789,500	$2,235,800
Total Annual O&M (to syngas)	**$902,000**	**$954,500**	**$1,109,500**	**$2,635,800**
Gasification O&M ($/MMBtu)	$3.250	$1.333	$0.884	$0.874

Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

A summary of the cost and performance for the range of biomass gasification systems considered is provided in **Table 5-16.**

Table 5-16. Biomass Gasification Cost and Performance

	Gasification Technologies			
	Atmospheric Gasification	**Atmospheric Gasification**	**Atmospheric Gasification**	**High-Pressure Gasifier**
Gasifier type	Fixed	Fluidized	Fluidized	Fluidized/ high-pressure
Tons/day (as received)	100	260	450	1,200
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)(%)	65	71	71	72
Biomass fuel value to gasifier (MMBtu/hr)	49.6	127.9	224.1	531.9
Fuel produced (MMBtu/hr)	32.2	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
Capital Costs				
Gasifier equipment	$1,225,000	$10,050,000	$15,158,000	$34,682,000
Installation	$612,000	$5,024,000	$7,578,000	$17,338,000
Total Installed Gasification Section	**$1,837,000**	**$15,074,000**	**$22,736,000**	**$52,020,000**
Biomass Prep-Yard	$2,639,700	$3,947,400	$4,972,000	$9,685,766
Total Installed Capital Cost	**$4,476,700**	**$19,021,400**	**$27,708,000**	**$61,705,766**
Unit Cost ($/MMBtu/hr) (syngas)	$127,164	$209,425	$174,130	$161,270

Source: Based on data from Antares Group, Inc., 2003; discussion with equipment suppliers and developers.

Commercial Status

The majority of commercial gasification projects use coal or petroleum coke as a feedstock. Biomass gasification technologies have been a subject of commercial interest for several decades. By the 1990s, CHP had been identified as a potential near-term technology. Research and development concentrated on integrated gasification combined cycle and gasification cofiring demonstrations, which led to a number of commercial-scale systems. In the United States, projects mostly processed hard-to-manage feedstocks like bagasse and alfalfa. Low-energy gasifiers are now commercially available, and dozens of small-scale facilities are in operation.

A review of gasifier manufacturers in Europe, the United States, and Canada[64] identified 50 manufacturers offering commercial gasification plants in which 75 percent of the designs were fixed bed downdraft type; 20 percent of the designs were fluidized bed systems. The actual number of biomass gasification systems in operation worldwide is unknown, but is estimated to be below 50 based on literature review and discussions with industry sources. There are only a handful of commercially operating biomass gasification systems in the United States at this time, and many of these are partially government-funded demonstration units. In comparison, there are currently more than 100 biomass-fueled fluidized bed boilers in operation around the world.

There is still a considerable amount of development activity underway to address existing technical and operational issues:

- **Gasification**—Some gasification technologies using biomass and black liquor have developed to the point of large-scale demonstration. However, gasifier systems have not reached widespread commercial availability for systems suitable for integration with hydrogen separation technologies for fuel cells or fuel synthesis. This is due in part to areas of fuel chemistry that are not established enough to support the commercial demonstration programs and facilitate the development and scale-up of advanced gasifiers and gas cleanup systems.

- **Syngas cleanup and conditioning**—The raw gases from biomass systems do not currently meet strict quality standards for downstream fuel, chemical synthesis catalysts, or those for some power technologies. These gases will require cleaning and conditioning to remove contaminants such as tar, particulates, alkali, ammonia, chlorine, and sulfur. Available cleanup technologies do not yet meet the needed cost, performance, or environmental criteria needed to achieve commercial implementation.

- **Sensors and controls**—Development of effective process controls is needed to maintain plant performance and emissions at target levels with varying load, fuel properties, and atmospheric conditions. New sensors and analytical instruments are under development to optimize control systems for thermochemical systems.

- **Process integration**—As with all new process technologies, demonstrating sustained integrated performance that meets technical, environmental, and safety requirements at sufficiently large scale is essential to supporting commercialization. Applications such as black liquor integration in paper mills has the added complexity of being attached to an existing commercial process where the unit operations associated with steam production, power, pulping, and chemical recovery must all be integrated.

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[64] European Biomass Industry Association, n.d.

- **Containment (materials of construction)**—Experience with existing gasifiers indicates that gasification reactions are difficult to contain and that materials development for reactor shells and internals, refractory materials to line containment vessels, vessel design, and increased knowledge of bed behavior and agglomeration will improve performance over the long term.

5.3 Modular Systems

Modular biomass-fueled CHP systems are defined as small systems, less than 5 MW, though typically smaller, with the main operating components coming in one or more pre-engineered and packaged modules for simple installation at the user's site. The systems typically include a fuel processor (combustion or gasification), necessary intermediate fuel cleanup, an electric generator, and heat recovery from both the power generation and energy conversion sections. An automatic fuel storage and delivery system must be added for a complete operating system.

Small modular biomass systems can supply electricity to rural areas, farms, businesses, and remote villages. These systems use locally available biomass fuels such as wood, crop waste, animal manure, and LFG. Development of biomass-fueled modular power systems is of great interest internationally as a means to bring power to isolated communities in areas lacking power and fuel infrastructure. In the United States, there is interest in small systems to utilize opportunity fuels from a local area, such as crop wastes or fire control forest thinnings.

A partial listing of specific developer/manufacturer modular systems is provided in Appendix D.

Characterization

Modular systems are essentially scaled down versions of larger systems. There are systems that use direct-fired technology with steam power, and systems that use gasification technology and gaseous fuel burning power technologies (discussed in Chapter 6) such as internal combustion engines, microturbines, and Stirling engines. There are also direct fired systems that use Stirling engines for power production, as well as systems that employ gasification, wherein the hot raw gas is combusted to raise steam.

Modular Gasification Systems

Figure 5-8 shows a schematic of a 75-kW modular biomass gasification system that is representative of systems under development. The figure shows that there are eight submodules included in the basic system and that the storage and feed submodules are not included.

Basic Package Modules

1. Automatic biomass feed system.

2. Dryer to reduce the feedstock moisture content.

3. Chip sorter for sizing.

4. Heat exchanger that extracts heat from the gasifier for use in the dryer and for onsite thermal applications.

5. Gasifier feeder.

6. A downdraft gasifier producing low Btu gas (heating value of about 110 Btu/scf—HHV).

7. Filtering stages that remove particulates.

8. The power module—this can be an internal combustion engine designed to run on low Btu fuel, a microturbine, a Stirling engine, or even a fuel cell. The power module also has heat recovery equipment to provide additional useable thermal energy for onsite use. Because the gas is of such a low Btu content, propane or natural gas is required on system start-up. After start-up, the system can run on the syngas alone.

Systems such as these will require feedstock storage with an in-place delivery system. An in-ground storage bunker with a moving bed would allow direct delivery of fuel loads into the automated system. This can consist of a permanently installed live bottom van into which dump trucks can deliver a sized fuel supply.

Figure 5-8. Example Modular Biomass Gasification System
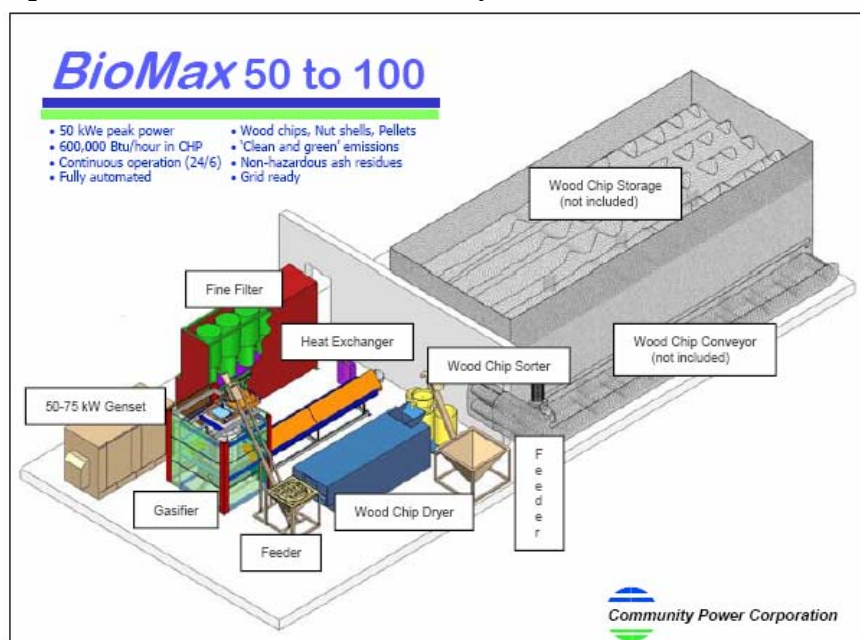
Source: Community Power Corporation, n.d.

Modular Combustion Systems[65]

Direct combustion in fixed bed combustors is a commercial technology in larger sizes. In these larger systems, as characterized previously, power is generated by steam turbines. In modular systems, other power systems are being developed that are more suitable for small-sized applications. The typical power and heat cycles being employed or explored for use are as follows:

- Steam cycle

- Organic Rankine cycle (ORC)

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[65] Example shown, BioMax, is developed by Community Power Corporation.

- Brayton cycle, hot air turbine

- Entropic cycle, as defined by its developer, similar to Organic Rankine cycle but with a higher temperature differential producing higher efficiencies

- Stirling Engine, external combustion

Modular power and heat cycles that can be driven by biomass combustion are shown in **Figure 5-9.**

Figure 5-9. Heat Engine Power Cycles for Modular Biomass Combustion Systems[66]
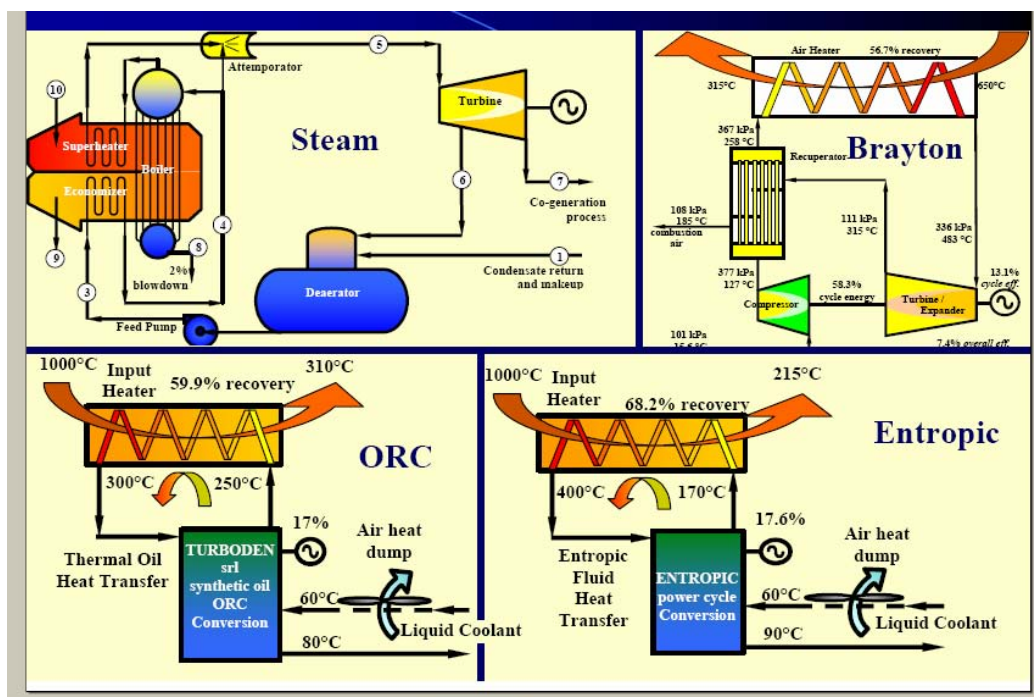
Source: Smith, 2006.

In addition to the four power cycles shown, very small (500 watts to 10 kW) modular systems are being developed using Stirling engine technology. The generators will convert various biomass fuels (wood, wood pellets, sawdust, chips, or biomass waste) to electricity and useful heat.[67] These systems typically convert 10 to 20 percent of the fuel energy to electricity; 60 to 70 percent of fuel energy is then available for heating water and spaces. The burner for the prototype system includes a ceramic fire box and a fuel hopper with a fuel capacity of 24 hours. It accomplishes complete two-stage combustion with comparatively low emissions. The Stirling engine-alternator requires minimal maintenance because its gas bearings eliminate contact, friction, and wear. Its projected life is 40,000 hours.

Modular Hybrid Gasification/Combustion Systems

The modular hybrid gasification/combustion system operates functionally like a direct combustion system. Power is derived by a back-pressure steam turbine that also provides steam for onsite thermal energy requirements. The difference is that the combustion chamber is actually a gasification

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[66] Smith, 2006.
[67] A system under development by Sunpower Stirling engine technology licensee is External Power LLC of Indianapolis.

system that uses a two-chamber gasifier approach. The system is similar to a two-stage combustion boiler design. This approach allows the production of gas in a relatively cool chamber at temperatures from 1,000°F to 1,400°F, and then combustion in a relatively hot chamber—the boiler—at temperatures up to 2,300°F. These temperatures allow the complete removal of carbon from the fuel in the gasifier, and more complete oxidation of complex organics in the oxidation zone. The combination of these features results in a clean-burning, fuel-efficient system. CHP units include small back-pressure steam turbines from 100 kW up to several megawatts.

This approach combines the simplicity and low cost of a combustion system with the gasification advantages of more complete carbon conversion and cleaner combustion characteristics. An example of a modular gasification/combustion system is shown in **Figure 5-10**. This system has the capability to use fuels with moisture contents ranging from 6 to 55 percent (wet basis). The system also has a 20:1 turn-down ratio to allow it to idle during periods of low heat demand.

Figure 5-10. Example of Modular Gasification/Combustion Process
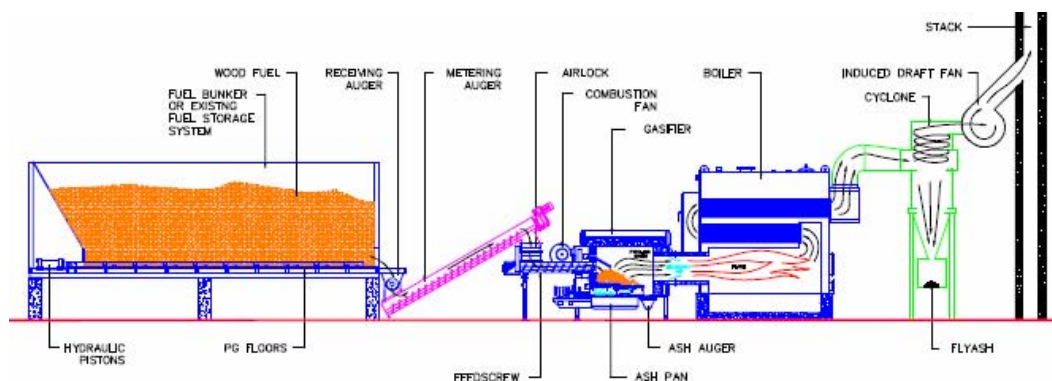
Source: Chiptec® Wood Energy Systems, n.d. [68]

Efficiency

Modular system electric generation efficiencies are typically fairly low as shown in **Table 5-17**. In applications requiring considerable thermal energy, the overall CHP efficiencies are comparable to gas-fired systems. However, the electric to thermal ratio for these systems is much lower, so more of the total useful energy is delivered in the form of heat rather than in the form of higher value electricity.

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[68] Example shown is a patented process by Chiptec® Wood Energy Systems, Burlington, Vermont.

Table 5-17. Efficiencies of Modular Biomass Systems, Based on Conversion of Switchgrass at 20 Percent Moisture

System Type	Electric Efficiency	Thermal Energy Delivered	Overall CHP Efficiency
Small steam	6%	59%	65%
Air Brayton	8%	41%	49%
Organic Rankine	11%	56%	67%
Entropic	13%	63%	76%
Stirling	13%	64%	77%
Modular gasifier	16–22%	29–53%	55–75%
Hybrid gasifier/combustor	<15%	45–55%	60–70%

Operating Advantages and Disadvantages

The main operating advantages today are in the use of opportunity biomass fuels of low value such as wood chips or forest thinnings. In addition, many of the systems are targeted at remote applications where it would be too costly to connect to grid electricity.

The main disadvantage affecting all types of modular systems is the comparatively high capital costs associated with all of the required equipment. This equipment also takes up considerable space compared to conventional gas-fired CHP systems. The engine generator systems occupy only about 5 percent of the total space required for the modular biomass system. Another disadvantage is the need for maintenance and repairs associated with the many subsystems, particularly the solids handling components and filters.

Equipment and Installed Cost

Equipment costs are speculative. Information in this section is as provided by the vendors and secondary sources. **Figure 5-11** shows a range of costs ($/kW) for different types of direct-fired systems. It is not clear that these costs include the costs of feedstock storage and delivery, which would add another $600 to 1,000/kW to the overall costs.

Figure 5-11. Size and Cost Ranges for Direct-Fired Modular Systems[69]
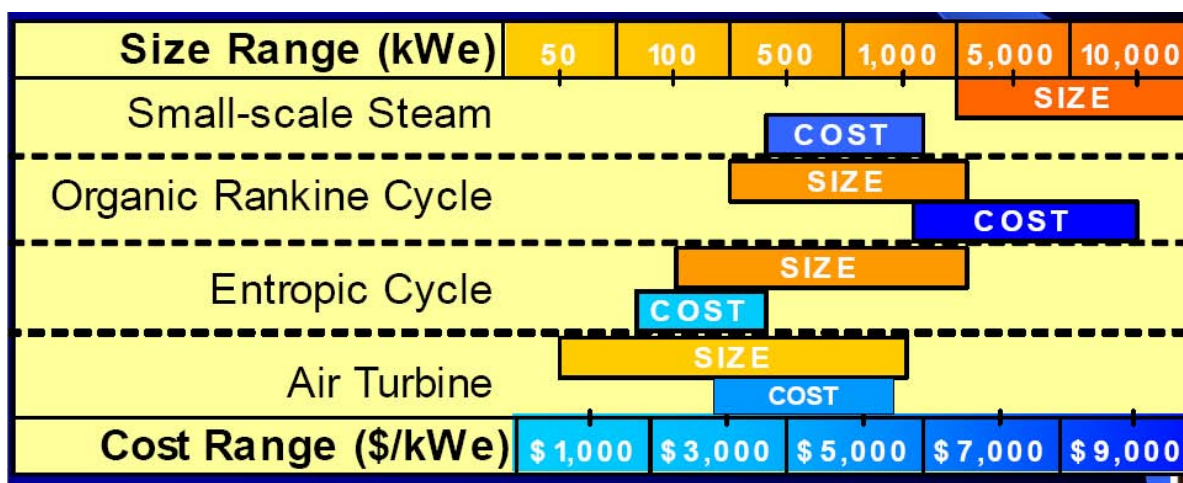
Source: Smith, 2006.

Modular gasification costs are estimated to be between $2,500 to $4,000/kW for the basic equipment with another $600 to $1,000/kW for a biomass storage bunker and $1,000 to $2,000/kW for installation.

The hybrid gasification/combustion system by itself costs about $300/kW. This component must be matched with feedstock storage and delivery ($600 to $1,000/kW), small-scale boiler, small-scale steam turbine generator ($900 to $1,200/kW), and other equipment, including controls, cyclone fly ash recovery system, and exhaust stack. Overall installed capital costs would be $12,000 to $18,000/kW.

O&M Costs

Most modular systems are characterized by continuous operation, automatic ash and char extraction, automatic feed, and automatic process control. Maintenance of 0.5 to 3 hours per week is required for monitoring feedstock deliveries, ash removal, filter cleaning or replacement, and inspecting and fixing problems with the automatic feed system. In addition, prime movers such as internal combustion engines or microturbines require similar maintenance attention as for gas-fired systems.

The overall costs and reliability of these systems has not yet been established.

Commercial Status

There are a number of small development companies working on modular biomass heat and power systems (listed in Appendix D). Most of the systems that have been installed in the United States are part of research, development, and demonstration projects funded by a variety of federal and state sources. DOE has an active research and development program on modular biomass as does USDA and the U.S. Forest Service. The United Nations also has an ongoing program in this area to develop village power systems using biomass.

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[69] Smith, 2006.

6.   Power Generation Technologies

CHP is the sequential or simultaneous generation of multiple forms of useful energy (usually mechanical and thermal) in a single, integrated system. CHP systems consist of a number of individual components—prime mover (heat engine), generator, heat recovery, and electrical interconnection—configured into an integrated whole. The type of equipment that drives the overall system (i.e., the prime mover) typically identifies the CHP system. Prime movers for CHP systems include steam turbines, gas turbines (also called combustion turbines), spark ignition engines, diesel engines, microturbines, and fuel cells. These prime movers are capable of burning a variety of fuels, including biomass/biogas, natural gas, or coal to produce shaft power or mechanical energy. Additional technologies are also used in configuring a complete CHP system, including boilers, absorption chillers, desiccants, engine-driven chillers, and gasifiers. Boilers and gasifiers are discussed in Chapter 5 of this document.

Although mechanical energy from the prime mover is most often used to drive a generator to produce electricity, it can also be used to drive rotating equipment such as compressors, pumps, and fans. Thermal energy from the system can be used in direct process applications or indirectly to produce steam, hot water, hot air for drying, or chilled water for process cooling.

The industrial sector currently produces both thermal output and electricity from biomass in CHP facilities in the paper, chemical, wood products, and food processing industries. These industries are major users of biomass fuels—utilizing the heat and steam in their processes can improve energy efficiencies by more than 35 percent. In these applications, the typical CHP system configuration consists of a biomass-fired boiler whose steam is used to propel a steam turbine in addition to the extraction of steam or heat for process use.

More information about how CHP systems work and an explanation of the key concepts of efficiency and power-to-heat ratios can be found in the "Catalog of CHP Technologies" on the EPA CHP Partnership's Web site.[70]

The following technologies are discussed in this chapter, with specific respect to their ability to run on biomass or biogas. A synopsis of key characteristics of each is shown in **Table 6-1**.

Steam turbines—Convert steam energy from a boiler or waste heat into shaft power.

Gas (combustion) turbines, including microturbines—Use heat to move turbine blades that produce electricity.

Reciprocating internal combustion (IC) engines—Operate on a wide range of liquid and gaseous fuels but not solid fuels. The reciprocating shaft power can produce either electricity through a generator or drive loads directly.

Fuel cells—Produce an electric current and heat from a chemical reaction between hydrogen and oxygen rather than combustion. They require a clean gas fuel or methanol with various restrictions on contaminants.

Stirling engines—Operate on any fuel and can produce either electricity through a generator or drive loads directly.

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[70] EPA, 2004b.

Table 6-1. Comparison of Prime Mover Technologies Applicable to Biomass

Characteristic	Prime Mover					
	Steam Turbine	Gas/ Combustion Turbine	Micro-turbine	Reciprocating IC Engine	Fuel Cell	Stirling Engine
Size	50 kW to 250 MW	500 kW to 40 MW	30 kW to 250 kW	Smaller than 5 MW	Smaller than 1 MW	Smaller than 200 kW
Fuels	Biomass/ Biogas-fueled boiler for steam	Biogas	Biogas	Biogas	Biogas	Biomass or Biogas
Fuel preparation	None	PM filter needed	PM filter needed	PM filter needed	Sulfur, CO, methane can be issues	None
Sensitivity to fuel moisture	N/A	Yes	Yes	Yes	Yes	No
Electric efficiency (electric, HHV)*	5 to 30%	22 to 36%	22 to 30%	22 to 45%	30 to 63%	5 to 45%
Turn-down ratio	Fair, responds within minutes	Good, responds within a minute	Good, responds quickly	Wide range, responds within seconds	Wide range, slow to respond (minutes)	Wide range, responds within a minute
Operating issues	High reliability, slow start-up, long life, maintenance infrastructure readily available,	High reliability, high-grade heat available, no cooling required, requires gas compressor, maintenance infrastructure readily available	Fast start-up, requires fuel gas compressor	Fast start-up, good load-following, must be cooled when CHP heat is not used, maintenance infrastructure readily available, noisy	Low durability, low noise	Low noise
Field experience	Extensive	Extensive	Extensive	Extensive	Some	Limited
Commercialization status	Numerous models available	Numerous models available	Limited models available	Numerous models available	Commercial introduction and demonstration	Commercial introduction and demonstration
Installed cost (as CHP system)	$350 to $750/kW (without boiler)	~ $700 to $2,000/kW	$1,100 to $2,000/kW	$800 to $1,500/kW	$3,000 to $5,000 /kW	Variable $1,000 to $10,000 /kW
Operations and maintenance (O&M) costs	Less than 0.4 ¢/kWh	0.6 to 1.1 ¢/kWh	0.8 to 2.0 ¢/kWh	0.8 to 2.5 ¢/kWh	1 to 4 ¢/kWh	Around 1 ¢/kWh

* Efficiency calculations are based on the higher heating value (HHV) of the fuel, which includes the heat of vaporization of the water in the reaction products.

Source: NREL, 2003.

Each of these technologies will require a fuel that has gone through the various preparation steps outlined in Chapters 4 and 5. For power generation technologies that require steam for fuel (steam turbine), a boiler is used to combust the biomass fuel, converting it to steam. For power generation technologies that require gas to operate (gas turbines, reciprocating engines, fuel cells, Stirling engines), the biomass feedstock will either be gasified (as discussed in Chapter 5) or will be collected as biogas from an anaerobic digester or LFG (as discussed in Chapter 4).

As discussed in more detail in Chapter 4, some amount of gas cleaning is required for almost any prime mover to run on biogas, as is standard practice to date. This cleaning would minimally include the removal of solids and liquid water. Removing only solids and liquid water can leave corrosive components and siloxanes, which may damage the prime mover. As described in more detail in Chapter 3, some options for further cleanup are beginning to emerge, such as:

- Chemical "filters" to remove sulfur compounds

- Cooling the gas to remove additional moisture

- Filter systems to remove siloxanes

- Chemical systems to remove CO_2

Specific details regarding the use of b iogas and biomass fuels in the various prime movers are discussed within each of the following subsections.

6.1   Steam Turbine Technologies

A steam turbine is a thermodynamic device that converts the energy in high-pressure, high-temperature steam into shaft power that can in turn be used to turn a generator and produce electric power. Unlike gas turbine and reciprocating engine CHP systems where heat is a byproduct of power generation, steam turbine CHP systems normally generate electricity as a byproduct of heat (steam) generation. A steam turbine requires a separate heat source and does not directly convert fuel to electric energy. The energy is transferred from the boiler to the turbine through high-pressure steam, which in turn powers the turbine and generator[71]. This separation of functions enables steam turbines to operate with an enormous variety of fuels, from natural gas to solid waste, including all types of coal, wood, wood waste, and agricultural byproducts (sugar cane bagasse, fruit pits, and rice hulls). In CHP applications, steam at lower pressure is extracted from the steam turbine and used directly or is converted to other forms of thermal energy.

In the thermodynamic cycle illustrated in **Figure 6-1**, called the Rankine cycle, liquid water is converted to high-pressure steam in the boiler and fed into the steam turbine. The steam causes the turbine blades to rotate, creating power that is turned into electricity with a generator. A condenser and pump are used to collect the steam exiting the turbine, feeding it into the boiler and completing the cycle. There are several different types of steam turbines: 1) A condensing steam turbine as shown in Figure 6-1 is for power-only applications and expands the pressurized steam to low pressure at which point a steam/liquid water mixture is exhausted to a condenser at vacuum conditions; 2) Extraction turbines have openings in their casings for extraction of a portion of the steam at some intermediate pressure for process or building heating; 3) Back-pressure turbines exhaust the entire flow of steam to the process or facility at the required pressure.

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[71] Steam turbines are also used to drive pumps, compressors and other mechanical equipment.

Steam turbines are one of the most versatile and oldest prime mover technologies still in commercial production. Power generation using steam turbines has been in use for about 100 years, when they replaced reciprocating steam engines due to their higher efficiencies and lower costs. Conventional steam turbine power plants generate most of the electricity produced in the United States. The capacity of steam turbines can range from 50 kW to several hundred MW for large utility power plants. Steam turbines are widely used for CHP applications.

Figure 6-1. Simple Steam Turbine Power Cycle
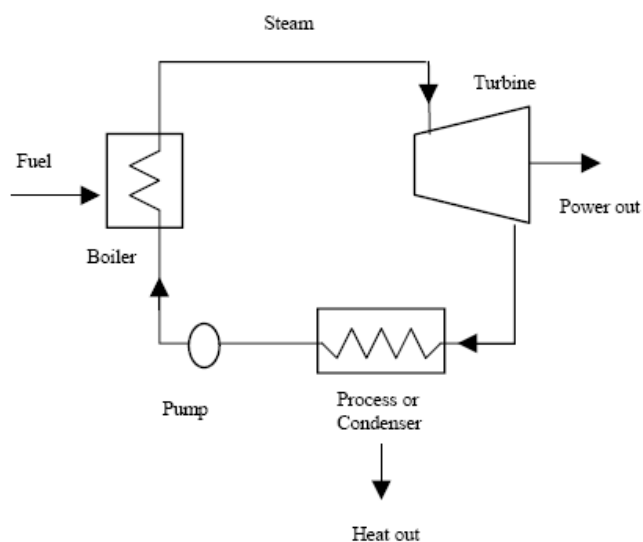
Source: EPA, 2004b.

Key performance characteristics of a steam turbine CHP system are shown in **Table 6-2.**

Table 6-2. Steam Turbine CHP Typical Performance Parameters

Steam Turbine Parameters	System 1	System 2	System 3
Nominal electricity generating capacity (kW)	500	3,000	15,000
Turbine type	Back-pressure	Back-pressure	Back-pressure
Equipment cost ($/kW)*	600	275	225
O&M costs ($/kWh)*	0.004	0.004	0.004
Turbine isentropic efficiency (%)	50	70	80
Generator/gearbox efficiency (%)	94	94	97
Steam flow (lbs/hr)	21,500	126,000	450,000
Inlet pressure (psig)	500	600	700
Inlet temperature (°F)	550	575	650
Outlet pressure (psig)	50	150	150
Outlet temperature (°F)	298	366	366
CHP System Parameters			
Boiler efficiency, HHV (%)	80	80	80
Fuel input (MMBtu/hr)	26.7	147.4	549.0
Steam to process (MMBtu/hr)	19.6	107.0	386.6
Power/heat ratio	0.09	0.10	0.13
Total CHP Efficiency, HHV (%)	79.8	79.5	79.7

* Steam turbine gen-set only (boiler and fuel prep equipment not included).
Source: NREL, 2003.

6.2   Gas Turbine Technologies

Combustion turbines, or gas turbines, have been used for power generation for decades and are often the technology of choice for new electric generation in the United States and much of the world due to their low capital cost, low maintenance, and low emissions. Turbine technology was developed in the 1930s as a means of propulsion for jet aircraft. Use of turbines for power generation began in the 1940s and 1950s, but it was not until the early 1980s that improvements in turbine efficiency and reliability resulted in increased utilization for power production.

The gas turbine is an internal combustion engine that operates with rotational rather than reciprocating motion. Turbines can be fueled by natural gas or biogas and are used in a broad scope of applications, including electric power generation, gas pipeline compressors, and various industrial applications requiring shaft power. While many newer turbines are large utility units, manufacturers are producing smaller and more efficient units that are well-suited to distributed generation applications. Turbines range in size from 30 kW (microturbines) to 250 MW (large industrial units).

Gas turbines can be used in a variety of configurations:

- **Simple-cycle operations**—a single gas turbine producing power only.

- **CHP operations**—a simple-cycle gas turbine with a heat recovery/heat exchanger that recovers the heat from the turbine exhaust and converts it to useful thermal energy, usually in the form of steam or hot water.

- **Combined-cycle operation**—high-pressure steam is generated from recovered exhaust heat and used to create additional power using a steam turbine. Some combined-cycle turbines extract steam at an intermediate pressure for use in industrial processes, making them combined cycle CHP systems.

An illustration of the configuration of a gas turbine is shown in **Figure 6-2**. As illustrated in the figure, gas turbine power generation systems use the Brayton cycle and consist of a compressor to compress the air to high pressure, a combustor chamber operating at high pressure, the gas turbine itself (shown in two parts), and the generator. The turbine section comprises one or more sets of turbine blades that extract mechanical energy from the hot combustion products. Some of that energy is used to power the compressor stage; the remaining energy is available to drive an electric generator or other mechanical load. The compressor and all of the turbine blades can be on one shaft or there can be two shafts, one for the compressor and the turbine stages that drive it, and a second for the turbine stages that produce useful output. To inject the fuel into the pressurized combustion chamber, the fuel must also be pressurized. A low Btu gas—like most biogas—will require only a small pump, while high-Btu (greater than about 1,000 Btu/standard cubic feet [scf]) gas requires a small compressor. Theoretical turbine efficiency is a function of turbine inlet temperature and pressure ratio across the power turbine, with higher levels of both factors leading to higher efficiency. Inlet temperature is limited by the ability of the turbine blades to operate at that temperature over the lifetime of the turbine.

Figure 6-2. Components of a Simple-Cycle Gas Turbine
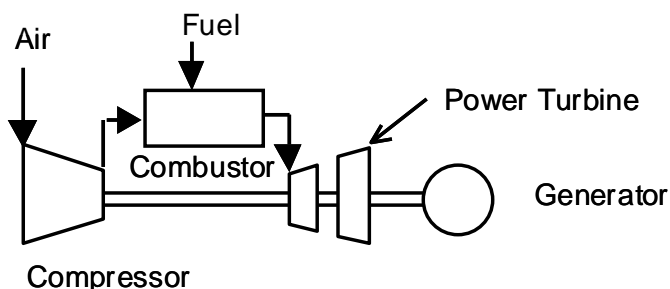
Source: Energy and Environmental Analysis, Inc., 2003.

Typical performance and cost characteristics of gas turbines based on natural gas fuel are shown in **Table 6-3.** There are some notable differences in gas turbine performance with biogas fuels, as discussed below.

Table 6-3. Gas Turbine CHP Typical Performance Parameters

Cost and Performance Characteristics	System 1	System 2	System 3	System 4	System 5
Electricity capacity (kW)	1,000	5,000	10,000	25,000	40,000
Equipment cost ($/kW)*	$1,200	$600	$600	$520	$460
O&M costs ($/kWh)*	0.010	0.006	0.006	0.005	0.005
Electric heat rate (Btu/kWh), HHV	15,580	12,555	10,950	9,945	9,220
Electrical efficiency, HHV (%)	21.9	27.8	31.2	34.3	37.0
Fuel input (MMBtu/hr)	15.6	62.8	109.5	248.6	368.8
Required fuel gas pressure (psig)	95	160	250	340	435
CHP Characteristics					
Steam output (MMBtu/kWh)	7,108	5,018	4,549	3.592	3,189
Power/heat ratio	0.48	0.68	0.75	0.95	1.07
Total CHP efficiency, HHV (%)	68	67	73	70	72

* Cost for natural gas fueled gas turbine-generator set only (gasification and heat recovery not included).
Source: NREL, 2003.

A biomass gas turbine system requires LFG, anaerobic digester gas, or a biomass gasifier to produce the biogas for the turbine. This biogas must be carefully filtered of PM to avoid damaging the blades of the gas turbine. Additionally, because a typical biomass gasifier produces a low-Btu biogas (e.g., 100 Btu/scf), the fuel compressor must be sized to handle about 10 times the gas flow compared to natural gas to provide the same Btu to the combustor. These flow needs make the shaft power to the fuel compressor comparable to the power of the air compressor, thereby reducing the turbine's efficiency. In a conventional gas turbine, the turbine is designed to handle about 10 percent more flow (standard cubic feet per minute) than the air compressor. In a low-Btu gas turbine, the turbine must be designed to handle about twice the flow of the air compressor. In addition, the air-to-fuel ratio is lower for biogas than for natural gas, so not all of the compressed air is needed. Some of this compressed air can be redirected to provide energy to the air compressors for pressurized direct gasifiers or to help compress the biogas in atmospheric gasifiers. Without removal of the excess air, the capacity of the turbine would be significantly reduced.

Because of all the modifications required, existing natural gas turbines cannot easily be retrofitted to operate on low-Btu biogas (< 300 Btu/scf). Gas turbines designed for low-Btu biogas generally cost at least 50 percent more than natural gas turbines on a per kW basis. Many gas turbine manufacturers offer turbine products that operate on medium-Btu landfill and wastewater treatment gas at equipment costs that are slightly higher than natural gas turbines, assuming the gas is properly treated and cleaned. Non-fuel O&M costs will increase for gas turbines using low- and medium-Btu biogas due to increased cleaning and more frequent maintenance intervals (this does not include the O&M costs of biogas treatment and cleanup, which is discussed separately); natural gas O&M costs provided in **Table 6-3** would increase by at least 75 percent for low-Btu biogas operation.[72]

Figure 6-3 shows the proposed integration of a gas turbine in a biomass gasification facility. While a number of gas turbines have been studied and tested for low-Btu biogas use modification and integration, commercial experience is very limited. At the time this report was prepared, there were no identified gas turbines operating on low-Btu syngas from gasification. There are biomass gasifiers that produce syngas for cofiring in integrated coal gasification combined-cycle power plants. There have also

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[72] Resource Dynamics Corporation, 2004.

been biomass gasifiers built with the intention of ultimately integrating them with gas turbines; in the interim, biogas is being used as a supplemental fuel.

There are a large number of gas turbines operating on the medium-Btu gas produced by landfills and, to a lesser extent, wastewater treatment plants. In these applications, gas cleaning is required to remove siloxane, chlorine and sulfur compounds, and moisture.

Figure 6-3. Proposed Gas Turbine Configuration in Integrated Biomass Gasification Facility

HRSG = Heat Recovery Steam Generator
LCV = Low Caloric Value
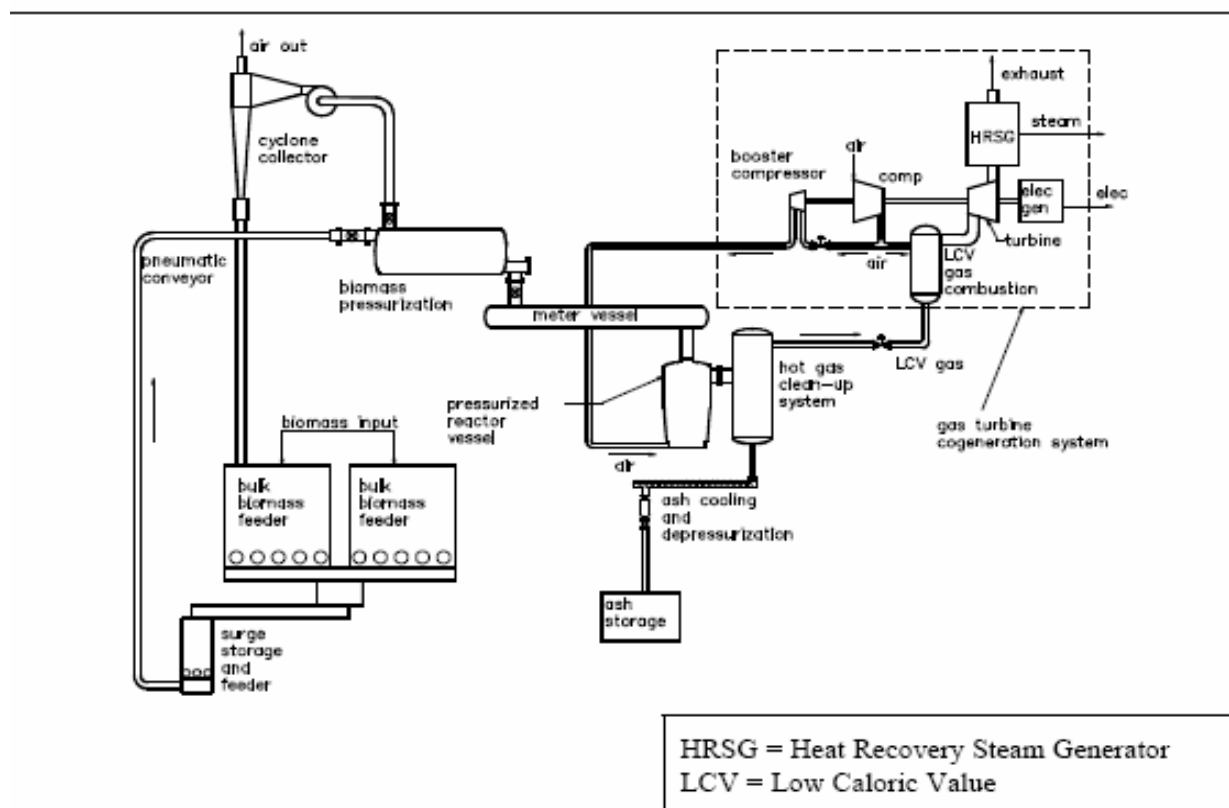
Source: Purvis, 1998.

6.3 Microturbine Systems

Microturbines are small gas turbines that burn clean gaseous and liquid fuels to create mechanical energy that turns an electrical generator or other load. Today's microturbine technology is the result of development work in small stationary and automotive gas turbines, auxiliary power equipment, and turbochargers, much of which was pursued by the automotive industry beginning in the 1950s. Microturbines entered field-testing around 1997 and began initial commercial service in 1999.

The size range for microturbines, either commercially available or in development, is from 30 to 250 kW. Microturbines, like larger gas turbines, can be used in power-only generation or in CHP systems. They are able to operate using a wide variety of fuels, including natural gas; sour gases (high sulfur content); biogas and medium-Btu gases, such as LFG and digester gas; biofuels; and liquid fuels such as gasoline, kerosene, and diesel fuel/distillate heating oil.

Microturbines generally have lower electrical efficiencies than similarly sized reciprocating engine generators and larger gas turbines. However, because of their design simplicity and relatively few moving parts, microturbines offer the potential for reduced maintenance compared to reciprocating engines.

Microturbines usually have an internal heat recovery heat exchanger called a recuperator. In typical microturbines, the inlet air is compressed in a radial compressor and then preheated in the recuperator using heat from the turbine exhaust. Heated air from the recuperator is mixed with fuel in the combustor and ignited. The hot combustion gas is then expanded in one or more turbine sections, producing rotating mechanical power to drive the compressor and the electric generator. In single-shaft models, a single expansion turbine turns both the compressor and the generator. Two-shaft models use one turbine to drive the compressor and a second turbine to drive the generator, with exhaust from the compressor turbine powering the generator turbine. The power turbine's exhaust is then used in the recuperator to preheat the air from the compressor.

The basic components of a microturbine are shown in **Figure 6-4.** The heart of the microturbine is the compressor-turbine package, which is most commonly mounted on a single shaft along with the electric generator. Because the turbine shaft rotates at a very high speed, the electric output of the generator must be processed to provide 60 Hertz (Hz) power (the frequency standard in the U.S.)

The single shaft is supported by two (or more) high-speed bearings. Because single-shaft turbines have only one moving part, they have the potential for low maintenance and high reliability. There are also two-shaft versions of the microturbine, in which the turbine on the first shaft only drives the compressor while a power turbine on a second shaft drives a gearbox and conventional electrical generator producing 60 Hz power. The two-shaft design has more moving parts but does not require sophisticated power electronics to convert high-frequency alternating current (AC) power output to usable 60 Hz power.

Figure 6-4. Microturbine-Based CHP System (Single-Shaft Design)
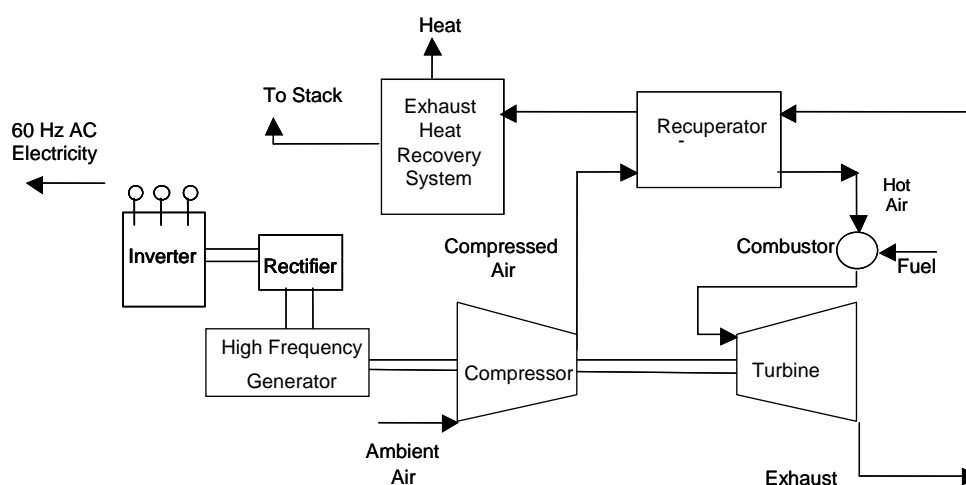
Source: Energy and Environmental Analysis, Inc., 2003.

Microturbines require gaseous fuel to be supplied in the 64 to 100 psig range, or above. Rotary vane, scroll, and screw compressors have been used to boost fuel gas pressure at the site to the pressure needed by the microturbine. However, this further reduces the efficiency of the system.

In CHP operation, a second heat recovery heat exchanger—the exhaust gas heat exchanger—can be used to transfer remaining energy from the microturbine exhaust to a hot water system. Recuperated microturbines have lower temperature exhaust than simple-cycle turbines; however, exhaust heat at low temperatures can be used for a variety of different applications, including process or space heating, heating potable water, driving absorption chillers, or regenerating desiccant dehumidification equipment. Some microturbine-based CHP applications have the ability to bypass their recuperator to adjust their thermal-to-electric ratio or do not use recuperators at all. The temperature of the exhaust from these microturbines is much higher (up to 1,200 ºF) and thus, more and higher temperature heat is available for recovery.

Typical performance and cost characteristics of microturbines based on natural gas fuel are shown in **Table 6-4.**

Microturbines have demonstrated that they can handle landfill and wastewater treatment gas, and in some cases low-Btu biogas, reasonably well because of their simple design. No major modifications are needed, but in addition to the power required by the fuel gas compressor, there is a small reduction in power output (10 to 15 percent) when running on landfill or digester gas. With both factors considered, a 15 to 20 percent increase in price per kW would be expected for microturbines operating on landfill or digester gas compared to the price for natural gas fired units of the same size. Maintenance costs would also increase 30 to 40 percent due to shorter maintenance intervals and increased inspections.[73]

Table 6-4. Microturbine CHP Typical Performance Parameters

Cost and Performance Characteristics	System 1	System 2
Electric Capacity (kW)	100	250
Equipment Cost ($/kW)*	$1,350	$1,100
O&M Cost ($/kWh)*	0.015	0.012
Electric Heat Rate, HHV (Btu/kWh)	13,555	11,850
Electrical Efficiency, HHV (%)	25.2	28.8
Fuel Input (MMBtu/hr)	1.4	3.0
CHP Characteristics		
Heat Recovered (MMBtu/kWh)	5,018	3,630
Total CHP Efficiency (%)	62	59
Power/Heat Ratio	0.68	0.94

*Cost for natural gas-fueled microturbine only (gasification and biogas treatment not included).
Source: NREL, 2003.

6.4   Reciprocating Internal Combustion Engine Technologies

Reciprocating internal combustion engines are a widespread and well-known technology. North American production exceeds 35 million units per year for automobiles, trucks, construction and mining equipment, marine propulsion, lawn care, and a diverse set of power generation applications. A variety of stationary engine products are available for a range of power generation market applications and duty cycles, including standby and emergency power, peaking service, intermediate and base load power, and CHP. Reciprocating IC engines are available for power generation applications in sizes ranging from a few kilowatts to more than 5 MW.

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[73] Resource Dynamics Corporation, 2004.

There are two basic types of reciprocating IC engines—spark ignition (SI) and compression ignition (CI). SI engines for power generation use natural gas as the preferred fuel, although they can be configured to run on propane, gasoline, biogas, or LFG. CI engines (often called diesel engines) operate on diesel fuel or heavy oil, or they can be set up to run in a dual-fuel configuration that burns primarily natural gas or biogas with a small amount of diesel pilot fuel.

Although diesel engines have historically been the most popular type of reciprocating IC engine for power generation applications, their use has been increasingly restricted to emergency standby or limited duty-cycle service in the United States and other industrialized nations because of air emission concerns, particularly associated with NO_x and PM. Consequently, the natural gas-fueled SI engine, which could also run on biogas, is now the engine of choice for the higher-duty-cycle stationary power market (more than 500 hr/yr) and is the primary focus of this discussion.

Reciprocating IC engine technology has improved dramatically over the past three decades, driven by economic and environmental pressures for power density improvements (more output per unit of engine displacement), increased fuel efficiency, and reduced emissions. Computer systems have greatly advanced reciprocating engine design and control, accelerating advanced engine designs and enabling more precise control and diagnostic monitoring of the engine process. Stationary engine manufacturers and worldwide engine research and development firms continue to drive advanced engine technology, including accelerating the diffusion of technology and concepts from the automotive market to the stationary market.

Typical performance and cost characteristics of reciprocating engines based on natural gas fuel are shown in **Table 6-5.**

Table 6-5. Gas IC Engine CHP Typical Performance Parameters

Cost and Performance Characteristics	System 1	System 2	System 3	System 4	System 5
Electric capacity (kW)	100	300	1000	3,000	5,000
Equipment cost ($/kW)*	$900	$770	$720	$570	$550
O&M cost ($/kWh)*	0.018	0.013	0.009	0.008	0.008
Electric heat rate, HHV (Btu/kWh)	11,500	11,000	10,200	9,533	9,213
Electrical efficiency, HHV (%)	29.7	31.0	33.5	35.8	37.0
Fuel input (MMBtu/hr)	1.11	3.29	10.2	28.6	46.1
CHP Characteristics					
Heat recovered (MMBtu/kWh)	5,593	5.093	3,709	3,281	3,345
Total CHP efficiency (%)	78	77	70	70	73
Power/heat ratio	0.61	0.67	0.92	1.04	1.02

* Costs for natural gas fueled engine-generator set only (gasification and fuel treatment not included).
Source: NREL, 2003.

A biogas-fired reciprocating engine system will encounter many of the same operating issues as a biogas-fired gas turbine:

LFG, an anaerobic digester, or a biomass gasifier is needed to produce the biogas fuel for the engine.

The biogas must be carefully filtered of PM to avoid damaging the engine.

The engine must be de-rated for burning low-Btu biogas rather than natural gas.

The engines will require modification to accommodate higher flow rates and impurities. However, required modifications to reciprocating engines are achieved more easily. In most cases, more filtration devices and new manifolds are all that is required to accommodate medium-Btu gases such as landfill and digester gas, typically adding about 5 percent to the cost of a natural gas engine. In addition, the lower heating values of biogas result in about a 15 percent decrease in power output compared to a natural gas engine, further increasing the overall equipment cost on a per kilowatt basis. Maintenance issues associated with biogas use in reciprocating engines include increased wear and tear, more cleaning, and up to eight times more frequent oil changes. Total non-fuel O&M costs for a biogas engine are approximately 60 to 70 percent higher than for a natural gas engine.[74]

The recovery of heat from a reciprocating IC engine is more complex, but more flexible, than from a gas turbine. As illustrated in **Figure 6-5**, heat can be recovered not only from the exhaust, but also from the jacket water and the engine oil. The high-temperature heat source is the engine exhaust, at 600-1,200° F. Depending upon the design, between 1,000 and 2,200 Btu can be recovered from the exhaust per kilowatt of engine shaft power. The jacket water leaves the engine (shown in the lower left corner of the engine) at about 200° F. As much as 4,000 Btu/kWh of heat can be recovered from the jacket water, depending on the system design, but 2,500 Btu/kWh is more typical. In this diagram, the heat from the engine exhaust is used to heat the jacket water before it is sent to the heat exchanger. If the heat demand is less than the heat produced by the CHP system, some of the jacket water is shunted to the excess heat exchanger, where the heat is dumped to the atmosphere. After moving through the heat exchangers, the jacket water is pumped through the oil cooler heat exchanger (slightly heating the jacket water) and back into the engine. In a separate circuit, the engine lube oil is pumped from the oil pan through the oil cooler and back into the engine. Only 300 to 900 Btu/kWh can be recovered from the engine lube oil. Another heat source (not shown) is turbocharger intercooling and aftercooling, which may be either separate or part of the jacket cooling system. The three potential heat loops offer an opportunity to design the heat recovery to most closely match the heat load of the site.

Figure 6-5. Closed-Loop Heat Recovery System for a Reciprocating IC Engine
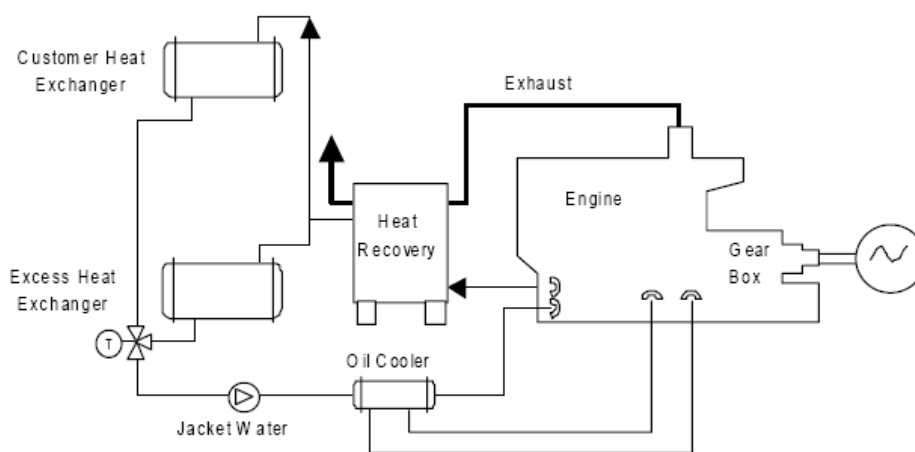
Source: EPA, 2004b.

There are a large number of gas IC engines operating on medium-Btu gas from landfills, wastewater treatment plants, and some installations at animal feedlots. Major engine manufacturers offer engine configuration packages and ratings specifically for medium-Btu gas. Additionally, some modular

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[74] Resource Dynamics Corporation, 2004.

biomass gasification development and demonstration projects fire a low-Btu biogas in reciprocating IC engines. These systems require a supplementary liquid or gaseous fuel for start-up.

6.5 Fuel Cell Systems

Fuel cells are an emerging small-scale power generation technology with high electrical efficiency and very low emissions. In fuel cells, the fuel is chemically combined with oxygen to create electricity, with useful heat as a byproduct. Because there is no combustion, fuel cells are quiet, have no moving parts, and can achieve electric efficiencies up to two times greater than internal combustion engines. Fuel cells can be sized for a wide variety of applications—from laptop computers (50 to 100 watts) to vehicles (50 to 85 kW) to central power generation (0.2 to 2 MW).

Cost and durability are the major challenges to fuel cell commercialization. Fuel cells are currently more expensive than internal combustion engines and have difficulty maintaining performance over the full useful life of the load served. The size, weight, thermal management, and water management of fuel cells are also barriers.

A fuel cell power system has many components, but its heart is a fuel cell "stack." The stack is actually made of many thin, flat fuel cells layered together. The term "fuel cell" is often used to refer to the entire stack, but strictly speaking, it refers only to the individual cells. A single cell produces a small amount of electricity, but hundreds of cells can be stacked together to produce a useable quantity of electricity.

A single fuel cell consists of an electrolyte and two catalyst-coated electrodes (a porous anode and cathode). Several different types of fuel cells are currently under development—each classified primarily by the kind of electrolyte it uses. The electrolyte determines the kind of chemical reactions that take place in the cell (see discussion below), the temperature range in which the cell operates, and other factors that affect the applications for which the fuel cell is most suitable, as well as its advantages and limitations.

Fuel cells require hydrogen for operation[75]. However, it is generally impractical to use hydrogen directly as a fuel source; instead it is extracted from hydrocarbon fuels or biogas feed using a reformer. The reformers produce and/or increase the concentration of hydrogen and decrease the concentration of gas species toxic to the fuel cell. In all three types of reformers (partial oxidation, autothermal reformation, and preferential oxidation), fuel processing techniques use some of the energy contained in the fuel to convert the hydrocarbons to hydrogen and CO. The reforming process is often performed at elevated pressure to allow a smaller equipment footprint.

Four main types of fuel cells are in various phases of development for stationary applications: phosphoric acid fuel cell (PAFC), proton exchange membrane fuel cell (PEMFC), molten carbonate fuel cell (MCFC), and solid oxide fuel cell (SOFC). To date, only the PAFC and the MCFC have operated on biogas. Typical performance and cost characteristics of fuel cells based on natural gas fuel are shown in **Table 6-6.**

As listed in **Table 6-7**, the fuel cell technology determines what constituents are desirable and acceptable in the processed fuel and oxidant streams. For example, fuel sent to a PAFC needs to be hydrogen-rich and have less than 5 percent CO, while both the MCFC and SOFC are capable of utilizing CO. PEMFCs require a pure hydrogen stream with less than 10 parts per million (ppm) CO. SOFCs and internal reforming MCFCs are capable of utilizing methane from anaerobic digesters or LFG within the cell, whereas PAFCs are not (PAFCs need an external reformer and have a low tolerance for methane

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[75] Direct methanol fuel cells are under development.

directly in the stack). Each fuel cell technology also has specific contamination limits that define the cleanup processes that are required.

Table 6-6. Fuel Cell CHP Typical Performance Parameters

Cost and Performance Characteristics	System 1	System 2	System 3	System 4	System 5
Fuel cell type	PAFC	MCFC	MCFC	PEM	SOFC
Nominal electric capacity (kW)	200	250	2,000	200	100
Commercial status	Commercial	Commercial	Demonstration	Demonstration	Demonstration
Equipment cost ($/kW)*	5,100	5,100	2,900		
O&M costs ($/kW)*	0.03	0.043	0.033		
Electric heat rate (Btu/kWh)	9,480	7,930	7,420	9,750	7,580
Electrical efficiency, HHV (%)	36	43	46	35	45
Fuel input (MMBtu/hr)	1.90	2.00	14.80	2.00	0.80
CHP Characteristics					
Heat output (MMBtu/kWh)	3,709	1,750	1,777	3,592	1,906
Total CHP efficiency, HHV (%)	75	65	70	72	70
Power/heat ratio	0.92	1.95	1.92	0.95	1.79

Costs for natural gas fueled fuel cell only (gasification and fuel treatment not included).
Source: NREL, 2003.

Table 6-7. Contamination Limitations on Fuel and Oxidant Delivered to Fuel Cells

Contaminant	Fuel Cell Type			
	PAFC	PEMFC	MCFC	SCFC
Oxidant	Air or oxygen-enriched air	Air to oxygen	Air	Air
Hydrogen	> ~90%	> ~99%	Yes	Yes
CO	< 3-5%	<10 ppm (toxic)	Some OK	Some OK
CO_2	Tolerates	< ~1%	Some OK	Some OK
Methane (CH_4)	No	No	Some OK	Up to 100% OK
Methanol (CH_3OH)	No	No	No	No
Hydrogen sulfide (H_2S)	< ~1 ppm	< 1 ppm	< ~1 ppm	< ~1 ppm
H_2S, carbonyl sulfide (COS), ammonia (NH_3), hydrogen cyanide (HCN), particulates, tars, oils, and phenols	No (sulfur is toxic)	No (sulfur and ammonia are toxic)	No (sulfur is toxic)	No (sulfur is toxic)

Source: NREL, 2003.

While most operating experience with fuel cells has been with natural gas, there are a handful of fuel cell installations operating in the United States powered by digester gas or LFG. Both PAFC and MCFC configurations have been demonstrated. These systems require a different fuel reformer with larger fuel injectors and additional piping. Gasifiers typically produce contaminants, which need to be removed before the hydrogen enters the fuel cell anode. The contaminant levels are dependent upon both the fuel composition and the gasifier employed. To meet the fuel standards described in **Table 6-7**, the gas product from the gasifier must be processed, which might involve gas cleanup, reforming, and purification. Gas cleanup equipment that efficiently and reliably removes contaminants to the specifications required by fuel cells is yet to be demonstrated.

Since fuel cells are in the early stages of commercial introduction, long-term experience on both natural gas and biogas has been limited, making it difficult to estimate what impacts the use of biogas would have on overall equipment and maintenance costs. Units operating on biogas would likely cost slightly more than natural gas versions and have a small decline in output. Maintenance would also likely be higher as biogas with more impurities might require increased cleaning and maintenance of the fuel gas reformer. It is likely that both equipment and maintenance costs of a biogas-fueled fuel cell would be at least 10 percent higher than a comparable natural gas-fueled system.

6.6   Stirling Engines

Like internal combustion engines, the Stirling engine is a reciprocating engine. However, the Stirling engine is an externally heated engine, and if that heat is supplied by a combustion process, it is an external combustion engine. The heat is transferred to the working gas and is then converted to work via the Stirling thermodynamic cycle. The internal combustion engine, by comparison, requires a pressure change—generated by burning of fuel in the cylinder—to work. Because the Stirling engine heat is supplied externally, a wide variety of heat sources can be used (such as fossil fuels, solar, nuclear, and waste heat), but the Stirling engine is particularly well-suited to biomass fuels.

As an external combustion engine, fuel is burned in a continuous manner outside of the Stirling engine's cylinders. This is unlike an internal combustion engine, where the fuel is injected into the cylinders intermittently and then exploded. Thus, external combustion allows for more complete burning of the fuel, which results in lower emissions. The external combustion also provides the extra benefit of reduced noise and vibration compared to internal combustion engines.

To complete the thermodynamic cycle, a Stirling engine must also be externally cooled. This can be accomplished in a variety of ways:

Forced or free convection cooling (e.g., air flowing over fins).

Water, ethylene glycol, or a mixture of both circulated through a cooling jacket surrounding the cold end of the engine. (The coolant is kept cool by a heat exchanger similar to or identical to a radiator in an automobile.)

Stirling engine systems are not commercially available today for stationary power applications. A number of Stirling generating systems are under development, and prototype systems are in field testing in wastewater treatment and other biomass applications. The key research and development challenge facing Stirling engine commercialization is to develop and mass-produce reliable, low-cost Stirling engines that compete with the cost and performance achieved by other traditional technologies. Typical Stirling engine CHP systems are compared in **Table 6-8.**

Table 6-8. Comparison of Stirling Engine Technologies

Characteristics	System 1	System 2	System 3
Electric Output (kW)	10	25	25
Usable Heat Output (kW$_{thermal}$)	24	44	N/A
Electric Efficiency[76] (%)	24	31	38

Source: NREL, 2003

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[76] Based on low heating value fuel input to AC electric power output.

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° 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

Plant Flowsheet and Design Information
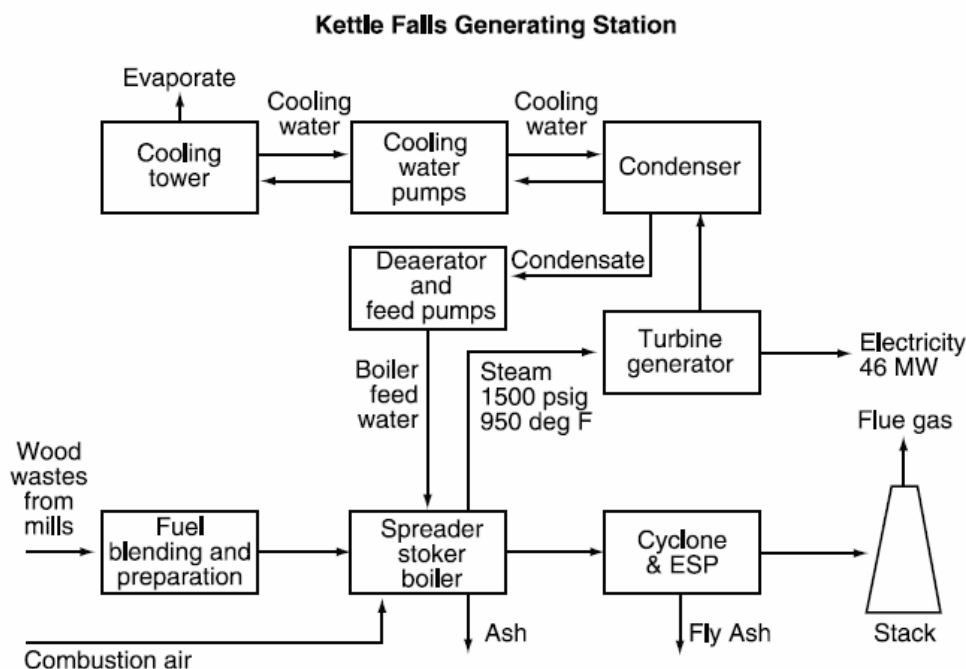
Source: Appel Consultants, Inc., 2000.

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

Biomass Cases	Tons/Day (as received)		
	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
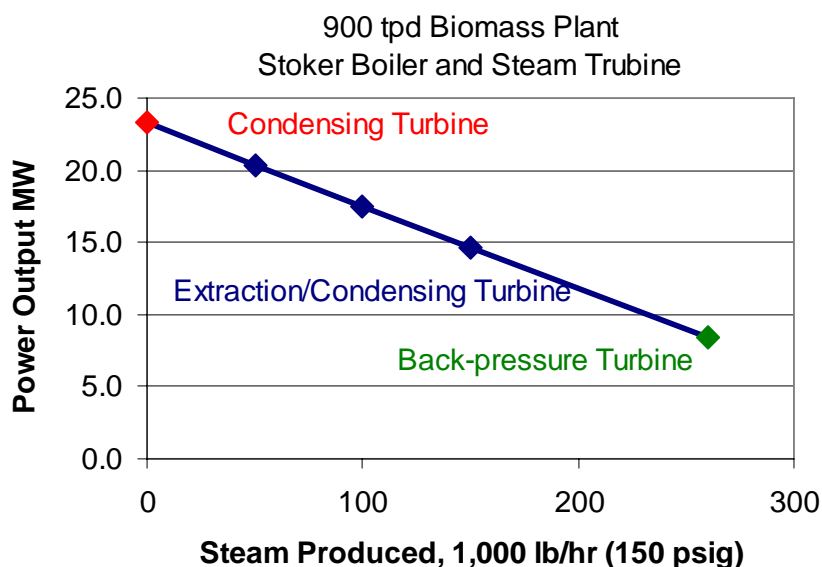
Table 7-4 presents the capital cost estimates for the three stoker boiler power systems. The capital requirements for the integrated power generation systems include:

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)

Cost Components	Tons/Day (as received)		
	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)**

| Cost Components	Tons/Day (as received)		
	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
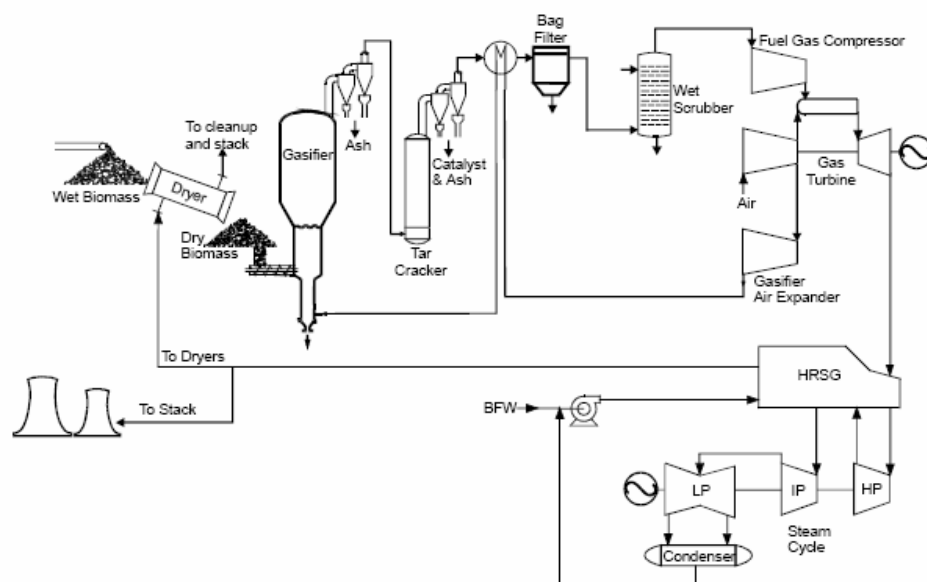
Source: Craig, 1996.

Figure 7-4. High-Pressure Biomass Gasification Combined-Cycle
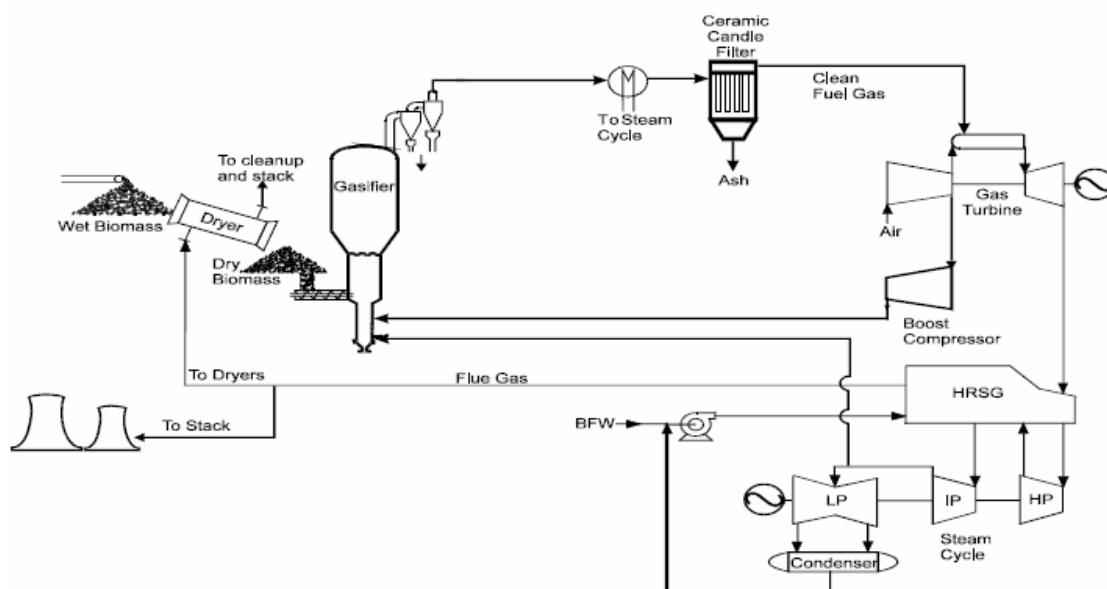
Source: Craig, 1996.

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)	$2.00
Natural gas/diesel cost ($/MMBtu)	$8.00
Plant operating factor	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.

Appendix A—Climate Change Benefits of Biomass CHP

CHP systems offer considerable environmental benefits when compared with purchased electricity and onsite-generated heat. By capturing and utilizing heat that would otherwise be wasted from the production of electricity, CHP systems require less fuel than equivalent separate heat and power systems to produce the same amount of energy. Because less fuel is combusted, greenhouse gas emissions, such as CO_2, as well as criteria air pollutants like NO_x and SO_2, are reduced. The use of biomass fuels in CHP, rather than natural gas or coal, further reduces CO_2 emissions from heat and power production. In addition to displacing the emissions of purchased fossil fuels that would otherwise be needed to separately generate thermal energy (rather than using captured waste heat), biogenic biomass[77] is typically considered a net zero emitter of CO_2 when used as a fuel for electricity and heat generation.[78]

National and international protocols for calculating and reporting GHG emissions generally require consideration of the three GHGs that are released when biomass is combusted for electricity (and heat) production: CO_2, methane, and nitrous oxide (N_2O). Scientific consensus states that the CO_2 emitted from burning biomass will not increase total atmospheric CO_2 if this consumption is done on a sustainable basis.[79] Because CO_2 is captured from the atmosphere by plants and trees during their growth, when it is released again during combustion it is reentering the carbon cycle, not being newly created. If plant materials are then regrown over a given period of time, the regrowth of new biomass takes up as much CO_2 as was released from the original biomass through combustion.[80] This process results in a cycle in which biomass fuels are considered to emit a total of zero net CO_2 emissions and are classified as green power when used to generate electricity.

Methane and N_2O are also created when biomass is combusted; however, unlike CO_2, they are not considered part of the natural degradation/recycling process and therefore are treated as direct emissions. Emissions of these gases from stationary combustion sources depend upon fuel characteristics, size and vintage of the combustion equipment, along with combustion technology, pollution control equipment, and ambient environmental conditions.[81] Emissions also vary with operation and maintenance practices. Therefore, most protocols (i.e., Intergovernmental Panel on Climate Change [IPCC] Guidelines, California Climate Action Registry [CCAR], EPA's National Inventory, and United Nations Framework Convention on Climate Change [UNFCCC] Clean Development Mechanism [CDM] Guidance)[82] require documentation of methane emissions from biogenic biomass combustion, though these emissions are generally small compared to CO_2 emissions. Though a potent GHG, N_2O as a byproduct of combustion is typically created in such small quantities that most protocols do not require estimation or reporting of N_2O emissions, although two do—the IPCC Guidelines (national-scale inventory) and CCAR (company-level inventory).[83]

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[77] Biogenic biomass refers to all organic biomass, such as wood, agricultural crops, landfill gas, and digester gas. Anthropogenic biomass consists of human-made materials that can be combusted for electricity and heat production, such as waste tires or portions of MSW, and is not included in the discussion of biomass fuels within this appendix. Note that the GHG emissions from the biogenic portion (e.g., yard waste, food scraps) of MSW is typically netted out of the total emissions and treated as biogenic biomass (e.g., CCAR, 2005).

[78] CCAR, 2007; Center for Resource Solutions, 2007; IPCC, 2006; EPA, 2004c; EPA, 2007b; UNFCCC, 2007a; UNFCCC, 2007b; UNFCCC, 2006a; UNFCCC, 2006b; WRI/WBCSD, 2007.

[79] UNFCCC, n.d.

[80] EPA, 2007b.

[81] EPA, 2007b.

[82] CCAR, 2007; IPCC, 2006; EPA, 2007b; UNFCCC, 2007a; UNFCCC, 2007b. Note that the UNFCCC does not require reporting of methane emissions for biogas projects because the emission source is assumed to be very small (UNFCCC, 2006a).

[83] CCAR, 2007; IPCC, 2006; EPA, 2004c; EPA, 2007b; UNFCCC, 2006a; UNFCCC, 2006b; UNFCCC, 2007a; UNFCCC, 2007b.

Additional Issues

Some project-specific evaluations of GHG emissions calculate emissions based on the life cycle of the fuel, in addition to the combustion process used to transform its energy into electricity and/or heat (e.g., UNFCCC CDM).[84] These life-cycle analyses often consider the energy required to plant, grow, fertilize, harvest, transport, and convert the fuel to a usable feedstock before it is combusted. Currently, this type of calculation is not generally used in most of the major international or national protocols and guidance, but may be included in some project-level analyses depending on how project boundaries are drawn.

Offset project protocols typically require calculating emission reductions based on a comparison to the counterfactual—what the emissions would have been in the absence of the project. For example, for a biogas-fueled CHP project, the GHG emission reductions from offsetting purchased grid electricity and a natural gas-fueled boiler are calculated relative to the efficiency of the CHP system and the state of the digester fuel (biogas) before the project started. If the digester were in place prior to the CHP system's addition and the gas had been flared, the GHG emission reductions from the biogas fuel will be calculated relative to those released when flaring the digester gas. If the digester and the CHP system were installed at the same time, the GHG emission reductions of the biogas will be calculated relative to the emissions from uncontrolled manure decomposition. Emission reductions from certified offset projects are typically calculated through a detailed and laborious process and might include life-cycle analysis of emissions.[85]

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[84] UNFCCC, 2006a; UNFCCC, 2006b; UNFCCC, 2007a; UNFCCC, 2007b.
[85] DOE, n.d.; RGGI, 2007; UNFCCC, 2006a; UNFCCC, 2006b; UNFCCC, 2007a; UNFCCC, 2007b.

Appendix B—EPA CHP Partnership Biomass Tools and Resources

The EPA CHP Partnership is a voluntary program designed to foster cost-effective CHP projects. The goal of the partnership is to reduce the environmental impact of power generation by working closely with energy users, the CHP industry, state and local governments, and other stakeholders to help develop new projects and promote their energy, environmental, and economic benefits.

The CHP Partnership is open to CHP industry members; institutions and non-governmental organizations; energy users; and state, local, and tribal governments interested in developing CHP projects or promoting the benefits of CHP. The partnership offers a variety of tools and services designed to facilitate and promote partners' development of CHP projects.

The CHP Partnership's many tools and services, provided free of charge to all partners, fall into three categories: outreach and education to energy users, industry, and policymakers; direct project assistance; and public recognition for outstanding projects. Following is a list of biomass-related tools and resources that the CHP Partnership offers on its Web site.

For more information about becoming an EPA CHP partner and what the CHP Partnership can do to help you, visit <www.epa.gov/chp/partnership/index.html>.

Funding and Regulatory/Rates Opportunities (www.epa.gov/chp/funding/index.html)
The CHP Partnership posts regularly updated lists of:

- State and federal biomass/biogas incentives.
- State and federal CHP incentives.
- Utility, state utility commission, and state environmental agency rules, regulations, and rates that remove unintended barriers to clean distributed generation projects.

The CHP Partnership updates this information every two weeks. Each incentive is listed and sortable by name, state, and type of incentive (e.g., grant, tax incentive, rebate, low-interest loan).

CHP Emissions Calculator (www.epa.gov/chp/basic/calculator.html)
The CHP Emissions Calculator is a tool that compares the anticipated CO_2, SO_2, and NO_X emissions from a CHP system to the emissions from a comparable system that uses separate heat and power. The calculator allows a user to select from a large number of default or user-specified system profiles (including renewably fueled) to describe the CHP and separate heat and power systems for comparison. It then estimates the CO_2, SO_2, and NO_X emission reductions from CHP, presenting its estimates in terms of metric tons of carbon equivalent, acres of trees planted, and emissions from cars.

Technical Assistance for Candidate Sites (www.epa.gov/chp/partnership/tech_assistance.html)
The CHP Partnership provides information, tools, and technical assistance to energy users who are considering CHP projects. With a short phone call, the partnership can help:

- Identify opportunities for cost-effective CHP (including CHP fueled with biomass or biogas).
- Assess goals, drivers, and potential barriers for a project.
- Direct energy users to existing tools and resources.
- Determine next steps for project-specific technical assistance.

Project-specific assistance can include performing comprehensive Level 1 feasibility analyses; researching technical, permitting, or regulatory questions; providing information on the CHP project development and procurement process; or answering questions about CHP applications and technologies,

siting, and system configuration. The goal of the CHP Partnership's technical assistance efforts is to provide energy users with technology, fuel, and vendor neutral information regarding CHP projects.

CHP Project Development Process (www.epa.gov/chp/project-development/index.html)
CHP technology and applications are proven and running successfully nationwide; however, potential CHP users do not always understand all of the steps required to complete a successful project. To streamline the complex and time-intensive task of CHP implementation, those considering CHP systems for their facilities should understand the entire project development process. The CHP Partnership has developed a series of key questions, considerations, and decisions that will be part of any CHP development project—outlined as a five-stage process on this Web site. The CHP Partnership offers services and tools to help project developers, end users, and others at each stage of project development.

Municipal Wastewater Facilities Strategic Market (www.epa.gov/chp/markets/wastewater.html)
Wastewater treatment facilities (WWTFs) that use anaerobic digesters to treat their waste are an excellent technical fit for CHP. At a WWTF, the biogas flow from the digester can be used as "free" fuel to generate electricity and power in a CHP system using a turbine, microturbine, fuel cell, or reciprocating engine. Installing a CHP system at a WWTF offers in a number of benefits:

- Producing power at a cost below retail electricity.
- Displacing purchased fuels for thermal needs.
- Qualifying as a renewable fuel for green power programs.
- Enhancing power reliability for the plant.
- Offering a cost-effective opportunity to reduce greenhouse gas and other air emissions.

The CHP Partnership recently analyzed the potential market and technical fit for CHP in this sector. A report describing this work is now available from the CHP Partnership:

- *Opportunities and Benefits of Combined Heat and Power at Wastewater Treatment Facilities* (www.epa.gov/chp/documents/wwtf_opportunities.pdf)
  A report on WWTFs throughout the country, engineering rules of thumb for estimating the generation potential at a WWTF, and numerous links to case studies showing the benefits of CHP at WWTFs.

Dry Mill Ethanol Strategic Market (www.epa.gov/chp/markets/ethanol.html)
The CHP Partnership has been working with the ethanol industry since 2003 and has developed many useful documents that discuss the benefits of CHP for ethanol production facilities. Relevant case studies and presentations are also available on the Web site. Key documents include:

- *Combined Heat and Power: An Energy-Efficient Choice for the Ethanol Industry* (www.epa.gov/chp/markets/ethanol_fs.html)
  A four-page fact sheet that explains the efficiency gains of CHP over separate heat and power, discusses the strong technical fit for CHP at ethanol production facilities, and provides information on some ethanol facilities currently employing CHP.

- *Assessment of the Potential for Energy Savings in Dry Mill Ethanol Plants from the Use of Combined Heat and Power (CHP)* (www.epa.gov/chp/documents/ethanol_energy_assessment.pdf)
  A report on the energy savings from using CHP to generate electricity and steam for ethanol production instead of natural gas– and coal-fired, state-of-the-art boilers to generate steam and purchase grid electricity. Reductions in total fuel use are shown to be greater than 12 percent versus natural gas and 10 percent versus coal. The report includes a detailed discussion of performance and output characteristics and estimation methodologies.

Appendix C—Landfill Gas

MSW landfills are the largest source of human-related methane emissions in the United States, accounting for about 25 percent of these emissions in 2004. At the same time, methane emissions from landfills represent a lost opportunity to capture and use a significant energy resource. LFG is created as solid waste decomposes in a landfill. This gas consists of about 50 percent methane (the primary component of natural gas), about 50 percent CO_2, and a small amount of non-methane organic compounds.[86]

Instead of allowing LFG to escape into the air, it can be captured, converted, and used as an energy source. LFG is extracted from landfills using a series of wells and a blower/flare or vacuum system. This system directs the collected gas to a central point where it can be processed and treated depending upon the ultimate use for the gas. From this point, the gas can be simply flared or used to generate electricity, replace fossil fuels in industrial and manufacturing operations, fuel greenhouse operations, or be upgraded to pipeline-quality gas. Using LFG helps to reduce odors and other hazards associated with LFG emissions, and it helps prevent methane from migrating into the atmosphere and contributing to local smog and global climate change.

LMOP is an EPA voluntary assistance program that helps to reduce methane emissions from landfills by encouraging the recovery and use of LFG as an energy resource. LMOP forms partnerships with communities, landfill owners, utilities, power marketers, states, project developers, tribes, and non-profit organizations to overcome barriers to project development by helping them assess project feasibility, find financing, and market the benefits of project development to the community. For information about the specific technical assistance, outreach and education, and networking opportunities that LMOP offers, visit the program's Web site at <www.epa.gov/lmop>.

A Landfill Gas to Energy Project Development Handbook describes the major aspects of LFG project development, including economic analysis, financing, choosing project partners, environmental permitting, and contracting for services. Download the handbook at <www.epa.gov/lmop/res/pdf/handbook.pdf>.

Funding Landfill Gas Energy Projects: State, Federal, and Foundation Resources is an online funding guide that offers detailed information on innovative state, federal, and foundation funding resources available for LFG energy projects. View the funding guide at: <www.epa.gov/lmop/res/guide/index.htm>. Project developers can find additional technical guidance documents and case studies at <www.epa.gov/lmop/res/index.htm>. These include various documents that discuss considerations and approaches for handling siloxanes in LFG. See sections labeled "Fact Sheets" and "Case Studies" for resources and information.

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[86] EPA has developed a computer software program called the MSW Decision Support Tool that allows decision makers to compare MSW management strategies with respect to cost, energy consumption, and environmental releases to the air, land, and water, www.epa.gov/ord/NRMRL/scienceforum/thorneloe_s.htm.

Appendix D—Anaerobic Digesters

EPA, USDA, and DOE offer resources on the design and performance characteristics and benefits of anaerobic digesters—used to convert bio-based materials to biogas that can be used for power and/or heat production.

One such resource is the AgSTAR Program, a voluntary effort sponsored by the three agencies. (See <www.epa.gov/agstar>.) The program encourages the use of methane recovery technologies, such as anaerobic digestion, at confined animal feeding operations that manage manure as liquids or slurries. These technologies reduce methane emissions while achieving other environmental benefits.

The EPA Office of Wastewater Management, Municipal Technologies Branch, offers resources and information to municipal wastewater treatment facilities, which can also process their biosolid waste in anaerobic digesters and then capture and use the gas. (See <www.epa.gov/owm/mtb>.)

The USDA Natural Resource Conservation Service (NRCS) has published design guidelines for three types of anaerobic digesters:[87]

- A *covered anaerobic lagoon,* as defined by NRCS, is "a constant volume lagoon designed for methane production and recovery in conjunction with a separate waste storage facility." A cover can be floated on or suspended over the surface of a properly sized anaerobic lagoon to recover methane. Ideally, the cover is floated on the primary lagoon of a two-cell lagoon system, with the primary lagoon maintained as a constant volume treatment lagoon and the second cell used to store treated effluent until it can be properly applied to land. The lagoons are not usually heated and the lagoon temperature and biogas production vary with ambient temperatures. Coarse solids, such as hay and silage fibers in cow manure, must be separated in a pretreatment step and kept from the lagoon. If dairy solids are not separated, they will float to the top and form a crust. That crust will thicken, reducing biogas production and eventually filling the lagoon.

A *complete-mix digester* is a constant volume, flow-through, controlled temperature tank designed for methane production and recovery. These digesters can accommodate the widest variety of wastes. Complete-mix digesters are usually above-ground, heated, insulated, round tanks; however, the complete-mix design has also been adapted to function in a heated, mixed, covered earthen basin. Wastes can be mixed using gas recirculation, mechanical propellers, or liquid circulation. A complete-mix digester can be designed to maximize biogas production as an energy source or to optimize volatile solids reduction with less regard for surplus energy.

A *plug-flow digester* is a heated, unmixed, rectangular tank. New waste is pumped into one end of the digester, horizontally displacing an equal portion of older material and pushing the oldest material out through the opposite end. Biogas formed in a digester bubbles to the surface and can be collected by a fixed rigid top, a flexible inflatable top, or a floating cover, depending on the type of digester.

The demand for anaerobic digesters for livestock manure treatment, wastewater treatment, and energy production has accelerated quickly throughout the past few years. Factors influencing this market demand include increased technical reliability of anaerobic digesters through the deployment of successful operating systems during the past five years; growing concern of farm owners and municipal treatment works about environmental quality; an increasing number of state and federal programs that share in development costs; increasing energy costs and the desire for energy security; and the emergence

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[87] USDA, n.d.

of new state energy policies (such as net metering legislation) designed to expand growth in reliable renewable energy and green power markets.

Managing Manure With Biogas Recovery Systems: Improved Performance at Competitive Costs, an AgSTAR brochure, provides background on anaerobic digestion and explains how the methane it produces can be captured and used to generate heat, hot water, and electricity. It includes information to help dairy and swine farmers determine if a biogas recovery system is right for their farm and describes the environmental benefits of anaerobic digestion systems. It also provides a table that compares the cost and environmental effectiveness of conventional animal waste systems to those of anaerobic digester systems. Download the brochure at <www.epa.gov/agstar/pdf/manage.pdf>.

Emerging Technologies for Wastewater Biosolids Management, a report from the EPA Office of Wastewater, is designed to help municipal wastewater treatment system owners and operators find information on emerging biosolids management technologies, such as anaerobic digestion. Featured technologies can be used to reduce the volume of residuals to be managed, produce stabilized biosolids that can be used to help improve soil fertility and tilth, or promote the recovery of energy from biosolids. Technical and cost data for more than 60 technologies are provided. Another 25 early-stage technologies are also identified. Download the report at <www.epa.gov/owm/mtb/epa-biosolids.pdf>.

Appendix E—Modular Biomass Systems Available or in Pre-Commercial Development

A number of small development companies are working on modular biomass CHP systems. **Table E-1** compares the specifications and costs, as available, for five modular systems. The systems are all available in sizes of 250 kW or less. None of them could be categorized as being fully commercial.[88] Contact information for each of the companies that offers the systems follows.

CPC and Chiptec have demonstration projects at customer sites that have been supported by federal and state funding sources. Emery Energy is more active in larger gasification systems, but has expressed interest in commercializing small systems based on the pilot test facility operating at its research and manufacturing facility. Ormat is demonstrating its heat recovery technology at a larger scale (4 MW) using the heat available from combustion turbines operating on natural gas at a natural gas pipeline compression station. The system has not yet been integrated with a biomass combustion system in an operating facility. There are no identified demonstration installations for the Entropic Turbion system.

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[88] The modular systems under development are identified here for informational purposes only. EPA has not verified the accuracy of the developers' claims nor is the inclusion of this information an endorsement.

Table E-1. Small Modular Biomass System Comparison

Company	Community Power Corporation	Chiptec Wood Energy Systems	Emery Energy Company	Ormat	Entropic Energy
Web site	www.gocpc.com	www.chiptec.com/	www.emeryenergy.com	www.ormat.com/	www.entropicenergy.com
Equipment Type	Downdraft gasifier, gas cleanup, mostly IC engine prime mover	Two-chamber gasification with hot gas combustion to produce steam	Small- to large-scale biomass gasification equipment and design	Direct combustion organic Rankine bottoming cycle	Direct combustion entropic cycle
Available Sizes	5 to 75 kW	0.4 to 50 MMBtu/hr gasifier/boilers	Small to large, custom design	100 to 5,000 kW	100 to 5,000 kW
Commercialization Status	Several field demonstrations in the United States and internationally, four sites in California	250 kW commercial demonstration CHP system installed in Vermont hospital	Large systems installed worldwide, modular system in pre-commercial stage	Demonstration of waste heat recovery for geothermal energy and gas turbines	Developmental projects in Canada
Applicable System	BioMax Series	250 kW was minimum economic size	75 kW CHP system designed but not built	Ormat Energy Converter	Biopower Turbion Series
Cost	$2,500 to $4,000/kW for equipment plus estimated $600 to $1,000/kW for fuel handling	Budgetary quote for 100 boiler horsepower gasifier/boiler (3,400 thousand Btu/hr): $215,000 (equipment only); steam turbine generator not included	$12,350/kW installed (~$925,000 total installed costs, not including fuel preparation)	$4,500 to $7,500/kW equipment cost	$3,000 to 5,000/kW equipment cost
Electric Output (kW)	50	250	75		250 kW
Thermal Output (Btu/kWh)	600	11,000	No information provided	17,400	16,500
Electric/Thermal Ratio	0.28	0.08	No information provided		
Electric Efficiency	16 to 22%	< ~15%	30% from fuel gas (~20% from biomass)	11%	13%
CHP Efficiency	55 to 75%	~60 to 70%	Data requested	67%	76%
Emissions	2003 California Air Resources Board-certified	C-Series has been BACT-approved	No information provided	No information provided	No information provided

Modular Biomass System Developers and Suppliers

Chiptec Wood Energy Systems

Equipment type: two-chamber gasification with hot gas combustion to produce steam, 0.4 to 50 MMBtu/hr gasifier/boilers

48 Helen Avenue
South Burlington, VT 05403

Telephone: (800) 244-4146
E-mail: BobBender@Chiptec.com
Web site: www.chiptec.com

Community Power Corporation

Equipment type: downdraft gasifier, gas cleanup, mostly IC engine prime mover, 5 to 75 kW

8110 Shaffer Parkway
Littleton, CO 80127

Telephone: (303) 933-3135
E-mail: rwalt@gocpc.com
Web site: www.gocpc.com

Emery Energy Company

Equipment type: small- to large-scale biomass gasification equipment and design

157 West Pierpoint Avenue
Salt Lake City, UT 84101

Telephone: (801) 364-8283
E-mail: bphillips@emeryenergy.com
Web site: www.emeryenergy.com

Entropic Energy

Equipment type: direct combustion entropic cycle, 100 to 5,000 kW

106-1656 Martin Drive, Suite 189
White Rock, BC, Canada
V4A 6E7

Telephone: (604) 538-3033
E-mail: porter@EntropicEnergy.com
Web site: http://entropicenergy.com

FlexEnergy

Equipment type: microturbines for burning very low Btu gases, applied to a portable wood gasifier

22922 Tiagua
Mission Viejo, CA 92692

Telephone: (949) 380-4899
E-mail: info@flexenergy.com
Web site: www.flexenergy.com

Ormat Technologies, Inc.

Equipment type: direct combustion organic Rankine bottoming cycle power systems for geothermal, waste heat, and biomass systems, 100 to 5,000 kW

6225 Neil Road
Reno, NV 89511

Telephone: (775) 356-9029
E-mail: ormat@ormat.com
Web site: www.ormat.com

Sunpower, Inc.

Equipment type: Stirling engines matched to biomass combustion, 0.5 to 10 kW

182 Mills Street
Athens, OH 45701

Telephone: (740) 594-2221
E-mail: info@sunpower.com
Web site: www.sunpower.com/index.php

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