Technical Report

Biopower Technical Assessment: State of the Industry and Technology

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BIOPOWER TECHNICAL ASSESSMENT
State of the Industry and the Technology

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Chapter	Source	Authors
2: Barriers	"2001 EERE Strategic Program Review"	Raymond Costello, DOE Paul Grabowski, DOE Other?
4: Lessons Learned	"Biomass Energy Production in California: The Case for a Biomass Policy Initiative"	Gregory Morris, Future Resources Associates, Inc.
4: Lessons Learned	"Lessons Learned from Existing Biomass Power Plants"	George Wiltsee, Appel Consultants, Inc.
5: Technology Characterizations	" Renewable Energy Technology Characterizations"	Kevin Craig, NREL Kevin Comer, Antares Group
6: Environmental Performance	"Green Power Fact Sheets"	Ask MM
6: Environmental Performance	" A Comparison of the Environmental Consequences of Power from Biomass, Coal, and Natural Gas"	Margaret Mann, NREL Pamela Spath, NREL
7: Policy	"Biomass and Bioenergy in the United States"	Helena Chum, NREL Ralph P. Overend, NREL
7: Policy	" Incentives, Mandates, and Government Programs for Promoting Renewable Energy"	Mark Gielecki, DOE-EIA Fred Mayes, DOE-EIA Lawrence Prete, DOE-EIA

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EXECUTIVE SUMMARY

Biopower (biomass-to-electricity generation), a proven electricity generating option in the United States and with about 11 GW of installed capacity, is the single largest source of non-hydro renewable electricity. This 11 GW of capacity encompasses about 7.5 GW of forest product industry and agricultural industry residues, about 3.0 GW of municipal solid waste-based generating capacity and 0.5 GW of other capacity such as landfill gas based production. The electricity production from biomass is being used and is expected to continue to be used as base load power in the existing electrical distribution system.

An overview of sector barriers to biopower technology development is examined in Chapter 2. The discussion begins with an analysis of technology barriers that must be overcome to achieve successful technology pathways leading to the commercialization of biomass conversion and feedstock technologies. Next, an examination of institutional barriers is presented which encompasses the underlying policies, regulations, market development, and education needed to ensure the success of biopower.

Chapter 3 summarizes biomass feedstock resources, characteristics, availability, delivered prices, requirements for processing, and the impediments and barriers to procurement.

A discussion of lessons learned includes information on the California biomass energy industry, lessons from commercial biopower plants, lessons from selected DOE demonstration projects, and a short summary of the issues considered most critical for commercial success is presented in Chapter 4.

A series of case studies, Chapter 5, have been performed on the three conversion routes for Combined Heat and Power (CHP) applications of biomass—direct combustion, gasification, and cofiring. The studies are based on technology characterizations developed by NREL and EPRI. Variables investigated include plant size and feed cost, and both cost of electricity and cost of steam are estimated using a discounted cash flow analysis. The economic basis for cost estimates is given.

Environmental considerations are discussed in Chapter 6. Two primary issues that could create a tremendous opportunity for biomass are global warming and the implementation of Phase II of Title IV of the Clean Air Act Amendment of 1990 (CAAA). The environmental benefits of biomass technologies are among its greatest assets. Global warming is gaining greater salience in the scientific community and among the general population. Biomass use can play an essential role in reducing greenhouse gases, thus reducing the impact on the atmosphere. Cofiring biomass and fossil fuels and the use of integrated biomass gasification combined cycle systems can be an effective strategy for electric utilities to reduce their emissions of greenhouse gases.

The final chapter reviews pertinent Federal government policies. U.S. government policies are used to advance energy strategies such as energy security and environmental quality. Many of the benefits of renewable energy are not captured in the traditional marketplace economics. Government policies are a means of converting non-economic benefits to an economic basis, often referred to as "internalizing" of "externalities." This may be accomplished by supporting the research, development, and demonstration of new technologies that are not funded by industry because of projected high costs or long development time lines.

1.   SITUATION ANALYSIS

Biopower (biomass-to-electricity power generation) is a proven electricity generating option in the United States, and with about 11 GW of installed capacity, is the single largest source of non-hydro renewable electricity, as shown in Figure 1.1. This 11 GW of capacity encompasses about 7.5 GW of forest product and agricultural industry residues, about 3.0 GW of MSW-based generating capacity, and 0.5 GW of other capacity such as landfill gas based production. The electricity production from biomass is being used and is expected to continue to be used as base load power in the existing electrical distribution system.

Figure 1.1: 1999 Renewable Electricity Generation
(Billion Kilowatthours)

Hydropower   312   Other   77.12

PV   0.05
Geothermal   13.07
Solar Thermal   0.89
Biomass   58.65
Wind   4.46

Source: DOE EIA Annual Energy Outlook 2001
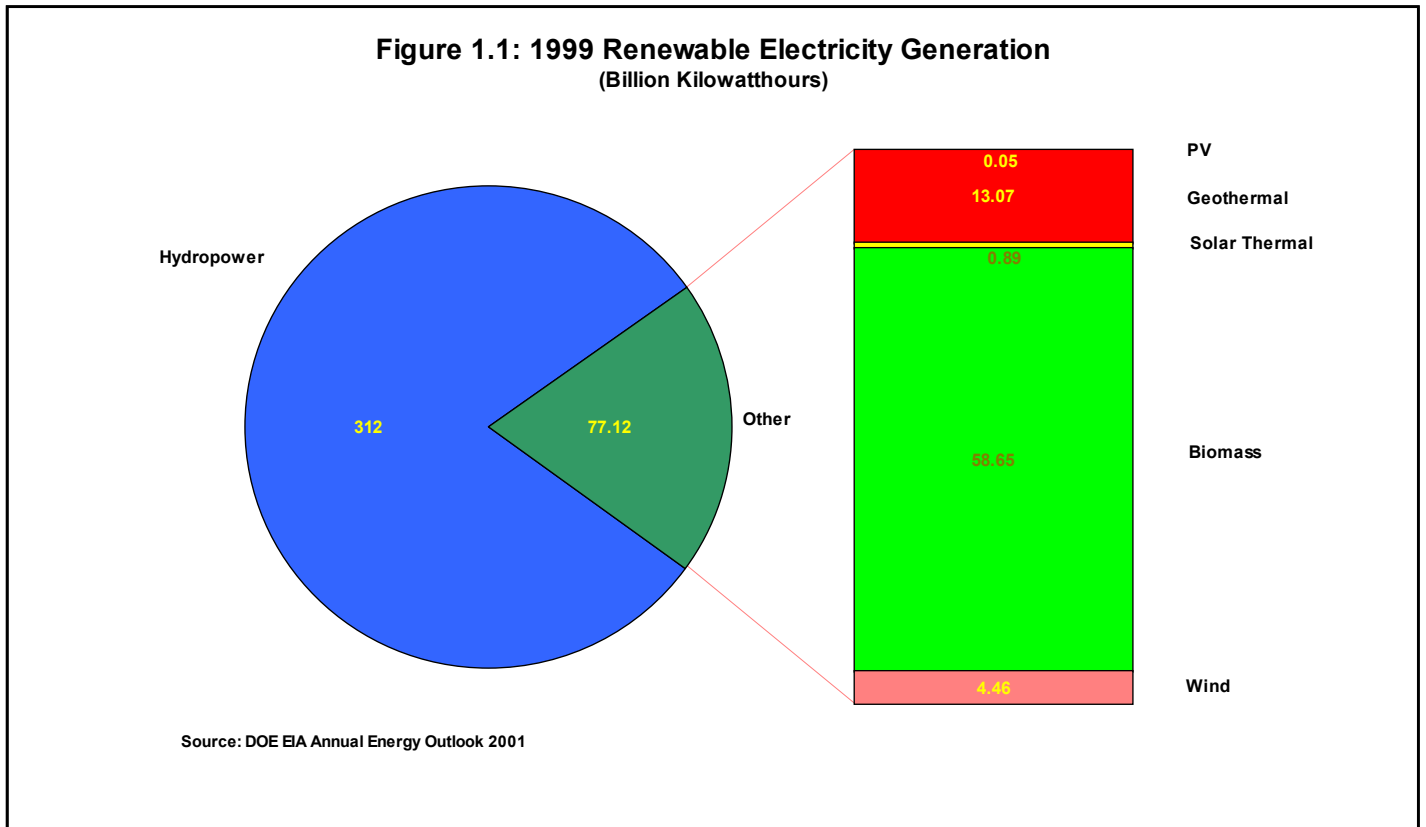
In the United States, biopower experienced dramatic growth after the Public Utilities Regulatory Policy Act (PURPA) of 1978 guaranteed small electricity producers (less than 80 MW) that utilities would purchase their surplus electricity at a price equal to the utilities' avoided cost of producing electricity. The passage of PURPA as well as various state incentives resulted in a factor-of-three increase in grid-connected biopower generating capacity in the period from 1980-1990 (See Figure 1.2). The certainty of these contracts propelled industry investment to $15 billion dollars and created 66,000 jobs. The PURPA legislation had no energy efficiency criterion and no incentives to add capacity at higher efficiency. In addition, the time needed to recover the investment was less than 10 years, so most investments were made on state-of-the-art technology at the time (combustion/steam). As a consequence, these plants, as a whole, had fairly low efficiency (industry average of 20% with notable exception at individual plants).

Since "conventional" biopower was apparently well on its way in the commercial marketplace, research during subsequent periods focused on more advanced combustion technologies and gasification.

Figure 1.2: Bioenergy Electricity Generation, 1981 - 1999
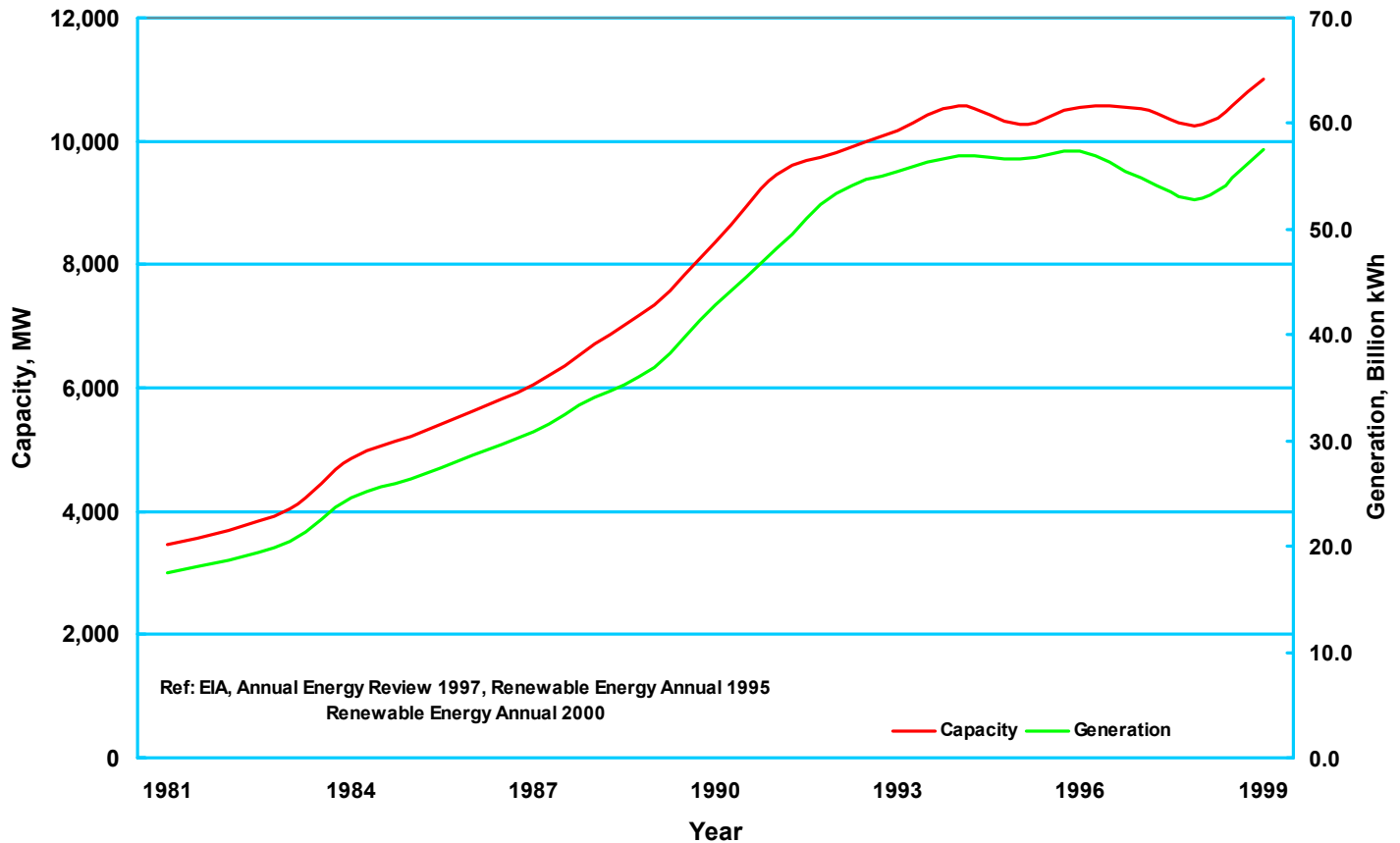
By the early 1990s, the biopower industry was beginning to stall for many reasons including higher feedstock costs, caused by inadequate infrastructure and no explicit accounting for the environmental benefits in utility regulation or market costing, and much lower new generation costs compared to natural gas CC. In addition, avoided cost contracts signed under PURPA were expiring and the utilities were unsuccessful in petitioning to buy back the contracts. More recently, the biopower industry has experienced uncertainty surrounding impending utility restructuring in a number of states. This situation has had detrimental effects on the industry that are still being felt today.

The 7.5 GW of traditional biomass capacity represents about 1% of total electricity generating capacity and about 8 % of all non-utility generating capacity. More than 500 facilities around the country are currently using wood or wood waste to generate electricity. Fewer than 20 of these facilities are owned and operated by investor- or municipally- owned electric utilities. The majority of the capacity is operated in combined heat and power (CHP) facilities in the industrial sector, primarily in pulp and paper mills and paperboard manufacturers. Some of these facilities have buy-back agreements with local utilities to purchase net excess generation. Additionally, a moderate percentage of biomass power facilities are owned and operated by non-utility generators, such as independent power producers that have power purchase

agreements with local utilities. The number of such facilities is decreasing somewhat as utilities buy back existing contracts. The stand-alone power production facilities largely use non-captive residues, including wood waste purchased from forest products industries and from urban wood waste streams, agricultural residues from harvesting and processing, used wood pallets, and some waste wood from construction and demolition, to generate electricity. In most instances, the generation of biomass power by these facilities also facilitates a reduction in local and regional waste streams.

All of today's capacity is based on mature, direct combustion boiler/steam turbine technology. The average size of existing biopower plants is 20 MW (the largest approaches 75 MW) and the average biomass- to-electricity efficiency of the industry is 20%. These small plant sizes (which lead to higher capital cost per kilowatt-hour of power produced) and low efficiencies (which increase sensitivity to fluctuation in feedstock price) have led to electricity costs in the 8-12 ¢/kWh range.

The near term domestic opportunity for gasification combined cycle technology is in the forest products industry, where a majority of whose power boilers will reach the end of their useful life in the next 10-15 years. This industry is familiar with use of its low-cost residues ("hog" fuel and a waste product called "black liquor") for generation of electric and heat for its processing needs. The higher efficiency of gasification based systems would bolster this self-generation (offsetting increasing electricity imports from the grid) and perhaps allow export of electricity to the grid. The industry is also investigating the use of black liquor gasification in combined cycles to replace the aging fleet of kraft recovery boilers.

An even nearer-term and lower-cost option for the use of biomass is cofiring with coal in existing boilers. Cofiring biomass with coal has the potential to produce 7.5 GW by 2010 and 26 GW by 2020. Though the current substitution rate is negligible, a rapid expansion is possible based on wood residues (urban wood, pallets, secondary manufacturing products) and dedicated feedstock supply systems (DFSS) such as willow, poplar and switchgrass. The carbon replacement rate in 2010 would be 14.5 Tg.

The next generation of stand-alone biopower production will substantially mitigate the high costs and efficiency disadvantages of today's industry. The industry is expected to dramatically improve process efficiency through the use of cofiring of biomass in existing coal-fired power stations, through the introduction of high-efficiency gasification combined cycle systems, and through efficiency improvements in direct combustion systems made possible by the addition of dryers and more rigorous steam cycles at larger scales of operation. Technologies presently at the research and development stage, such as Whole Tree Energy™, integrated gasification fuel cell systems, and modular systems are expected to be competitive in the future.

2.   BARRIERS[1]

An overview of sector barriers to biopower technology development is examined below. The discussion begins with an analysis of technology barriers that must be overcome to achieve successful technology pathways leading to the commercialization of biomass conversion and feedstock technologies. Next, an examination of institutional barriers is presented which encompasses the underlying policies, regulations, market development, and education needed to ensure the success of biopower. This document draws upon recent insights contained in *The Biopower Roadmap* (to be published), which was developed through a series of three industry-led stakeholder workshops facilitated by the U.S. Department of Energy during the past year.[2]

Technology Barriers

Biomass is a very desirable fuel and feedstock because it is renewable, sustainable, and clean (generally does not contain many pollutant-forming species such as sulfur, nitrogen and heavy metals.) Biomass is also widely available throughout the world and amenable to conversion to a wide variety of useful forms. However, biomass, more so than virtually any other fuels or energy source, varies considerably in its elemental composition, energy content, and physical characteristics. It also contains species, such as alkali metals, that, while not considered pollutants, often cause mechanical problems, such as deposition and corrosion of heat transfer surfaces, in conversion systems. As such, it presents considerable technical challenges at virtually all phases of conversion to useful energy forms and products.

Combustion/Cofiring

Combustion has been, for the entire history of the human species, the most common method of extracting energy from biomass (other than food) either directly, in the form of heat and light from a fire, or indirectly through use of this heat to produce steam that turns electricity-generating turbines. Direct combustion of biomass to raise steam is used in all of the existing 7 GW of biomass generation plants in operation in the U.S. today.

Many types of biomass used for fuel contain alkali metal species such as sodium, potassium, and calcium. In a combustion environment, the combustion products of these species, chlorides, silicates, etc., can form deposits on heat transfer surfaces reducing heat transfer, and thus, overall plant efficiency. They can also accelerate the corrosion or erosion of the heat transfer surfaces. Both of these mechanisms increase the maintenance requirements of the power plant. When biomass is cofired with coal (even in small percentages), the biomass containing these alkali species can change the properties of the resulting mixed ash, which can have a significant impact on the coal plant's O&M costs or even operability.

In 1996, the Biopower Program funded a collaboration between Sandia, NREL, University of California at Davis, Foster Wheeler Development Corp., Thomas R. Miles Consulting Design Engineers, and the U.S. Bureau of Mines to conduct an integrated study that elucidated the mechanisms of alkali species formation and deposition and developed guidelines for use by plant operators to avoid deposition problems. An on-going collaboration between Sandia, NREL and, later, NETL continued the investigation of the formation and deposition mechanisms. Results of these studies have been of great use in ongoing experiments being carried out by industry.

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[1]Excerpted from *2001 EERE STRATEGIC PROGRAM REVIEW Biopower*, DOE

[2] *The Biopower Roadmap*, Office of Power Technologies, May 2001 (draft)

For cofiring to see widespread use, a number of technology-related issues must be resolved. Some, but not all cofiring tests have resulted in significant NO_x reductions. The mechanisms responsible for these reductions need to be identified and taken advantage of. It must be demonstrated that a variety of biomass feedstocks can be effectively burned in the full range of coal boiler types. This demonstration will allow these plants the fuel flexibility that the existing industry has demonstrated is necessary for economic viability. There is some concern that components of some biomass feedstocks may reduce the efficiency and effectiveness of systems for the selective catalytic reduction of NO_x (SCR systems). This could be a significant technical barrier to market penetration of cofiring. The existence of this problem must be confirmed or refuted and, if valid, guidelines must be developed for biomass feedstock compositions as well as possible cost-effective methods for eliminating the harmful components.

Gasification

In the longer term, gasification technologies hold the most promise for next-generation power generation efficiency improvements from combined cycles and fuel cells, as well as for production of high value co-products along with power generation. DOE has had a notable success with the FERCO Vermont gasifier project by successfully operating its commercial scale demonstration plant. This gasifier has since proven to be even more efficient than it was first thought to be in that the gasifier throughput has been in excess of 175 percent of the original design.

For this technology class to flourish, however, a number of technical barriers must be overcome. These include scale-up of the technology, replication of successful demonstrations and technologies that will aid in the integration of gasification systems with gas turbines and fuel cells. Existing technologies such as scrubbing can accomplish gas cleanup, but to achieve maximal efficiencies with minimal environmental impact, other options such as tar cracking must be developed to enhance the removal of tars and condensable organics. Some of the technical issues with conversion devices (turbines and fuel cells) have been at least partially addressed by efforts such as the DOE Clean Coal Program; however, these must be adapted for use with biomass.

Small Systems

A significant number of the world's 2 billion people who lack access to electricity have available substantial quantities of biomass resources but lack the means to convert this resource into electricity in a clean, reliable, and efficient manner. In addition, in the developed world, distributed generation is receiving increased attention as a way of increasing energy reliability as well as the efficiency of the transmission and distribution system. To be economically competitive and environmentally acceptable, a new generation of small biopower systems is being developed. These will couple biomass conversion devices (combustors and gasifiers) to conventional and advanced electricity generators such as microturbines, Stirling engines, and eventually fuel cells. These systems must overcome a number of technical issues including reliable and automated feeding and operation, reliable small-scale combustor and gasifier system development, small-scale gas cleaning systems and emission reduction methodologies. As an example, research at NREL has shown that CO and NO_x emissions from a gasifier/internal combustion engine system (a very common system in the developing world) can be substantially reduced below equivalent emissions on natural gas by carefully tuning engine operating parameters and using a medium heat content gas.

Feedstock Production, Harvest, Transport, and Preparation

All biomass energy systems have the economic and energy cost of producing, transporting, and preparing the biomass feedstock as technical barriers. Significant progress has been made in this area, but to be truly economically competitive, new feedstocks and methods for their harvesting and preparation must be developed. In addition, harvesting, preparation, transportation, and feeding of a variety of biomass feedstocks that are suitable for power production must be demonstrated and new methods developed for reducing costs and energy requirements must be verified. This will reduce the delivered cost of feedstock to the energy facility to a level more competitive with fossil fuels as well as increase the return to the farmer producing the biomass.

Institutional

The commercial development of renewable energy technologies can be impeded by barriers that do not involve technical aspects of a given technology. Technological progress that improves performance or increases system efficiencies can open doors to deployment; however, market issues ultimately depend on overcoming the institutional challenges that these technologies will face. It can be far more difficult to put into place the necessary institutional mechanisms that will drive these commercial efforts. The keys to the successful implementation of energy technologies, and in particular, biopower technologies, are overcoming issues that can be categorized as the following:
> –Regulatory
> –Financial
> –Infrastructural
> –Perceptual

These categories were first developed in *The Potential of Renewable Energy: An Interlaboratory White Paper*, by INEEL et al, prepared for the Department of Energy, March 1990.

Regulatory

Through the regulatory process, governments direct activities in the broader societal interest. Regulations usually pertain to two broad issues: (1) markets and (2) health, safety, and environmental protection. Regulatory factors can create technology development opportunities that would not exist in unregulated environments. Within the United States, for example, the passage of the Public Utilities Regulatory Policy Act (PURPA) in 1978 required electric utilities to buy power from independent power producers and was designed to encourage small-scale electric power production from renewables, cogeneration, and energy conservation. This law has been considered by some analysts to be "the single most important spur to creation of a commercial renewable power market...".[3] During the 1980s, biomass power capacity rapidly expanded as a result of laws mandating that utilities purchase power from suppliers under contracts based on avoided power generation costs (as specified under PURPA). These contractual prices were substantially higher than current wholesale power prices, and permitted biomass projects to be financed and operated at a profit.

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[3] Silverman, Murray and Susan Worthman, The Future of Renewable Energy Industries, *The Electricity Journal,* March 1995)

In the 1990s, changes in the electric power industry due to massive restructuring resulted in lower avoided costs and as present contracts are concluded, this biomass generation could be at risk. The closing of high cost power plants and the introduction of high-efficiency natural gas facilities are also putting considerable downward pressure on electricity prices. In the United States and some other countries, utilities are breaking into multiple companies that compete for the power generation, transmission, distribution, and on-site elements of the power market. The eventual impacts of these and other trends on individual power producers are not yet clear. However present trends suggest that profit margins will be even tighter in the future. This atmosphere of heightened competition has already had the effect of reducing the willingness of power companies to take risks with new technology and to use renewable energy resources.

Although this situation presents challenges, the restructuring of the power industry is also providing new opportunities for biopower. Markets are developing for "green power," where electricity from selected generation sources can be sold at high prices (typically 1-2 cents per kilowatt-hour). Through consumer choice, green markets offer opportunities to expand the use and future development of renewable technologies. Increased biopower is also being encouraged through Renewable Portfolio Standards (RPS) established by state regulatory agencies. These standards require utilities to provide certain percentages of power, typically 5-10 percent, from renewable sources. Recognizing that these market-driven forces are currently undergoing clarification, the Biopower Program participates with environmental groups (such as Green-e) to resolve issues such as defining "green power" and understanding the public perception of biomass conversion technologies. Despite this progress, state and market incentives for biopower only exist in certain states. In addition, Federal, state and municipal policies and definitions with regard to green power and qualifying biopower technologies (e.g. some states and municipalities only include landfill gas) need to be harmonized to create a robust portfolio standard. This could lead to increased acceptance of biopower and resultant grassroots demand for increased deployment.

In the United States today, the regulations that control the release of oxides of sulfur (SO_2) and nitrogen (NO_x) are rapidly tightening under a variety of cap and trading schemes now being proposed for pollutants, particularly for NO_x. These regulations may work as a potential boon to biopower because biopower technologies such as cofiring improve utilities' emissions profiles in SO_x and NO_x. However, in some instances, EPA regulations and policies discourage existing coal plants from cofiring by opening them up to New Source Reviews if they modify their existing plants to accept biomass. The Biopower Program is currently collaborating with environmental regulatory bodies such as the EPA to reduce regulatory uncertainty related to NSR and emissions. This is a critical issue because there are more than 200 companies outside the wood products and food industries that generate biopower in the U.S. Where power producers have access to very low cost biomass supplies, cofiring is an attractive option for power companies to save fuel costs and earn emissions credits.

In the future, the potential regulation of greenhouse gas emissions will likely result in a particular advantage for the carbon dioxide-neutral biopower technology.

Financial

Financial constraints pertain to the availability and cost of a project and to the overall financial attractiveness of renewable energy technologies. Capital markets generally perceive the deployment of emerging technologies as involving more risk than established technologies. The higher the risk, the higher the rate of return demanded on capital thus impacting the rate of investment in these new, emerging technologies. Although the Biopower Program has worked to respond to these constraints through collaborative cost-sharing arrangements with developers, more needs to be done such as accelerating capital depreciation to facilitate investments in new technologies.

Tax incentives for renewable energy technologies have been passed by Congress to offset their higher tax burden and the hidden costs of fossil fuels. Under the Energy Policy Act of 1992 (EPACT), electricity production from wind and biomass grown from energy crops became eligible for a 1.5 cents/kWh production incentive, available for 10 years. Yet this production incentive is overly restrictive as EPACT provisions only allow for "closed loop biomass" (crops grown exclusively for power generation). The Program is hopeful that pending legislation will expand to include open loop biomass with a broader definition of qualifying feedstocks.   To date, in the biomass area, ethanol is the main beneficiary of tax policy. While that may change under the President's National Energy Plan with the revisiting of Section 29 tax credits for landfill gas, tax credits need to be expanded to open loop firing and cofiring.

Infrastructural

Infrastructure is a general term for the entire energy service production and delivery system. It involves decisions made by a broad range of players including consumers, energy service providers such as utilities, fuel suppliers, and others. The nature of the biomass technology requires the need for infrastructure for the supply of feedstocks and for distributing products. Unlike fossil fuels such as coal and natural gas, which have a highly developed and sophisticated infrastructure in the U.S via railroad transportation and pipelines, a similar infrastructure does not currently exist for biofuels.

At this time, the biomass supplies are dominated by low-cost residues streams. The residue stream consists of materials self-generated by industries that process biomass for fiber or food uses (such as paper mills, lumber mills, sugar mills, etc.) or other economic activities (agriculture, urban construction and demolition, rate of waste generation, etc.). The quality, quantity, and cost of these resources continually vary in response to economic growth rates, discount factors, and regulation, e.g., the regulation of landfill activity and policies towards recycling.

In the future, a dedicated feedstock supply system based on short-rotation woody crops and herbaceous perennial crops could dramatically expand the assured availability of biomass for energy applications. The Biopower Program is working with Oak Ridge National Laboratory through the Bioenergy Feedstock Development Program to help expand the supply of these energy crops. Furthermore, establishing a Biomass Reserve Program (BRP) of perennial tree and grass crops that are particularly suitable for low-quality cropland, like that currently enrolled in the Conservation Reserve Program (CRP), could help to remove some infrastructural barriers related to the cost and supply of feedstocks. DOE will collaborate with USDA to assess the potential for using CRP-like programs to produce both energy and environmental benefits from investments in agricultural programs.

Another problem associated with the technology infrastructure concerns the 50-mile supply radius for the economic collection and transportation of fuel. In the future, the development of new technology (Fischer-Tropsch) that allows for the conversion of biomass into a liquid may allow for the feedstock to be transported more cost-effectively at greater distances. In the meantime, small modular systems are being looked at for distributed applications. These systems are less than 5 MW and can be transported directly to the feedstock production site.

Perceptual

The Biopower Program has a number of activities related to outreach, technology transfer, education and communication, as there is a lack of familiarity with biomass power technologies by the public and government and industry decision makers. Many people still do not know what the term "biomass" means, let alone understand the benefits and new technology developments associated with biomass. In addition, some environmental groups do not view biomass as a "green" technology. Awareness of biomass tends to be associated with wood stoves and concerns over emissions from the combustion of wood than with

biomass as an alternative energy technology. Less is known by the public and others about the low emissions, high efficiency, and environmental benefits offered with state-of-the-art biomass power systems. There are also concerns related to harvesting of trees as well as the need for sustainable supply. These unfavorable perceptions translate into financial costs and risks to any biomass project. Only with considerable education efforts and demonstration that environmental concerns are being accounted for can the risks of nonacceptance be overcome. In terms of these perceptual barriers, the program is examining a number of activities to educate and disseminate better information on the benefits of biopower to industry, regulators, environmental organizations, and the public to gain appreciation for bioenergy and, in turn, harness support for biopower-friendly policies.

3.   FEEDSTOCK SUPPLY

This section summarizes biomass feedstock resources, characteristics and availability, delivered prices and requirements for processing, and the impediments and barriers to procurement.

Biomass resources – characteristics and availability

Biomass resources are generally classified into five major categories – urban wood wastes, mill residues, forest residues, agricultural residues, and dedicated energy crops. The availability, characteristics, and costs of acquisition of each of these resources are very different. Availability and price estimates for urban wood wastes and forest residues are highly uncertain and depend on local conditions. Availability of mill residues and agricultural residues can be estimated more precisely; however, prices depend on local market conditions and, in the case of agricultural residues, cropping patterns and environmental restrictions. Energy crops are not currently grown as a fuel feedstock. Availability and price is therefore more speculative. More detailed discussion on each of these feedstocks is summarized below. Discussion of the specific resource methodologies and data sources can be found in Walsh et al., 2000.[1] In addition, there are numerous other useful studies that have estimated biomass feedstock availability, including Wiltsee (1998), Rooney (1998), Fehrs (1999), Antares (1999), and Goldstein (2000).

Urban wastes.

Urban waste is a generic category that encompasses a variety of woody materials, such as yard and tree trimmings, site clearing wastes, pallets, and packaging materials, that can be diverted from municipal solid waste (MSW) landfills and possibly composting facilities. Urban wood wastes also include construction and demolition debris that is typically disposed of in construction and demolition (C/D) landfills. The physical characteristics of these materials varies widely. Yard and tree trimmings are a relatively clean woody fuel that have a moisture content of 35%-60% depending on the vegetation type and season (Badger, 2002). Site clearing wastes are similar to tree trimmings except they may contain rocks and dirt, if stumps are not separated. Yard trimmings and site clearing wastes are often processed with drum chippers that can blow the chips directly into a chip van for transport. Processing requirements are therefore minimal once the material has been separated from the MSW stream. Pallets and packaging materials are also relatively high quality resources with moisture content tending to be rather low (<15%). C/D debris contains many different wastes including chemically treated wood and non-woody materials, such as metal, concrete, wallboard, and shingles. These non-woody materials must be source separated or taken to a recycling center for separation and recovery. Pallets and C/D debris are usually processed with hammermills to break apart. Magnets and non-ferrous metal detectors, screens, and hogs may also be required for processing.

Estimating quantities and delivered prices of urban wood wastes is confounded by a general lack of data. For the most part, regional and state-level surveys, per capita waste generation coefficients, and compositional analysis data are used to estimate availability. Walsh et al. (2000) estimated total annual urban wood wastes at about 36 million dry tons. This estimate is based on surveys of the wood waste deposited in MSW landfills, C/D landfills, and compost facilities. These data indicate that 6%-8% of material taken to MSW landfills is wood, 20-50% deposited at C/D landfills is

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[1]Walsh et al. (2000) is currently being updated. The updated report will include the state-level biomass resource database and a selected county-level database.

wood, and 80%-90% taken to compost facilities is wood. The product of these composition fractions and total waste deposited, corrected for moisture content, provides an estimate of total availability.

The delivered prices at which urban wood waste is available are highly location specific. Delivered prices can be estimated as a function of an average processing cost (e.g., hammermills and separation), an average transport cost including loading and unloading, less some fraction of the landfill disposal or tipping fee. Local and state regulatory policies (e.g., recycling requirements and certification), the extent of competing uses, such as mulch and compost, as well as other factors can affect costs. Given the uncertainties about availability, location-specific factors affecting delivered prices, and anecdotal evidence, Walsh et al. assume that 60% of the resource could be available at delivered prices of $25/dry ton or less and the remainder at delivered prices of less than $35/dry ton. In some cases, delivered prices could be negative due to the presence of high offsetting tipping fees. For example, Goldstein (2000) reports state landfill tip fees ranging from $13 to $70/ton and Wiltsee (1998) shows supply curves for urban wastes ranging from a low of -$80/ton to over $20/ton. The approximate breakdown of the delivered prices for urban wood wastes is summarized below.

	Avoided landfill tipping fee	Collection & processing	Transport	Total
Urban wood wastes	($0-$100)	~$20-$25	$5-$10	<$25-$35

Mill residues.

Primary mill residues are classified into three types–bark stripped from logs, coarse residues (chunks and slabs), and fine residues (shavings and sawdust). These residues are generated in the processing of lumber, pulp, veneers, and composite wood fiber materials. Moisture content of this material is about 20%. These residues are advantageous because they tend to be clean, uniform, and concentrated at a single source. However, nearly all of these residues are currently used as fuel or as inputs in the manufacture of products. Very little of this resource is currently unused. For bark, about 80% is used for fuel with 18% used in low-value products (e.g., mulch).   For coarse residues, about 85% is used in the manufacture of fiber products with about 13% used for fuel. About 55% of the fine residues are used as fuel with 42% used in products.

Although most mill residues are used, payments to mill operators greater than the residue's value in their current use could make them available as a fuel feedstock. This is especially true of the mill residues used on-site in relatively low efficiency boiler systems to produce heat and steam (Walsh et al., 2000). Walsh et al. (2000) report anecdotal evidence suggesting that residues used on-site for low-value energy purposes could be purchased for $15-25/dry ton and residues used to produce higher-valued wood fiber products could be purchased for about $30-40/dry ton. Payments to mill operators to make these residues available could thus range from $0 to $40/dry ton. Some minimal processing of the residues could also be required. In total, most of the unused residues could be obtained at prices below $25/dry ton and residues in current use could be had for $15-$40/dry ton.

	Mill payments	Collection & processing	Transport	Total
Mill residues	$0-$40	$0-$5	$5-$10	<$25-$55

Forest residues.

Forest wood residues include two sources–logging residues and the rough, rotten, and salvable dead wood (RRSD). Logging residues are the unused portion of the growing stock that are cut or killed by harvest

operations and left behind. These materials include small branches, limbs, tops, and leaves. According to Smith and Sheffield (2000), logging residues account for about 6% of softwood growing stock removals and about 11% of hardwood removals. The total amount of logging residue produced annually is about 11 million dry tons. The RRSD resource is considerably larger than the logging residues resource. Rough trees are those that do not contain a sawlog (i.e., 50 percent or more of live cull volume) or are a non-merchantable species. Rotten trees are trees that do not contain a sawlog because of rot (i.e., 50 percent or more of the live cull volume). Salvable dead wood includes downed or standing trees that are not considered merchantable. The size of this resource is vast and easily exceeds 1 billion dry tons. However, most of this RRSD material is inaccessible due to the absence of roads or access, is not economically retrievable with current technology, or is located in environmentally sensitive areas. About 10% of the RRSD resource might be considered available after accounting for access, material retrieval efficiency, and environmental restrictions (Walsh et al., 2000).

Recovery of the RRSD material (i.e., whole-trees) is done most cost-effectively with conventional feller-bunchers, skidders, and whole-tree chippers. Recovery of logging residues from the commercial harvest of timber and fiber operations at landings requires a whole-tree chipper or tub grinder. In both cases, chipping converts low-quality material into easily handled wood chips, which can be blown directly into a tractor trailer and chip van for transport. Quality of the material is generally high since much of the dirt debris is removed by differences in particle density when the chips are blown into the transport trailer (Badger, 2002). Although the chips may be relatively uniform in size they are often mixed with long slivers and splinters from small branches and limbs. For this reason, screening may be required before they are introduced into a wood energy handling system. The moisture content for both sources ranges from about 40-60%.

Delivered prices for forest residues could include a stumpage fee for gaining access to the material, collection costs (felling, skidding, and chipping), and hauling (including loading/unloading). Collection costs will depend on the scale of operation, utilization of the equipment, and the size and density of the available material. Logging residue collection costs also depend on whether the material is collected concurrently with the commercial timber or pulp operation or whether removal is done after the commercial operation. Hauling costs for forest residues are generally higher than the other biomass resources because roads may be unpaved, curvy, and otherwise limit truck size and travel speeds.

	Stumpage	Collection	Transport	Total
Logging residues	<$5	$10-$30	$5-$20	<$25-$55

Agricultural residues.
Corn stover and wheat straw are the two primary sources of agricultural residues. Other grain crops are either limited in acreage or else the amount of residue is small. The quantity of corn stover and wheat straw available depends on grain yield (bu/acre), total grain production or acreage, and the amount of residue that must be left to maintain soil quality (i.e., nutrients and organic matter) and limit erosion. These environmental sustainability restrictions differ by crop and rotation, soil type, field slope, weather conditions, and tillage system. Under average conditions, about 30 to 40 percent of corn stover and wheat straw residues may be removed. Currently, most of these agricultural residues are left on the ground and plowed under. A major limitation of agricultural residues is the limited collection season–usually a couple of months following grain harvest. Year-round utilization of these resources may require storage of up to ten months.

The costs of gathering these materials include mowing, raking, baling, loading and unloading, storage, and hauling. Collection costs using conventional baling equipment range from about $20-$25/dry ton. Uncovered storage of the bales for year-round use adds another $5/dry ton. As reported by Walsh et al.

(2000), typical payments to farmers to compensate for lost nutrients and environmental benefits can vary between $10-$15/dry ton. Haul costs depend on distance and numerous logistical factors, such as crop acreage density, proportion of farmers selling residues, etc.

	Collection	Farmer payments	Storage	Transport	Total
Agricultural residues	$20-$25	$10-$15	$5	$5-$10	<$35-$55

Dedicated energy crops.

Dedicated energy crops include short rotation woody crops (SRWC) such as hybrid poplar and hybrid willow, and herbaceous crops such as switchgrass. Management practices for each crop are regionally dependent. For hybrid poplars, trees are planted at a density of about 500-600 trees/acre and are harvested after 6 to10 years of growth depending on the region of country and growth rates. Although these trees will re-sprout, current management guidelines suggest replanting with improved clones following harvest. Hybrid willow is relegated to the northern states. It is planted at much higher densities (about 6200 trees/acre) and harvested after 4 years of growth. Hybrid willow stands are regenerated by coppicing with as many as 7 succeeding coppice stands expected from the initial establishment. Hybrid poplars are harvested with conventional forestry equipment (feller-bunchers, skidders, and whole-tree chippers) and willow with some form of combine machine. Both woody crops are delivered as whole-tree chips. The establishment of switchgrass is similar to that of a conventional hay crop. Once established it can produce for about 10 years before replanting is required. Switchgrass is harvested with conventional baling equipment and is delivered to conversion facilities as large round or rectangular bales. The ability to use existing on-farm equipment is a major advantage of switchgrass over tree crops.

Energy crops are not currently grown as fuel feedstocks, but research indicates that energy crops would be produced provided farmers could earn a risk-adjusted return equal to that from traditional agricultural crops. Walsh et al. (2000) used an agricultural sector model to estimate the quantities of energy crops that would be grown at various energy prices and assuming given agricultural policies, such as Conservation Reserve Program acreage. Analysis results indicate that these crops could be produced at delivered prices starting about $35/dry ton.

	Production/harvesting	Hauling	Total
Poplars	$50-$60	$5-$10	<$55-$70
Willows	$60-$65	"	<$65-$75
Switchgrass	$30-$45	"	<$35-$55

Regional availability

It is estimated that about 24 million dry tons of biomass resources might be available nationally to conversion facilities at delivered prices of about $25/dry ton or less ($1.60/MMBtu). The amount of biomass resources available increases more than fourfold at prices under $35/dry ton ($2.20/MMBtu). At prices under $55/dry ton ($3.40/MMBtu), over 510 million dry tons might be available annually. Figure 3.1 summarizes national biomass feedstock availability at delivered prices ranging from under $25 to under $55/dry ton. State-level estimates are provided in Table 3.1. No assumptions about the spatial distribution of resources within a state are made. As such, proposed conversion facilities may not be within an economically feasible transport distance. Feasibility studies of proposed conversion facilities must therefore conduct detailed local analyses to verify feedstock availability, prices, and reliability.

Generally, urban wood wastes are the least expensive followed by mill residues, forest residues, agricultural residues, and energy crops. This ordering reflects more or less the costs of acquisition (offsetting landfill tipping fees) and the significance of collection (or production and harvesting) and processing costs. Urban wood wastes, mill residues, agricultural residues, and forest residues are often available in small and dispersed amounts, creating high transaction costs. Supply reliability and quality requirements may also be difficult to meet consistently. Further, prices do not include any processing of the wastes at the conversion facility. For example, bales would need to be broken and ground, whole-tree chips may need to be screened, and urban wastes may require more specialized processing to remove non-combustible materials. Finally, it should be reiterated that the uncertainty surrounding these estimates is high. Site-specific analyses are required to determine specific estimates of available quantities at given delivered feedstock prices. Bio-resource procurement is complex, costly, and a significant barrier to potential use.

Fig. 3.1. Total U.S. Biomass Resources at Selected Prices

■ Urban Wastes □ Mill Wastes ▣ Forest Residues ▢ Ag Residues ▨ Energy crops ▨
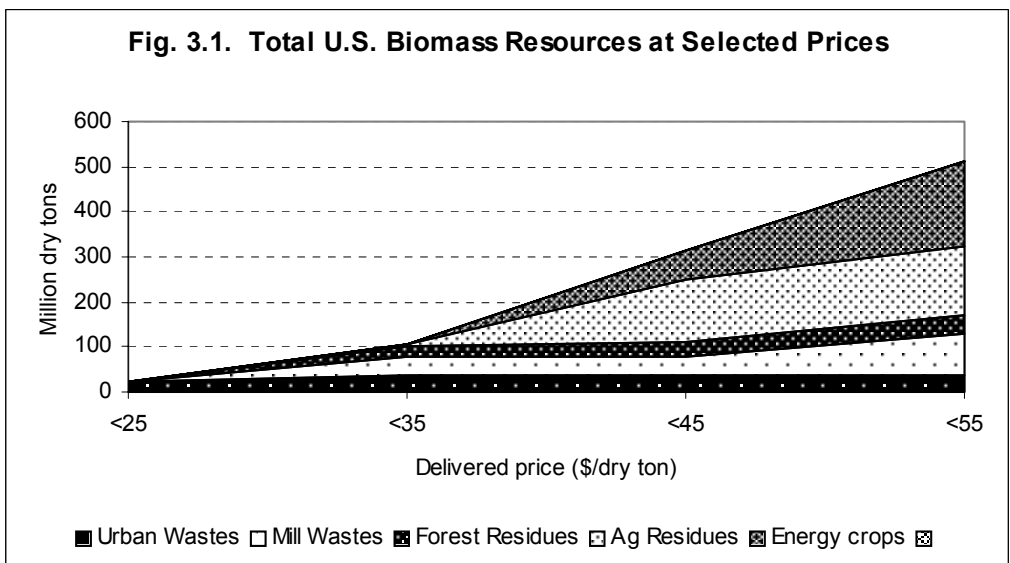
Table 3.1: Estimated Biomass Resources Available by State and Price

State	Delivered price ($/dry ton)			
	<25	<35	<45	<55
	thousand dry tons			
Alabama	841	6,963	10,712	17,682
Arizona	220	575	863	1,100
Arkansas	402	4,092	7,086	13,604
California	1,588	6,158	8,224	11,299
Colorado	181	652	3,357	3,582
Connecticut	247	561	611	906
Delaware	39	95	194	462
Florida	2,762	6,524	6,778	9,533
Georgia	934	6,391	8,541	16,112
Idaho	204	2,572	4,117	7,166
Illinois	435	1,038	26,839	33,359
Indiana	348	994	13,410	18,607
Iowa	174	404	24,583	32,786
Kansas	737	1,283	12,733	21,344
Kentucky	455	1,472	5,758	10,809
Louisiana	516	3,569	7,977	11,834
Maine	151	1,196	1,572	2,214
Maryland	205	543	900	1,959
Massachusetts	419	939	1,027	1,436
Michigan	506	2,468	4,627	12,163
Minnesota	991	2,917	15,494	21,247
Mississippi	599	4,909	10,673	17,931
Missouri	478	1,346	8,030	19,523
Montana	69	1,422	2,159	6,761
Nebraska	114	210	18,467	21,773
Nevada	184	315	333	337
New Hampshire	134	922	1,061	2,016
New Jersey	389	726	791	976
New Mexico	168	424	961	1,082
New York	1,168	3,328	3,885	8,438
North Carolina	669	4,188	5,790	10,856
North Dakota	327	558	2,507	21,043
Ohio	745	1,473	13,018	18,963
Oklahoma	111	3,874	7,816	12,700
Oregon	193	3,341	4,126	9,810
Pennsylvania	572	2,206	2,832	7,427
Rhode Island	30	81	88	116
South Carolina	1,294	4,469	6,332	9,368
South Dakota	132	286	9,602	16,005
Tennessee	878	3,382	10,720	15,233
Texas	1,227	4,222	13,526	20,747
Utah	159	388	648	723
Vermont	41	392	513	1,023
Virginia	599	3,059	5,055	8,715
Washington	297	3,979	5,939	9,920
West Virginia	241	1,361	1,972	3,736
Wisconsin	425	2,450	11,502	14,963
Wyoming	224	552	787	1,466
Total	23,820	105,267	314,535	510,855

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4.   LESSONS LEARNED

This discussion includes information on lessons learned the California biomass energy industry and reported on in 2000, a brief update on the California situation, lessons from commercial biopower plants, lessons from selected DOE demonstration projects, and a short summary of the issues considered most critical for commercial success.

The California Biomass Energy Industry[1]

California has one of the largest and most diverse biomass energy industries in the world. At its peak, the California biomass energy industry produced almost 4.5 billion kilowatt hours per year of electricity and provided a beneficial use outlet for more than 10 million tons per year of the state's solid wastes. The peak, however, occurred during the early 1990s. Since that time, a quarter of the biomass energy facilities have agreed to buyouts of their power sales contracts and terminated operations, while others have reduced their operations. This has occurred because of concerns about the long-term viability of these facilities in a competitive, deregulated electricity market. This uncertainty casts an ominous cloud over the future viability of biomass energy generation in California.

Development of the California Biomass Energy Industry

California's diversity and extent of agriculture and forestry industries are unrivaled in the world. Both activities produce large quantities of solid wastes, many of which are biomass residues that can be used as fuel. Before the federal Public Utilities Regulatory Policy Act (PURPA) was passed in 1978 only a few biomass-fired boilers were operating in California, and little electricity was being generated from biomass. Most of the state's biomass wastes were being disposed of, mainly by open burning and landfill burial. PURPA changed all that by requiring that electric utility companies buy privately produced power at their "avoided cost" of generation. PURPA created the market context that allowed for the development of the independent power industry in the United States. High avoided cost rates in many areas of the country, and favorable federal tax treatment for investments in renewable energy projects, provided the motivation for its development.

California was a leader in the development of renewable energy generating facilities. A combination of circumstances, including a high growth rate in electricity demand, oil dependence, and rising concerns about environmental deterioration, led to the implementation of state energy policies that were highly conducive to the development of renewable energy sources. These policies and opportunities stimulated a major development of biomass energy generating capacity in the state. During a period of less than 15 years (roughly 1980–1993), nearly 1,000 MW of biomass generating capacity were placed into service. The biomass energy sector expanded from an outlet for a small quantity of the state's wood processing residues to an essential component of the state's solid-waste disposal infrastructure. Today the California biomass energy industry provides a beneficial use for almost 6.5 million tons of the state's solid wastes. However, it has a highly uncertain future. The expiration of fixed-price power sales provisions for many facilities, combined with the deregulation of the electric utility industry and the current availability of cheap natural gas, threaten its long-term economic viability.

The 1980s: Decade of Growth

The early 1980s mark the nascent period for the California biomass energy industry. During this period, several pioneering biomass energy generating facilities were built and placed into service. The early

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[1]Excerpted from: Morris, G. (2000) "Biomass Energy Production in California: The Case for a Biomass Policy Initiative," NREL/SR-570-28805, National Renewable Energy Laboratory, Golden, CO, November.

facilities tended to be small, generally 2-10 MW, and most were associated with sawmills or food processing operations that were looking for beneficial use outlets for their wastes. Figure 4.1 shows a map of the state's operating biomass energy facilities at the end of 1985.

Figure 4.1: California Biomass Power Plants, 1985
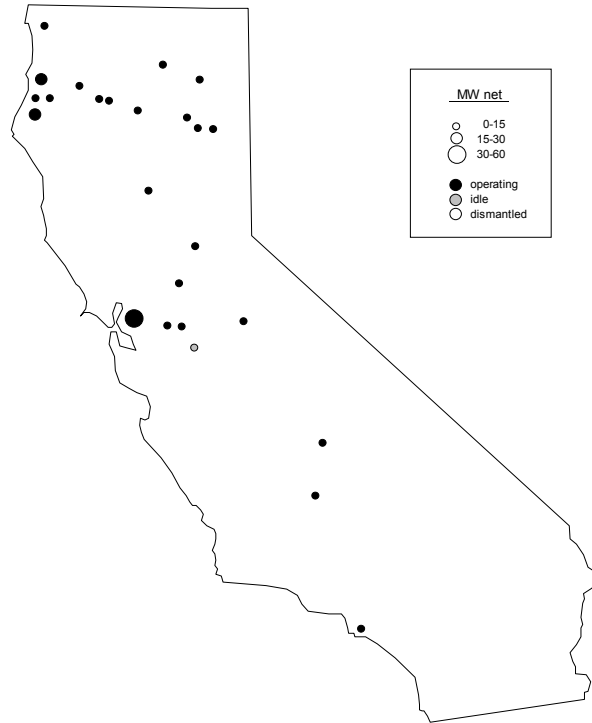
Also during the early 1980s, the California electric utility companies developed standard offer contracts for power purchases from independent generators. These contracts had particularly favorable provisions for renewable energy projects. A great deal of biomass project development activity was initiated during this period, which led to an explosion of new facility openings during the second half of the decade.

The California biomass energy industry became an important part of the state's electricity supply infrastructure and its waste disposal infrastructures during the second half of the 1980s. The incentives for renewable energy development that were offered during the first half of the decade led to the opening of 33 new biomass generating facilities between 1985 and 1990. A few of the pioneering facilities were shut down during this period, but the state's total operating biomass energy capacity grew by more than 650 MW. The average size of the facilities brought on line during this period was about 17.5 MW; the largest facilities were 50 MW. The explosive growth of biomass generating capacity culminated in 1990, when 11 new facilities were commissioned in a single year, adding 232 MW of biomass generating capacity to the state's electricity supply. Figure 4.2 graphically illustrates the development of the biomass energy generating industry in California from 1980 to the present. Figure 4.3 shows a map of the state's installed biomass power infrastructure as of the end of 1990.

Figure 4.2
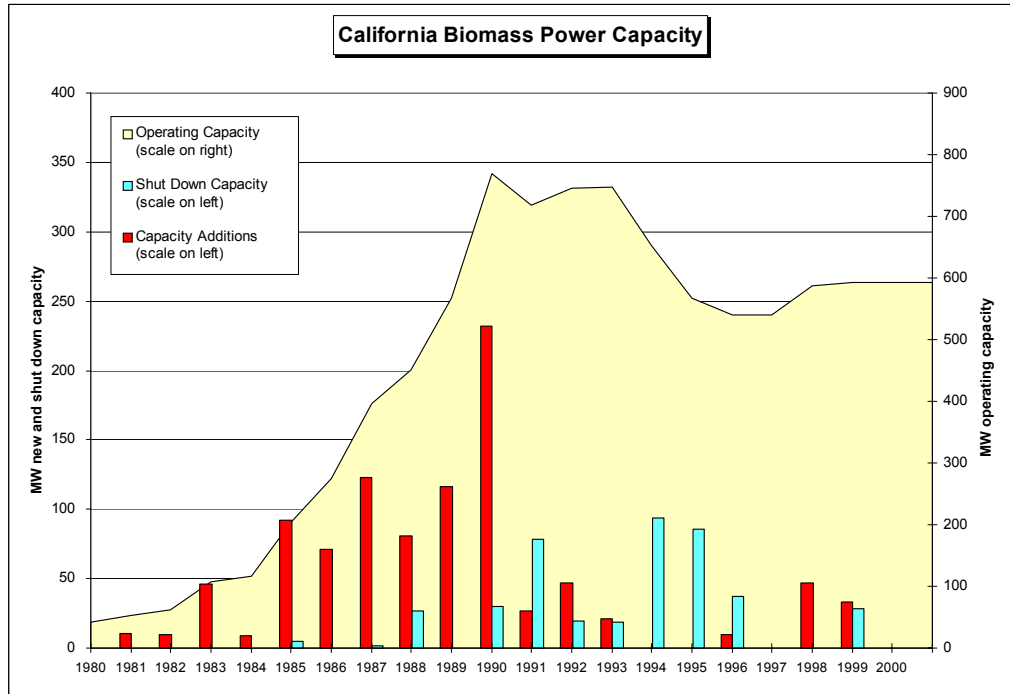
Figure 4.3: California Biomass Power Plants, 1990
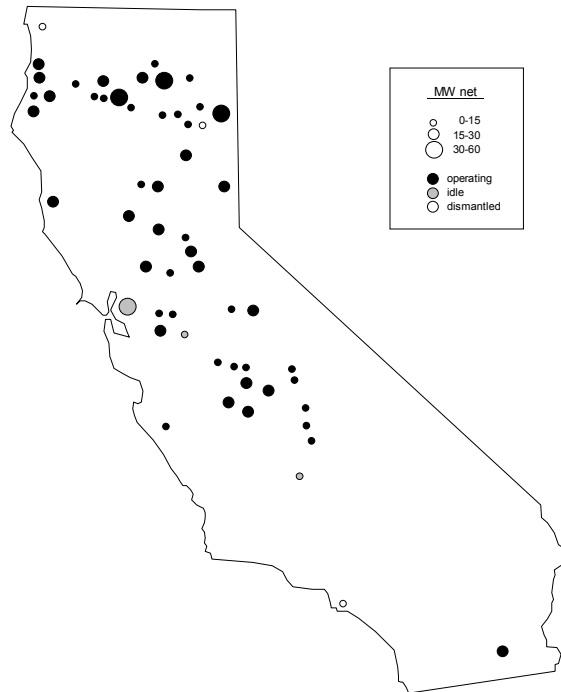
Many of the facilities that entered service during the late 1980s had Interim Standard Offer No. 4 (SO#4) power purchase agreements (PPAs) with the state's two major electric utility companies, Pacific Gas and Electric Co. (PG&E) and Southern California Edison (SCE) Co. The SO#4s were the most favorable contracts available to independent project developers in California. These contracts were available for signing only during 1984 and 1985, and contract holders were given 5 years to bring their facilities into operation. The most significant feature of the SO#4s was an option for energy sales from electricity generated from renewable resources to be based on a forecasted schedule of energy prices for the first 10 years of facility operations, rather than being subject to fluctuating, short-term prices. These schedules were based on the high avoided cost rates then in effect (5¢–6¢/kWh), and an expectation that rates would remain high throughout the terms of the agreements. At the completion of the 10-year fixed price period generators are compensated based on the then current market price, which is called the short-run avoided cost (SRAC).

The SO#4 power purchase provisions for biomass energy facilities were designed to encourage the development of base-load generators that would provide the power grid with dependable generating capacity during peak demand periods, which are summer weekday afternoons. Most of the contracts were written with 30-year firm capacity terms of performance, which obligate biomass facilities to generate at their contract capacity at least 80% of the time during defined peak hours of the year, for the entire term of the agreement. Payments to generators for providing firm capacity are levelized over the contract term, and confer a significant liability on generators that do not operate for the entirety of the agreements.

The second half of the 1980s was also significant for a reversal in world oil markets. World oil prices, which had remained high since the price explosions of the 1970s, collapsed during the period 1985-1986. SRACs in California fell by 50% over an 18- month period. Most biomass power plants, however, were immune to the decline in SRAC rates during this period, because they received fixed-schedule rates under their contracts, based on early 1980s energy prices.

The attention of the biomass generating facilities focused instead on a looming crisis in the biomass fuels market. As the state's installed biomass generating capacity grew rapidly during the later half of the 1980s, the demand for fuel soon overwhelmed the readily available supply. Virtually all sawmill and food processing residues that did not have higher valued uses were being sold into the fuel market, and still there was a significant deficit between biomass supply and demand. Numerous efforts were under way to develop technologies to produce biomass fuels from new sources of supply, such as agricultural prunings, agricultural field residues, forestry residues, and urban waste wood, with rising fuel prices providing the incentive. The state's biomass fuels crisis peaked in 1990 with average prices topping $40/bdt[2] of fuel, and spot prices reaching $60/bdt or higher. Moreover, several major new facilities were approaching the completion of construction, and there was a fear that biomass fuel prices might continue to rise.

The 1990s: Maturity and Consolidation

At the end of 1990, more than 770 MW of biomass energy generating capacity were operating in California, and an additional 100 MW of capacity were in advanced stages of construction. The early years of the 1990s saw the state's biomass energy industry stabilize at a level of about 750 MW of operating capacity. During this period, the startup of the last of the SO#4 facilities was balanced by the retirement of several pre-SO#4 facilities, many of which had serious design flaws or operational problems. 1993 also saw the first retirement and dismantling of a facility with an SO#4 contract. This

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[2]bdt = bone-dry ton equivalent, a unit of measure used for biomass fuels. A bdt refers to an amount of material that contains a ton of moisture-free biomass fiber. Generally, 1 bdt is equivalent to 1.2–2.4 actual, or green tons of biomass. In this discussion on California the term ton used alone refers to green tons of biomass, and bdt refers to bone-dry ton equivalents of biomass.

was a facility that had been beset with technical and operational problems that prevented its profitable operation.

The California biomass fuels market also stabilized during the early 1990s, with average market prices settling at a level of about $37.50/bdt, at an average consumption level of approximately 9 million tons per year. This stability was reached despite the beginning, in 1990, of a long-term decline in the state's wood products industry, which was caused by a combination of environmental restrictions and economic conditions. This is significant because wood processing residues are the lowest-cost biomass fuels in the state. By the end of 1993, the biomass energy industry appeared to have attained a level of maturity, and a workable equilibrium between fuel supply and fuel demand had been established. Although there were winners and losers, the California biomass energy industry as a whole successfully weathered the storm of the fuel crisis that marked the beginning of the decade.

The stability, however, was short lived. In April 1994 the California Pubic Utilities Commission (CPUC) issued its landmark *Blue Book* proposal for restructuring the state's regulated electric utility industry (CPUC 1994). The *Blue Book* proposal provided for competition among generating sources on the basis of price alone, without regard to non-market factors such as resource diversity and environmental impact. This represented a major threat to biomass energy generation. Because of the low density of biomass fuels and the resultant high handling and transportation costs, the relatively small size of biomass generating facilities, and the low cost of natural gas, the cost of power production from biomass was inherently higher than the cost of power generation using natural gas. Competition based on price factors alone would not favor biomass energy generation.

The most immediate effect of the *Blue Book* restructuring proposal for the biomass energy industry was that it provided an incentive for the state's regulated electric utility companies to buy out the SO#4 PPAs held by the biomass generators in their service territories. Many biomass generators were receptive to these offers because of their concern about their own long-term liabilities to the utility companies in connection with the firm-capacity obligations in their contracts. Over the next 3 years 17 biomass facilities, rated collectively at more than 215 MW, accepted buyout offers and shut down operations.[3] Unlike in earlier years, when only marginal facilities were closed, most of the facilities that shut down following the issuing of the *Blue Book* proposal were first-rate facilities that had been operating efficiently and profitably until the buyouts of their PPAs.

Annual biomass fuel use in the state shrank by 37% during the 2 years following the appearance of the *Blue Book* proposal. More than 3 million tons/year of biomass residues that were being used for energy production in the early 1990s were returned to open burning and landfilling for disposal. In addition, at its peak the state's biomass industry was supporting forest treatment operations on approximately 60,000 acres/year of forest land that was not otherwise being commercially harvested or treated. These treatments reduce the risk of destructive wildfires and improve the health and productivity of the thinned forest. With the retraction in the demand for biomass fuels the amount of this type of forest treatment activity has declined dramatically.

The CPUC's original restructuring proposal underwent a process of refinement that lasted for more than two years. By the summer of 1996 the CPUC had acknowledged the desirability of incorporating environmental factors into the choice of energy sources, and embraced the concept of a minimum purchase requirement for renewable energy sources. A working group made up of the utility companies,

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[3]One of the 17 facilities was sold and restarted during this period. This facility was purchased by a buyer who intended to operate it at about one-half of its rated capacity, supplying steam and electricity to an over-the-fence industrial customer. Two other shut-down facilities, which only sold out the remaining fixed-price period of their PPAs, have since restarted. The other 14 facilities that were shut down during this period remain shut down today.

independent power generators, and public interest groups worked on formulating a consensus proposal to the CPUC to implement a minimum renewables purchase requirement for California's regulated electric utility sector (Morris et al. 1996). The biomass industry, which pioneered the concept of a renewables portfolio standard (RPS), played a key role in this process.

In late August 1996, just before the end of the state legislative session, the California legislature formulated its own electric utility restructuring program, superseding the efforts of the CPUC. The legislation that emerged, AB 1890, included a program of short-term support for renewable energy during the 4-year transition period (1998-2001) to full implementation of restructuring. However, no long-term support program for renewables was included. AB 1890 explicitly recognized the special waste disposal benefits associated with biomass energy in California. The legislation directed the California Environmental Protection Agency (Cal/EPA) to study policies that would shift some costs of biomass energy production away from the electric ratepayer, and onto the beneficiaries of the waste disposal services it provides. Cal/EPA was directed to report to the legislature on biomass cost-shifting measures by April 1997.

Cal/EPA had difficulty coming to grips with this political football. Two of the principal agencies under the Cal/EPA umbrella, the California Air Resources Board and the California Integrated Waste Management Board (CIWMB), had obvious interests in the outcome of the process. In addition, agencies outside Cal/EPA, such as the California Department of Forestry and Fire Prevention and the California Energy Commission, also have a strong interest in policies affecting biomass energy production. Rather than take the lead itself, Cal/EPA assigned the task to the Waste Board. CIWMB convened a series of public workshops, during which they solicited research and information about the public benefits of biomass energy production, and policy proposals to support continued biomass energy production. A great deal of public input was received, which the agency tried to distill into a report to the legislature within a very tight time frame. At some point a decision seemed to have been made that any information that caused interagency disagreements would be removed from the report. The result was a watered-down report that provided the legislature with no basis for enacting the kinds of cost-shifting policies for biomass envisioned in AB 1890.

The legislature made one more attempt to develop the background necessary for the developing biomass support policies in California. In 1998, AB 2273 was passed and signed into law. AB 2273 directs Cal/EPA to report annually to the legislature on progress in developing biomass cost-shifting policies in the state. CIWMB was assigned the lead role in developing the first report under this legislation. Although a report was prepared in early 1999 and sent to the Cal/EPA Board for approval, it was never released and sent to the legislature.

Despite the cloud of uncertainty over the future viability of biomass energy production in California, the state's biomass energy industry has operated with relatively stability during the latter half of the 1990s. Following the shutdowns of 1994-1996, 27 biomass facilities, representing 540 MW of generating capacity, remained in operation. Twenty operated under intact SO#4s. The other seven had special circumstances, such as a captive fuel supply or an ability to earn retail-offset for most or all of their electricity output, that allowed them to continue operating. The fixed-price periods in the SO#4 PPAs came to an end at the end of the 1990s, but the renewables transition fund created by AB 1890 offered biomass generators a supplement of 1.5¢/kWh for facilities that did not receive SO#4 fixed-scheduled prices for their sales of electricity.

The operating biomass energy generating capacity in California actually increased slightly at the end of the 1990s, to almost 600 MW. This was mainly because two 25-MW facilities that had accepted contract buyouts and shut down operations in 1994 had special provisions in their buyouts that provided for restarting the facilities at the end of their fixed-price periods. These facilities resumed operations in 1998

and 1999, respectively. Biomass fuel use increased by 15% over its low point following the 1994-1996 shutdowns, but was still more than 30% lower than the peak level achieved during the early part of the decade. Table 4.1 shows a list of all the biomass energy generation facilities that have operated in California since 1980. Figure 4.4 shows a current map of the California biomass energy facilities, keyed to the list of facilities in Table 4.1.

Figure 4.4: California Power Plants, 2000
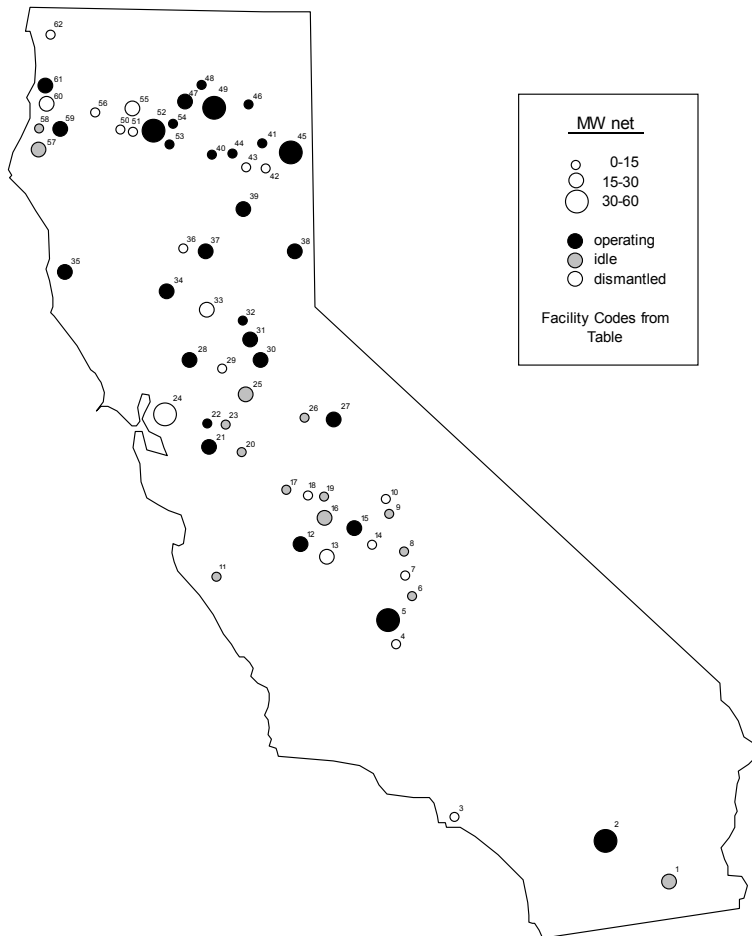
TABLE 4.1:CALIFORNIA BIOMASS POWER PLANTS, 1980-2000

	Project	County	Net MW	mBDT/y	Cogen	Own Fuel	Boiler Type	Status	Utility	PPA	Start Up	Shut Down	Re-Start
1	Western Power	Imperial	15.0	122			grate	Idle	SCE	SO #4 bo	1990	1996	
2	Colmac Energy	Riverside	47.0	330			cfb	Operating	SCE	SO #4	1992		
3	Proctor & Gamble	Los Angeles	13.5	98	x		grate	Dismantled	SCE	Pre SO	1985	1988	
4	Apex Orchard	Kern	5.5	48	x		grate	Dismantled	PG&E	Pre SO	1983	1988	
5	Thermo Ecotek Delano	Tulare	48.0	375			bfb	Operating	SCE	SO #4	1991		
6	Sierra Forest Products	Tulare	9.3	75	x	x	grate	Idle	SCE	SO #4 bo	1986	1994	
7	Lindsay Olive	Tulare	2.2	20	x	x	grate	Dismantled	SCE		1980	1993	
8	Dinuba Energy	Tulare	11.5	97	x	x	bfb	Idle	PG&E	SO #4 bo	1986	1995	
9	Auberry	Fresno	7.5	70	x	x	bfb	Idle	PG&E	SO #4 bo	1986	1994	
10	North Fork	Madera	8.0	68	x	x	bfb	Dismantled	PG&E	SO #4 bo	1988	1994	
11	Soledad Energy	Monterey	13.5	98			bfb	Idle	PG&E	SO #4 bo	1990	1994	
12	Thermo Ecotek Mendota	Fresno	25.0	185			cfb	Operating	PG&E	SO #4	1990		
13	Agrico Cogen	Fresno	25.0	198	x		grate	Conv. to gas	PG&E	SO #2	1990	1991	
14	Sanger (biomass → feed)	Fresno	0.0	50	x		-	Dismantled	NA	NA	1991	1991	
15	Rio Bravo Fresno	Fresno	25.0	180			cfb	Operating	PG&E	SO #4	1989	1994	1998
16	SJVEP--Madera	Madera	25.0	182			bfb	Idle	PG&E	SO #4 bo	1990	1995	
17	SJVEP--El Nido	Merced	10.2	88			bfb	Idle	PG&E	SO #4 bo	1989	1995	
18	SJVEP--Chowchilla I	Madera	9.9	99			grate	Dismantled	PG&E	SO #4 bo	1988	1995	
19	SJVEP--Chowchilla II	Madera	10.8	90			bfb	Idle	PG&E	SO #4 bo	1989	1995	
20	Redwood Food Pkg	Stanislaus	4.5	36	x	x	grate	Idle	PG&E	SO #1	1980	1985	
21	Tracy Biomass	San Joaquin	19.5	150			grate	Operating	PG&E	SO #4	1990		
22	Diamond Walnut	San Joaquin	4.5	35	x	x	grate	Operating	PG&E	Pre SO	1981		
23	California Cedar Products	San Joaquin	0.8	11	x	x	grate	Idle	PG&E	SO #1	1984	1991	
24	Gaylord Antioch	Contra Costa	30.0	225	x		grate	Conv. to gas	PG&E	Pre SO	1983	1990	
25	Jackson Valley, Ione	Amador	18.0	140				Idle	PG&E	negotiated	1998	1999	
26	Fiberboard, Standard	Tuolumne	3.0	27	x	x	grate	Idle	PG&E	Pre SO	1983	1996	
27	Chinese Station	Tuolumne	22.0	174			bfb	Operating	PG&E	SO #4	1987		
28	Thermo Ecotek Woodland	Yolo	25.0	200			cfb	Operating	PG&E	SO #4	1990		
29	Blue Diamond Growers	Sacramento	9.5	68	x	x	grate	Dismantled	PG&E	Pre SO	1982	1996	
30	Wheelabrator Martell	Amador	18.0	135	x	x	grate	Operating	Industrial Cust.		1987		
31	Rio Bravo Rocklin	Placer	25.0	180			cfb	Operating	PG&E	SO #4	1990	1994	1999
32	Sierra Pacific Lincoln	Placer	8.0	70	x	x	grate	Operating	PG&E	SO #4	1985		
33	EF Feather River	Yuba	16.5	150			cfb	Dismantled	PG&E	SO #4 bo	1987	1993	
34	Wadham Energy	Colusa	26.5	209			cfb	Operating	PG&E	SO #4	1989		
35	Georgia Pacific	Mendocino	15.0	119	x	x	grate	Operating	PG&E	SO #1	1987		
36	Koppers	Butte	5.5	110	x	x	grate	Dismantled	PG&E	SO #2	1984	1994	
37	Ogden Pacific Oroville	Butte	18.0	142			grate	Operating	PG&E	SO #4	1986		
38	Sierra Pac. Loyalton	Sierra	17.0	134	x	x	grate	Operating	Sierra Pacific		1990		
39	Sierra Pacific Quincy	Plumas	25.0	200	x	x	grate	Operating	PG&E	SO #4	1987		
40	Collins Pine	Plumas	12.0	90	x	x	grate	Operating	PG&E	SO #2	1986		
41	Sierra Pac. Susanville	Lassen	13.0	105	x	x	grate	Operating	PG&E	SO #4	1986		
42	Lassen College	Lassen	1.5	12	x		grate	Dismantled	PG&E	SO #1	1985	1987	
43	Jeld Wen Industries	Lassen	2.5	20	x	x	grate	Conv. to gas	PG&E	Pre SO	1984	1992	
44	Ogden Westwood	Lassen	11.4	90			grate	Operating	PG&E	SO #4	1985		
45	Honey Lake Power	Lassen	30.0	225			grate	Operating	PG&E	SO #4	1989		
46	Big Valley Lumber	Lassen	7.5	59	x	x	grate	Operating	PG&E	Pre SO	1983		
47	Sierra Pacific Burney	Shasta	17.0	145	x	x	grate	Operating	PG&E	SO #4	1987		
48	Ogden Burney	Shasta	10.0	77			grate	Operating	PG&E	SO #4	1985		
49	Burney Forest Products	Shasta	31.0	245	x	x	grate	Operating	PG&E	SO #4	1990		
50	Roseburg Lumber	Shasta	4.0	32	x	x	grate	Dismantled	PG&E	Pre SO	1980	1992	
51	Paul Bunyan	Shasta	3.0	24	x	x	grate	Dismantled	PG&E	Pre SO	1980	1992	

The year 1999 saw a renewal of interest in PPA buyouts. One small facility, which was already operating past its fixed-price period, accepted a buyout agreement for its remaining capacity obligation and shut down. One of the state's largest facilities accepted a buyout of its contract, and remains in operation as a merchant power facility, although its future viability is in doubt. Other possible buyouts were in various stages of discussion, and future shutdowns are possible as the new century begins. The cap on the renewable transition supplement paid to biomass generators decreased to 1.0¢/kWh on January 1, 2000, and more than 100 MW of capacity will see their fixed-schedule energy provisions expire during 2000. No biomass support measures have yet been enacted. The industry's future remains very much in doubt.

Characteristics of California's Biomass Power Plants

Gregory Morris of the Green Power Institute has developed and maintained an extensive database on the California biomass energy industry (Morris 1997), which has been brought up to date as part of this project. The California biomass energy database contains information about every solid fuel biomass energy generating facility that has operated in California since 1980. The database includes information about biomass fuel use and price on an annual basis, and annual electricity production, for the 20-year period covered, 1980-1999, as well as projections for the current year (2000). This database is the source of much the data used in the environmental and economic analyses in this report.

Sixty-two biomass energy generating facilities have operated in California during the past 15 years. Twenty-nine still operate. Eighteen have been dismantled or otherwise modified to render them no longer available for service as biomass energy facilities. Most of the remaining 15 facilities are currently idle and available for future operations. They are located throughout the state, as shown in Figure 4.4. Half obtain at least some of their fuel from captive sources, although only a few obtain all their fuel from captive sources. Thus, most have participated in the state's biomass fuels marketplace. California biomass facilities range from 1–50 MW, with annual fuel requirements of 10,000–750,000 tons/year.

All biomass energy generation facilities in California employ conventional steam-turbine technology for converting biomass fuels to electricity. This technology has been in use for almost 100 years, and has been used extensively with a wide variety of fuels, including biomass and fossil fuels. Nevertheless, the technology continues to evolve, and has shown significant improvement as the modern biomass energy industry in California has developed. Much of the development since 1980 has been in the area of environmental performance, which includes improvements in combustion technology and in emissions-control technology.

Most of California's biomass power plants employ conventional biomass combustion technology with fixed or traveling grate furnaces. Seventeen of the facilities were built with fluidized-bed boilers, including bubbling bed and circulating bed configurations. Fluidized-bed boilers provide for lower emissions and higher efficiency than conventional boilers, but have higher capital and operating costs. The major deployment of fluidized-bed biomass boilers has contributed valuable learning experience to the continuing technological refinement and commercial development of this promising technology.

The industry is poised to continue to contribute to technological innovation in the biomass energy arena as the twenty-first century begins. The newest biomass generating facility in the state, taking advantage of the IRS Section 29 gasification tax credit, employs a close-coupled gasifier as part of its combustion system, achieving high efficiency and low emissions. Several biomass facilities are considering the development of associated ethanol production operations as an enhancement to the overall energy production enterprise. It is hoped that synergies between the electricity production enterprise and the ethanol production enterprise, such as shared biomass procurement and handling facilities, and segregation of the resource into higher and lower valued outlets, will provide benefits to both. The California biomass energy industry can contribute to future biomass technology innovation only if it continues to be viable in the near-term.

Fuel Use and Alternative Disposal Options for Biomass Residues in California

The biomass energy industry in California can be thought of as much as a solid waste disposal service provider as an electricity generating enterprise. It provides for the disposal of 6.4 million tons/year of the state's solid wastes. The biomass residues used as fuel come from a variety of sources, and would be subject to a variety of alternative fates, such as open burning or landfill burial, if the biomass industry were not a disposal option. The major categories of biomass fuels used in California include:
- Wood processing residues
- In-forest residues

- Agricultural residues
- Urban wood residues

Most biomass generating facilities in California were built with an expectation of using either wood processing residues or agriculture residues as their major fuel source. The facilities designed to burn primarily agricultural residues are concentrated in the Central Valley. Those designed to burn primarily residues from the forest products industry are concentrated in the northern and eastern mountain regions. Three biomass facilities were designed to burn primarily urban wood waste. These were located close to the Los Angeles and San Francisco Bay Areas. Urban wood waste fuels, which were largely ignored during the industry's development, have become far more important than anyone originally anticipated. They are second only to sawmill residues in terms of their contribution to the California biomass fuels market.

Several California biomass facilities burn supplemental fuels in addition to solid biomass residues. Biomass energy facilities that are qualifying facilities (QFs) are allowed to obtain as much as 25% of their input heat from conventional fossil fuels. In addition, they can burn unlimited quantities of other renewable fuels or approved waste materials, such as petroleum coke and old tires. Landfill gas,[4] tires, and petroleum coke are the major supplemental fuels used by the state's biomass generators. One facility uses geothermal heat to preheat boiler water.

Wood Processing Residues

Wood processing residues are the waste materials produced during the processing and conversion of lumber into wood products. Those residues are the most important biomass fuel source in California, consistently accounting for more than one-third of the total biomass fuel supply used. Almost half the biomass content of a typical sawlog becomes residue at a primary sawmill. A variety of secondary forestry industries have been developed to use some of this material. Active markets for wood processing residues include pulp chips, wood fiber for fiberboard and composites, animal bedding, and garden products such as decorative bark. Sawmills are used to segregating their residues into the highest-value markets available, but a substantial quantity of the residues, typically 15%-20% of the total biomass in a sawlog, has no useful application and must be disposed of. Wood-processing residues are produced in a variety of forms, including:

- Bark
- Round-offs
- End cuts
- Trimmings
- Sawdust
- Shavings
- Reject lumber

The traditional method of disposing of sawmill residues in California before the biomass energy industry was developed was incineration in teepee burners, a technology that produces large quantities of smoke and air pollution. Beginning in the early 1970s, air pollution control efforts applied increasing pressure on sawmills to close down their teepee burners, leading them to look for new disposal alternatives. This was one important factor that led to the early development of the biomass industry in California. Virtually all the readily available wood processing residues generated that have no higher valued application are now used as power-plant fuel.

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[4] California has 30 power generation installations powered exclusively by landfill gas. This report is focused on the solid fuels biomass power industry, and does not cover the landfill gas facilities.

Teepee burners are no longer used to dispose of wood processing residues in California. The only readily available option for disposing of these materials, if fuel use were not a possibility, would be landfill burial – a highly undesirable alternative. Waste wood has a slower decay rate than other forms of biomass in the landfill environment, and thus is slower to stabilize. Moreover, state solid waste policy is strongly oriented to reducing the amount of material being buried in landfills, and introducing a sizable new waste stream would make compliance with recycling regulations almost impossible.

If there were no biomass energy industry in California today, some sawmill residues currently used for fuel would be used for energy production in sawmill kiln burners, an old disposal option for some of a sawmill's residues. This application would probably use one-third or more of the residues currently used for power production. A small quantity would be composted and/or spread; the rest would be landfilled.

Wood processing residues are the cheapest of the four categories of biomass fuels to produce and deliver to the power plants. They form the backbone of the state's biomass fuel supply, and would probably be the last type of fuel to exit the system if the demand for biomass fuels state declined. The major factor that determines the quantity of mill residues used as fuel in California is the level of activity in the forest products industry. Economic factors and environmental restrictions on timber supplies have led many sawmills to shut down. This has led to a decline in the amount of wood processing residues used as power plant fuels, which began during the early 1990s.

In-Forest Residues
In-forest biomass residues include two major categories: residues generated in the forest when timber is harvested for wood products, generally called slash, and material naturally occurring in forests whose removal would provide environmental benefits to the remaining forest. Harvesting residues include the tops and limbs of harvested trees, bark when debarking takes place in the forest, and cull logs[5] that are cut and removed during harvesting operations. The cheapest way to manage this material is to leave it in the forest as it is generated, but that is also the worst management practice from a forestry perspective, as leaving harvesting residues in the field retards regrowth of the forest and represents a substantial fire hazard. Virtually all timber harvesting contracts in California require loggers to manage the slash they generate. Slash that is generated close enough to an operating biomass energy plant can be collected and converted to fuel. The alternative is to collect the slash and burn it in piles. Open burning leads to high levels of emissions of smoke, particulates, and other air pollutants.

The other category of in-forest residue is overstocked material in vast areas of California's forests. Poor forestry practices and aggressive fire-fighting efforts during most of the past century have resulted in vast areas of the state's forests becoming overstocked with biomass. This material represents an enhanced risk of destructive wildfires, and generally degrades the functioning of the forest ecosystem. Overstocked forests benefit greatly from thinning operations. The quantity of in-forest biomass whose removal would benefit California's forests is far greater than the total amount of biomass fuel demand in the state. However, this fuel source is generally more expensive to produce than other types of biomass fuels, so less is used.

Two basic alternatives can be used to reduce the biomass overloading in standing forests: prescribed burning and mechanical thinning. The primary goal of reducing fire risks in standing forests is to protect mature trees. Most of the tonnage of forest overgrowth biomass is material on and near the forest floor, called ground fuel. Periodic fires in undisturbed California forests tended to be primarily ground fires, and control the buildup of these materials. When ground fuels are left uncontrolled for prolonged periods, such as in areas where fires have been excluded for 75 years or more, some of the undergrowth

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[5]Cull logs are trees that are diseased, damaged, misshapen, or otherwise unsuitable for use in producing commercial wood products.

begins to grow into taller poles, which become "ladder fuels." Ladder fuels provide a mechanism to transfer ground fires to the crowns of mature trees in the forest, thus greatly increasing the damage caused by the fires, in the worst cases turning benign ground fires into out-of-control, destructive wildfires. Traditional commercial harvesting operations do not affect the fuel overloading problem in the forest, because neither ground nor ladder fuels are removed. In fact, if slash is left untreated, the fire risk can be increased. Mechanical thinning and prescribed burning remove ladder and ground-based fuels.

Forestry officials would like to see large areas of California's forests thinned. An official of the U.S. Forest Service, which manages approximately one-half the state's forest land, has asserted that at least 250,000 acres per year of the land under their jurisdiction needs to be thinned to fully realize the desirable fire suppression, forest health, and watershed improvement benefits (Morris 1998a). During the peak of the California biomass fuels market in the early 1990s only about 60,000 acres per year were being thinned statewide for fuel production. With the decline in biomass fuels demand that occurred in the middle of the decade, the level of thinning for fuels production has been cut by more than half.

The alternative to biomass fuels production for reducing overstocking in the state's forests is prescribed burning. However, environmental and safety concerns may limit the amount of prescribed burning that will be allowed in California. Prescription burning produces more pollution per ton of material consumed than open burning of biomass in piles (EPA 1995). In addition, prescribed burning in densely overstocked forest stands entails a significant risk of residual stand damage and may initiate of offsite, uncontrolled wildfires. The recent massive wildfire in Los Alamos, New Mexico, has already become a notorious example of a prescribed burn running amok, but northern California has experienced this phenomenon on a smaller scale repeatedly during the past decade. Mechanical thinning and residue removal before prescription burning reduces the pollution and risk factors associated with the treatment, and in some cases can eliminate the need to burn. Mechanical thinning, however, is expensive, and rarely performed in the absence of fuel applications for the thinned material.

Agricultural Residues

Agriculture is a multibillion-dollar enterprise in California, producing large quantities of biomass residues in the process. Approximately one-third of California's biomass energy plants were built in the state's agricultural regions in order to use these residues as fuel. Many receive emissions offsets for pollutants that are avoided when biomass residues that would otherwise be open burned are used for energy production. Agricultural fuels provide about 20% of the state's biomass fuel supply. Agricultural residues come in a wide variety of forms, some which are unsuitable for use as power plant fuel. Agricultural residues suitable for fuel use in solid-fuel biomass energy plants include materials in the following categories:

- Food processing residues such as pits, shells, and hulls
- Orchard and vineyard removals
- Orchard and vineyard prunings
- Field straws and stalks

Food processing residues are generated in concentrated quantities and require some form of disposal. Like wood products manufacturers, food processors have worked diligently to develop high-valued uses for these materials, such as in feed products. Nevertheless, a surplus of food processing residues is available for use as biomass fuel. In the absence of fuel markets, these materials would otherwise be buried in a landfill or open burned. Some wastes that have been used as fuels in California, such as nut hulls, shells, pits, and rice hulls, present special combustion problems that limit their application to facilities able to deal with these materials. Several pioneering biomass generating facilities were built at food processing facilities specifically to dispose of the processing residues. Although some experienced

operating problems when first starting up, most were able to adapt and adjust their equipment to handle the specific fuels.

California's agriculture includes extensive plantings of orchards and vineyards, permanent woody crops that require annual pruning operations and produce large quantities of residues. Conventional agricultural practice for the disposal of these prunings is to pull them to the sides of the rows, where they are piled and burned. It has long been recognized that agricultural burning is a major contributor to the air pollution problems in California's major agricultural regions. During the early development of the biomass energy industry there was a great deal of interest in using orchard and vineyard prunings as fuels. Combustion of this material in a power plant greatly reduces the resulting emissions of smoke and air pollutants compared with open burning. In addition to the environmental benefits anticipated, many farmers were under the impression that fuel sales would offset the cost of pruning, and even create a new profit center for their operations.

Orchard and vineyard prunings are more expensive and difficult to use as fuels than was originally anticipated. This is a consequence of two factors. First, the density of the resource (tons per acre) is less than originally projected. The result of this miscalculation is that more area needs to be covered to produce a given amount of fuel, which results in concomitant increase in fuel production cost. Second, compared with other sources of biomass boiler fuels, prunings are very stick-like, which makes them more difficult to process into fuel form and creates a special hazard for fuel handling and delivery equipment at the power plant. These considerations have limited the amount of fuel produced from orchard prunings in California. It is estimated that less than 7.5% of the state's agricultural prunings are being converted to fuel in the current market environment. The remainder continues to be open burned.

In contrast to the experience with prunings, orchard and vineyard removals constitute very desirable source of biomass fuel. Orchards and vineyards are cleared periodically for purposes of replanting, and in response to changing land use decisions. Orchard clearing, in particular, provides a high density of material (tons per acre) that can be processed into conventional whole tree chips. In addition, this material is generally felled in the mid to late summer from plantations that have not been irrigated, the wood is often very dry compared with other sources of recently cut biomass fuels. Fuels derived from orchard clearings, and to a more limited extent from vineyard clearings, are the major agricultural residue fuels used in California.

California agriculture also produces large quantities of field residues in the forms of straws and stalks that are disposed of either by open burning, or by plowing under in the fields. These residues can be collected and processed into power plant fuels. Straw and stalk-based fuels tend to be expensive to produce, and their low bulk density (lb/ft^3) presents materials handling problems and combustion difficulties. As a result, very little of this material contributes to the fuel supply, even though these materials qualify as agricultural offset fuels.

Most agricultural residues used as fuels in California are woody residues derived from extensive orchard crops. Whole-tree chips produced from orchard removals constitute a particularly successful source of biomass fuel. Even with the present level of agricultural biomass fuel use, an enormous amount of agricultural residues suitable for use as power plant fuels continues to be open burned. The alternative fate for most agricultural residues used for fuel is open burning, although a small percentage of these materials would likely be landfilled or plowed under in the absence of fuel applications.

Urban Wood Residues
Fifteen to twenty percent of the material traditionally disposed in municipal landfills is clean, separable waste wood. This material comes from a variety of sources, including:

- Waste wood from construction contractors
- Old and damaged pallets
- Waste wood from land clearing
- Waste wood from public and private tree trimmers and landscapers
- Waste wood from industrial manufacturers, including packing materials and trimmings

Urban wood residues are brought to landfills in a variety of forms, including loads of chipped wood and brush from public and private tree trimmers and land clearers, debris boxes from manufacturers of wood products and construction contractors, and mixed loads of yard debris. Some amount of demolition wood waste is also used as a biomass fuel, although many facilities have permit restrictions that prohibit the use of painted wood and/or treated wood because of emissions concerns. Transfer station and landfill operators can segregate loads containing fuel-usable materials as they enter the gate, and process the material to produce a high-quality fuel product. Urban wood residues contribute much more to California's biomass fuels mix than anyone anticipated during the early development of the industry.

Landfill-diverted waste wood supplied about 1.5 million tons of fuel annually to the biomass energy industry during the 1990s, hitting a peak of 1.9 million tons in 1993. As the overall biomass fuels market declined through the decade, the percentage of landfill-diverted fuels in the state's biomass fuel mix has increased, from approximately 20% at the beginning of the decade, to 30% today. Landfill-diverted waste wood is the second cheapest source of biomass fuel to produce after sawmill residues, in large part because of the pressure to divert wastes away from landfill disposal.

The traditional disposal option for urban wood waste is burial in landfills. However, the alternative disposal options that might be available for this material in the future, should the fuels market disappear, are more complicated to project. California's solid waste diversion law, AB 939, mandates that by the end of 2000 all counties must achieve a diversion rate of 50% of their total solid waste, compared to their performance during 1990. An intermediate target of 25% diversion by 1995 was met statewide, but compliance with the year 2000 standards will be significantly more difficult to achieve. Peak urban biomass fuel use of 1.9 million tons/year represents 6.6% of the amount of solid waste that must be diverted statewide by the end of 2000.

Solid waste managers are under pressure to develop diversion applications of all kinds. The alternatives, however, are limited, and most of the obvious markets that can accept waste wood, such as spreading as mulch or composting, are already being flooded with material. Most of the urban biomass fuels would otherwise probably be landfilled; some would be spread as mulch or composted.

The California Biomass Fuels Market

During the early development of the biomass energy industry in California, wood processing and agricultural residues provided virtually all the fuel used by the various biomass power producers. As the industry grew the use of these sources of fuel grew in step, and two new sources of fuel were introduced: in-forest residues and urban wood residues. Figure 4.5 shows the time course of the use of the four categories of biomass fuels as a function of fuel type. Wood processing residues have continued to be the primary source of supply for the biomass energy industry throughout the period covered by this study. The use of wood processing residues as fuel increased rapidly during the 1980s, peaking in 1990 at more than 5.5 million tons/year. At that point all but the most remote wood processing residues were being used as biomass fuels.

California Biomass Fuels Market by Category
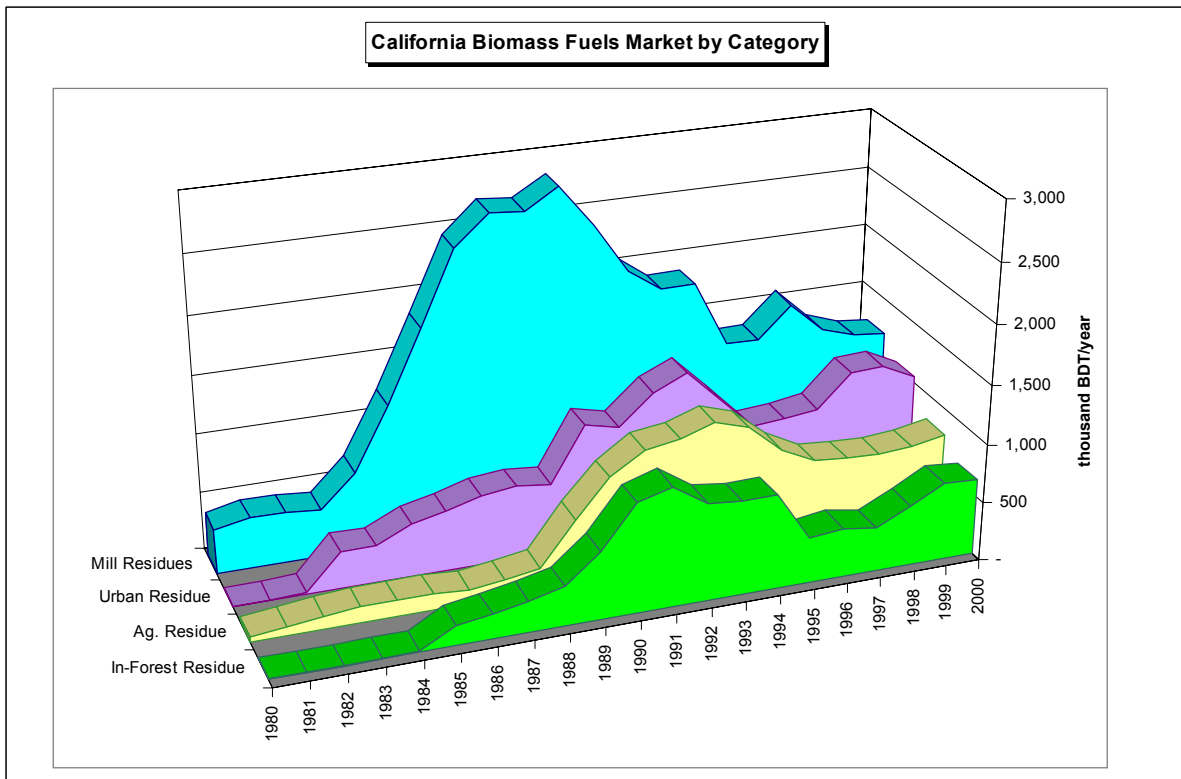
Figure 4.5

Although the demand for biomass fuels remained relatively stable during the early 1990s, the use of mill residues dropped dramatically during this period. This was a result of the fact that sawmilling activity in the state declined in response to poor economic conditions and increasing environmental restrictions on the supply of round wood. At the same time supplies of the other types of biomass fuels became more available as high biomass fuel prices and long-term fuel supply contracts required by the financial institutions that funded the power plants stimulated a variety of new ventures in the fuel supply business. As the lowest-cost-to-produce fuel source, mill residues are used to the full extent they are available. The state's biomass energy industry would have to shrink to less than half its current size before significant quantities of mill residues would start to be disposed of using alternative disposal options.

The other category of biomass fuels that has been in use since the beginning of the development of the biomass energy industry is agricultural residue fuels. The first agricultural fuels to be used were food processing residues such as nut hulls and pits. Several pioneering biomass energy facilities were built at food processing facilities to provide for the disposal of these materials. Expansion of the use of agricultural fuels has been more gradual than many industry observers originally predicted, because converting of orchard and vineyard prunings to fuels was more difficult and expensive than originally projected. Agricultural fuel use increased significantly between 1988 and 1990, as the statewide biomass fuel crisis hit, and many new facilities entered operation with permit requirements to burn agricultural wastes to offset their air pollutant emissions. With the closure of many agricultural fuels-based facilities during the mid-1990s, agricultural residue fuel use declined by about 33% from its peak in the early part of the decade.

Urban waste wood began to contribute to the state's biomass fuel mix in 1983, when Gaylord Paper Corp. started up its pioneering facility in the San Francisco Bay area. This facility was designed to burn

primarily urban waste wood fuel, and was a very successful venture. In 1985 a second facility designed to burn urban wood fuel, Procter & Gamble, began operations in the Long Beach (Los Angeles) area. These two facilities, located in the two largest metropolitan areas, stimulated the development of a market for producing fuel from material that was traditionally buried in landfills.

As the technical viability of using urban waste wood fuels was proven, biomass energy facilities designed to burn primarily sawmill and agricultural residue fuels began purchasing fuels derived from urban waste wood, and the use of urban biomass fuels in California increased gradually during the mid-1980s. When the statewide biomass fuel crisis hit at the end of the decade, urban biomass fuel use doubled, reaching approximately 1.5 million tons/year in 1990. This fuel source continued to grow over the next several years, as statewide fuel demand remained stable and the availability of wood processing residues decreased. Urban biomass fuel use peaked at almost 1.9 million tons in 1993. Urban biomass fuel use contracted to below 1.2 million tons/year as overall biomass fuel demand declined with the shutdowns of the middle of the decade, then began to pick up again as the 1990s came to a close. With increasing pressure to divert material from landfill disposal to comply with AB 939, urban biomass fuel use currently exceeds 1.5 million tons/year.

In-forest residues are the most expensive of the four types of biomass fuel sources used in California. Significant in-forest fuel production did not begin until 1985, and grew gradually until the end of the decade, when the statewide fuel crisis forced fuel prices above $40/bdt. In-forest biomass fuel use peaked in 1990-1991 at about 1.8 million tons/year, then began to fall as the market reached equilibrium, sawmilling activity recovered slightly, and cheaper urban and agricultural fuels out competed in-forest fuels. When the buyouts and closures hit the biomass energy industry in 1994-1995, in-forest biomass fuel use took the greatest hit, dropping to less than 700,000 tons/year in 1997. Since then in-forest residue fuel use has rebounded to more than 1 million tons/year.

Biomass Fuel Market Price Trends

Before the development of the modern biomass energy industry in California most agricultural and wood-processing residues, as well as a significant quantity of the forest harvesting residues, were being open burned, while urban wood residues were being buried in landfills. In addition, the amount of overstocking of fuel in the state's forests was increasing relentlessly, a process that has spanned the entire twentieth century. These disposal alternatives have economic costs as well as adverse environmental consequences. The early development of the state's biomass energy industry was spurred as much by sawmills and food processors looking for improved disposal options for their residues, as by the incentives provided by the energy sector.

During the early development of the biomass fuels market in California, a surplus of residue material was available for conversion to fuel, and fuel prices were based primarily on the cost of processing the residues and transporting them to the power plants. During the early 1980s, biomass fuel prices were stable, about $15-20 per bdt. Some sawmill residues were sold to nearby generating facilities for less than $10/bdt. Figure 4.6 shows the average price of biomass fuels as a function of time.

Figure 4.6
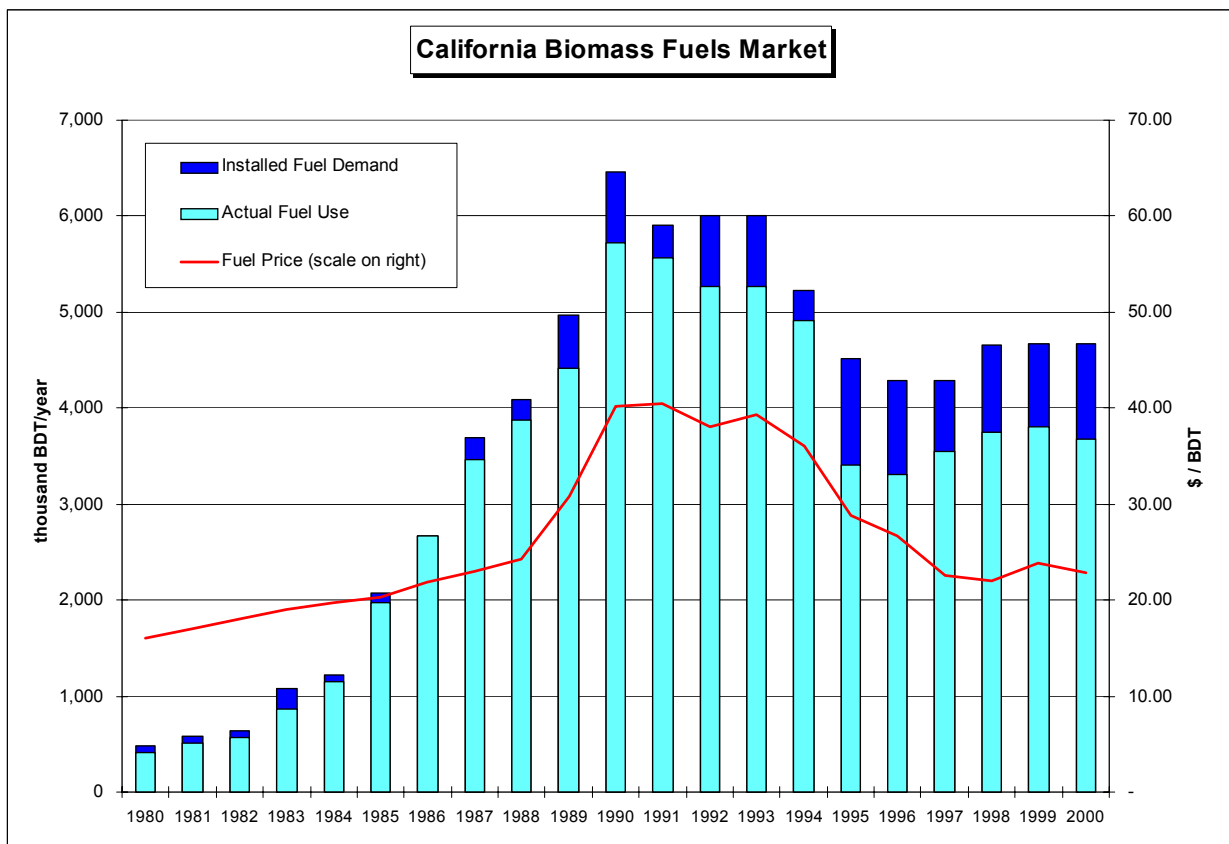
As biomass fuel demand increased during the mid to late 1980s, the average statewide price of biomass fuels began to climb upward, reaching an average value of almost $25/bdt by 1988. From 1980 to 1988, fuel demand grew at a greater rate than the rate of increase in fuel prices. The inflation-corrected price of biomass fuel was virtually unchanged during this period. From that point forward, however, fuel demand reached a critical level, and prices shot up, reaching more than $40/bdt during the early 1990s, with spot prices reportedly tipping $60/bdt. The industry appeared to be in a full-blown fuel crisis, which was precipitated by the extremely rapid increase in generating capacity, and the requirements for long-term fuel supply contracts imposed by the banks on the power plants as a condition of funding.

By 1988, statewide biomass fuel demand had grown to the point that it exceeded the capacity to provide biomass fuels. The cheapest source of biomass fuels, mill residues, was completely committed to the fuels market, and additional mill residues were no longer available to satisfy new fuel demand. New sources of biomass fuels were required, and significant investments had to be made to develop the new fuel supplies. In general, the new supplies of fuel were more expensive than the fuel sources that had already been developed. These were all factors in the rapid increase in biomass fuels prices that occurred between 1988 and 1990, during which statewide average biomass fuel prices increased by approximately 60%.

By the end of 1990 the demand for biomass fuels stabilized, as did the price, which averaged about $40/bdt. The fuel-supply infrastructure had a chance to catch up with the demand, and a great deal of experience was accumulating with respect to the technologies necessary to produce power plant fuels from new sources of biomass, such as urban wood residues and various types of agricultural and in-forest residues. Fuel prices might have decreased somewhat during the early 1990s as a better balance was

achieved between supply and demand, except that the supply of mill residues decreased significantly because of a cutback in lumber production (see Figure 4.5). Thus, the pressure for fuel price decreases due to an improved supply-demand balance was countered by the loss from the market of a fraction of the wood processing residues. The loss of wood processing residues had to be made up for by sources of supply that were more expensive to produce.

Beginning in 1994, the regulated California electric utility companies, in response to the deregulation process at the CPUC, initiated a series of buyout negotiations with many biomass generating facilities. Owners of approximately 200 MW of capacity accepted buyouts during 1994 and 1995, shutting down 25% of the state's operating capacity, and decreasing the demand for biomass fuels by more than one-third. Supply and demand were again out of balance, and fuel prices began a fall that brought them back to pre-1988 levels. Figure 4.7 shows a plot of the supply curve for biomass fuels in California. The data points represent the period 1986 to the present, showing, for each year in the range, the quantity of biomass fuel used and the average price.

Figure 4.7
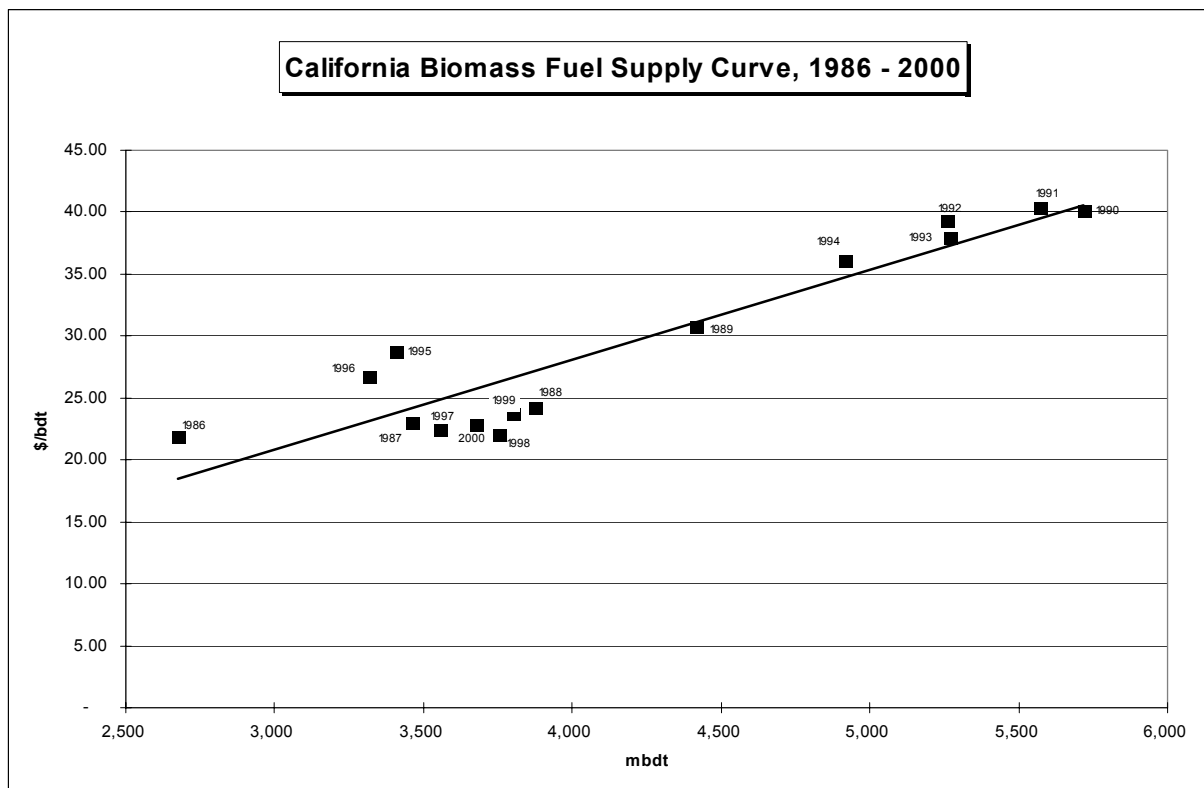
The future for biomass fuel prices in California is difficult to predict. The renewable transition fund payments to biomass generators over the past 2 years have provided sufficient incentive for generators earning SRAC rates to increase their production during off-peak hours, compared with what they were doing before the transition funds were available. This, combined with the restart of two twenty-five MW facilities, has increased total fuel use, with a concomitant rise in fuel prices. As fixed-price periods expire for more facilities, and the renewable transition fund payments are ramped down and disappear by the end

of 2001, this upturn in statewide fuel demand might very well be short lived. Power plant operating economics will ultimately determine the marginal price of fuel that producers will be willing to pay.

Summary of California Situation in 2000

The biomass energy industry in California reached its peak level of production during the early 1990s, and has since declined by more than one-third. This decline has a variety of causes, but the underlying reality is that biomass energy is expensive to produce compared with the lowest cost alternatives available on the grid. The high cost of biomass energy production, an inevitable result of the small facilities and the high cost of collecting and transporting low-density residue materials, is a considerable liability in a marketplace that is being deregulated and that increasingly emphasizes cost. As a result, unless biomass energy generators are compensated for the environmental benefits they provide, the viability of the enterprise is in serious doubt.

Loss of a significant fraction of the present level of biomass energy production in California would present serious social and environmental consequences. Almost 3 million tons/year of residues currently used as fuel would be added to the burden of material entering sanitary landfills, making compliance with AB 939 virtually impossible for many counties. Moreover, burying this material will burden the country with future greenhouse gas emissions that will not be avoidable when the Kyoto greenhouse gas emissions reductions must be achieved in 2012.

Disappearance of the industry would mean that more than 1.75 million tons of residues currently being used as fuels will return to open burning piles, where they will add measurably to the air pollution problems in agricultural and forested regions, many of which are already out of compliance with state and federal air-quality standards. Moreover, an additional 500,000 tons/year of residues will be allowed to accumulate in overstocked or otherwise unhealthy forests and watersheds. These residues will exacerbate the risks of destructive wildfires and ecosystem degradation that plague California's forests, and depress the productivity of many key watersheds.

The loss of the biomass energy industry would represent a loss of almost 3,000 rural employment positions, with serious negative impacts. Many rural communities would also lose their largest source of property taxes, and would suffer other economic multiplier effects as well. Energy diversity and security values would be lost.

The loss of the California biomass energy industry would exacerbate a number of important environmental problems, and leave affected rural regions with virtually irreplaceable losses of quality employment opportunities and tax base. In fact, increasing the capacity utilization of the infrastructure and encouraging the development of new biomass installations using ever-advancing technology, should be important goals of state and federal policy. The ancillary benefits of biomass energy production are worth far more than the above-market costs of operations. A modest level of compensation for these benefits will achieve a several-fold return in social and environmental benefits. The California experience with providing of biomass production credits 1.5¢/kWh demonstrates that this level of support can stabilize and increased the use of facilities. A higher level of support would be needed to encourage idle facilities to reopen, or the development of new biomass energy production capacity.

The California biomass energy industry provides a valuable, environmentally preferred waste disposal service for more than 6.4 million tons of the annual solid-waste stream. These services have been provided without compensation, as the electricity market was able to underwrite them fully. They will be lost to competitive electric market unless means are developed to compensate generators for their environmental services.

The total cost of support to maintain biomass energy production in California at its present level of activity is approximately $50 million/year, based on conditions that are expected at the beginning of 2002, the end of the transition period to full competition and the end of the RTF program. Most of the required amount could be provided by modifying the federal renewable energy tax credit, or extending public purpose funding for renewables in California beyond the end of the transition period. The remainder could be provided by targeted policy measures, such as appropriations of funds for wildfire risk reduction activities on state and federal forest lands, and for diverting agricultural prunings from open burning to energy production. Expanding the use of particular forms of residues through targeted policy measures will be well worth the cost in terms of the value of the benefits produced.

2002 Update on California Biomass Power Industry[6]

Natural gas prices in California, which had been stable throughout the 1990s, abruptly shot upwards during the winter of 2000. This was in no small part a result of pipeline capacity bottlenecks that were related more to business issues than to physical capacity constraints. Whatever the cause, this staggering increase in gas prices, combined with rapidly growing electricity demand fueled by the booming high tech industries in California, and a drought-caused decrease in hydroelectric production in the Pacific Northwest, led to electricity supply shortages in California.

Wholesale electricity prices, which had remained within a penny of three cents per kWh for more than 15 years, broke through the four-cent barrier in May of 2000. In June, they hit double digits. By August prices at the state power exchange were averaging more than 15¢/kWh. California was engulfed in a full-fledged energy crisis. The Governor resolved to hold the line on consumer electricity prices, and the utilities found their cash reserves evaporating rapidly.

Biomass power generators in the state responded quickly to what was a considerable opportunity. Each of the operating biomass facilities looked to expand its fuel purchasing, and pushed its facility to maximize output around the clock. All of the facilities that were eligible opted to convert to power exchange pricing in order to take advantage of the higher prices available there. Ten of the biomass facilities in California that had been shut down during the 1990s, representing 130 MW of generating capacity, began investigations to see whether they could profitably resume operations. The ten facilities, many of which are located near the state's Central Valley region, are shown in Table 4.2. The state support payments to the biomass generators were suspended because market prices exceed the target level. By the end of the year biomass fuel prices were on the rise, but few of the generators were complaining.

The complaints started promptly in December of 2000, when the utility companies stopped paying power producers for energy. Six months of unprecedented wholesale energy prices had mortally wounded the utility companies, and they were teetering on the verge of bankruptcy. To put the topping on the cake, prices at the power exchange suddenly shot up again in December, averaging more than 35¢/kWh during the month. They remained at that level into January 2001, when the power exchange itself was shut down. The electricity market in California was in chaos, and the state's investor-owned electric utility companies were crippled.

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[6]Reference: Morris, G. (2002) "Biomass Energy Production in California," NREL Progress Report, Task Order No. KCL-0-30040-02, April

Table 4.2: Idle California Biomass Facilities that Began Re-Start Investigations in 2000

Auberry Energy, Auberry	7.5 MW	restart abandoned
Blue Lake Energy, Blue Lake	10.0 MW	restart abandoned
Capitol Power, Ione	18.0 MW	start up summer 2002
Chow II, Chowchilla	10.0 MW	restart abandoned
Dinuba Biomass, Dinuba	11.5 MW	started up in 2001
El Nido, Chowchilla	10.0 MW	restart abandoned
EPI Madera, Madera	25.0 MW	started up in 2001
Primary Power, Brawley	15.0 MW	started up in 2001
Sierra Forest Products, Terra Bella	9.5 MW	started up in 2001
Soledad Energy, Soledad	13.5 MW	started up in 2001

California's biomass power producers were faced with a mind-boggling irony. At the very time that they were earning unprecedented profits, they were facing insolvency. The supposed profits, of course, were only on paper. With their revenues suspended, fuel prices elevated, and the state demanding that they produce as much power as they could, their short-term cash positions were precarious. Many biomass operators talked openly of giving up and shutting down for good.

In spite of the troubles faced by the operating biomass facilities, the efforts to restart ten of the state's idled biomass facilities were proceeding full-speed ahead. Wholesale electricity prices had never been higher, actual operations for these facilities were months away, and it seemed reasonable to assume that something would be done to get the flow of money moving again. In fact, in many ways it appeared in the beginning of 2001 that the idled facilities that were trying to restart would enjoy a couple of distinct advantages over the operating facilities. They were not hobbled by having had to endure a prolonged period of operating without any revenues, and they were not saddled by old power purchase contracts that now were paying below-market prices.

Governor Gray Davis convened an emergency session of the state legislature in January 2001 to deal with the still burgeoning energy crisis. Many commentators were predicting that a long, hot summer of brownouts and blackouts lay ahead. The governor was negotiating bailout deals with the utility companies that would have them sell their entire transmission systems to the state for prices that were well above book value. In March the CPUC, for the first time since the energy crisis hit, granted the utility companies across-the-board rate increases of ten percent. Nevertheless, negotiations with PG&E broke down and the utility company declared bankruptcy. The negotiations with SCE eventually broke down too, although SCE avoided bankruptcy.

The state's electricity generators were desperately searching for a way to get the utility companies to pay them. A deal was struck in late March at the CPUC that allowed the utility companies to resume payments to the power generators on a going-forward basis, with the matter of payments for past due bills left unresolved. None of the thirty operating biomass facilities had been forced to shutdown, although many were severely stretched. Short-run avoided cost rates hovered in the neighborhood of 10¢/kWh through the Spring of 2001, well below their unbelievable levels of December and January, but still some three times higher than historical levels.

With the collapse of the state power exchange and the crippled financial status of the utility companies, the emergency session of the state legislature passed legislation that allowed the state, through the Department of Water Resources (DWR), to begin buying electricity on behalf of the state's consumers. DWR immediately set up a trading unit and created an exchange for short-term energy purchases. In addition to purchasing energy on a short-term basis the DWR embarked on a program of negotiating

long-term energy contracts at prices below the then prevailing rates, but above historical levels. Many of the state's generators were eager to join the negotiations, and the state began to deal.

The ten idled biomass generating facilities in the state that had initiated startup preparations during late 2000 and early 2001 looked at long-term contracts with the state as the obvious way to go. At first they were rebuffed. DWR's initial request for proposals specified a minimum generating unit size of 50 MW. This excluded all of the candidate biomass facilities. One of the potential biomass startups, the 13.5 MW Soledad facility, applied to DWR in spite of not meeting the size qualification. They explained on their application that they understood they were undersized, but hoped that DWR would consider them for what they were, which included the possibility of starting up before the crucial summer season just ahead. The remaining biomass restarts waited to enter into negotiations with DWR until after the first wave of applications from the large producers had entered into negotiations.

In parallel with the state's efforts to negotiate long-term contracts with large generators, the CPUC developed a program to allow biomass facilities operating under old standard offer PPAs to select a five-year fixed price payment of 5.37 ¢/kWh, instead of being paid at variable short-term market rates. Many, but not all, of the biomass facilities operating under standard offer contracts accepted this offer, and began receiving the fixed price payments beginning in July 2001.

At this point the biomass power plants in California could be divided into two functional groups based on their power sales arrangements. The first group, which included most of the facilities operating under the old standard offer PPAs, had fixed price agreements that would cover the next five years, with prices that were high enough to ensure their continued ability to operate throughout this period. The second group, which included a few of the facilities that had operated continuously during the 1990s, and most of the facilities that were in various stages of restarting, were stuck without long-term PPAs. The already operating facilities in this group were selling their output on the short-term market, where prices were in the neighborhood of 10 ¢/kWh during the spring of 2001. Many of the facilities in this group were actively negotiating long-term contracts (five years or more) with the DWR. A few were content to remain players in the short-term market.

Available power supplies for the California grid remained at very low levels during the spring of 2001, as unusually large numbers of the state's fossil fuel-fired power plants seemed to be out of operation for servicing, many for prolonged periods of time. A couple of rolling blackouts of two or three hours duration each were imposed on many PG&E customers, despite the fact that spring is traditionally a period of low electrical demand in the state. Rumors and charges began to surface that some of the state's largest generators were manipulating their production units to game the market. The state was petitioning the FERC to impose price controls on the wholesale market, but the FERC was resistant. The situation was rapidly coming to a boiling point.

By the beginning of the summer of 2001, the DWR had signed some forty long-term contracts with generators for more than 10,000 MW of power. Although the contracts were not made public, prices were rumored to be in the range of 7 - 10¢/kWh, with terms ranging from 2 - 10 years. Soledad's gamble had paid off. Their biomass power plant was among the recipients of the first set of DWR contracts, and was already firing fuel. Seven of the biomass restarts were now actively engaged in negotiations with DWR. The other two attempted restarts, twin 10 MW facilities near Chowchilla (Chow II and El Nido), suspended their efforts to restart.

The newspapers continued to be full of dire warnings of looming summer blackouts. The crisis was beginning to spread to the entire Western U.S., and electricity supplies were reportedly strained in the Northeast. The Governor pushed hard for conservation in California, and for FERC price caps to be

imposed in Washington. Finally FERC acted and imposed price caps on the wholesale electric market in the western U.S.

Then something totally unexpected happened. The long-dreaded summer of 2001 had arrived. But wholesale energy prices fell from May to June by more than a third, despite the fact that it was the beginning of the peak demand season. By the middle of the summer prices had fallen below four cents per kWh, which was within the range of pre-crisis levels. Not one blackout occurred during the entire summer. A combination of factors, including aggressive conservation efforts by consumers, an economic recession, an unusually cool summer, the long-term contracts signed by the DWR, the end of the drought in the Northwest, and the breaking of the bottleneck in the natural gas market, seemed to have combined to knock out the energy crisis. The FERC price caps were reached a couple of times soon after their imposition, then quickly became irrelevant. By late summer there were grumblings that the state had signed too many contracts at too high prices. There were even periods when the state was purchasing more contract electricity than it could use, and had to sell the excess into the out-of-state markets at a loss.

More than 99 percent of the long-term contracts the state signed in the spring of 2001 were for energy generated from natural-gas fired power plants, a result of the crisis atmosphere that had been in effect when the DWR began to seek long-term power supplies. Due to size and other considerations, renewables had been put on the back burner in the spring, and were just coming up for consideration at the DWR as the summer reached its peak, and the energy crisis ebbed.

Timing was distinctly against the biomass facilities. The DWR was coming under fire for the contracts they had just signed with the natural gas generators. Negotiations for additional long-term power purchase contracts suddenly ground to a halt, even in cases where there were signed letters of intent for power to be purchased from clean generating sources. Biomass project proponents complained that their questions went unanswered, and their phone calls were not returned. With the exception of Soledad, all of the other facilities attempting to restart, as well as several operating biomass power plants that did not have standard offer PPAs, found themselves relegated to selling into the short-term market at prices that were insufficient to cover their fuel and operating costs.

One of the many actions taken by the emergency session of the state legislature was the creation of the California Power Authority (CPA), which began operations in August 2001. The CPA was vested with $5 billion in bonding authority to invest in generating assets that would give the state power grid an adequate reserve margin of generating capacity. A minimum of $1 billion of the total was earmarked for conservation and renewables. Soon after its creation, the CPA put out a request for proposals, asking for any kind of proposal that a proposer wished to make. They were particularly interested in peakers, renewables, efficiency, and any kind of generator that would be located in known voltage-constrained regions. All of the biomass facilities that were negotiating with the DWR filed applications for their projects with the CPA.

One of the CPA's mandates was to produce, within six moths of its creation, an investment plan for its $5 billion capital fund. The investment plan had to be submitted to the legislature by the middle of February 2002. A series of meetings were held around the state to solicit public input, and a strategic document was hashed out. The official document rejected the notion of having the CPA support the development of a new generation of natural gas-fired peaking plants in California, and enthusiastically embraced renewables. In particular, the CPA *Investment Plan* recognizes the importance of maintaining and enhancing the state's biomass generating infrastructure, and stated an intention to contract with the biomass generators who did not have standard-offer contracts, and had so far been unable to negotiate contracts with the DWR.

Despite their good intentions with regards to biomass, the CPA has been thwarted in their efforts to move forward with any biomass contracts. The problem is that, due to a dispute between the state and the CPUC over regulatory jurisdictional issues, the CPA, in concert with the state Treasurer's Office, is unwilling to issue the bonds that will supply the funds they need in order to make commitments to generating facilities. At the present time the state underwriters have taken the position that the state lacks the authority to ensure that ratepayers will be held fully responsible for the costs of energy procurement. They will not issue the CPA bonds until the guarantees they are seeking are in place.

December 2001 was the sixth consecutive month in which short-run avoided cost rates were insufficient to cover all of the costs of biomass power generation. The group of facilities that did not have long-term contracts were nearing the end of their ability to hang on, a finding that was recognized and confirmed by the CPA, the DWR, and the Governor's Office. One project, Capital Power Ione, an 18 MW facility, was able to finalize a contract with DWR during the last months of 2001. This project had obtained a signed letter of intent with DWR in the early spring, and continued to negotiate faithfully throughout the summer and fall, enlisting support wherever it could be found. They were finally able to come to terms that were substantially less favorable than those that had been granted to the natural gas industry earlier in the year. This was the second, and so far last, of the restarts that has managed to finalize a long-term power purchase agreement with the state.

Recognizing that the issues that were holding up the issuance of the CPA's bonds were not going to be resolved quickly, the DWR, in conjunction with the CPA, signed 90-day interim contracts with eleven facilities before the end of the year, with a common intention to enter into long-term contracts as soon as it became possible. The interim contracts were extended for a second 90-day period at the end of March, carrying these facilities through the end of June 2002.

The interim contracts provide for average revenues of 6.5¢/kWh, differentiated by time-of-use and seasonal factors. The payment level covers both energy and capacity, and as such is below the level earned by the facilities with old standard offer utilities contracts (5.37 ¢/kWh energy plus 2.0 ¢/kWh capacity), and on the low side of the range of the legitimate costs of energy production from biomass (see Morris, G., *Biomass Energy Production in California: The Case for a Biomass Policy Initiative*, NREL Report No. NREL/SR-570-28805, November 2000).

California currently has thirty-five biomass power plants in operation, representing a total of 685 MW of electricity generating capacity. Approximately two-thirds of the total are operating under old standard-offer power purchase agreements with fixed energy prices that will remain in effect through the middle of 2006. These facilities are well served by their contracts, and should be able to operate viably until at least that time. The other one-third of California's biomass power plants are operating under interim 90-day contracts that provide them with minimally acceptable operating revenues. The long-term fate of this group of facilities is a function of whether they are ultimately able to obtain longer-term contracts with adequate power purchase provisions.

Lessons Learned - Existing Industry[7]

This discussion includes summary information on 20 biomass power plants—18 in the United States, one in Canada, and one in Finland, which represent some of the leaders in the industry. Table 4.1 lists the 20 plants in order of on-line date, the same order in which they are presented in the report. In some cases, the on-line date means the date an older fossil-fired plant started using biomass fuel commercially (not its original on-line date). Some of the information in the table is abbreviated, but can be clarified by referring to the specific plant sections.

The on-line dates of the plants span about 18 years, from December 1979 to January 1998. The types of biomass fuels used are abbreviated: "mill" refers to mill wastes, etc. Many boiler types are represented: six traveling grate stoker boilers, four water-cooled vibrating grate boilers, four bubbling fluidized bed combustors (FBCs), one circulating fluidized bed (CFB) boiler, one fixed-grate boiler, one sloping grate boiler, and two pulverized coal (PC) boilers retrofitted to cofire solid or gasified biomass. Steam temperatures for the biomass-fired boilers are 750˚-980˚F; for the PC boilers, 1,004˚-1,005˚F. The nominal sizes of the plants range from 10 MW to 79.5 MW.

Electricity Generation and Fuel Consumption
Table 4.2 lists the plants in order of electricity generation, in gigawatt-hours/yr (GWh/yr). For some plants, the generation numbers are actual statistics from a recent year (1996, 1997, or 1998). For plants that did not provide these statistics, the generation rates were estimated based on available information. The same is true for the annual capacity factors (CFs, %) and net plant heat rates (Btu/kWh). The biomass fuel consumptions were calculated by multiplying GWh/yr times Btu/kWh, and dividing by 8.5 million Btu/t (4250 Btu/lb, or 8500 Btu/dry lb with 50% moisture content).

Capacity Factors
Annual CFs range from 19% to 106%. Some plants with low CFs (e.g., Multitrade and McNeil) are peaking units. The plants with very high CFs have special circumstances. Shasta and Colmac were still under the first 10 years of California Standard Offer contracts when the data were obtained. Williams Lake can operate as high as 15% over its rated capacity, and can frequently sell extra power.

Heat Rates
The Williams Lake plant also holds the distinction of having the largest single boiler (60 MW) and the lowest heat rate (11,700 Btu/kWh) of any 100% biomass-fired power plant. Biomass-cofired coal plants can achieve slightly lower heat rates, as exemplified by Greenidge Station (11,000 Btu/kWh on the biomass portion of the fuel, compared to 9818 on coal alone). The least efficient plants in this report have heat rates of about 20,000 Btu/kWh. A "typical" value is about 14,000 Btu/kWh (24.4% thermal efficiency, HHV).

Cogeneration
The four cogeneration plants in the report—Okeelanta, Snohomish, Lahti, and Camas—are recent plants, using the latest technology, in traditional niches for biomass power: two at pulp and paper mills (Snohomish and Camas), one at a sugar mill (Okeelanta), and one at a municipal district heating plant (Lahti). The estimates given in Table 4.2 for these plants represent only the solid fuel biomass portion of the energy input. At the two pulp and paper mills, recovery boilers produce large fractions of the total steam from waste liquor; the wood waste boilers at these facilities constitute focus of this report. At Lahti, coal and natural gas produce most of the energy; wood wastes and refuse derived fuel (RDF) are fed to a

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[7]Excerpted from Wiltsee, G. (2000). "Lessons learned from existing biomass power plants," NREL/SR-570-29-6946, National Renewable Energy Laboratory, Golden, CO.

gasifier that supplies low-Btu gas to the boiler. The Okeelanta cogeneration plant burns bagasse for about 6 months of the year, and burns urban and other wood wastes at other times.

Table 4.3: Summary of Biomass Power Plants in this Report

Plant	Location	MWe	GWh/yr	CF, %	Btu/kWh	Tons/yr*
Williams Lake	British Columbia	60.0	558	106	11,700	768,000
Okeelanta (cogen)	Florida	74.0	454	70	13,000	694,000
Shasta	California	49.9	418	96	17,200	846,000
Colmac	California	49.0	393	90	12,400	573,000
Stratton	Maine	45.0	353	90	13,500	561,000
Kettle Falls	Washington	46.0	327	82	14,100	542,000
Snohomish (cogen)	Washington	39.0	205	60	17,000	410,000
Ridge	Florida	40.0	200	57	16,000	376,000
Grayling	Michigan	36.0	200	63	13,600	320,000
Bay Front	Wisconsin	30.0	164	62	13,000	251,000
McNeil	Vermont	50.0	155	35	14,000	255,000
Lahti (cogen)	Finland	25.0	153	70	14,000	252,000
Multitrade	Virginia	79.5	133	19	14,000	219,000
Madera	California	25.0	131	60	20,000	308,000
Tracy	California	18.5	130	80	14,000	214,000
Camas (cogen)	Washington	17.0	97	65	17,000	194,000
Tacoma	Washington	40.0	94	27	20,000	221,000
Greenidge	New York	10.8	76	80	11,000	98,000
Chowchilla II	California	10.0	53	60	20,000	125,000
El Nido	California	10.0	53	60	20,000	125,000

*Tons/year are calculated, assuming 4250 Btu/lb.

Table 4.4: Plant Electricity Generation and Biomass Fuel Consumption Estimates

Plant	Online	Fuels	Boiler(s)	lb/hr	Psig	ÞF	MWe
Bay Front	Dec-79	Mill, TDF, coal	2 modified coal stokers	280,000			30
Kettle Falls	Dec-83	Mill	1 traveling grate stoker	415,000	1500	950	46
McNeil	Jun-84	Forest, mill, urban	1 traveling grate stoker	480,000	1275	950	50
Shasta	Dec-87	Mill, forest, ag,	3 traveling grate stokers	510,000	900	905	49.9
El Nido (closed)	Oct-88	Ag, forest, mill,	1 bubbling FBC	130,000	650	750	10
Madera (closed)	Jul-89	Ag, forest, mill,	1 bubbling FBC	260,000	850	850	25
Stratton	Nov-89	Mill, forest	1 traveling grate stoker	400,000	1485	955	45
Chowchilla II (closed)	Feb-90	Ag, forest, mill,	1 bubbling FBC	130,000	650	750	10
Tracy	Dec-90	Ag, urban	1 water-cooled vib grate				18.5
Tacoma (cofiring)	Aug-91	Wood, RDF, coal	2 bubbling FBCs		400	750	12
Colmac	Feb-92	Urban, ag, coke	2 CFB boilers	464,000	1255	925	49
Grayling	Aug-92	Mill, forest	1 traveling grate stoker	330,000	1280	950	36.17
Williams Lake	Apr-93	Mill	1 water-cooled vib grate	561,750	1575	950	60
Multitrade	Jun-94	Mill	3 fixed grate stokers	726,000	1500	950	79.5
Ridge	Aug-94	Urban, tires, LFG	1 traveling grate stoker	345,000	1500	980	40
Greenidge (cofiring)	Oct-94	Manufacturing	1 tangentially-fired PC	665,000	1465	1005	10.8*
Camas (cogen)	Dec-95	Mill	1 water-cooled vib grate	220,000	600	750	38-48
Snohomish (cogen)	Aug-96	Mill, urban	1 sloping grate	435,000	825	850	43
Okeelanta (cogen)	Jan-97	Bagasse, urban,	3 water-cooled vib grate	1,320,000	1525	955	74
Lahti (cofiring, cogen)	Jan-98	Urban, RDF	1 CFB gasifier + PC	992,000	2500	1004	25**

*108 total net MW, 10% from wood and 90% from coal.
**167 total net MW, 15% from biofuels and 85% from coal.

Fuels

The cost of biomass fuel from mill wastes and urban wood wastes can range from about $0/MBtu to about $1.40/MBtu, depending on the distance from the fuel source to the power plant. Getting to zero fuel cost depends on locating a power plant in an urban area next to a wood waste processor, or next to a large sawmill or group of sawmills. Deregulation will make this zero fuel cost strategy more important in the future.

Agricultural residues (primarily orchard tree removals) can be processed into fuel and delivered to nearby biomass power plants for about $1/MBtu. Only if open burning of residues is prohibited will transferring some of this cost to the orchard owners be possible.

Forest residues are much more costly ($2.40-$3.50/MBtu), because of the high costs of gathering the material in remote and difficult terrain, processing it to fuel, and transporting it to power plants. There are strong arguments for government programs to bear the costs of forest management and (in the West) fire prevention. Only if such programs are created will forest residues be as cost-competitive fuel as in the future.

Plants that have come close to zero fuel cost are Williams Lake, which is located very close to five large sawmills, and Ridge, which accepts raw urban wood wastes and whole tires, and burns landfill gas. Other plants burning primarily mill wastes include Shasta, Kettle Falls, Stratton, Snohomish, Grayling, Bay Front, Multitrade, and Camas. Other plants burning primarily urban wood wastes (and in some cases RDF) are Okeelanta, Colmac, Lahti, and Tacoma. Sawdust from furniture manufacturing is the main biomass fuel at the Greenidge plant. Plants burning agricultural residues include Okeelanta, Tracy, Madera, Chowchilla II, and El Nido. Plants burning significant amounts of forest residues include McNeil, Shasta, Stratton, and Grayling.

Lessons Learned

The project experiences described in the following sections capture some important lessons learned that lead in the direction of an improved biomass power industry. Undoubtedly, many other problems and solutions did not surface in the interviews and in the documents and articles that served as source materials. A summary of the lessons learned from these 20 biomass plants follows; in each category an effort is made to identify plants that illustrate particular points, so the reader can go to those sections to learn more.

Fuel

The highest priority at most biomass power plants is to obtain the lowest-cost fuels possible. This involves tradeoffs in fuel quality, affects the design and operation of the system, and frequently is limited by permit requirements. Some fuel-related lessons illustrated in this report are:

- At Bay Front, the conversion from coal and oil to biomass and other waste fuels kept an old generating station operating and provided continued employment.
- At the McNeil Station, long-term fuel contracts insisted on by financing institutions created some costly problems. As required, McNeil had 15 or 20 long- term fuel contracts when it started up. The CF dropped because of dispatch requirements, resulting in lawsuits and settlements with fuel suppliers and odors from the wood piles. The plant now runs more economically by buying wood fuel under short-term contracts.
- Maintaining adequate fuel supply in the midst of a declining regional timber industry has been the single biggest challenge for the Shasta plant. Almost from startup, Shasta has tried to diversify its fuel sources. From an initial list of permitted fuels that included only mill waste, logging/thinning residue, and cull logs, Shasta added agricultural residues, fiber farm residues, land and road clearing wood wastes, tree trimmings and yard wastes, and natural gas.
- The San Joaquin Valley Energy Partners plants (Chowchilla II, El Nido, and Madera) experimented in combusting low-cost, low-demand agricultural waste materials such as grape pomace, green waste, onion and garlic skins, and bedding materials not desired by competing facilities. However, the most difficult-to-burn agricultural residues were assigned to the "tertiary" fuel category and mixed in small percentages with better fuels, primarily wood.
- Experience at the Tracy plant shows that urban wood waste can be a comparatively inexpensive fuel (~$0.35/MBtu) if the plant is located close to the urban area. Compared to urban wood waste, orchard wood is relatively expensive (~$1.00/MBtu) because growers are used to simply pushing and burning it, and are generally not willing to pay a fee to have the wood removed.
- Tacoma found that focusing on fuel cost (¢/kWh) rather than fuels that provide highest efficiency (Btu/kWh) saved the plant $600,000/yr. Opportunity fuels (with tipping fees) can eliminate fuel costs and generate net revenues. Fuel procurement should be one of the highest priorities and a full-time job.
- At the Williams Lake plant, with uncertainty in the forestry industry, unknown impacts of Asian market upheaval, high provincial stumpage fees, and closure of some coastal sawmills and pulp mills, the biggest threat to an enviable operating record appears to be fuel availability.
- The Ridge Generating Station is an urban waste recycling facility, working within the local waste management infrastructure to provide a low-cost recycling service to waste generators, and to obtain a free or negative-cost fuel mix (urban wood wastes, scrap tires, and landfill gas) for energy production.
- The Snohomish Cogeneration plant design anticipated the trend toward declining quantities of sawmill residues, and the increasing use of urban wood wastes in the region. Siting the plant at a paper mill provided an excellent fit for steam use, as well as expertise in wood waste handling and combustion.

<u>Fuel Yard and Fuel Feed System</u>

The area of a biomass power plant that can almost be counted on to be mentioned in response to the question "Have you had any significant problems or lessons learned?" is the fuel yard and fuel feed system. Most plants in this report spent significant time and money during the first year or two of operation, solving problems such as fuel pile odors and heating, excessive equipment wear, fuel hangups and bottlenecks in the feed system, tramp metal separation problems, wide fluctuations in fuel moisture to the boiler, etc., or making changes in the fuel yard to respond to market opportunities. Examples noted in this report include:

- At Bay Front Northern States Power (NSP) engineers installed and improved (over time) a system that allows feeding of 100% biomass, 100% coal, or any combination of the two. Because wood fuel quality varies more than coal quality, proper tuning of the automatic combustion controls is more important when firing wood. Operators must pay close attention and periodically adjust feeders.
- With the addition of a debarker, high-speed V-drum chipper, chip screen, and overhead bins, the Shasta plant was able to offer to custom chip logs, keeping the 35% of the log not suitable for chips. In times of low chip prices, Shasta still purchases the whole log. Shasta successfully marketed the program to some of the largest landowners in California.
- At Shasta, the operators learned to blend all the fuels into a homogeneous mixture that allowed the boilers to fire at a consistent rate and maintain maximum load under all conditions, without violating environmental standards, excessively corroding heat transfer surfaces, or slagging beyond the point where the boilers required cleaning more than twice per year.
- At Stratton, the original owners spent about $1.8 million during the first year of operation to improve the operation of the fuel yard.
- Tacoma personnel stress the need to take extra care at the beginning of the project with design of the fuel feed system. Selecting a proven fuel feed system is important.
- The only area of the Williams Lake plant that was modified after startup was the fuel handling system. Minor modifications were made to improve performance, such as adding the ability to reverse the dragchains on the dumper hoppers, to make it easier to unplug fuel jams; and adding three more rolls to each disk screen (12 rolls were provided originally), to reduce the carryover of fine particles that tended to plug up the hog.
- The Multitrade plant's minor problems included fuel feeding problems in the early days of operation (quickly corrected); erosion and corrosion in the fuel splitter boxes and conveyor belt shrouds (corrected by relining with plastic); and occasional heating and odor problems in the fuel pile until they learned not to let any part of the pile age more than 1 year.
- The Greenidge Station found that the technology for preparing biomass fuel for cofiring in a PC boiler needs further economic evaluation, research, and development. Grinders do not normally produce a product that has good flow characteristics. The wood fibers are sticky, stringy, and elongated when produced from a grinding operation. The fuel product needs to processed by equipment that produces a chip.

<u>Design for Fuel Flexibility</u>

Many biomass plants change fuels significantly over the years, as opportunities arise or old fuel sources dry up. These changes are often not predictable. The best strategy to deal with this problem is to have a plant design and permits that allow as much fuel flexibility as possible. For example:

- Bay Front was a coal-fired stoker plant that converted to wood firing and cofiring capability in 1979. Experience showed that ash fouling and slagging problems were much more severe when cofiring wood and coal than when firing either fuel alone. NSP now operates in either 100% coal or 100% wood firing mode.

- In 1989, the ability to burn natural gas was added to McNeil Station. Summer pricing for Canadian gas was more attractive than wood prices at that time. Six fossil fuel burners were installed, allowing full load capability (50 MW) on gas and 15 MW capability on No. 2 oil. Gas prices rose during the mid-1990s, and McNeil burned almost no natural gas from 1997 to 1998.
- At the Shasta plant, a large hammermill was added to the fuel processing system to allow the use of a broader range of fuels. This reduced fuel costs by allowing the plant to process opportunity fuels such as railroad ties, brush, and prunings.
- The Tacoma plant was constrained by a limited fuel supply and permit, and worked hard to develop more options to use opportunity fuels (tipping fee fuels, some of which are not biomass)—waste oil, asphalt shingles, petroleum coke, etc.
- Colmac found that modifying its permit to allow the use of petroleum coke was worthwhile. At times, waste fossil fuels can be more economical than biomass.
- The Ridge fuel yard can handle essentially any type or size of wood waste; its only restriction is that it will not accept palm trees. The simple and reliable traveling grate stoker boiler can burn these mixed wood wastes, including yard wastes, and can burn crude tire-derived fuel (TDF) and landfill gas. The emission control system with a lime spray dryer and baghouse can remove almost any significant pollutant encountered in these wastes.

Location

As realtors say, "Location, location, location!" Biomass residues and wastes are local fuels, with very low energy densities compared to fossil fuels. Transport costs become very significant after about 20 miles, and usually prohibitive beyond 100 or 200 miles. The ability to have the waste generators deliver the fuel to the plant site at their own expense requires a location very close to the sources of waste. There are also other considerations, such as the proximity to residential neighborhoods. For example:
- The primary lesson learned from the McNeil plant experience in Burlington, Vermont, is the need to pay careful attention to the siting of a biomass-fueled plant. Siting the plant in a residential neighborhood of a small city has caused a number of problems and extra expenses over the years: a permit requirement to use trains for fuel supply, high taxes, high labor rates, local political involvement, and neighborhood complaints about odors and noise.
- The Colmac plant shows that urban wood waste can be a comparatively expensive fuel (~$1.50/MBtu) if the plant is located far outside the urban area. The transportation cost is significant. An urban biomass plant can derive income from its fuel with a location and tipping fees that attract wood waste generators with loads to dump.

Reliability and Dependability

Several plant managers with the best long-term operating records stressed the necessity for placing a high value on reliability and dependability. This is true during plant design and equipment selection, and during operation. For example:
- Outside of planned outages, the Kettle Falls plant has an availability factor of about 98% over a continuous 16-year period. The superintendent has high praise for the people on the staff. The plant is always exceptionally clean and neat.
- The Shasta general manager advises: "Always place a high value on reliability and dependability, for these will allow you to be considered a 'player' and thus a participant in the development of special programs with the utility."
- At Williams Lake, which has an outstanding performance record, the chief engineer stressed that staying on top of maintenance programs at all times is essential.

Partnerships

The most successful projects have developed formal or informal partnerships with their key customers and suppliers. The relationship with the utility company that buys the power is usually the most important. This may change as generators simply bid their power into a power pool. Cogeneration plants by definition must

have close relationships with their steam users. Sometimes there are a few large fuel suppliers (such as sawmills) with whom special relationships are crucial. Examples in this report that illustrate the importance of strong partnerships include:

- In the words of the Shasta general manager: "But these new approaches must go forward on a very different basis than our past biomass developments. They must go forward in partnership with utilities. While the utility may want to participate in such systems, they will not and cannot do so unless the cost to ratepayers is very close to that of other generating options."
- Like several other biomass power plants, the Grayling Station is operated as a cycling plant. It has run at about a 70%-80% CF during peak demand periods, and at about a 40%-50% CF during off-peak periods. The McNeil, Multitrade, and Ridge plants are other examples of cycling plants.
- The arrangement between the Camas Mill and its electric utility (PacifiCorp) is mutually beneficial. The utility-financed turbine/generator provides the mill with an additional source of cash flow, without significantly changing the mill's steam generation and delivery system. The utility has added about 50 MW of reliable generating capacity to its system for a relatively small investment, and has strengthened its relationship with a major customer.
- The Okeelanta Cogeneration Plant provides many environmental benefits, and should serve as a reliable energy source for the sugar mill and the electric utility. Unfortunately, the owners and the utility could not amicably resolve their differences over a "standard offer" contract. The ensuing lawsuits, bankruptcy, shutdown, and layoffs significantly affected the project.

Cofiring

Once the availability of low-cost biomass fuel is established, the primary issue addressed in most retrofitted cofiring projects is how to feed the fuel (and in what form to feed it) to the coal-fired boiler. There are of course many other issues, such as effects on boiler operations, plant capacity, emissions, and ash quality. Some of these are highlighted by lessons learned at four plants in this report:

- Bay Front could use standard wood sizing and feeding equipment because its coal-fired boilers were stokers. Cofiring was possible at any ratio of wood to coal from 0% to 100%. However, slagging and fouling was very severe because of the interaction between the alkali in the wood and the sulfur in the coal.
- The bubbling FBCs at Tacoma can fire 0%-100% wood, 0%-50% coal, and 0%-50% RDF (permit limitation). The actual fuel mix on a heat input basis from 1993 to 1997 was 54%-68% waste wood, 12%-32% coal, and 12%-20% RDF. Opportunity fuels that command a tipping fee or can be obtained free became a high priority in 1997.
- The cofiring experience at Greenidge Station demonstrates that a separate fuel feed system can effectively feed wood wastes to a PC unit. The economics at this site are favorable; the difference between coal and wood prices is $0.45-$0.79/MBtu. The plant has continued to cofire wood and invest in system improvements since the testing began more than 4 years ago.
- The Lahti cofiring project at a PC- and natural gas-fired district heating and electric generation plant in Finland uses a CFB gasifier to convert wood wastes and RDF to low-Btu gas that is burned in the boiler. The operation has been technically successful for 1 year, and gives utilities in the United States another option to consider when examining the feasibility of cofiring biomass and waste fuels in coal-fired boilers.

Benefits

The 20 biomass projects in this report provide many concrete illustrations of environmental and economic benefits. The Kettle Falls, Williams Lake, and Multitrade plants provide air quality benefits in rural settings where sawmills used to pollute the air with teepee burners. The Ridge, Tacoma, and Lahti plants serve urban areas by burning urban waste fuels cleanly; Lahti provides district heat as well. The Okeelanta, Tracy, and San Joaquin plants burn agricultural residues cleanly, which formerly were burned with no emission controls. The Shasta, McNeil, and Grayling plants serve the forest management operations in their areas by cleanly burning unmerchantable wood, brush, and limbs. For example:

- The Bay Front plant was being considered for phase out as larger, more efficient units came on line in the NSP system. Adding the ability to use biomass fuel kept the plant operating, saved jobs, and improved waste management.
- Long-term residents in the Kettle Falls area reported major reductions in haze after the plant went into operation. The plant improved air quality by eliminating numerous wigwam burners formerly used to dispose of mill wastes.
- In the forests near the Shasta plant: "The result is a healthier, faster growing forest that has a dramatically lowered potential to be destroyed by fire. There are now adequate moisture, nutrients and sunlight for the remaining trees and net growth often triples. The remaining trees regain their traditional resistance to insect and disease attack."
- The Grayling and Ridge projects were planned and the plants were designed with waste management roles in mind—one in a rural setting and the other in an urban setting. Efforts were made to fit constructively into the local economic and environmental landscapes, with clearly positive results.

Subsidy Programs Do Not Last

As a final note, the Shasta general manager's list of lessons learned includes this one: "Beware of entering a regulatory system in which the utility commission or legislature has determined that it is acceptable for ratepayers to pay the full cost of your technology. Such things do not last."

DOE Hawaii Project Lessons Learned

This section discusses the "Hawaii Gasification Facility" project. The pilot facility is shown in Figure 4.8. The purpose is to review the chronology of major milestones for the project, and to discuss lessons learned from the project.

Figure 4.8: Hawaii Gasification Facility

Project Chronology
- DOE Request for Proposal Issued
- DOE Reorganization
- Cooperative Agreement, DOE and PICHTR

1994: Phase 1 Plant Completion
1995: Phase 1 Experimental Completion
1996: Cooperative Agreement, DOE and Westinghouse
1997: Plant Modifications Complete
1997: Initial Westinghouse Experiments Performed
1997: Westinghouse Experimental Work Stopped
1998: Project Stopped

Project Overview

The solicitation for the project "Federal Assistance Solicitation for Cooperative Agreement Proposals DE-PS02-89CH10407 for a Biomass Gasifier Scale-up Facility" was issued by the DOE SERI Area Office July 31, 1989, (DOE 1989) with a proposal due date of November 28, 1989. The solicitation was a reissue of a solicitation issued in 1986 by the DOE Richlands Office, in which the proposals were withdrawn during the final negotiation stage.

The abstract of the solicitation stated that DOE desired to share with a U.S. citizen, U.S. corporation, or a state or local government the cost of a project to design, construct, start-up, test and evaluate an experimental scale-up facility to produce a medium-BTU gas (300-500 BTU/scf) from the thermochemical conversion of biofuel feedstocks. DOE intended that the facility provide industry with the engineering data necessary for the commercialization of the technology and that the facility serve as a centerpiece from which DOE and industry could develop additional capabilities such as the conversion of medium-BTU gas to methanol. It was stated that a majority of the medium-BTU gas produced by the facility be available for sale or used to provide data on gas utilization and to support facility operations; however a portion of the gas was to be made available for experimental purposes such as gas cleanup, compression, water-gas shift reactions, and/or synthesis gas reactions.

Other requirements were:

1. The gasification system was to be capable of processing 50 to 200 tons of feedstock per day.
2. Although not required, it was desirable that the facility be capable of handling a variety of biomass feedstocks. Fossil fuels were not allowed, except for start up.
3. The system was to allow for the later addition of process development units (PDUs) necessary to cool, shift, clean up, and compress the gas so that it was suitable for the production of liquid fuels such as methanol. The funding of such future PDUs was dependent on future negotiations and the availability of DOE funds.
4. The medium-BTU product gas was to be applied to a process to (a) provide an example of its usefulness as an energy product; (b) provide financial support to gasifier operations; and (c) provide for a complete technoeconomic evaluation of the process from feedstock preparation to gas utilization.
5. The project was to be constructed and operated within the 50 United States or the U.S. territorial possessions.
6. The DOE funding was to be limited to a maximum of 50% cost share with an upper limit of $5 million.

The Pacific International Center for High Technology Research (PICHTR), Honolulu, Hawaii proposed a project at Paia, Maui, Hawaii to scale-up the Institute of Gas Technology (IGT) RENUGAS® biomass gasification technology. The total proposal cost was $11.8 million, with a DOE cost share of $5 million (PICHTR 1989). PICHTR was selected by DOE for negotiation, and on September 30, 1991 a cooperative agreement was awarded to PICHTR for $9,156,904. DOE's share was $5,000,000; the State of Hawaii, with contributions from the Ralph M. Parsons Company and Hawaii Commercial and Sugar Company (HC&S), was $4,156,904. The following purpose for the project was given:

> "*The purpose of this cooperative agreement is: To design, construct and operate a biomass gasification facility to produce medium-Btu gas. The gas will be suitable for use as a gaseous fuel or for upgrading to a synthesis gas for conversion to liquid transportation fuels or utilization in a gas turbine for electrical energy production. This effort will also provide scale-up and operating engineering data from which the commercial feasibility of the gasification technology employed can be assessed. Upon completion of the initial program, an ongoing two-part Phase 2*

Program is anticipated. Part 1 would be primarily oriented toward electrical production; Part 2 toward biomass fuels or methanol production."

In addition, although the stated purpose of the project was to produce a medium-Btu gas, initial design and operation would be as an air-blown gasifier to produce a low-Btu gas (150 Btu/scf), with limited testing using bottled oxygen to produce a medium-Btu gas (Kearns, 1991). This change was instituted to reduce project costs.

PICHTR - Phase I

Between 1991 and 1996 PICHTR directed the Phase 1 cooperative agreement. PICHTR was assisted by a Project Oversight Board consisting of representatives of PICHTR, DOE, and the State of Hawaii. A technical advisory committee with members from DOE, PICHTR, NREL, IGT, and HNEI advised PICHTR on technical issues. During Phase 1 the basic unit was permitted, designed, constructed, and tested. A total of three test runs were conducted in 1995. These initial tests operated the Biomass Gasification Facility (BGF) over a range of 20 to 50 tons per day of bagasse. Operating pressures ranged from 28 to 100 psi, and operating temperatures were from 1,000°F to 1,650°F. The range of product gas higher heating value was 81.5 - 155.5 BTU/scf, and carbon conversion efficiencies of 95.4% - 98.7% were obtained. Total running time for the tests was 108 hours, during which time 165 tons of wet bagasse were gasified. The Phase 1 effort was summarized in a final summary report (Trenka, et al 1997).

A number of system limitation and problems were identified, primarily with components of the bagasse feeding system, including:

- Feed rate out of the walking floor was non-uniform due to batch feed from a front end loader and minimal leveling using a leveling bar. PICHTR recommended the use of doffing rolls in future tests.
- Problems were encountered in maintaining dryer throughput because of choking of the inlet rotary valve and buildup of bagasse in the dryer. The buildup of bagasse in the dryer was believed to be caused by the high degree of variability in bagasse moisture content. Later analysis by the vendor during the Westinghouse operations would show that the solids buildup was caused by improper operation, and that when air flows were properly set that the dryer operation was not a problem.
- Blow over of stones and plastic drip tubing to the downstream feed system caused excessive wear and plugged blower screens.
- The metering feeder to feed the weigh belt was grossly oversized for the feed rates used in Phase 1 and, in fact, did not meter feed. Therefore, feed fluctuations caused by the walking floor were not evened out, and uneven feed was delivered to the plug-screw feeder.
- The weigh belt performed well mechanically. However, variations in belt weight (splices, etc.) gave varying tare weights and masked variations in bagasse feed rate. Therefore, actual flow rate was only known within 10-15 %.
- The original concept was to use two plug-screw feeders in series, because the vendor believed that a maximum pressure seal of 150 psi per feeder was all that could be obtained. Therefore, a vertical space was left between the weigh belt and the plug-screw feeder to accommodate installation of a second feeder when higher-pressure operations were attempted. A tapered down-comer chute was installed between the weigh belt and plug-screw feeder. This chute, in combination with other system limitations, caused the majority of problems with the plug-screw feeder. Bagasse, shown below in Figure 4.9, has a bimodal particle size distribution.

Figure 4.9: Bagasse

The majority of the bagasse consists of very fibrous material. A certain fraction is the 'pith' of the original sugar cane and is non-fibrous in nature. During unit start up, bagasse feed was recycled back to the walking floor. During this operation, pith dust built up in the chute leading to the metering feeder. When the metering feeder started, this pocket of pith dust moved as a unit through the weigh belt to the chute and on to the plug-screw feeder. The plug screw feeder is designed to use the fibrous nature of biomass to mechanically move the material through the feeder. When a pocket of non-fibrous material was encountered a center plug would break free and the feeder would no longer work. This made start up very difficult. Small pockets of pith dust normally caused no problem, but in some instances the plug-screw feeder chute would tend to segregate pith causing non-fibrous pockets to reach the feeder. The variable fiber content also caused the density of the plug to vary, causing blow-backs under pressure, leading to unit shut-down.

- Other problems encountered with the plug-screw feeder included speed mismatches with the upstream feed delivery system. If the speed of the feeder was too fast, the plug was lost, causing blow-backs. If the speed of the screw was too slow, feed built up in the inlet chute and plugged. In addition, if the feed was too dry, excessive friction led to high current draws on the feeder motor and feeder shutdown. The feeder design could have been modified to fix the majority of the mechanical problems. The addition of a barrel lubricator would have lessened the friction and barrel wear and permitted operation with dry feed. The installation of a two-piece barrel would have greatly lessened the time to correct plug problems.

- The shredder conveyor was used to feed bagasse from the plug-screw feeder to the gasifier. This conveyor worked fine, but seal design made it difficult to hold pressure.
- The gasifier air-spargers tended to plug during periods of pressure variations. A design change was indicated.
- The back pressure valve tended to plug, and system pressure was controlled with the back-pressure bypass valve. It was not clear whether the basic design of the valve was incorrect, or whether the fluctuations in system operation was causing excessive blow-out of fluid-bed media.

The Phase 1 effort was contractually completed with the operation of the gasifier for 100 hours.

Westinghouse Electric Corporation Technology Validation Phase

Westinghouse Electric Corporation (WEC) was chosen by DOE as the lead organization for the second phase of the Hawaii project, called the Technology Validation Phase (TVP). WEC was chosen because of their interest in commercially developing the gasification technology and their interest in moving ahead with a commercial demonstration in the Hawaiian islands. WEC was supported in the TVP by PICHTR, the Institute of Gas Technology, the Hawaii Natural Energy Institute, and the Hawaii Commercial and Sugar Company. Funding was supplied by DOE, the State of Hawaii, and WEC. The State of Hawaii funding included $2 million for the TVP, plus $2 million conditional on establishing a commercial project in the islands. The Project Oversight Board and Technical Advisory Committee were disbanded.

The objective the Technology Validation Phase of the Hawaii Project was

1. To operate the gasifier for a total of 1500 hours at 100 tpd, 300 psi, and with a slip-stream hot-gas filter unit in operation,
2. To demonstrate sustained mechanical reliability of the overall core system (including the feed system and gasifier and their support systems) and the hot-gas filter system,
3. To determine plant performance, including
   - gas quality/variability
     - focusing on gas turbine needs
     - permitting baseline
   - up-load response time
   - turndown limits (3:1)
   - hot-gas filter system performance
     - operating temperature
     - cleanability
     - pressure drop across filter.

In addition to performing extended testing, WEC proposed extensive modifications to the BGF, including

- The plug-screw feeder was replaced. WEC stated "*The current plug-screw feeder must be replaced with a commercially viable system. After reviewing several alternate feed system designs, a lock-hopper feed system was selected for the program because of its commercial viability and operating experience on a wide range of fuels*" (Bartol 1996).
- An inert gas delivery system was added, to provide purge nitrogen for the lock-hopper system, and to provide additional purge gas for instruments and the gasifier.
- The air delivery system was upgraded to supply sufficient air for operation at 300 psi and 100 tpd.
- The front end of the feed system was modified to provide a cleaner, more uniform feed to the lock-hopper. Modifications included a new discharge assembly on the walking floor bin, a vibrating screen for oversize material removal, a destoner to remove small rocks, a chopper to

reduce the particle size to about minus 1 inch, a day-bin for intermediate dry feed storage, and a weigh bin to measure the amount of bagasse fed.

- A lock-hopper, designed by Thomas R. Miles Engineers, was installed to replace the plug-screw feeder.
- A pressurized metering bin was installed below the lock-hopper to convert the batch feed mode of the lock-hopper to a continuous mode.
- A collector screw was installed to transfer bagasse from the metering bin to the existing shredder conveyor.
- A hot-gas filter unit, sized for a 10 tpd equivalent slipstream, was installed downstream of the gasifier. This unit had been constructed and successfully operated by WEC at the IGT test facility in Chicago under subcontract to NREL. The unit was moved to Hawaii to perform long-term testing, since the pilot unit in Chicago was not designed for such operation.
- The system back-pressure valves were replaced with a design used by IGT in the Chicago pilot plant.
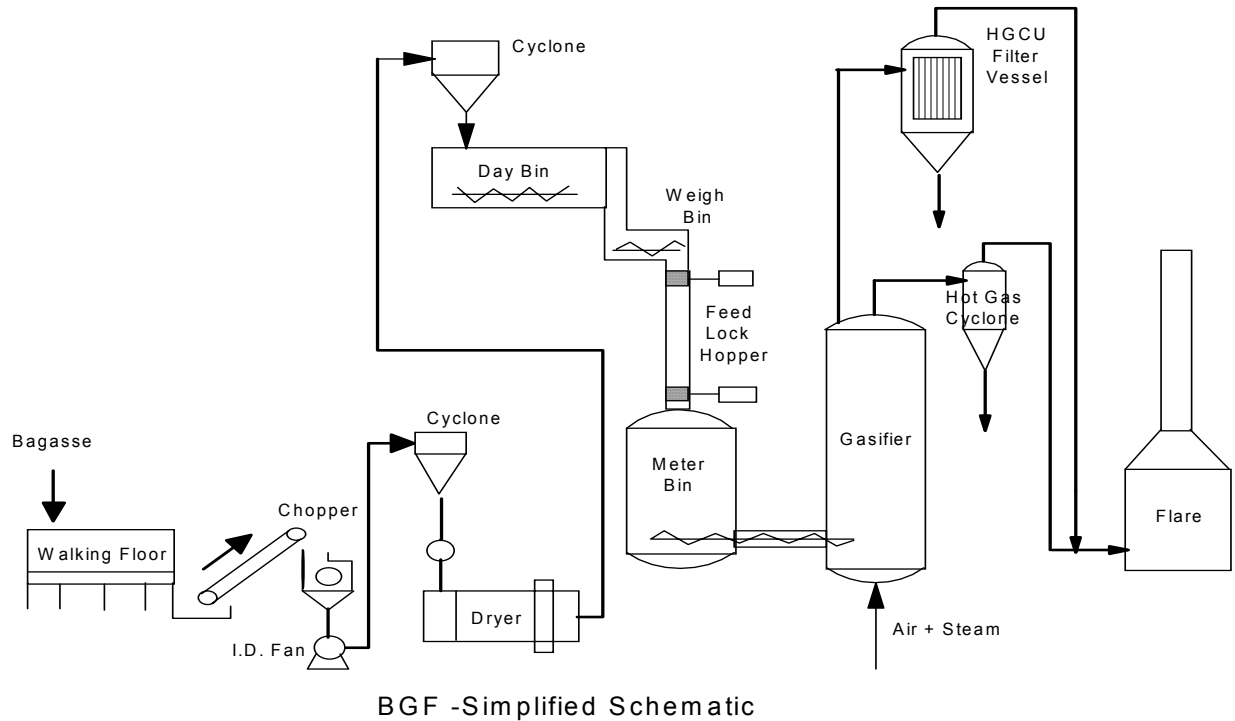
Figure 4.10: Gasifier Process Flow Diagram

The TVP Phase started in the summer of 1996, with a WEC estimated completion date of September 1997. A number of problems, briefly discussed below, were encountered and the TVP Phase was not completed by November 1997, at which time WEC determined that there were insufficient funds to complete the project.

A significant number of problems were encountered during the TVP. Given below is a summary of the problems.

- The schedule proposed by WEC was extremely ambitious, with no allowance for any major problems or delays. Insufficient funds were estimated to cover major delays.
- As a general statement, the majority of the equipment designed and installed during the TVP was undersized for operation at full capacity. Although the vendor had extensive experience in wood and straw handling systems, the direct applicability of items such as required horsepower was not correct. Based on the experience obtained during the TVP a rule of thumb would be to double the size of all motors if not based on previous operation with bagasse.
- Although doffing rolls were installed at the end of the walking floor to even out feed rate, the feed was still non-uniform. The basic problem was the walking floor.
- The vibratory conveyor was not long enough to permit good segregation of impurities. Modifications were made in the finger design to permit better flow, but very little separation of rock and plastic tubing occurred. The bagasse tended to make a mat which prevented bagasse from dropping through the fingers. When the fingers were enlarged almost everything dropped though.

- The destoner did a good job of separating stones out of the feed. The only problem was some blockage of the vacuum system.
- The primary problem with the chopper was that the original motor was undersized. A new motor was installed. Because of other problems with the feed system, screen size and shape was not optimized. Because of limited continuous operating time, a reliable estimate of required blade sharpening interval was not completed. Some capacity tests were performed at the completion of the TVP experimental program.
- The primary problems with the day bin were an incorrect screw rotation direction for the live bottom, motors incorrectly sized for bagasse, and the use of belt drives, instead of chain drives. All of these problems were corrected during the TVP. The day bin then worked correctly for traditional bagasse with a bulk density of 7 lb/ft^3. HC&S processed a new variety of sugar cane in 1997 which caused large problems with the sugar mill operation, including excess sugar in the bagasse and a higher bulk density of the bagasse. At times the bulk density of bagasse reached 11 lb/ft^3. Because all of the bins were designed for volumetric control of flow, the higher bulk density caused additional problems. These problems were overcome by reducing the solids inventory permitted in the bin.
- There were a number of problems with the lockhopper. The liner for the lockhopper was incorrectly fabricated. It did not extend to the bottom of the lockhopper. A sleeve was fabricated, but the welds seemed to cause some hangup of material. As a consequence, the lockhopper could not be filled to capacity, resulting in rapid cycling of the lockhopper to obtain throughput, and increased inert gas usage. A major reliability problem was encountered with the lock hopper valves. As bagasse built up on the rails, the valves would not move far enough for the limit switches to indicate that the valves were open or closed. The distributed control system interlocks would then stop operations. Many minor adjustments were tried during the tests, but were unsuccessful in giving reliable valve operation. The proposed solution involved modifying the connector between the valve and actuator with a universal joint with more tolerance, and the use of a hydraulic actuator instead of an air actuator. These changes would also require that the valve bonnet (a pressure vessel) be modified. These recommended changes were not made and tested during TVP operations.
- The metering bin had a basic design problem. The bin liner had a converging wall. It was not obvious from process schematics that this was the case. The converging wall caused plugging of the metering bin. The problem was solved by field installation of a straight wall. In addition, the level sensors in the bin did not work reliably, and a lot of time was involved in testing to obtain believable readings. This was critical since metering bin inventory was a key control variable for the feed system.
- The collector screw bearings caused problems throughout the TVP, although not bad enough to stop operations. At the end of the TVP a decision had been made to redesign the bearings. It was felt that the existing design would not permit operation for extended periods of time.
- Problems were encountered in plugging of the air sparge ring in the gasifier. Analysis showed degradation of the fluid-bed media was causing the problems. Because of supply problems a different media was used for the TVP than for Phase 1. The solution would seem to be to use the original media.
- Extreme problems were encountered on the back pressure control valve. The valve was a ceramic gate valve. On two occasions loss of pressure control was observed. When the valve was disassembled the ceramic gate was gone. Small pieces of ceramic were later found down-stream in the flare. Speculation is that during start-up and non-steady-state operations that some of the attemperator water was not vaporized and that liquid water impacted the valve gate causing thermal shocks that destroyed the gate. The valve was eventually replaced by the valve used in Phase 1.
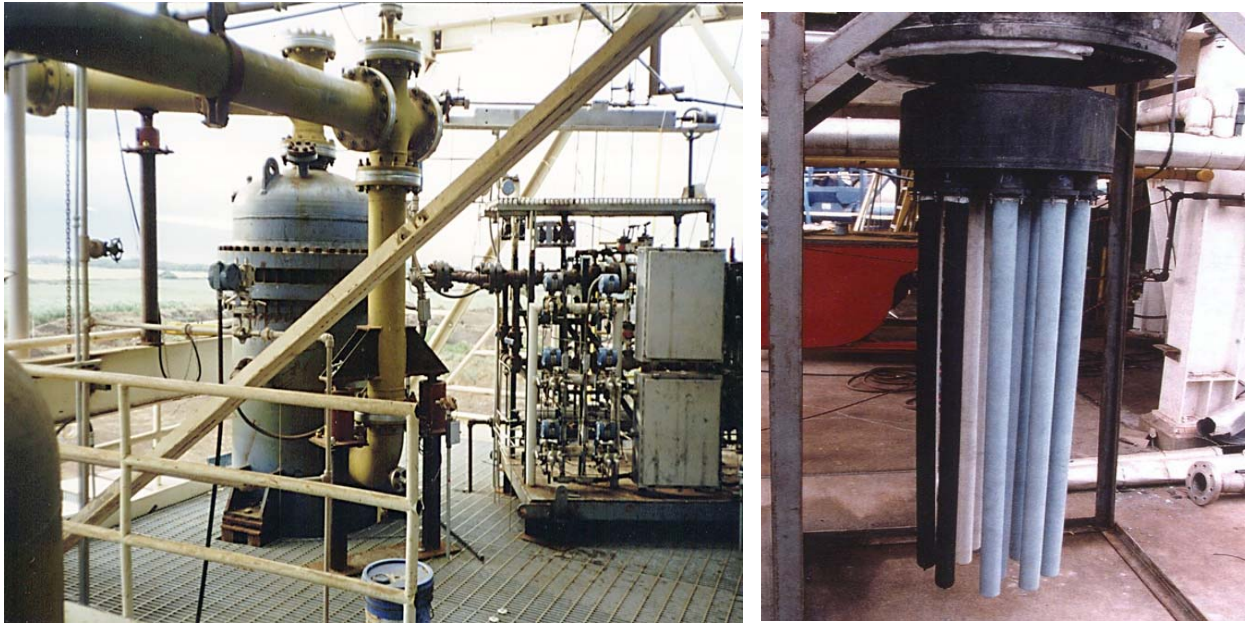
Figure 4-11: Hot Gas Filter Unit

Approximately 130 hours of gasification were achieved during the TVP. None of the operation was steady-state and only very limited gasification data were obtained. Filters were removed from the HGCU at the end of the test period and sent to WEC in Pittsburgh for analysis. Analytical results were presented in the WEC final report. Operations were stopped in November 1997 when WEC determined that there were insufficient funds to make needed modifications to the lock-hopper and continue operations.

Status
The TVP Phase of the Hawaii project was completed without reaching any of the major goals. In 1998 DOE completed an evaluation of future options and decided to discontinue participation in the project.

Summary of Lessons Learned
A brief summary of lessons learned for the Hawaii project is given below.
<u>Non-technical</u>

• Impact of Initial Cost Increase:

    Major experimental programs of this nature must have the leadership of a commercial E&C firm during the design and construction phase.

• Environmental Assessment:

    The most important lesson coming out of the environmental permitting process is that solicitations should require substantial environmental reviews before committing to the decision to proceed with a project. Given the time and expense to perform such reviews the time and cost impacts of environmental assessments should be included in project plans. To a large extent the

Biomass Power Program has learned from the Hawaii Project in this area. The Vermont Project was able to structure a project involving feeding the product gas to an existing boiler, without requiring a complete evaluation of the existing power plant permits, and using the using the existing boiler emission permits.

- Impact of the Energy Policy Act of 1992

  DOE was required to evaluate the project under the rules of EPACT92. Given the requirement by the State of Hawaii for commercial application for funding, a DOE determination was made that the project was a commercial, not an experimental, project. The conversion into a commercial project placed expectations on the project that could not be met.

  Commercialization required a number of conditions to be met. HS&S, the host company, needed to agree to assume ownership of the facility. They did not. Since the completion of the Hawaii project, HC&S has closed the Paia mill. Second, the facility was an experimental unit at a small scale. The capital cost of an experimental facility and the associated labor-intensive design (needed for experimental data gathering/analysis but not commercial operation) made the commercial cost of electricity uneconomic.

  Although the stated experimental goals were not reached in the proposed time, much valuable technical experience was gained in material handling systems, and in system integration. Therefore, the project was successful in addressing issues in start-up, testing and evaluation, and scaling up of biomass gasification technology.

- TVP Project:

  The advisory groups should not have been disbanded. On highly developmental projects of this nature, limiting technical input greatly increases technical risk.

  Technical

- Impact of Initial Cost Increase:

  Bagasse is an extremely difficult feedstock. Organizations with direct operating and design experience should be involved in bagasse projects. Decisions to modify the feed system design to fit within the allowable funding did not recognize the potential for technical difficulties and led to the majority of operational difficulties through the life of the project.

- Phase 1 Equipment Decisions:

  Uniformity of feed is critical to the successful operation of a gasifier. The use of a feeder designed for a particular feed, rather than adaptation of a system not designed as a process feed system is needed.

- Phase 1 Equipment Decisions:

  We need to do a better job of evaluating the ability of the non-Federal partner to operate new equipment such as the plug-screw feeder. We probably would have had more success using a system closer to commercialization.

- Phase 1 Equipment Decisions:

     We should more carefully evaluate the details of equipment. In the case of the plug-screw feeder, the use of a lubrication system would have eliminated many of the problems with overheating and high-current draws.

Minnesota Alfalfa Project

This section discusses the "Minnesota Agri-Power" project. The alfalfa biomass pilot separation facility in Priam, Minnesota is shown below. The purpose of this section is to review the chronology of major milestones for the project, and to discuss lessons learned.

Project chronology

1994 - DOE, NSP, and U of M complete feasibility study
1994 - DOE Biomass Power for Rural Development Request for Proposal
1996 - MnVAP purchases Priam, MN processing and separation facility
1996 - DOE and MnVAP execute a cooperative agreement for development of MAP
1997 - MnVAP and UPA execute a letter of intent to provide technical services
1997 - MnVAP and NSP execute a PPA
1998 - Enron Capital and Trade Resources Corporation and MnVAP execute a joint development agreement for co-ownership of the MAP Project
1998 - FERC approves MAP Project as an exempt wholesale generator
1999 - AAPA is allowed by the MPUC to submit comments opposing the PPA
1999 - Enron terminates the joint development agreement
1999 - DOE suspends funding and withdraws from participation

Project Overview

MnVAP was incorporated as a cooperative under chapter 308A of the laws of the State of Minnesota in December 1994. MnVAP is an agricultural cooperative, currently owned by nearly 500 alfalfa farmers in western Minnesota. The company was formed in response to the interest shown by DOE, USDA, and others, in the development of biomass electric projects that use farm-grown, closed loop energy crops as primary fuels.

A 1994 feasibility study of biomass power, funded by DOE and conducted by NSP, U of M, and several other renewable energy industry organizations, determined that alfalfa would be a viable energy crop. During this feasibility study, staff of NSP and U of M sought participation of farmers in southwestern Minnesota to appraise their interest in developing an alfalfa fuel production system. NSP sealed this realistic possibility by committing to obtain 125 MW of farm-grown closed-loop biomass power, and when DOE made a significant financial commitment to energy crop power systems with the BiomassPower for Rural Development initiative.

MnVAP's proposal for the Minnesota Agri-Power Project was submitted to the DOE in mid-1995. The project's goal was to demonstrate the commercial viability and environmental sustainability of an integrated energy crop and "new technology" biomass electric generation system. MnVAP Project Phase I of the cooperative agreement provided funding for technology testing, feedstock supply development, preliminary design, environmental review, and other preliminary business and project development tasks. Final design and construction of the MAP project would have been accomplished in Phase II.

In early 1995, NSP requested proposals to supply biomass generation resources to satisfy the first phase of the Biomass Mandate. MnVAP and its project team submitted two proposals to NSP: one for a biomass gasification combined-cycle power plant, and another for a conventional power generation plant. Each project would use alfalfa stems as a primary fuel source. The original design of the project called for a Tampella Power gasification island and a 75-megawatt combined-cycle power plant with a Westinghouse 251B combustion turbine. At full production, the power plant would require nearly 350,000 tons of alfalfa stem material per year.

In late 1996, NSP selected MnVAP's biomass gasification combined-cycle project for negotiation of a PPA. MnVAP and NSP executed an MOU that outlined the terms to be incorporated in a power purchase agreement. By the end of 1997, MnVAP executed a long-term PPA with NSP. It was expected that this would provide long-term project viability. Execution of the PPA justified accelerated development work to prepare for financial closing and start of construction.

Phase I of the cooperative agreement provided DOE funds on a cost-shared basis to complete work in seven major project task areas. Each task area supported completion of items necessary for the MAP Project to reach financial closing and start construction; however there was insufficient time to begin commercial operations before the end of the calendar year 2001, the date by which NSP was required to bring biomass resources on line. Most tasks were completed, or were progressing well, but development work was suspended prior to financial closing de to a combination of events precipitated largely by regulatory delays.

Summary of Lessons Learned: Minnesota Agri-Power Project

1. Vendor Guarantees and Warranties: If plant configuration has not been tested, and/or if the feed has not been tested, then extended pilot testing is required (1000 - 2000 hours at steady state conditions) to develop vendor confidence leading to guarantees and warranties for commercial operation.

2. Pilot Plant Experience: Such testing may be doubly important when guarantees and warranties are needed from "downstream" unit operation vendors such as gas clean-up, gas turbine and stearn turbine original equipment manufacturers.

3. Project Scale-Up: A scale-up of ten times is too large to incorporate guarantees and warranties for untested processing steps or combinations of unit operations.

4. Project Financing: Developmental projects are inherently risky, requiring the development of creative approaches to investment and financing arrangements.

5. Entering New Markets: A marketing plan and study of existing markets for agriculturally-based, and other potential feedstock products must be developed. Expect resistance (political and economic) from current market suppliers.

6. Feedstock Suitability and Flexibility: Criteria for suitability of feedstocks for electrical conversion need to be developed. If possible, the conversion system should be designed to handle multiple feedstocks.

7. Technical Readiness: DOE needs to perform in-depth reviews of the technical status of development in relation to the proposed commercial project to better estimate the technical/commercial feasibility of the project. At a minimum, the project technical development time and cost should be reviewed in detail.

8. Reviews Prior to Award: A detailed technical review is required at the solicitation technical review stage to identify technology readiness for commercialization, rather than addressing such issues after agreements have been reached and project timing and costs have been contractually set.

Success Factors

Successful commercial implementation of technology is dependent on a wide range of positive and negative drivers. A preliminary analysis was performed that identified drivers in the areas of policy, corporate policy, regulation, legal, infrastructure, and technology, which resulted in a preliminary methodology for ranking relative importance. The analysis methodology involves development of an estimate of the impact of drivers on CHP systems (high, medium, low), the relative importance of each driver, and the probability of the driver occurring by 2020. Multiplying the three factors gives a weighted probability of the impact. This weighted probability can be normalized to 100% and ordered in terms of numerical importance. An example of the rating of drivers was estimated by the authors to demonstrate the methodology. Eventually, it would be desirable to ask a group of experts in the area to provide independent estimates of factors, and then develop a group evaluation of drivers. The example positive and negative drivers are given in Table 4-5. Table 4-6 presents a summary of key drivers, ranked by weighted probability.

Seventy-five percent of the positive drivers are given by 10 factors in the categories of technology, corporate policy, regulation and finance. The top three positive factors are the technology maturity of combustion and cofiring systems, the corporate need for CHP , and Federal mandates such as PURPA. Seventy-five percent of the negative drivers are given by nine factors in the categories of finance, corporate policy, and legal. The top three negative factors are lack of feedstock infrastructure, the cost of products compared to traditional sources, a corporate resistance to new technology introduction.

A qualitative comparison of key success factors relative to coal and natural gas was made and is presented in table 4-7. In general, biomass systems compare favorably with new coal facilities, especially in the area of environmental impact. In general, biomass systems do not compare favorably with natural gas systems, except in the area of environmental impact.

DRIVERS FOR BIOMASS CHP SYSTEMS

Ref	Category	DRIVERS	A (H,M,L) (5,3,1) Impact on CHP systems	B (1 to 20) Relative Importance	C (1-100%) Probability of Occurring by 2010	A x B Importance x Impact	A x B x C Weighted Probability of Impact	Weighted Probability % of Total	Weighted Cumulative Probability % of Total
		POSITIVE DRIVERS							
A	Policy	National Security (Domestic Sourcing Rulings)	5	10	25%	50	12.5	2.2%	2.2%
B	Regulation	Air Emissions Controls (National, State)	5	10	75%	50	37.5	6.7%	9.0%
C	Policy	State Programs for RE	5	15	25%	75	18.8	3.4%	12.4%
D	Finance	Federal Tax Incentives for RE	5	20	25%	100	25.0	4.5%	16.9%
E	Regulation	Federal Mandates, e.g., PURPA, RPS	5	20	50%	100	50.0	9.0%	25.8%
F	Infrastructure	Transmission Bottlenecks / Disruptions	3	10	25%	30	7.5	1.3%	27.2%
G	Regulation	Distributed Energy Certification Standards	3	5	100%	15	15.0	2.7%	29.9%
H	Regulation	Electricity Wheeling	3	10	50%	30	15.0	2.7%	32.6%
I	Policy	Climate Change Policy (international)	1	5	50%	5	2.5	0.4%	33.0%
J	Finance	Fuel Price Volatility (coal, oil, natural gas)	3	15	50%	45	22.5	4.0%	37.1%
K	Finance	Fuel Supply Disruptions (Oil, Natural Gas)	3	20	25%	60	15.0	2.7%	39.8%
L	Corp Policy	Corporate Energy Autonomy	3	5	50%	15	7.5	1.3%	41.1%
M	Corp Policy	Corporate RE Mandate	5	20	25%	100	25.0	4.5%	45.6%
N	Corp Policy	Corporate Use/Need for CHP	3	20	100%	60	60.0	10.8%	56.4%
O	Finance	Use of Existing Residues	5	10	100%	50	50.0	9.0%	65.4%
P	Technology	Alternative Future Uses, e.g., SYNGAS	3	5	100%	15	15.0	2.7%	68.1%
R	Finance	Cost of Fuel - Stability	3	10	75%	30	22.5	4.0%	72.1%
S	Corp Policy	Support of Local Economy - Indigenous Feed	1	5	100%	5	5.0	0.9%	73.0%
T	Finance	Low Interest Rates	5	5	10%	25	2.5	0.4%	73.5%
U	Finance	Cofiring Capital Cost	3	15	100%	45	45.0	8.1%	81.6%
V	Finance	Production of Export Electricity	3	10	50%	30	15.0	2.7%	84.3%
W	Technology	Technology Maturity, Combustion and Cofiring	5	15	100%	75	75.0	13.5%	97.8%
X	Legal	Environmental Community Acceptance	5	5	50%	25	12.5	2.2%	100.0%
		Average for Positive Factors	3.70	11.52		45.0			
		Sum for Positive Factors					556.3	100.0%	

Drivers for Biomass CHP Systems

		DRIVERS NEGATIVE DRIVERS	A (H,M,L) (5,3,1) Impact on CHP systems	B (1 to 20) Relative Importance	C (1-100%) Probability of Occurring by 2010	A x B Importance x Impact	A x B x C Weighted Probability of Impact	Weighted Probability % of Total	Weighted Cumulative Probability % of Total
AA	Corp Policy	Resistance to Change	5	20	80%	100	80.0	9.1%	9.1%
BB	Corp Policy	Corporate Experience	5	20	50%	100	50.0	5.7%	14.7%
CC	Finance	Feedstock Infrastructure	5	20	100%	100	100.0	11.3%	26.1%
DD	Finance	Feedstock Cost	3	15	80%	45	36.0	4.1%	30.1%
EE	Finance	Feedstock Transportation	3	10	50%	30	15.0	1.7%	31.8%
FF	Finance	Competition for Feedstock	5	20	50%	100	50.0	5.7%	37.5%
GG	Technology	Process Efficiency	3	10	95%	30	28.5	3.2%	40.7%
HH	Finance	Capital Cost, Economy of scale	5	15	95%	75	71.3	8.1%	48.8%
II	Finance	Operating Costs	5	15	95%	75	71.3	8.1%	56.9%
JJ	Finance	Cost of Products	5	20	95%	100	95.0	10.8%	67.6%
KK	Finance	Higher Interest Rates	3	10	90%	30	27.0	3.1%	70.7%
LL	Finance	Low Coal Prices	1	15	95%	15	14.3	1.6%	72.3%
MM	Finance	Low Oil and Gas Prices	1	15	25%	15	3.8	0.4%	72.7%
NN	Regulation	Permitting / Siting Problems	5	20	50%	100	50.0	5.7%	78.4%
OO	Legal	Environmental Community Opposition	5	20	75%	100	75.0	8.5%	86.9%
PP	Corp Policy	Power Purchase Agreements	3	20	95%	60	57.0	6.5%	93.4%
QQ	Regulation	Cost of Environmental Controls	3	15	100%	45	45.0	5.1%	98.5%
RR	Technology	Technology Immaturity - Gasification	1	15	90%	15	13.5	1.5%	100.0%
		Average for Negative Factors	3.67	16.39		63.056			
		Sum for Negative Factors					882.5		

KEY SUCCESS FACTORS FOR BIOMASS CHP SYSTEMS

Ref	Category	KEY DRIVERS	Weighted Probability % of Total	Weighted Cumulative Probability % of Total
		POSITIVE FACTORS		
W	Technology	Technology Maturity, Combustion and Cofiring	13.5%	13.5%
N	Corp Policy	Corporate Use/Need for CHP	10.8%	24.3%
E	Regulation	Federal Mandates, e.g., PURPA, RPS	9.0%	33.3%
O	Finance	Use of Existing Residues	9.0%	42.2%
U	Finance	Cofiring Capital Cost	8.1%	50.3%
B	Regulation	Air Emissions Controls (National, State)	6.7%	57.1%
D	Finance	Federal Tax Incentives for RE	4.5%	61.6%
M	Corp Policy	Corporate RE Mandate	4.5%	66.1%
J	Finance	Fuel Price Volatility (coal, oil, natural gas)	4.0%	70.1%
R	Finance	Cost of Fuel - Stability	4.0%	74.2%
C	Policy	State Programs for RE	3.4%	77.5%
G	Regulation	Distributed Energy Certification Standards	2.7%	80.2%
H	Regulation	Electricity Wheeling	2.7%	82.9%
K	Finance	Fuel Supply Disruptions (Oil, Natural Gas)	2.7%	85.6%
P	Technology	Alternative Future Uses, e.g., SYNGAS	2.7%	88.3%
V	Finance	Production of Export Electricity	2.7%	91.0%
A	Policy	National Security (Domestic Sourcing Rulings)	2.2%	93.3%
X	Legal	Environmental Community Acceptance	2.2%	95.5%
F	Infrastructure	Transmission Bottlenecks / Disruptions	1.3%	96.9%
L	Corp Policy	Corporate Energy Autonomy	1.3%	98.2%
S	Corp Policy	Support of Local Economy - Indigenous Feed	0.9%	99.1%
I	Policy	Climate Change Policy (international)	0.4%	99.6%
T	Finance	Low Interest Rates	0.4%	100.0%
		NEGATIVE FACTORS		
CC	Finance	Feedstock Infrastructure	11.3%	11.3%
JJ	Finance	Cost of Products	10.8%	22.1%
AA	Corp Policy	Resistance to Change	9.1%	31.2%
OO	Legal	Environmental Community Opposition	8.5%	39.7%
HH	Finance	Capital Cost, Economy of scale	8.1%	47.7%
II	Finance	Operating Costs	8.1%	55.8%
PP	Corp Policy	Power Purchase Agreements	6.5%	62.3%
BB	Corp Policy	Corporate Experience	5.7%	67.9%
FF	Finance	Competition for Feedstock	5.7%	73.6%
NN	Regulation	Permitting / Siting Problems	5.7%	79.3%
QQ	Regulation	Cost of Environmental Controls	5.1%	84.4%
DD	Finance	Feedstock Cost	4.1%	88.4%
GG	Technology	Process Efficiency	3.2%	91.7%
KK	Finance	Higher Interest Rates	3.1%	94.7%
EE	Finance	Feedstock Transportation	1.7%	96.4%
LL	Finance	Low Coal Prices	1.6%	98.0%
RR	Technology	Technology Immaturity - Gasification	1.5%	99.6%
MM	Finance	Low Oil and Gas Prices	0.4%	100.0%

KEY SUCCESS FACTORS

	Relative to Coal	Relative to N. Gas
Construction/Installation		
Experience	NA	NA
Capital Cost	+	--
Predictability of Schedule	NA	NA
Space/Footprint, including acreage	0	--
Operating		
Labor Costs	0	++
Maintenance Costs	0	-
System Reliability	-	-
Feedstock		
Price		
Residues	+ / 0	0/-
Dedicated Feeds	--	--
Availability		
Reliability of Supply	--	--
Quality	-	--
Environmental		
Air Emissions	+	--
Green House Gases	++	++
Solid Wastes	+	--
Liquid Wastes	0/+	0/-
Permitting	+	-
Waste Reduction	++	++
Economic		
Financing		
Power Purchase Agreement		
Tax Incentives		
Regulatory Policy		

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5. TECHNOLOGY CASE STUDIES

A series of case studies have been performed on the three conversion routes for combined heat and power (CHP) applications of biomass—direct combustion, gasification, and cofiring. The studies are based on technology characterizations developed by NREL and EPRI [1], and the technology descriptions are excerpted from that study. Variables investigated include plant size and feed cost, and both cost of electricity and cost of steam are estimated using a discounted cash flow analysis. The economic basis for cost estimates is given below.

Table 5.1: Economic Assumptions

Parameter	Value	Discussion
Basis Year	3rd Qtr, 2001	
Cost Index	Marshall & Swift	
Scale Factor	0.7	
Debt	50%	
Inflation	None	
Capital	7% for 20 years	
Discount Rate	20%	
Salvage Value	0	

Taxes
  Federal
  State
  State Wholesale Excise
  Federal Alt. Min. Tax
	
	35%
	5%
	0
	Not estimated	

Industrial Electricity Purchase Price	3.8 cents/kWh	Chemicals Industry Costs: EIA Manufacturing Consumption of Energy 1998, Table N8.3, corrected to 2001 $
Industrial Steam Purchase Price	$3.3/1000lb	Chemicals Industry Costs: EIA Manufacturing Consumption of Energy 1998, Table N8.3, corrected to 2001 $
Construction Period	2 years	Comparable to EPRI/DOE Technical Characterization
Operating Life	30 years	Comparable to EPRI/DOE Technical Characterization
Stream Factor	90%	
Depreciation	7-year MACRS	For biomass specific operations
	20-year MACRS	For generating equipment, BOP
	5-year MACRS	For biomass qualifying facility sensitivity case
Tax Credit	0.5, 1, 1.5, 2 ¢/kWh	Sensitivity Case
Financial Parameter	NPV(0)	net present value
Feed Costs	-1,0,1,2,3,4 $/MBtu	
Plant Size	25, 50, 75, 100 MW 75 MW 45, 105 MW	Based on electricity only - direct combustion Gasification Cofiring (biomass contribution)

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[1] "Renewable Energy Technology Characterizations," EPRI-TR-109469, Electric Power Research Institute, Palo Alto, California, December 1997 (RETC97)

Technology Alternatives

The nearest term low-cost option for the use of biomass is cofiring with coal in existing boilers. Cofiring refers to the practice of introducing biomass as a supplementary energy source in high efficiency boilers. Boiler technologies where cofiring has been practiced, tested, or evaluated, include wall- and tangentially-fired pulverized coal (PC) boilers, cyclone boilers, fluidized-bed boilers, and spreader stokers. The current coal-fired power generating system represents a direct system for carbon mitigation by substituting biomass-based renewable carbon for fossil carbon. Extensive demonstrations and trials have shown that effective substitutions of biomass energy can be made up to about 15% of the total energy input with little more than burner and feed intake system modifications to existing stations. Since large scale power boilers (both utility and independent operators) in the 1999 345 GW (EIA 1999) capacity fleet range from 100 MW to 1.3 GW, the biomass potential in a single boiler ranges from 15 MW to 150 MW. Preparation of biomass for cofiring involves well known and commercial technologies. After tuning the boiler's combustion output, there is little or no loss in total efficiency, implying that the biomass combustion efficiency to electricity would be about 33-37%. Since biomass in general has significantly less sulfur than coal, there is a SO_2 benefit; and early test results suggest that there is also a NO_x reduction potential of up to 20% with woody biomass. Investment levels are very site specific and are affected by the available space for yarding and storing biomass, installation of size reduction and drying facilities, and the nature of the boiler burner modifications. Investments are expected to be in $100 - 700/kW of biomass capacity, with a median in the $180 - 200/kW range.

Another potentially attractive biopower option is based on gasification. Gasification for power production involves the devolatilization and conversion of biomass in an atmosphere of steam or air to produce a medium- or low- calorific gas. This biogas is used as fuel in a combined cycle power generation cycle involving a gas turbine topping cycle and a steam turbine bottoming cycle. A large number of variables influence gasifier design, including gasification medium (oxygen or no oxygen), gasifier operating pressure, and gasifier type. Advanced biomass power systems based on gasification benefit from the substantial investments made in coal-based gasification combined cycle (GCC) systems in the areas of hot gas particulate removal and synthesis gas combustion in gas turbines. They also leverage investments made in the Clean Coal Technology Program (commercial demonstration cleanup and utilization technologies) and in those made as part of DOE's Advanced Turbine Systems (ATS) Program. Biomass gasification systems will also stand ready to provide fuel to fuel cell and hybrid fuel-cell/gas turbine systems, particularly in developing or rural areas without cheap fossil fuels or problematic transmission infrastructure. The first generation of biomass GCC systems would realize efficiencies nearly double that of the existing industry. In a cogeneration application efficiencies could exceed 80%. This technology is very near to commercial availability with mid-size plants operating in Finland, the UK, the Netherlands, and Vermont. Costs of a first-of-a-kind biomass GCC plant are estimated to be in the $1800-2000/kW range with the cost dropping rapidly to the $1400/kW range for a mature plant in the 2010 time frame.

Direct-fired combustion technologies are another option, especially with retrofits of existing facilities to improve process efficiency. Direct combustion involves the oxidation of biomass with excess air, giving hot flue gases that produce steam in the heat exchange sections of boilers. The steam is used to produce electricity in a Rankine cycle. In an electricity-only process, all of the steam is condensed in the turbine cycle while, in CHP operation, a portion of the steam is extracted to provide process heat. Today's biomass-fired steam cycle plants typically use single pass steam turbines. However, in the past decade, efficiency and design features, found previously in large-scale steam turbine generators, have been transferred to smaller capacity units. These designs include multi-pressure, reheat and regenerative steam turbine cycles, as well as supercritical steam turbines. The two common boiler designs used for steam generation with biomass are stationary- and traveling-grate combustors (stokers) and atmospheric fluid-bed combustors. The addition of dryers and incorporation of more-rigorous steam cycles is expected to

raise the efficiency of direct combustion systems by about 10% over today's efficiency, and to lower the capital investment from the present $2,000/kW to about $1275/kW.

The three technologies are all at either the commercial scale or commercial prototype scale, and have been included in this technology case study. There are additional technologies which are at the conceptual or research and development stage and do not warrant development of a technology case study at this time, but which are potentially attractive from a performance and cost perspective and merit discussion. These technologies include biomass gasification fuel cell processes, and modular systems such as biomass gasification/Stirling engines.

Gasification fuel cell systems hold the promise for high efficiency and low cost at a variety of scales. The benefits may be particularly pronounced at scales previously associated with high cost and low efficiency (i.e., from < 1 MW to 20 MW). Fuel cell based power systems are likely to be particularly suitable for distributed power generation strategies in the U.S. and abroad. Extensive development of molten carbonate fuel cell (MCFC) technology has been conduced under DOE's Fossil Energy Program largely with natural gas as a test fuel. Several demonstration projects are underway in the U.S. for long-term testing of these cells. A limited amount of testing was also done with MCFC technology on synthesis gas from a DOW coal gasifier at DESTEC's facility in Plaquamine, LA. The results from this test were quite promising.

To date, little fuel cell testing has been done with biomass-derived gases despite the several advantages that biomass has over coal in this application. Biomass' primary advantage is its very low sulfur content. Sulfur-containing species is a major concern in fossil fuel-based fuel cell systems because all fuel cells are very sensitive to this contaminant. An additional biomass advantage is its high reactivity. This allows biomass gasifiers to operate at lower temperatures and pressures, while maintaining throughput levels comparable with their fossil fueled counterparts. These relatively mild operating conditions and a high throughput should permit economic construction of gasifiers of a relatively small scale that are compatible with planned fuel cell system sizes. Additionally, the operating temperature and pressure of MCFC units may allow a high degree of thermal integration over the entire gasifier/fuel cell system. Despite these obvious system advantages, it is still necessary for actual test data and market assessments to be obtained to stimulate commercial development and deployment of fuel cell systems.

The Stirling engine is designed to use any heat source, e.g., biomass, and any convenient working gas to generate energy, in this case electricity. The basic components of the Stirling engine include: a compression space and an expansion space with a heater, regenerator, and cooler in between. Heat is supplied to the working gas at a higher temperature by the heater and is rejected at a lower temperature in the cooler. The regenerator provides a means for storing heat deposited by the hot gas in one stage of the cycle and releasing it heat the cool gas in a subsequent stage. Stirling engine systems using biomass are ideal for remote applications, stand alone or cogeneration applications, or as backup power systems. A feasibility test of biomass gasification Stirling engine generation has been performed by Stirling Thermal Motors using a 25 kW engine connected to a small Chiptec updraft gasifier. While the results were encouraging, further demonstration of the concept is required.

Figure 5.1: Direct-fired Biopower Facility
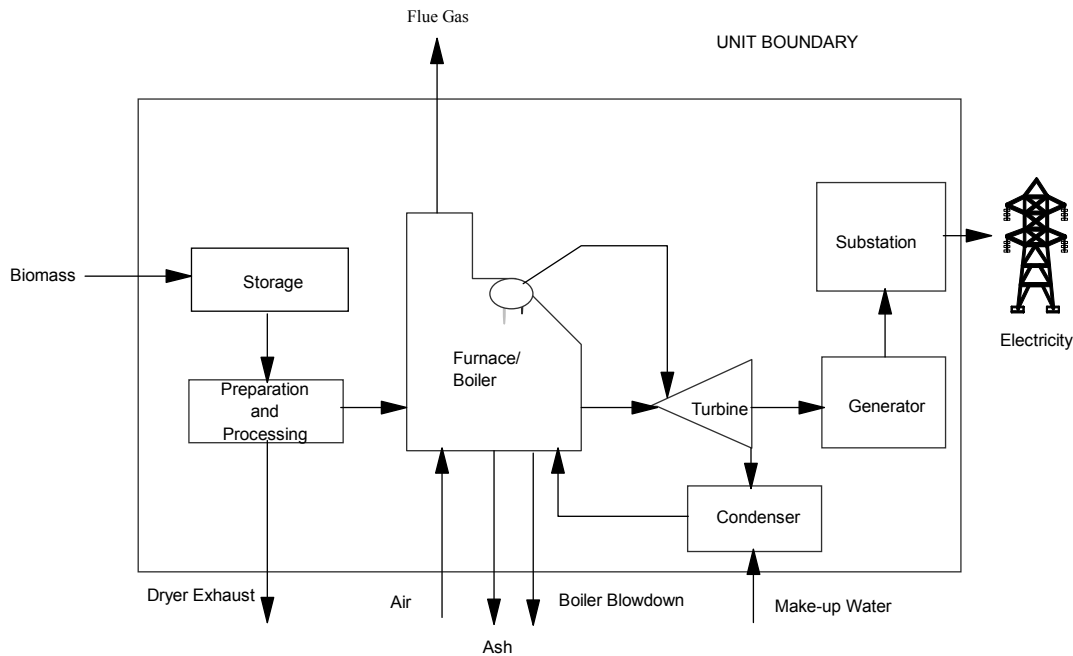
Direct-Fired Biomass

Direct combustoin, illustrated in Figure 5.1, involves the oxidation of biomass with excess air, giving hot flue gases that produce steam in the heat exchange section of boilers. The steam is used to produce electricity in a Rankine cycle; usually, only electricity is produced in a condensing steam cycle, while electricity and steam are cogenerated in an extracting steam cycle. Today's biomass-fired steam cycle plants typically use single-pass steam turbines. However, in the past decade, efficiency and design features, found previously in large scale steam turbine generators (>200 MW), have been transferred to smaller capacity units. These designs include reheat and regenerative steam cycles as well as supercritical steam turbines. The two common boiler designs used for steam generation with biomass are stationary- and traveling-grate combustors (stokers) and atmospheric fluid-bed combustors.

All biomass combustion systems require feedstock storage and handling systems. The 50-MW Burlington, Vermont, McNeil station, which uses a spreader-stoker boiler for steam generation, has a typical feed system for wood chips (Wiltsee and Hughes 1995). Whole tree chips are delivered to the plant gate by either truck or rail. Fuel chips are stored in open piles (about a 30 day supply on about 3.25 ha of land), fed by conveyor belt through an electromagnet and disc screen, then fed to surge bins above the boiler by belt conveyors. From the surge bins the fuel is metered into the boiler's pneumatic stokers by augers.

Pile burners represent the historic industrial method (Hollenbacher 1992) of wood combustion and typically consist of a two-stage combustion chamber with a separate furnace and boiler located above the

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

Stoker combustors (Hollenbacher 1992), improve on operation of the pile burners by providing a moving grate which permits continuous ash collection, thus eliminating the cyclic operation characteristic of traditional pile burners. In addition, the fuel is spread more evenly, normally by a pneumatic stoker, and in a thinner layer in the combustion zone, giving more efficient combustion. Stoker fired boilers were first introduced in the 1920's for coal; and in the late 1940's the Detroit Stoker Company installed the first traveling grate spreader stoker boiler for wood. In the basic stoker design the bottom of the furnace is a moving grate which is cooled by underfire air. Underfire air rate defines the maximum temperature of the grate and thus the allowable moisture content of the feed. More modern designs include the Kabliz grate, a sloping reciprocating water-cooled grate. Reciprocating grates are attractive because of simplicity and low fly ash carryover. Combustion is completed by the use of overfire air. Furnace wall configurations include straight and bull nose water walls. Vendors include Zurn, Foster Wheeler, and Babcock & Wilcox.

In a gas-solid fluidized bed, a stream of gas passes upwards through a bed of free-flowing granular materials in which the gas velocity is large enough that the solid particles are widely separated and circulate freely throughout the bed. During overall circulation of the bed, transient streams of gas flow upwards in channels containing few solids, and clumps or masses of solids flow downwards (Perry and Chilton 1973). The fluidized bed looks like a boiling liquid and has the physical properties of a fluid. In fluidized-bed combustion of biomass, the gas is air and the bed is usually sand or limestone. The air acts as the fluidizing medium and is the oxidant for biomass combustion. A fluidized-bed combustor is a vessel with dimensions such that the superficial velocity of the gas maintains the bed in a fluidized condition at the bottom of the vessel. A change in cross-sectional area above the bed lowers the superficial gas velocity below fluidization velocity to maintain bed inventory and acts as a disengaging zone. Overfire air is normally introduced in the disengaging zone. To obtain the total desired gas-phase residence time for complete combustion and heat transfer to the boiler walls the larger cross-sectional area zone is extended and is usually referred to as the freeboard. A cyclone is used to either return fines to the bed or to removes ash-rich fines from the system. The bed is fluidized by a gas distribution manifold or series of sparge tubes (Hansen 1992).

If the air flow of a bubbling fluid bed is increased, the air bubbles become larger, forming large voids in the bed and entraining substantial amounts of solids. This type of bed is referred to as a turbulent fluid bed (Babcock and Wilcox 1992). In a circulating fluid bed the turbulent bed solids are collected, separated from the gas, and returned to the bed, forming a solids circulation loop. A circulating fluid bed can be differentiated from a bubbling fluid bed in that there is no distinct separation between the dense solids zone and the dilute solids zone. The residence time of the solids in a circulating fluid bed is determined by the solids circulation rate, the attritibility of the solids, and the collection efficiency of the solids separation device. As with bubbling fluid beds, the primary driving force for development of circulating fluid beds in the United States is emissions. The uniform, low combustion temperature gives

low NO_x emissions. In a circulating fluid bed, with its need for introduction of solids to maintain bed inventory, it is easy to introduce a sorbent solid, such as limestone or dolomite, to control SO_2 emissions without the need for back-end sulfur removal equipment. Circulating fluid bed temperatures are maintained at about 870°C, which helps to optimize the limestone-sulfur reactions (Tampella Power 1992). The major manufacturers of circulating fluid bed boilers for biomass are Combustion Engineering (CE-Lurgi), B&W-Studsvik, Ahlstrom Pyropower (Foster Wheeler) and Gotaverken. A number of plants have been built in the 25 MW size range, primarily in California.

The suspension burning of pulverized wood in dedicated biomass boilers is a fairly recent development and is practiced in relatively few installations. Suspension burning has also been accomplished in lime kilns (MacCallum 1992) and is being investigated by the utility industry for cofiring applications (Tillman et al 1994). For successful suspension firing, a feed moisture content of less than 15% (Hollenbacher 1992) and a particle size less than 0.0015 m (MacCallum 1992) give higher boiler efficiencies, up to 80%, than firing wet wood chips, 50-55% moisture, in a stoker grate or fluid bed, at 65% efficiency. The higher efficiency also results in smaller furnace size. Offsetting the higher efficiency is the cost and power consumption of drying and comminution. In addition, special burners need to be used. Burners developed for suspension firing include scroll cyclonic burners and vertical-cylindrical burners (Hollenbacher 1992). Installations include the Oxford Energy, 27 MW facility at Williams, California (Hollenbacher 1992); the ASSI Lövholmen Linerboard Mill in Piteå, Finland (Westerberg 1981); the Klabin do Parana mill in Monte Alegre, Brazil (MacCallum 1992); and the E.B. Eddy Mill in Espanola Ontario (MacCallum 1992).

The base technology is a commercially available stoker-grate biomass plant constructed in the mid-1980's (EPRI 1993b), and is representative of modern biomass plants with an efficiency of about 23%. Plant efficiency of the stoker plant increased in the case study to 30% through the use of a dryer and steam cycle efficiency increases, e.g. higher pressure, higher temperature and reheat.

The feedstock used is assumed to be a mixture of pine and oak (40% pine - 60% oak) with 50% moisture content. This feed mixture was also used in the gasification analysis. For cofiring a mixture residues was assumed, with blending to reduce the moisture content to 21.5%, thus eliminating the need for a dryer. An analysis of the two feeds is given in Table 5.2.

The starting case is based on EPRI report TR-102107, v2 (Wiltsee and Hughes 1995), for the Burlington, VT, McNeil Station. Wood heating values are about 10 MJ/kg on a wet basis and 20 MJ/ kg on a dry basis; these values are about 40% and 80% of coal (24.78 MJ/kg [AEO97 1996]), respectively. The name plate efficiency of the McNeil station is 25%, while the Biopower model (EPRI 1995) gives 23.0%. An average of 24% was used as the starting point for the case study.

The RETC97 capital and operating costs were updated to 2001 dollars using the Marshall and Swift Index (Marshall and Swift ------), and plant costs were updated by adding a dryer (Craig and Mann 1996). Capital and operating costs for other plant sizes were scaled from the 50 MW values using a 0.7 scaling factor. Peters and Timmerhaus (Peters and Timmerhaus 1980) state, "It is often necessary to estimate the cost of a piece of equipment when no cost data are available for the particular size of operational

Table 5.2 Feedstock Composition for direct combustion and gasification

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

capacity involved. Good results can be obtained by using the logarithmic relationship known as the 'six-tenths-factor rule,' if the new piece of equipment is similar to one of another capacity for which cost data are available. According to this rule, if the cost of a given unit at one capacity is known, the cost of a similar unit with X times the capacity of the first is approximately $(X)^{0.6}$ times the cost of the initial unit." Valle-Riesta (Valle-Riesta 1983) states " A logical consequence of the 'sixth-tenths-factor' rule for characterizing the relationship between equipment capacity and cost is that a similar relationship should hold for the direct fixed capital of specific plants.....In point of fact, the capacity exponent for plants, on the average, turns out to be closer to 0.7." The exception to this rule happens when plant capacity is increased by change in efficiency, not change in equipment size. In this case, capital cost in dollars remains constant, and capital cost in $/kW decreases in proportion to efficiency increase.

The electrical substation is part of the general plant facilities, and is not separated out in the factor analysis. The convention follows that used in the EPRI Technical Assessment Guide (EPRI 1993a), as follows "It also includes the high-voltage bushing of the generation step-up transformer but not the switchyard and associated transmission lines. The transmission lines are generally influenced by transmission system-specific conditions and hence are not included in the cost estimate." A summary of capital and operating costs is given in Table 5.3.

To estimate plant performance as a CHP facility the steam conditions from the Biopower model (8.72 MPa and 510°C) were used in an ASPEN™ steam turbine simulation to estimate steam turbine performance in three modes of operation—as a condensing turbine (comparable to the RETC97 electricity case), as a backpressure turbine, and as an extraction turbine. The steam efficiency was assumed to be 80%. The extraction turbine case was used in CHP performance estimates. The use of the extraction turbine gave a heat (H) to power ratio (P) of 1.44, as shown in Table 5.12. A summary of turbine performance for a 50 MW$_e$ equivalent facility is given in Table 5.4. To convert to net plant efficiency a parasitic load of 5 MW$_e$ is subtracted from gross electricity production.

Table 5.3: Biomass Direct Combustion Plant Capital and Operating Costs (excluding feed)

Indicator Name	Units	M.F.	Scale Factor	Base	2001 Base	2001 25 MW	2001 75 MW	2001 100MW
				1996	2001	2001	2001	2001
M&S index				1039	1092			
Plant Size Net	MW			50	50	25	75	100
Gross	MW				55	28	83	110
General Performance Indicators								
Capacity Factor	%			80%	90%	90%	90%	90%
Efficiency	%			24.0%	30%	30%	30%	30%
Net Heat Rate	Btu/kWh			14,234	11,373	11,373	11,373	11,373
Annual Energy Delivery	GWh/yr			350	394	197	591	788
Capital Cost	$000							
Fuel Preparation			0.7	9,052	8,373	5,154	11,121	13,602
Dryer			0.7	-	4,418	2,719	5,868	7,177
Boiler			0.7	22,215	20,549	12,649	27,293	33,381
Baghouse and Cooling Tower			0.7	1,456	1,347	829	1,789	2,188
Boiler feedwater/ deaerator			0.7	2,784	2,575	1,585	3,420	4,183
Steam turbine/generator			0.7	7,407	6,851	4,218	9,100	11,130
Cooling water system			0.7	3,312	3,064	1,886	4,069	4,977
Balance of plant			0.7	13,641	12,618	7,767	16,759	20,498
Subtotal (A)				59,867	59,794	36,808	79,419	97,136
General Plant Facilities (B)			0.7	15,498	14,336	8,825	19,040	23,288
Engineering Fee, k*(A+B)		0.1		7,537	7,413	4,563	9,846	12,042
Process/project contingency		0.15		11,305	11,119	6,845	14,769	18,064
Total Plant Cost (TPC)				94,206	92,662	57,040	123,074	150,530
AFUDC				2,826	2,780	1,711	3,692	4,516
Total Plant Investment (TPI)				97,032	95,442	58,752	126,766	155,046
Prepaid Royalties		1		-				
Initial Cat & Chem Inventory		1		110	76	38	115	153
Startup costs		1		2,653	1,842	921	2764	3685
Inventory Capital		0.7		559	433	217	650	866
Land, 100 acres@ $7,250/acre		1		725	725	725	725	725
Total Capital Requirement (TCR)				**101,079**	**98,519**	**60,652**	**131,019**	**160,475**

Indicator Name	Units	M.F.	Scale Factor	Base	2001 Base	2001 25 MW	2001 75 MW	2001 100MW
Capital	$/kW							
Fuel Preparation				181	167	206	148	136
Dryer				-	88	109	78	72
Boiler				444	411	506	364	334
Baghouse and Cooling Tower				29	27	33	24	22
Boiler feedwater/ deaerator				56	52	63	46	42
Steam turbine/generator				148	137	169	121	111
Cooling water system				66	61	75	54	50
Balance of plant				273	252	311	223	205
Subtotal (A)				1,197	1,196	1,472	1,059	971
General Plant Facilities (B)				310	287	353	254	233
Engineering Fee, k*(A+B)				151	148	183	131	120
Process/project contingency				226	222	274	197	181
Total Plant Cost (TPC)				1,884	1,853	2,282	1,641	1,505
AFUDC				57	56	68	49	45
Total Plant Investment (TPI)				1,941	1,909	2,350	1,690	1,550
Prepaid Royalties				-	-	-	-	-
Initial Cat & Chem Inventory				2	2	2	2	2
Startup costs				53	37	37	37	37
Inventory Capital				11	9	9	9	9
Land, 100 acres@ $7,250/acre				15	15	29	10	7
Total Capital Requirement (TCR)	$/kW			2,022	1,970	2,426	1,747	1,605
Operating					1,628	814	2,442	3,256
Supervision and Clerical					408	408	408	408
Maintenance Labor and Material Costs @ 1.8% of TPC					1,668	834	2,502	3,336
Total Fixed Costs	K$/a				3,704	2,056	5,351	6,999
Variable Costs (without feed)								
Labor					1,349	675	2,024	2,699
Maintenance Labor and Material Costs					768	384	1,152	1,536
Total Variable Costs	K$/a				2,118	1,059	3,176	4,235
Consumables								
Chemicals					670	335	1,006	1,341
Water					169	85	254	338
Solids/ash disposal					182	91	273	364
Ammonia					106	53	160	213
Total Consumables	K$/a				1,128	564	1,692	2,256
Feed estimates								
Capacity Factor	%				90%	90%	90%	90%
Feed heating value	Mbtu/ton				17	17	17	17

Indicator Name	Units	M.F.	Scale Factor	Base	2001 Base	2001 25 MW	2001 75 MW	2001 100MW
Process efficiency	%				30%	30%	30%	30%
Feed req'd	Mbtu/MWh				11	11	11	11
Generation	MWh/a				394,200	197,100	591,300	788,400
Annual feed	Mbtu/a				4,483,368	2,241,684	6,725,052	8,966,736
	ton/a				263,728	131,864	395,591	527,455
Total Operating Costs	**K$/a**				**6,949**	**3,678**	**10,220**	**13,490**
Annual Operating Costs								
Fixed Costs								
Operating					0.0041	0.0041	0.0041	0.0041
Supervision and Clerical					0.0010	0.0021	0.0007	0.0005
Maintenance Labor and Material Costs @ 1.8% of TPC					0.0042	0.0042	0.0042	0.0042
Total Fixed Costs	$/kWh				0.0094	0.0104	0.0091	0.0089
Variable Costs (without feed)								
Labor					0.0034	0.0034	0.0034	0.0034
Maintenance Labor and Material Costs					0.0019	0.0019	0.0019	0.0019
Total Variable Costs	$/kWh				0.0054	0.0054	0.0054	0.0054
Consumables								
Chemicals					0.0017	0.0017	0.0017	0.0017
Water					0.0004	0.0004	0.0004	0.0004
Solids/ash disposal					0.0005	0.0005	0.0005	0.0005
Ammonia					0.0003	0.0003	0.0003	0.0003
Total Consumables	$/kWh				0.0029	0.0029	0.0029	0.0029
Total Operating Costs	**$/kWh**				**0.0176**	**0.0186**	**0.0173**	**0.0172**

Table 5.4: Direct-fired Combustion Cogeneration Gross Plant Efficiencies

	Temp		Pressure		Flow		Quality	Electricity	Steam	HP Steam	Efficiency		
	(°C)	(°F)	(MPa)	(psia)	(kg/s)	(lb/hr)	(%)	(MW$_e$)	(MW$_t$)	(MW$_t$)	Electric (%)	Thermal (%)	Steam (%)
Condensing Turbine													
Inlet	510	848	8.720	1,279	54.00	428,610	100	55	0	172.5	31.9	0	31.9
Extraction[a]													
Outlet	54	130	0.0152	2.2	54.00	428,610	91						
Backpressure Turbine													
Inlet	510	848	8.720	1,279	54.00	428,610	100	24.2	137.5	172.5	14.0	93.7	79.2
Extraction[a]													
Outlet	266	510	1.140	150	54.00	428,610	91						
Extraction Turbine													
Inlet	510	848	8.720	1,279	54.00	428,610	100	39.6	69.2	172.5	22.9	40.1	63.0
Extraction[a]	266	510	1.140	150	27.00	214,305	100						
Outlet	54	130	0.0152	2.2	27.00	214,305	91						

[a] Doesn't include process use extraction

Gasification

This discussion characterizes a biomass-based power plant that utilizes a gasification combined cycle (GCC) system as depicted in Figure 5.2. Generally speaking, the conversion of biomass to a low- or medium-heating-value gaseous fuel (biomass gasification) involves two processes. The first process, pyrolysis, releases the volatile components of the fuel at temperatures below 600°C (1112°F) via a set of complex reactions. Included in these volatile vapors are hydrocarbon gases, hydrogen, carbon monoxide, carbon dioxide, tars, and water vapor. Because biomass fuels tend to have more volatile components (70 - 86% on a dry basis) than coal (30%), pyrolysis plays a proportionally larger role in biomass gasification than in coal gasification. The by-products of pyrolysis that are not vaporized are referred to as char and consist mainly of fixed carbon and ash. In the second gasification process, char conversion, the carbon remaining after pyrolysis undergoes the classic gasification reaction (i.e. steam + carbon) and/or combustion (carbon + oxygen). It is this latter, combustion, reaction that provides the heat energy required to drive the pyrolysis and char gasification reactions. Due to its high reactivity (as compared to coal and other solid fuels), all of the biomass feed, including char, is normally converted in a single pass through a gasifier system.
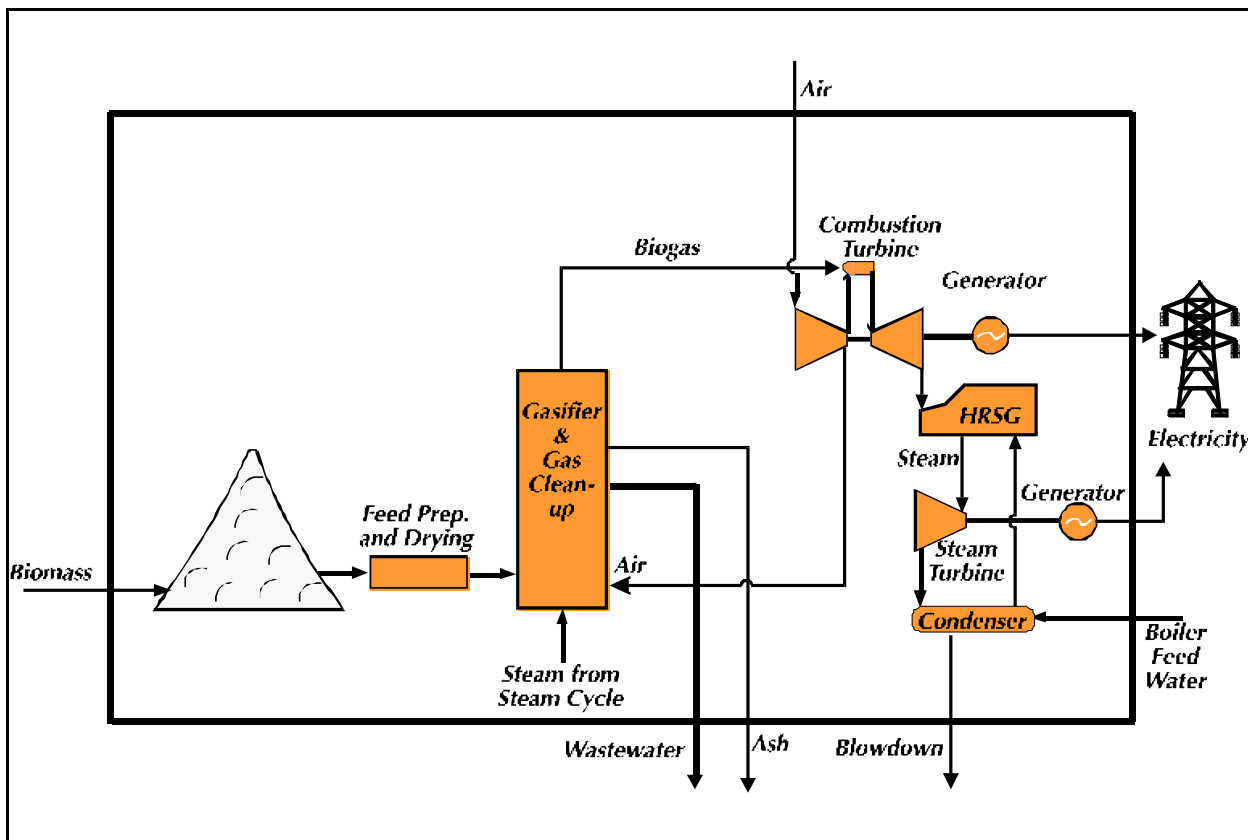
Figure 5.2: Generic Biomass Gasification Combined Cycle System

Depending on the type of gasifier used, the above reactions can take place in the same reactor vessel or separate vessels. These gasifier types are typically referred to as direct (pyrolysis, gasification, and combustion take place in one vessel) and indirect (pyrolysis and gasification in one vessel, combustion in a separate vessel). In direct gasification, air and sometimes steam are directly introduced to the single gasifier vessel (Figures 5.3 and 5.5). In indirect gasification, an inert heat transfer medium such as sand carries heat generated in the combustor to the gasifier to drive the pyrolysis and char gasification
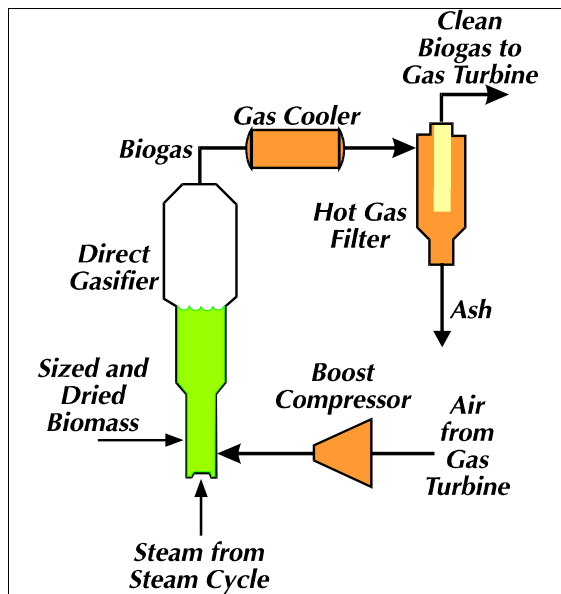
Figure 5.3: High Pressure Direct Gasifier
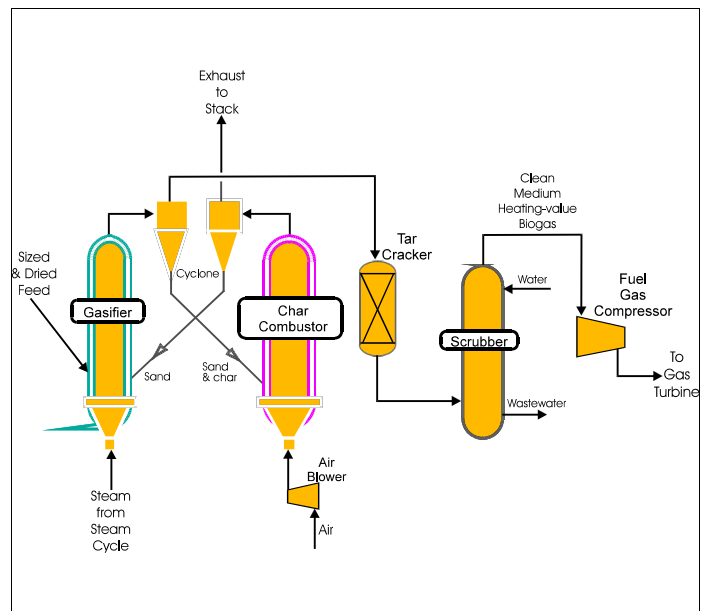
Figure 5.4: Indirect Gasifier
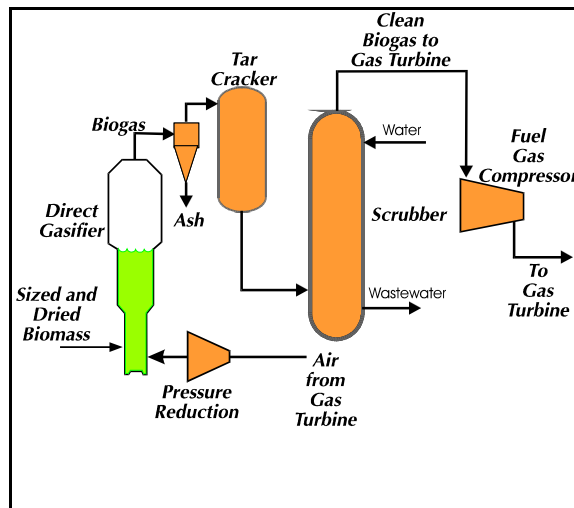
Figure 5.5: Low Pressure Direct Gasifier

reactions (Figure 5.4). Currently, indirect gasification systems operate near atmospheric pressure. Direct gasification systems have been demonstrated at both elevated (Figure 5.4) and atmospheric pressures (Figure 5.3). Any one of the gasifier systems shown in Figures 5.3 - 5.5 can be utilized in the generic gasifier block represented in the main system diagram above and have been utilized in a least one recent system design study (NSP 1995; Weyerhaeuser 1995; Craig and Mann 1996; EPRI 1995).

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

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

Gasifier operating pressure impacts not only equipment cost and size but the interfaces to the rest of the power plant including the necessary cleanup systems. Since gas turbines operate at elevated pressures, the fuel gas generated by low pressure gasifiers must be compressed. This favors low temperature gas cleaning since the fuel gas must be cooled prior to compression in any case. Air for a low pressure gasifier can be extracted from the gas turbine and reduced in pressure (direct, low pressure gasifier) or supplied independently (indirect gasifier). High pressure gasification favors hot, pressurized cleanup of the fuel gas and supply to the gas turbine combustor at high temperature (circa 538ºC or 1000ºF) and sufficiently high pressure for flow control and combustor pressure drop. Air for a high pressure, direct gasifier is extracted from the gas turbine and boosted in pressure prior to introduction to the gasifier.

Cooling, cold cleanup, and fuel gas compression add equipment to an indirect gasifier system and reduce its efficiency by up to 10% (Craig and Mann 1996, Marrison and Larson 1995). Gasifier and gas cleanup vessels rated for high pressure operation and more elaborate feed systems, however, add cost and complexity to high pressure gasification systems despite their higher efficiency. Results from several recent studies (NSP 1995, Weyerhaeuser 1995, Craig and Mann 1996, Marrison and Larson 1995) indicate that, at the current, preliminary grade of estimates (as defined by EPRI TAG, 1993) being performed, there is little discernable difference in cost of electricity (COE) between systems employing high and low pressure gasification.

For the purposes of this analysis, a high-pressure, direct gasification system as shown in Figure 5.3 was selected. The resulting system is very similar to that evaluated in a pre-feasibility study conducted by Northern States Power under subcontract AAE-5-14456-01 for NREL and EPRI, reported in NREL/TP-430-20517 (NSP 1995). This study examined a 75 MW$_e$ power plant that would gasify alfalfa stems to provide electricity to the Northern States Power Company and sell the leaf co-product for animal feed. A departure from the NSP study is the use here of wood as the biomass feedstock. Wood feedstock allows for a more generic plant representation. Alfalfa separation and leaf meal processing steps in the original NSP study would have added complexity and cost to the plant and have complicated the economic analysis.

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

Fuel gases exiting the gasifier are cooled in the product gas cooler to approximately 538ºC (1000ºF). In addition to protecting the fuel flow control valve, this cooling causes the vapor-phase alkali species present in the fuel gas, which could damage the gas turbine, to condense, congeal, and deposit on the fine particulate matter carried over from the gasifier. The combined particulate matter and alkali species are next removed in a Westinghouse hot ceramic candle filter unit to levels within gas turbine tolerances. Since biomass in general and wood in particular is very low in sulfur, a sulfur removal step is not

necessary prior to combustion in the gas turbine. Hot cleanup of the fuel gas also minimizes wastewater generation from this step of gas processing.

The fuel gas is combusted in a Westinghouse "ECONOPAC" 251B12 gas turbine producing electric power and a high temperature exhaust stream. A heat recovery steam generator (HRSG) is employed to recover this heat to generate high temperature, high pressure steam that is then expanded in a steam turbine to produce additional power. Steam for the gasifier is extracted from the steam cycle. As noted above, the total net electricity output from this system is 75 MW_e. The following cost and performance estimates, Table 5.5, were scaled to 150 MW using the 0.7 rule. It is worth noting that rapid developments are also being made in smaller turbine sizes as well, and the industrial and cogeneration markets (10 - 50 MW_e output) should not be ignored.

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

To estimate plant performance as a CHP facility the steam conditions given for year 2000 technology were used in an ASPEN™ steam turbine simulation to estimate steam turbine performance in three modes of operation—as a condensing turbine (comparable to the RETC97 electricity case), as a back-pressure turbine, and as an extraction turbine. The steam efficiency was assumed to be 80%. The back-pressure turbine case was used in CHP performance estimates. The back-pressure turbine was chosen to give a H/P approximately the same as the direct combustion case. The gasification H/P was 1.60 compared to 1.44 for direct combustion. A summary of turbine performance for a 75 MW_e equivalent facility is given in Table 5.6. To convert to net plant efficiency a parasitic load of 6.7 MW_e was subtracted from gross electricity production, and the gas turbine production of 51 MW_e was added.

Table 5.5: Biomass Gasification Capital and Operating Costs, Excluding Feed

Indicator Name	Units	M.F.	S.F.				
				1996	1996	2001	2001
M&S index				1039.1	1039.1	1092	1092
Plant Size Net	MW			75	75	75	150
Gross	MW						
General Performance Indicators							
Capacity Factor	%			80%	90%	90%	90%
Efficiency	%			36%	36%	36%	36%
Net Heat Rate	Btu/kWh			9,483	9,483	9,483	9,483
Annual Energy Delivery	GWh/yr			526	591	591	1,183
Capital Cost	$000						
Fuel Preparation			0.7	7,575	7,575	7,961	12,932
Gasifier			0.7	25,950	25,950	27,271	44,302
Gas Turbine			0.7	14,850	14,850	15,606	25,352
Steam Turbine			0.7	3,300	3,300	3,468	5,634
Balance of Plant			0.7	11,025	11,025	11,586	18,822
Control System			0.7	600	600	631	1,024
Hot gas Cleanup			0.7	2,325	2,325	2,443	3,969
Installation			0.7	9,900	9,900	10,404	16,901
Turbine Building			0.7	450	450	473	768
Waste Pond			1	150	150	158	315
Subtotal (A)				76,125	76,125	80,000	130,020
General Plant Facilities (B)		0.1	0.7	7,613	7,613	8,000	13,002
Engineering Fee, k*(A+B)		0.1		8,374	8,374	8,800	14,302
Process/project contingency		0.15		12,561	12,561	13,200	21,453
Total Plant Cost (TPC)				104,672	104,672	110,001	178,778
AFUDC				-		-	
Total Plant Investment (TPI)				104,672	104,672	110,001	178,778
Prepaid Royalties			1				
Initial Cat & Chem Inventory			1				
Startup costs			1	4,200	4,200	4,414	8,828
Inventory Capital			0.7	750	750	788	1,576
Land, 100 acres@ $7,250/acre				750	750	788	1,576
				5700	5,700	5,990	5990

Indicator Name	Units	M.F.	S.F.				
Total Capital Requirement (TCR)				**110,372**	110,372	115,991	**196,749**
Capital	$/kW						
Fuel Preparation				101	101	106	86
Gasifier				346	346	364	295
Gas Turbine				198	198	208	169
Steam Turbine				44	44	46	38
Balance of Plant				147	147	154	125
Control System				8	8	8	7
Hot gas Cleanup				31	31	33	26
Installation				132	132	139	113
Turbine Building				6	6	6	5
Waste Pond				2	2	2	2
Subtotal (A)				1,015	1,015	1,067	867
General Plant Facilities (B)		0.1		102	102	107	87
Engineering Fee, k*(A+B)		0.1		112	112	117	95
Process/project contingency		0.15		167	167	176	143
Total Plant Cost (TPC)				1,396	1,396	1,467	1,192
AFUDC				-			-
Total Plant Investment (TPI)				1,396	1,396	1,467	1,192
Prepaid Royalties							
Initial Cat & Chem Inventory							
Startup costs				56	56	59	59
Inventory Capital				10	10	11	11
Land, 100 acres@ $7,250/acre				10	10	11	11
						80	40
Total Capital Requirement (TCR)	**$/kW**			**1,472**	**1,472**	**1,626**	**1,312**
Annual Operating Costs							
Fixed Costs							
Operating				535	535	562	1,124
Supervision and Clerical				435	435	457	457
Maintenance Labor and Material Costs		0.7		2,285	2,285	2,402	3,901
Total Fixed Costs	K$/a			3,255	3,255	3,421	5,482
Variable Costs (without feed)							
Labor				1,787	2,010	2,113	4,021
Maintenance Labor and Material Costs				315	355	373	710
Total Variable Costs	K$/a			2,102	2,365	2,486	4,730

Indicator Name	Units	M.F.	S.F.			
Consumables						
Chemicals				210	237	249	473
Water				315	355	373	710
Solids/ash disposal				158	177	186	355
Ammonia							
Total Consumables	K$/a			683	769	808	1,537
Total Operating Costs	**K$/a**			**6,041**	**6,389**	**6,714**	**11,750**
Annual Operating Costs							
Fixed Costs							
Operating				0.0010	0.0009	0.0010	0.00095
Supervision and Clerical				0.0008	0.0007	0.0008	0.00039
Maintenance Labor and Material Costs @ 1.8% of TPC				0.0043	0.0039	0.0041	0.00330
Total Fixed Costs	$/kWh			0.0062	0.0055	0.0058	0.00464
Variable Costs (without feed)							
Labor				0.0034	0.0034	0.0036	0.0034
Maintenance Labor and Material Costs				0.0006	0.0006	0.0006	0.0006
Total Variable Costs	$/kWh			0.004	0.004	0.0042	0.004
Consumables							
Chemicals				0.0004	0.0004	0.0004	0.0004
Water				0.0006	0.0006	0.0006	0.0006
Solids/ash disposal				0.0003	0.0003	0.0003	0.0003
Ammonia							
Total Consumables	$/kWh			0.0013	0.0013	0.0014	0.0013
Total Operating Costs	**$/kWh**			**0.0115**	**0.0108**	**0.0114**	**0.0099**

Table 5.6: Gasification Cogeneration Gross Steam Turbine Efficiencies

	Temp		Pressure		Flow		Quality	Electricity	Steam	Efficiency		
	(°C)	(°F)	(MPa)	(psia)	(kg/s)	(lb/hr)	(%)	(MW$_e$)	(MW$_t$)	Electric	Thermal	Steam
										(%)	(%)	(%)
Condensing Turbine												
Inlet	468	874	5.860	865	32.64	259,045	100	31	0	30.4	0	30.4
Extraction[a]												
Outlet	54	130	0.0152	2.2	32.64	259,045	92					
Backpressure Turbine												
Inlet	468	874	5.860	865	32.64	259,045	100	12	84	11.8	82.4	94.1
Extraction[a]												
Outlet	266	510	1.140	165	32.64	259,045	92					
Extraction Turbine												
Inlet	468	874	5.860	865	32.64	259,045	100	21	42	20.6	41.2	61.8
Extraction[a]	266	527	1.140	165	16.32	129,522	100					
Outlet	54	130	0.0152	2.2	16.32	129,522	92					

[a] Doesn't include process use extraction

Cofiring

Cofiring is the co-combustion of multiple fuels in the same boiler. Many coal- and oil-fired boilers at power stations have been retrofitted to permit multi-fuel flexibility. Biomass is well-suited for cofiring with other solid fuels, primarily coal, as an acid rain and greenhouse gas emission control strategy. Cofiring is a fuel-substitution option for existing fuel capacity, and is not a capacity expansion option. Cofiring utilizing biomass has been successfully demonstrated and is currently practiced in the full range of coal boiler types, including pulverized coal boilers, stokers, cyclones, and bubbling and circulating fluidized beds (Winslow et al. 1993). The system described here is for pulverized coal-fired boilers, which represent the majority of the current fleet of utility boilers in the U.S.; however, there are also significant opportunities for cofiring with biomass in stokers, cyclones, and fluidized bed boilers. Cofiring in an existing pulverized coal (PC) boiler will generally require minor modifications or additions to fuel handling, storage, and feed systems. An automated system capable of processing and storing sufficient biomass fuel in one shift for 24-hour use is needed to allow continuous cofiring. Typical biomass fuel receiving equipment will include truck scales and hydraulic tippers; however, tippers are not required if deliveries are made with self-unloading vans. New automated reclaiming equipment may be added or existing front-end loaders may be detailed for use to manage and reclaim biomass fuel. Conveyors will be added to transport fuel to the processing facility, with magnetic separators to remove spikes, nails, and tramp metal from the feedstock. Since biomass is the "flexible" fuel at these facilities, a 5-day stockpile should be sufficient and avoids problems with longer term storage of biomass (Winslow et al. 1993).
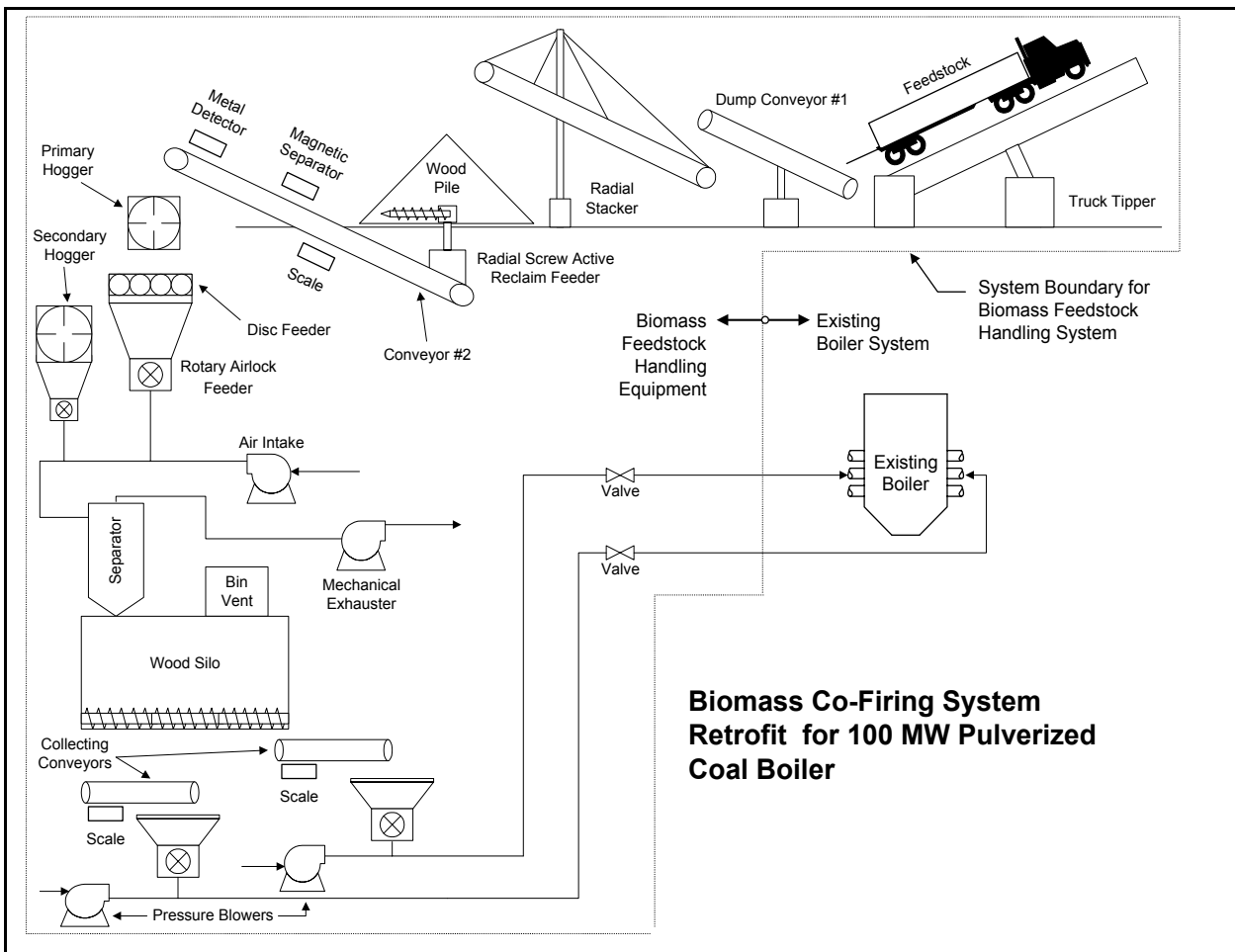
Figure 5.6: Biomass Co-firing System Retrofit for a Pulverized Coal Boiler

Fuel processing requirements are dictated by the expected fuel sources, with incoming feedstocks varying from green whole chips up to 5 cm (2 inches) in size (or even larger tree trimmings) to fine dry sawdust requiring no additional processing. In addition to woody residues and crops, biomass fuel sources could include alfalfa stems, switchgrass, rice hulls, rice straws, stone fruit pits, and other materials (Hughes and Tillman 1996). For suspension firing in pulverized coal boilers, biomass fuel feedstocks should be reduced to a particle size of 6.4 mm (1/4 inch) or less with moisture levels under 25% MCW (Moisture Content, Wet basis) when firing in the range of 5% to 15% biomass on a heat input basis (Antares and Parsons 1996, Ebasco 1993). Equipment such as hoggers, hammer mills, spike rolls, and disc screens are required to properly size the feedstock. Other boiler types, such as stokers and fluidized beds are better suited to handle larger fuel particles. There must also be a biomass buffer storage and a fuel feed and metering system. Biomass is pneumatically conveyed from the storage silo and introduced into the boiler through existing injection ports. Introducing the biomass at the lowest level of burners helps to ensure complete burnout due to the scavenging effect of the upper level burners and the increased residence time in the boiler.

The system described here and shown in Figure 5.6 is designed for high percentage cofiring (>2% on a heat input basis) and, for that reason, requires a separate feed system for biomass which acts in parallel to the coal feed systems. Existing coal injection ports are modified to allow dedicated biomass injection during the cofiring mode of operation. For low percentage cofiring (<2% on a heat input basis), it may be possible to use existing coal pulverizers to process the biomass. If using existing pulverizers, the biomass is processed and conveyed to the boiler with the coal supply and is introduced into the boiler through the same injection ports as the coal. Using existing pulverizers could reduce capital costs by allowing the avoided purchase of dedicated biomass processing and handling equipment, but the level of cofiring on a percentage basis will be limited by pulverizer performance, biomass type, and excess pulverizer capacity. The suitability of existing pulverizers to process biomass with coal will vary depending on pulverizer type and biomass type. Atritta mills, for example, have significant capability to process biomass fuels (Hughes and Tillman 1996).

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

The current fleet of low cost, coal-fired, base load electricity generators are producing over 50% of the nation's power supply (EIA 1996). With the Clean Air Act Amendments (CAAA) requiring reductions in emissions of acid rain precursors such as sulfur dioxide (SO_2) and nitrogen oxides (NO_x) from utility power plants, cofiring biomass at existing coal-fired power plants is viewed as one of many possible compliance options. In addition, cofiring using biomass fuels from sustainably grown dedicated energy crops is viewed as a possible option for reducing net emissions of carbon dioxide (CO_2), a greenhouse gas that contributes to global warming. Coupled with the need of the industrial sector to dispose of biomass residues (generally clean wood byproducts or remnants), biomass cofiring offers the potential for solving multiple problems at potentially modest investment costs. These opportunities have caught the interest of power companies in recent years.

Unlike coal, most forms of biomass contain very small amounts of sulfur. Hence, substitution of biomass for coal can result in significant reductions in sulfur dioxide emissions. Cofiring biomass with coal can allow power producers to earn sulfur dioxide (SO_2) emission allowances under section 404(f) of the CAAA (U.S. House of Representatives 1990) (1 allowance = 1 ton of reduced SO_2 emissions = 0.91 metric ton of reduced SO_2 emissions). An allowance is earned for each ton of SO_2 emissions reduced. This section of the CAAA includes provisions for earning credits from SO_2 emissions avoided through energy

conservation measures (i.e., demand side management or DSM) and renewable energy. In addition to any allowances which the producer saved by not emitting SO_2, two allowances can be given to the utility from an allowance reserve for every gigawatt-hour (GWh=10^6 kWh) produced by biomass in a co-fired boiler. These allowances may then be sold or traded to others who need them to remain in compliance with the CAAA.

Potential negative impacts associated with cofiring biomass fuels include: 1) the possibility for increased slagging and fouling on boiler surfaces when firing high alkali herbaceous biomass fuels such as switchgrass, and 2) the potential for reduced fly ash marketability due to concerns that commingled biomass and coal ash will not meet existing ASTM fly ash standards for concrete admixtures, a valuable fly ash market. These two issues are the subject of on-going research and investigation efforts. Two factors indicate that biomass cofiring (using sources of biomass such energy crops or residues from untreated wood) will have a negligible effect on the physical properties of coal fly ash. First, the mass of biomass relative to coal is small for cofiring applications, since biomass provides 15% or less of the heat input in the boiler. Second, combustion of most forms of biomass results in only half as much ash when compared to coal. Despite these factors, significant efforts will be required to ensure that commingled biomass and coal ash will be accepted by ASTM standards for concrete admixture applications.

Biomass cofiring is a retrofit application, primarily for coal-fired power plants. Biomass cofiring is applicable to most coal fired boilers used for power generation. A partial list of existing or planned utility applications is shown in Table 5.7. Recent DOE feasibility/demonstration projects are given in Table 5.8. Retrofits for coal-fired stokers, cyclones, and fluidized bed boilers are potentially simpler and less expensive than for pulverized coal. However, pulverized coal boilers are the most widely used steam generating system for coal-fired power generation in the U.S., and they represent most of plants affected by 1990 Clean Air Act Amendments (CAAA) provisions for reducing the emissions of SO_2 and NO_x from electric generating units.

The power plants characterized are pulverized coal plants which co-fire 15% biomass on a heat input basis. System capital and operating costs are assumed to be representative of plants which receive biomass via self-unloading vans and can utilize existing front-end loaders for receiving and pile management. The facilities are assumed to be located in a region where medium- to high-sulfur coal (0.8% by weight and greater) is used as a utility boiler fuel and where biomass residues are available for relatively low costs ($0.47/GJ, or $0.50/Mbtu). Areas with these characteristics include portions of the Northeast, Southeast, mid-Atlantic, and Midwest regions.

For each case, the performance of two systems is estimated. One is a pulverized coal power plant using only coal as a fuel source. These cases represent the plant operation prior to a biomass cofiring retrofit. The other case shows the performance of the same power plant operating with biomass cofiring. The tools used for this analysis were based on EPRI's BIOPOWER cofiring model (EPRI 1995). Input requirements for the model include ultimate analyses of the fuels (chemical composition of the fuels), capacity factor for the power plant, net station capacity, gross turbine heat rate, and percent excess air at which the plant operates. The technical input information used for the model were based on data from a representative Northeast power plant that intends to implement biomass cofiring. For a given biomass cofiring rate, the model calculates thermal efficiency, change in net heat rate, coal and biomass consumption, and reduced SO_2 and CO_2 emissions.

Table 5.7: Existing or Planned Biomass Cofiring Applications (Winslow et al. 1996)

PLANT	FUEL	SIZE	TECHNOLOGY
Northern States Power Allen S. King Station Minneapolis, Minnesota	Coal/wood residues (lumber)	560 MWe	Cyclone
Otter Tail Power Co. Big Stone City, South Dakota	Coal/RDF/tires/ waste oil/ag. refuse	440 MWe	Cyclone
Tennessee Valley Authority Allen (1) & Paradise (2) Stations Memphis & Dunmore, Tennessee	1) Coal/wood residues and coal/wood/tires 2) Coal/wood residues	1) 176 MWe 2) 700 MWe	1) Cyclone 2) Cyclone
Elsam Grenaa Co-Generation Plant Grenaa, Denmark	Coal/straw	150 MWe	Circulating Fluidized Bed
Tacoma City & Light Tacoma Two Station Tacoma, Washington	Coal/RDF/wood residues	2 x 25 MWe	Bubbling Fluidized Bed
GPU GENCO Shawville Station Johnstown, Pennsylvania	Coal/wood residues	130 MWe	Pulverized Coal
IES Utilities Inc. Sixth Street (1) & Ottumwa (2) Stations Marshalltown, Iowa	1) Coal/agricultural residues 2) Coal/switchgrass	1) 3 Units 6-15 MWe 2) 714 MWe	1) Pulverized Coal 2) Pulverized Coal
Madison Gas & Electric Blount Street Station Madison, Wisconsin	Coal/switchgrass	50 MWe	Pulverized Coal
New York State Elec & Gas Greenidge Station Dresden, New York	Coal/wood residues and coal/energy crops (willow)	108 MWe	Pulverized Coal
Niagara Mohawk Power Corp. Dunkirk Station Dunkirk, New York	Coal/wood residues and coal/energy crops (willow)	91 MWe	Pulverized Coal
Tennessee Valley Authority Kingston Station Oakridge, Tennessee	Coal/wood residues	150 MWe	Pulverized Coal
EPON Centrale Gelderland Netherlands	Coal/wood residues (demolition)	602 MWe	Pulverized Coal
I/S Midtkraft Energy Co. Studstrupvaeket, Denmark	Coal/straw	150 MWe	Pulverized Coal
Uppsala Energi AB Uppsala, Sweden	Coal (peat)/ wood chips	200 MWe & 320 MWt	Pulverized Coal
New York State Elec & Gas Hickling (1) & Jennison (2) Stations Big Flats & Bainbridge, New York	Coal/wood residues and coal/tyres	1) 37.5 MWe 2) 37.5 MWe	1) Stoker 2) Stoker
Northern States Power Bay Front Station Ashland, Wisconsin	Coal/wood residues (forest)	2 x 17 MWe	Stoker

Table 5.8: Ongoing DOE Cofiring Feasibility/Demonstration Projects

Title	Organization	Description
Blending Biomass with Tire-Derived Fuel for Firing at Willow Island Generating Station	Allegeny Energy Supply Company	Researchers are demonstrating the blending of fuels for cofiring at the Willow Island Generating Station in West Virginia. Biomass fuels are expected to reduce harmful emissions form the power generating station.
Development of a Validated Model for Use in Minimizing NO$_x$ Emissions and Maximizing Carbon Utilization When Cofiring Biomass With Coal	Southern Research Inst.	This project involves developing a computer model to calculate optimal energy and environmental benefits derived from cofiring biomass and coal.
Urban Wood/Coal Cofiring in the NIOSH Boiler Plant	University of Pittsburgh	The University of Pittsburgh is conducting cofiring demonstrations at the University's Bellefield boiler plant and at the NIOSH stoker boiler at the Bruceton Research Center.
Cofiring Biomass with Lignite Coal	Energy and Environmental Research Center, Grand Forks, ND	Tis demonstration wis cofiring wood waste with lignite coal at the North Dakota Penitentiary in Bismark.
Gasification-Based Biomass Cofiring Project	Northern Indiana Public Service Co.	The project is evaluating the feasibility of using wood waste, switchgrass, corn stover, non-recyclable paper and other related products to produce synthesis gas, and to fire the syngas in a generating that ordinarily fires natural gas.
Gasification-Based Cofiring Project	Nexant, LLC	Nexant will study the use of poultry litter in a biomass gasification cofiring demonstration at the Reid plant in Henderson, KY. This project will determine the optimum size at which gasifiers can be integrated, while maintaining boiler operation.
Calla Energy Biomass Gasification Cofiring Project		This project involves developing and Demonstrating as advanced version of the Gas Technology Institute RENUGAS™ biomass gasification technology to gasify biomass at a plant being built in Estill, KY. The gas will be used to produce steam and electricity in a 600-acre industrial park.
Feasibility Analysis for Installing a CFB Boiler for Cofiring Multiple Biofuels and Other Wastes with Coal	Pennsylvania State University	PSU is analyzing the installment of a state-of -the -art circulating fluidized bed boiler and ceramic emission control device, and is developing a test program to evaluate cofiring multiple biofuels and coal-based feedstocks.
Cofiring Coal: Feedlot and Litter Biomass Fuels in a Pulverized Fuel and Fixed-Bed Burners	Texas A&M University	Texas A&M University is investigating cattle feedlot and chicken litter biomass cofiring with coal to determine the optimum operating parameters and maximum combustion efficiency that can be achieved with the least emissions.
Cofiring Biomass at the University of North Dakota	University of North Dakota	This project is assessing local biomass resources available to the University and designing an economical feed system for the University's boiler.
Fuel-Lean Biomass Reburning in Coal-Fired Boilers	Iowa State University	ISU is examining the feasibility of adapting a commercially successful emissions reduction technology to herbaceous biomass when fired with coal.

The coal was assumed to contain 1.9% sulfur, compared to a 0.2% sulfur content for the biomass. Moisture contents were 7.2% for the coal and 21.5% for the biomass. The coal heating value was 31.75 MJ/kg (13,680 Btu/lb) (dry) and the biomass heating value was 19.10 MJ/kg (8,231 Btu/lb) (dry). These values for sulfur, moisture, and HHV were taken directly from tests conducted on the fuel supplies for the representative power plant. The resulting estimated net heat rate for coal-only operation is 10.93 MJ/kW

(10,359 Btu/kW). This value is typical of high capacity factor coal boilers in the range from 100 MW to 400 MW, and was therefore assumed constant for all cases.

All system capital costs are due to the retrofit of an existing pulverized coal boiler to co-fire biomass. Costs shown in Table 5.9 are based on engineering specifications, including materials and sizing of major system components, from a feasibility study for a corresponding 10 MW (biomass power) biomass cofiring retrofit at an existing plant (Antares and Parsons 1996).   The unit costs for the cofiring retrofit are expressed in $/kW of biomass power capacity, not total power capacity. Capital costs include costs for new equipment (e.g., fuel handling), boiler modifications, controls, engineering fees (10% of total process capital), civil / structural work including foundations and road ways, and a 15% contingency. Cost estimates for the example systems assume that front-end loaders and truck scales are already available at the plant for unloading and pile management. Costs also assume that live-bottom trucks are used for biomass delivery, allowing the avoidance of the purchase of a truck tipper. Land and substation (system interface) costs are zero because existing plant property and the existing substation will be utilized. Operation and maintenance costs, including fuel costs, are presented in the Table on an incremental basis. That is, each O&M cost component listed in the table represents the difference in that cost component when comparing biomass cofiring operation to coal-only operation. Negative costs, surrounded by parentheses in the table, represent a cost savings in the cofiring operation relative to coal-only operation. Updated plant performance indicators are given in Table 5.9, and updated capital and operating costs are given Table 5.10.

To estimate plant performance as a CHP facility, the biopower steam conditions (16.5 MPa and 538°C) were used in an ASPEN™ steam turbine simulation to estimate steam turbine performance in three modes of operation—as a condensing turbine (comparable to the RETC97 electricity case), as a backpressure turbine, and as an extraction turbine. The steam efficiency was assumed to be 80%. The extraction turbine case was used in CHP performance estimates. The use of the extraction turbine gave a heat (H) to power ratio (P) of 1.44, as shown in Table 5.12. A summary of turbine performance for a 100 MW_e equivalent facility is given in Table 5.11. To convert to net plant efficiency a parasitic load of 6 MW_e is subtracted from gross electricity production.

Table 5.9: Biomass Cofiring Performance Characteristics

Indicator Name	Units	Value	
Plant Size	MW	300	700
General Performance Indicators			
Capacity Factor	%	90	90
Total Electricity Generated	GWh/yr	2,365	5,518
Coal Moisture Content	%	7.2	7.2
Biomass Moisture Content	%	21.5	21.5
Coal-Only Performance Factors			
Plant Thermal Efficiency	%	32.9	32.9
Net Plant Heat Rate	KJ/kWh	10,929	10,929
	Btu/kWh	10,377	10,377
Net Power Capacity From Coal	MW	300	700
Annual Electricity From Coal	GWh/yr	2,365	5,518
Coal Consumption (wet)	tonnes/yr	877,550	2,047,617
Annual Heat Input From Coal	TJ/yr	25,847	60,310
Total Annual Heat Input	TJ/yr	25,847	60,310
Biomass Cofiring Performance Indicators			
Cofiring Rate (Heat Input From Biomass)	%	15	15
Plant Thermal Efficiency	%	32.5	32.5
Net Plant Heat Rate	kJ/kWh	11,066	25,821
	Btu/kWh	10,505	24,512
Net Power Capacity From Coal	MW	255	595
Net Power Capacity From Biomass	MW	45	105
Annual Electricity From Coal	GWh/yr	2,136	4,984
Annual Electricity From Biomass	GWh/yr	377	880
Coal Consumption (wet)	tonnes/yr	802,220	1,871,847
Biomass Consumption (Dry)	tonnes/yr	218,347	509,476
Annual Heat Input From Coal	TJ/yr	23,638	55,155
Annual Heat Input From Biomass	TJ/yr	4,172	9,735
Total Annual Heat Input	TJ/yr	27,810	64,890

Table 5.10: Biomass Cofiring Capital and Operating Costs, Excluding Feed

	1996$	2001$			
	300MW	300 MW	300 MW	700 MW	
Capital Cost (basis: Biomass Power Capacity)	$/kW	$/kW	$	$/kW	$
M&S Index	1039	1092			
Biomass Handling System Equipment					
Conveyor	10.3	10.8	487,097	8.4	881,452
Separation Equipment, Conveyor	2.8	2.9	132,415	2.3	239,618
Hogging Tower and Equipment	17.0	17.9	803,946	13.9	1,454,824
Pneumatic Conveying System (Vacuum)	3.6	3.8	170,247	2.9	308,080
Wood Silo with Live Bottom	4.4	4.6	208,080	3.6	376,543
Collecting Conveyers	5.3	5.6	250,642	4.3	453,563
Rotary Airlock Feeders	0.5	0.5	23,645	0.4	42,789
Pneumatic Conveying System (Pressure)	13.6	14.3	643,157	11.1	1,163,859
Controls	8.4	8.8	397,244	6.8	718,854
Total Equipment	65.9	69.3	3,116,472	53.7	5,639,583
Installation	40.9	43.0	1,934,199	33.3	3,500,136
Total Biomass Handling	106.8	112.2	5,050,671	87.0	9,139,718
Civil Structure Work	29.4	30.9	1,390,353	24.0	2,515,990
Modifications at Burners	2.4	2.5	113,498	2.0	205,387
Electrical	13.1	13.8	619,511	10.7	1,121,070
Subtotal (A)	151.7	159.4	7,174,033	123.6	12,982,165
Contingency @ 15%, 0.15*A	22.8	23.9	1,076,105	18.5	1,947,325
Total Direct Costs (B)	174.5	183.3	8,250,138	142.2	14,929,490
Engineering @ 10%, 0.1*B	17.4	18.3	825,014	14.2	1,492,949
Total Capital Requirements (TCR)	191.9	201.7	9,075,152	156.4	16,422,439
Incremental Operating and Maintenance Costs					
Variable Costs					
Consumables	0.00163	0.0016	614,510	0.0016	1,433,857
Coal Savings		(0.0051)	(1,916,829)	(0.0051)	(4,472,601)
Fixed Costs					
Labor	0.0006	0.00063		0.00063	
Maintenance	0.0005	0.00053		0.00053	
Total	0.0011	0.00116	435,812	0.00116	1,016,895

Table 5.11: Cofiring Cogeneration Gross Steam Turbine Efficiencies, 100 MW$_{eq}$ Plant

	Temp		Pressure		Flow		Quality	Electricity	Steam	HP Steam	Reheat	Efficiency		
	(°C)	(°F)	(MPa)	(psia)	(kg/s)	(lb/hr)	(%)	(MW$_e$)	(MW$_t$)	(MW$_t$)	(MW$_t$)	Electric	Thermal	Steam
												(%)	(%)	(%)
Condensing Turbine														
Inlet	538	1,000	16.50	2,048	95.51	758,046	100	106	0	303	39	36.8	0	36.8
Extraction[a]														
Outlet	54	130	0.0152	2.2	95.51	758,046	87							
Backpressure Turbine														
Inlet	538	1,000	16.50	2,048	95.51	758,046	100	63	260	303	39	17.5	76.6	94.1
Extraction[a]														
Outlet	212	414	1.140	165	95.51	758,046	100							
Extraction Turbine														
Inlet	538	1,000	5.860	865	95.51	758,046	100	94.5	130	303	39	26.1	38.3	64.4
Extraction[a]	212	414	1.140	165	47.76	379,023	100							
Outlet	54	130	0.0152	2.2	47.76	379,023	87							

[a] Doesn't include Process Extraction

Case Studies

A technoeconomic comparison has been made the direct combustion, gasification, and cofiring systems. A listing of cases, along with technical performance is given in Table 5.12. Plants are defined in terms of electricity-only base cases. For example, the 25 MW CHP case has a feed rate equal to the feed rate for a 25 MW$_e$ electricity-only plant. The actual electric capacity for the 25 MW CHP case is 19.8 MW$_e$, and the plant also produces 107,000 lb/hr of 150 lb steam. On an energy basis, the H/P ratio is 1.44; and the overall HHV efficiency is 62%.

Table 5.12: Biomass Plant Technical Performance

Case	Efficiency %	Feed Rate MBtu/hr (TPH*)	Electricity MW	150 lb Steam 1000 lb/hr	H/P
25 MW Electric - Direct Comb	30	284 (16.73)	25.0	0	--
25 MW CHP - Direct Comb	62	284 (16.73)	19.8	107	1.44
25 MW Steam	75	284 (16.73)	-2.5	214	--
50 MW Electric - Direct Comb	30	569 (33.45)	50.0	0	--
50 MW CHP - Direct Comb	62	569 (33.45)	41.5	214	1.44
50 MW Steam	75	569 (33.45)	-5.0	429	--
75 MW Electric - Direct Comb	30	853 (50.18)	75.0	0	--
75 MW CHP - Direct Comb	62	853 (50.18)	62.2	321	1.44
75 MW Steam	75	853 (50.18)	-7.5	643	--
100 MW Electric - Direct Comb	30	1,137 (66.90)	100.0	0	--
100 MW CHP - Direct Comb	61	1,137 (66.90)	83.0	428	1.44
100 MW Steam	75	1,137 (66.90)	-10.0	857	--
75 MW Gasification-Electric	36	711 (41.80)	75.0	0	--
75 MW Gasification - CHP	82	711 (41.80)	59.3	324	1.60
150 MW Gasification - Electric	36	711 (41.80)	150.0	0	--
150 MW Gasification - CHP	82	1,422 (83.60)	118.6	648	1.60
45 MW Cofiring CHP (15%)	60	518 (30.46)	41.0	170	1.21
45 MW Cofiring Steam	66	518 (30.46)	-2.7	341	--
105 MW Cofiring CHP (15%)	60	1,208 (71.08)	95.7	397	1.21
105 MW Cofiring Steam	66	1,208 (71.08)	-6.30	796	--

* Dry tons @ 17 MBtu/ton

For each of the cases a discounted cash flow (DCF) analysis was performed, using the economic parameters presented in Table 5.1. Since CHP operations have two products, electricity and steam, a protocol for prorating values was needed. One way to do this would be to assign market value to one product and determine the required cost of the second. However, this can unduly penalize or benefit the product being calculated if the required cost differs significantly from market value. Therefore, this method was not used. A second method is to estimate the present market value of the two products, and use the ratio to determine required costs of both. An estimate of relative market values was made using EIA[2] cost of manufacturing data from 1998. Based on survey data, the EIA presented purchased electricity

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[2]Energy Information Agency, Department of Energy, EIA Manufacturing Consumption of Energy 1998, Table N8.3, 1998.

and steam data for the United States and census region by manufacturing sector. A complete set of cost data for chemical industry sub-sectors in given in Appendix 2. For this study, the average values for the chemical sector were used. Figure 5-7 shows census regions. Figures 5-8 and 5-9 show purchased electricity and steam costs, respectively, updated to 2001 dollars using the GDP deflator. The United States average value of industrial electricity was $0.038/ kWh and industrial steam was $3.20/1,000 lb. In practice, as can be seen in the figures, the actual ratio will be site specific. When converted to a consistent set of units, the ratio of heat to power value ($H/$P) was 0.287. The matrix of cases analyzed was relatively large. For example, for direct combustion there were four plant sizes and five feed cost levels. A graphical presentation of the results using the 0.287 ratio with electricity in ¢/kWh and steam in $/1,000 lb was confusing simply because of the number of lines on each graph. In discounted cash flow analysis, if the capital and operating costs are fixed, and the discount rate is held constant, all feasible solutions give identical cash flows, e.g. identical incomes. Therefore, the absolute ratio of electricity and steam costs does not significantly impact the analysis. A $H/$P value was determined, 0.341, which would simplify graphical presentation of results, and would still be realistic; this value was used for the case studies.

Figure 5.7: United States Census Regions
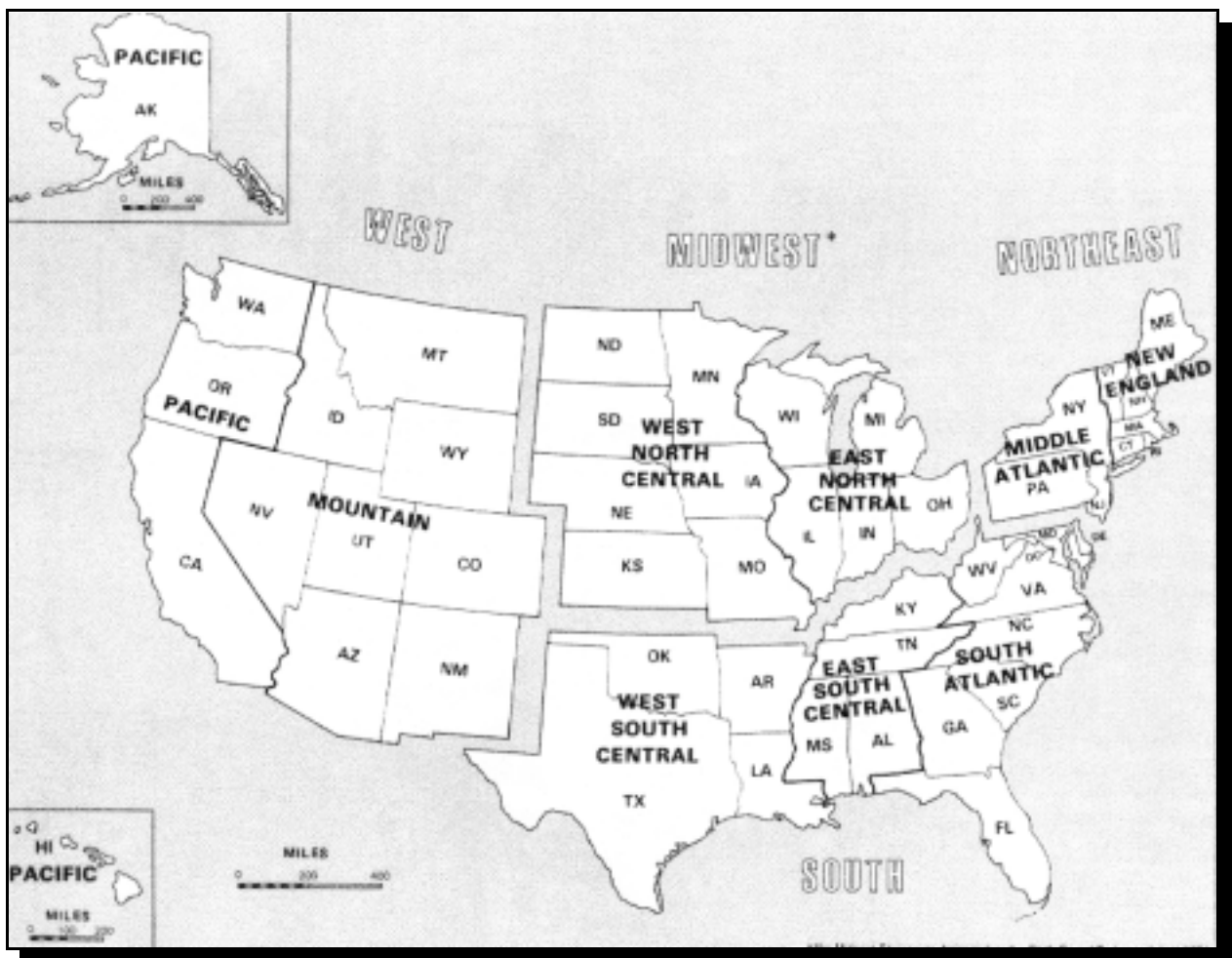
Figure 5.8: Chemical Industry Cost of Purchased Electricity
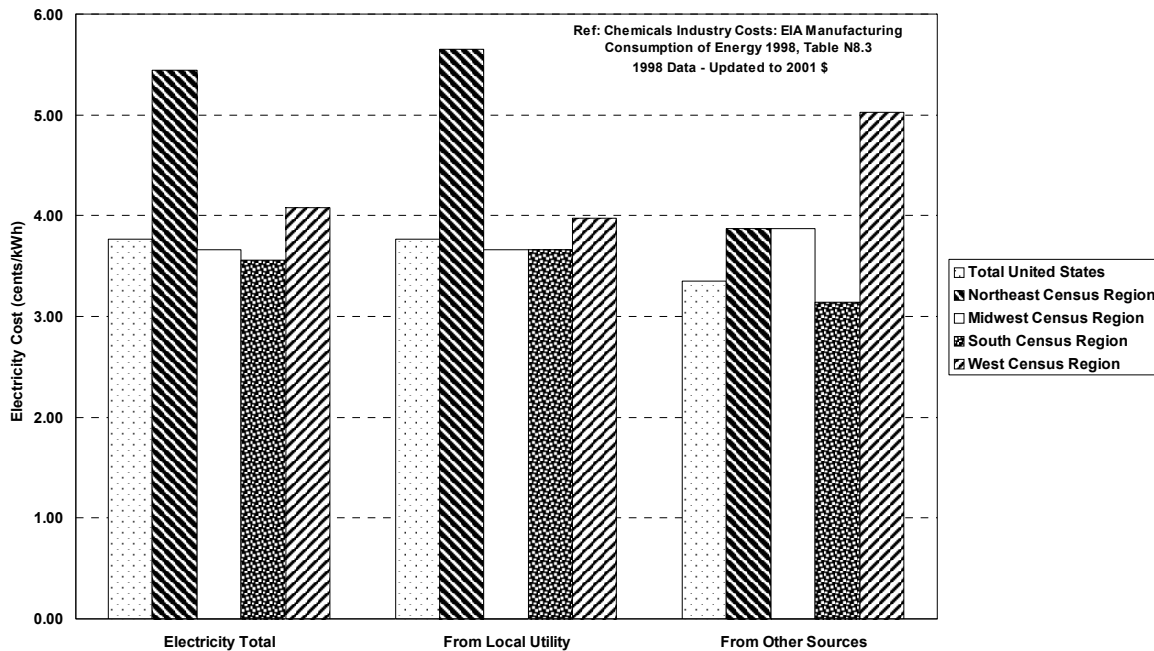
The DCF analysis was performed as a net present value (NPV) equals zero calculation in which the internal rate of return was set at the assumed discount rate, and the cost of products varied until NPV equaled zero. An example set of input values is given in Table 5.13, and the corresponding cash flow result shown in Table 5.14.

Feed Cost

In Figure 5.10, the effect of feed cost on required electricity and steam costs is shown for all systems The negative feed cost represents residue material generated in a chemical manufacturing or other industrial facility that is presently disposed of at some net cost, and where the negative cost represents a savings in disposal cost that can be represented by a negative transfer price. The 0 - 1 $/ton values represent residue materials presently used (see Figure 3.1 in Chapter 3), and the higher values represent marginal costs for larger supply levels. Typically, dedicated feeds will only be available at > $3/MBtu.   The results show that all combustion CHP cases give required product costs greater than existing industrial market prices. The gasification plants show a comparable trend, but with required product costs 2 to 3¢/kWh ($2-3/1,000 lb steam) lower than the direct combustion cases. Gasification CHP using technology presently available, i.e., 1st generation commercial systems, may be competitive with existing sources of industrial electricity and steam if a manufacturing facility has an internal source of waste available. For higher cost residues or dedicated crops, incentives or more advanced technologies, i.e., nth plant technology with higher efficiency, will be required to reduce product costs to a competitive level. Cofiring represents fuel substitution for existing coal feed. The coal savings offsets the required capital investment and the incremental cost of cofiring reflects the cost of biomass feed.

Plant Size

Figure 5.11 shows the effect of plant size on required product cost for the base feed cost of $2/MBtu. Capital and operating costs were scaled using a 0.7 scaling factor. The rationale for the scaling factor was discussed earlier in the direct-fired biomass section. Since only two plant sizes were calculated for gasification and cofiring, the shape of the curve is not apparent, but would follow the same trend if more sizes were estimated. The cost of electricity (steam) for direct combustion varied from 10.6 ¢/kWh

($/1,000 lb steam) at 25 MW$_{eq}$ to 8.4 ¢/kWh ($/1,000 lb steam) at 100 MW$_{eq}$. Gasification production costs were 6.7¢/kWh ($/1,000 lb steam) at 75 MW$_{eq}$ and 6.1 ¢/kWh ($/1,000 lb steam) at 150 MW. For cofiring at 15% the incremental costs were 2.2 ¢/kWh ($/1000 lb steam) for 45 MW$_{eq}$ biomass and 2.1 ¢/kWh ($/1,000 lb steam) for 105 MW$_{eq}$ biomass.

Capital Cost
The sensitivity of cost of production on capital cost is shown in Figure 5.12. Because of the low capital investment required for 15% cofiring CHP the sensitivity to a ± 25% variation in capital cost is small, e.g., 2.1 ± 0.08 ¢/kWh ($/1,000 lb steam) at 105 MW$_{eq}$ biomass. For gasification CHP, the sensitivity at 150 MW$_{eq}$ is 6.10 ± 0.73 ¢/kWh, and for direct combustion at 100 MW$_{eq}$ is 8.44 ± 0.97 ¢/kWh for the same ± 25% variation.

Discount Rate
The base case study uses a 20 percent discount rate, but the allowable discount rate is dependent on the individual organization performing the evaluation. NREL typically uses 15% for analyses, and EPRI has used 10.8% for utility cash flow comparisons (EPRI TAG, 1993). Therefore, a set of sensitivity cases was performed to look at the sensitivity to discount rate over the range 10%-25%. The results are given in

Figure 5.9: Chemical Industry Cost of Purchased Steam

5-32
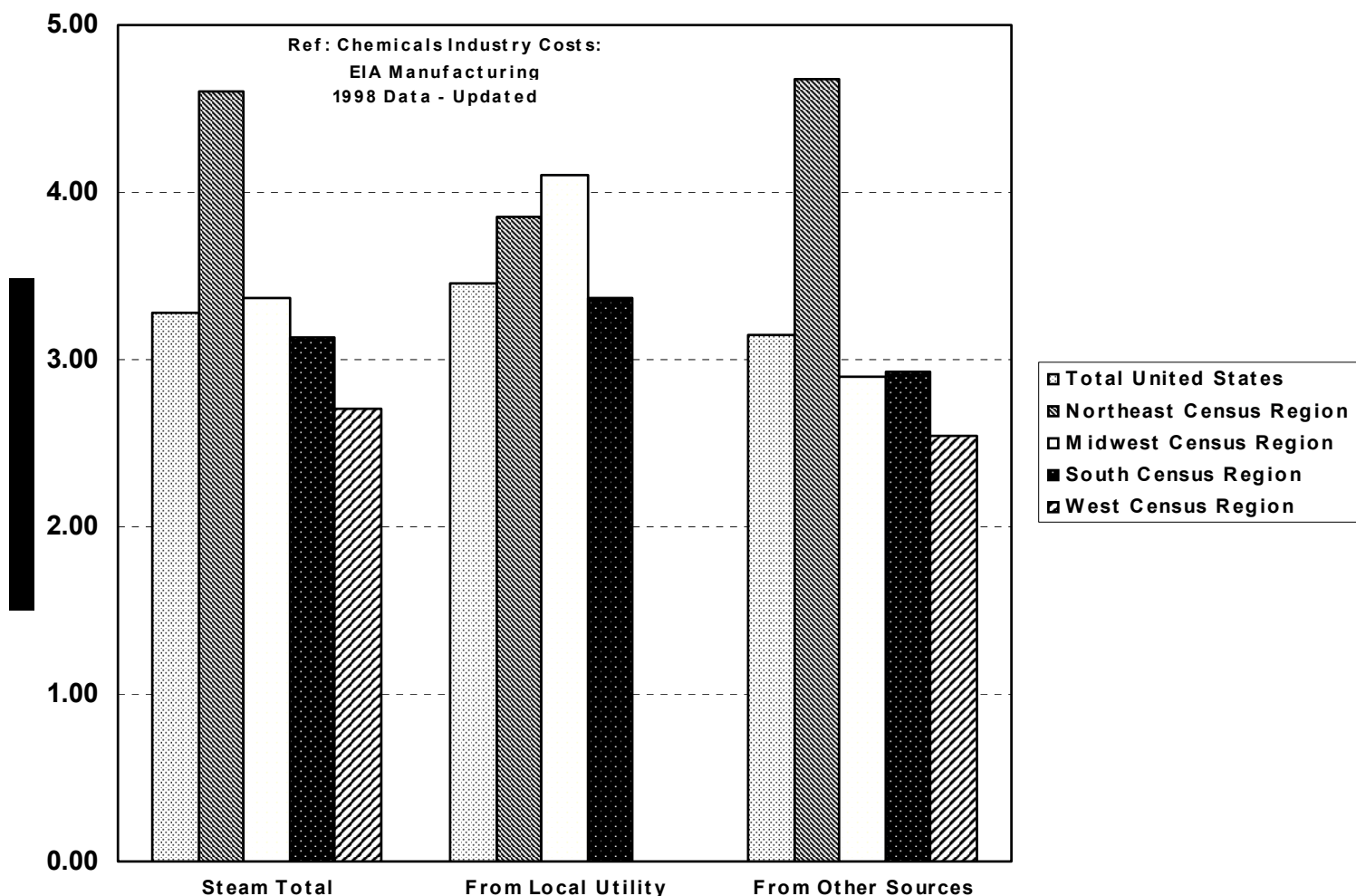
Figure 5.13. Over the range of 10% to 25 %, the 100 MW$_{eq}$ direct combustion CHP system cost varies from 6.4 ¢/kWh ($/1,000 lb steam) to 9.6 ¢/kWh, the 150 MW$_{eq}$ gasification CHP cost from 4.5¢/kWh to 7.0¢/kWh, and the 105 MW$_{eq}$ cofiring CHP cost from 1.9¢/kWh to 2.2¢/kWh.

Debt Sensitivity
Each organization has its own debt-equity protocol for cash flow estimation. A set of sensitivity cases was performed to estimate the required cost sensitivity to level of debt and the results are shown in Figure 5.14. For the 100 MW$_{eq}$ direct combustion system, the required CHP costs are 10.5¢/kWh ($/1,000 lb steam) and 7.5¢ at 100% equity and 50%equity-50% debt, respectively. For the 150 MW$_{eq}$ gasification system the respective CHP costs at 100% and 50% equity are 7.6¢/kWh and 5.4¢/kWh, and for cofiring CHP at 105 MW$_{eq}$ are 2.2 and 2.0 ¢/kWh.

Carbon Allowances
There is a significant amount of ongoing discussion about the use of carbon taxes, carbon sequestration credits, or carbon emission penalties as a way to reduce greenhouse gas emissions. An estimate of the impact of carbon allowances on biomass CHP was estimated over the range of 0-100 $/ton carbon emissions avoided. U.S. average carbon emissions for electricity production from coal-fired utility stations were used to estimate carbon allowances (EIA AEO 2002). The estimated value is 2.75 x 10^{-4} metric tons carbon/kWh. The carbon allowance was credited only against electricity production and was considered a before-tax income stream. The results are given in Figure 5.15. The cost of electricity (steam) for the 100 MW$_{eq}$ direct combustion CHP case at 0, 25, 50, and 100 $/metric ton carbon avoided are 8.44, 8.01, 7.58, and 6.71 ¢/kWh ($/1,000 lb steam), respectively. For the 150 MW$_{eq}$ gasification CHP case, the respective costs are 6.10, 5.65, 5.21, and 4.32 ¢/kWh; and for 15% cofiring CHP at 105 MW$_{eq}$ biomass the costs are 2.06, 1.58, 1.09, and 0.12 ¢/kWh.

Tax Credits
Various proposals are before Congress to modify and expand the definition of the IRS Section 49 "closed loop" biomass tax credit to include residues and cofiring. Therefore, estimates of the impact of such tax credits were made. The estimates were made using two assumptions–a project basis and a corporate basis. Using the project basis assumption, only project generated taxable income is used. In this case, the capital equipment depreciation in the early years of the project greatly limits taxable income, and the impact of a tax credit is small. For the corporate basis cases, the assumption is made that the corporation has other taxable income that the tax credit can be applied against so that all potential tax credit can be used. Other assumptions are that the tax credit is available for 100% of the net plant production, i.e, that the net production of electricity is sold, and that the tax credit applies for 10 years of plant operation.

Figure 5.16 shows the impact of a electricity production tax credit on the required cost of production of electricity for direct combustion CHP and for gasification CHP. For the 100 MW$_{eq}$ direct combustion system, the impact on electricity (steam) cost of production with a 1¢/kWh production credit is minus 0.36 ¢/kWh ($/1,000 lb steam) for a project basis and minus 0.77 ¢/kWh for a corporate basis; with a 2 ¢/kWh production credit the respective values are minus 0.57¢/kWh and minus 1.51 ¢/kWh. For the 150 MW$_{eq}$ gasification CHP system with a 1¢/kWh production credit, the cost of production is lowered by 0.42 and 0.81 ¢/kWh for the project and corporate cases, respectively; with a 2¢/kWh credit, the respective cost of production reduction is 0.50 and 1.57 ¢/kWh.

Comparable estimates can be made for the cofiring CHP cases, but the analysis is somewhat more complicated. Figure 5.17 shows the impact of a production credit on 15% cofiring CHP incremental costs. For the project cases, the decrease in cost of production for the 45 and 105 MW$_{eq}$ plants reaches a maximum of about 0.07 ¢/kWh at a tax credit of about 0.5¢ /kWh. For the corporate analysis, the NPV calculation does not give meaningful results above a tax credit level of 0.5¢/kWh. At this level, the reduction is about 0.40 ¢/kWh for both plants sizes. Above this level a NPV calculation can be made but

to satisfy the 20% return constraint, a solution is obtained that gives negative cash flows in the years after expiration of the tax credit. This indicates that the 10-year production tax credit has a large impact on potential project rate of return. A return on investment (ROI) estimate was made to show the impact of the production tax credit, assuming a fixed cost of production. For this example, the incremental cost of production of electricity (steam) was set at 2.0 ¢/kWh ($2/1,000 lb steam), and the 10-year production tax credit varied from 0 to 1 ¢/kWh. For the 45 MW_{eq} plant, the ROI varies from 13.6%, to 31.6%, to 47.8% at a 0, 0.5, and 1 ¢/kWh tax credit, respectively. The comparable ROIs for the 105 MW_{eq} case are 17.0, 38.6, and 57.5%.

Steam Only

For the direct combustion and cofiring systems based on the Rankine cycle, cases were analyzed to see if steam-only production was more economic. For the direct combustion system, the steam turbine was removed from the capital cost estimate, and for both systems the steam exiting the boiler was used as product. The results are shown in Figure 5.19. Production of steam results in an increase in the cost of production in comparison to CHP. At 50 MW_{eq} the cost of steam is 11.90 $/1,000lb, an increase of 2.53 $/1,000 lb over the comparable CHP case. At 100 MW_{eq}, the steam cost is 10.81 $/1000lb, an increase of 2.37 $/1,000 lb. For cofiring steam-only production at 45 MW_{eq} the incremental cost of steam is 4.16 $/1000 lb, versus 2.16$/1000 lb for CHP; at 105 MW_{eq}, the incremental cost of steam is 3.82 $/1,000 lb versus 2.06 $/1,000 lb for CHP.

Site and Incentives Impact

To see the potential impact of regional plant location, discount rate, and incentives, one set of gasification CHP cases was performed. The discount rate was assumed to be 5%, and both a carbon allowance (15$/ton carbon equivalent) and production tax incentive (1.5 ¢/kWh) were allowed. The tax incentive was taken on a corporate basis. The results were compared to U.S. and Northeast region costs of purchased electricity and steam, and are presented in Figure 5.20. For 75 MW_{eq} both the cost of electricity and steam are higher than the national average purchased prices, but are lower than purchase prices in the Northeast. At 150 MW_{eq} the results are comparable, but the cost of electricity is equal to the national average price.

Capital Requirements and Required Cash Flow

Although the three technologies–direct combustion, gasification, and cofiring–were evaluated at a constant discount rate to determine the required costs of electricity and steam, another important investment consideration is capital required and cumulative cash flow realized over the life of the project. A comparison of costs and cash flow is given in Table 5.15. Cofiring has the smallest capital investment and lowest operating costs, and gives the smallest cash flow. Gasification at 150 MW has an intermediate investment requirement, and direct combustion has the highest requirements.

Recommendations for Further Work

The case studies give a good base comparison of the three technologies. Further analysis is needed to fully investigate CHP applications.

- An advanced gasification case with higher efficiency-to-electricity ratios should be analyzed to determine if costs can be reduced to purchase prices.

- Given the variation in regional prices of electricity and steam, a resource evaluation relative to chemical plant locations should be performed to determine if there are site specific cases where feasibility studies should be performed. The project should map currently available biomass feedstocks (e.g., industrial processing residues, urban wood residues, agricultural residues) against locations of industrial facilities capable of biorefinery operations. The mapping should allow for a preliminary identification and ranking of prospective opportunities based on feedstock characteristics (i.e., type and availability, processing requirements, delivered costs) and industrial facility characteristics (i.e., type, size, location).

It should utilize a biomass feedstock database being developed by ORNL that provides quantity and delivered price information at the county level. Feedstock evaluations should include secondary residues generated by biorefineries. It should also utilize secondary data and information sources, such as EPA Sector Notebooks and U.S. Census Bureau County Business Patterns, where appropriate.

- For a few of the more promising identified facilities, we should apply the technical and economic findings of this report to determine the appropriate biomass CHP systems (e.g., gasification, co-firing) as well as syngas opportunities for chemicals, such as ethanol or mixed alcohols. This latter analysis should assess opportunities for specific facilities as well as develop a replicable methodology (including information requirements) for identifying biorefinery opportunities for industrial sites throughout the U.S.

Table 5.13: Cash Flow Analysis Input Data, 75MW$_{eq}$ Gasification CHP System

Construction Period		2	yrs			
Operating Life		30	yrs			
Electrlcity Prod	4.6750E+08		kWh/yr			
Electricity Rate	0.06711		$/kWh			
Capital Cost	115,991,000					
Depreciable Capita	110,001,000					
3 year						
5 year						
7 year	82,454,000					
10 year						
15 year						
20 year	27,547,000					
% capital year 1	75%					
Inflated Capital	115,991,000					
Inflated depreciabl	110,001,000					
Variable Cost (I = 0)						
year 1						
year 2						
year 3-n	3,294,000					
Fixed Cost	3,421,000					
Feed						
ton/yr	329,847					
$/ton (I=0)	34.00					
$/yr	11,214,798					
Working Cap	22,500,000					
Revenues						
Electricity	31,374,189					
Capacity Paymt						
Coproduct	17,112,492					
Total Revenue	48,486,681					
Yr 3 Prod, %	75.0%					
Inflation rate, %	0.00%					
Percent Debt	50.0%					
Cost of Debt	7.0%					
Term	20					
Inflated Debt	57,995,500					
Payment	5,474,365					

Depreciation Schedule-MACRS w half-yr convention	3-yr	5-yr	7-yr	10-yr	15-yr
Percentage	0%	0%	75%	0%	0%

Taxes				
Federal	35.0%			
State	5.0%			
State Wholesale Excise	0.0%		Coal Carbon	2.75E-04
Carbon Allowance	0.000	$/kWh	Carbon Allowance	0.000
Fed Tax Credit	0.000	$/kWh		
Corporate Basis (Yes=1, No = 0)	0			

Table 5.14: Cash Flow, 75 MW$_{eq}$ Gasification CHP System

Year	Income	Production Credit	Equity	Debt	Debt Service	Remaining Capital	Principal Paymt	Working Capital	Fixed Op cost	Variable Op cost	Pre-Dep Income F =
	I	PC	A		B		P	C	D	E	I-A-B-C-D-E
1			43,496,625	43,496,625	3,044,764						(46,541,389)
2			14,498,875	14,498,875	4,059,685	57,995,500					(18,558,560)
3	36,365,011	0			4,059,685	56,580,820	1,414,680	22,500,000	3,421,000	10,881,599	(4,497,273)
4	48,486,681	0			3,960,657	55,067,113	1,513,708		3,421,000	14,508,798	26,596,226
5	48,486,681	0			3,854,698	53,447,446	1,619,667		3,421,000	14,508,798	26,702,185
6	48,486,681	0			3,741,321	51,714,402	1,733,044		3,421,000	14,508,798	26,815,562
7	48,486,681	0			3,620,008	49,860,045	1,854,357		3,421,000	14,508,798	26,936,875
8	48,486,681	0			3,490,203	47,875,883	1,984,162		3,421,000	14,508,798	27,066,680
9	48,486,681	0			3,351,312	45,752,830	2,123,053		3,421,000	14,508,798	27,205,571
10	48,486,681	0			3,202,698	43,481,163	2,271,667		3,421,000	14,508,798	27,354,185
11	48,486,681	0			3,043,681	41,050,480	2,430,683		3,421,000	14,508,798	27,513,202
12	48,486,681	0			2,873,534	38,449,648	2,600,831		3,421,000	14,508,798	27,683,350
13	48,486,681	0			2,691,475	35,666,759	2,782,890		3,421,000	14,508,798	27,865,408
14	48,486,681	0			2,496,673	32,689,067	2,977,692		3,421,000	14,508,798	28,060,210
15	48,486,681	0			2,288,235	29,502,937	3,186,130		3,421,000	14,508,798	28,268,649
16	48,486,681	0			2,065,206	26,093,778	3,409,159		3,421,000	14,508,798	28,491,678
17	48,486,681	0			1,826,564	22,445,977	3,647,800		3,421,000	14,508,798	28,730,319
18	48,486,681	0			1,571,218	18,542,830	3,903,147		3,421,000	14,508,798	28,985,665
19	48,486,681	0			1,297,998	14,366,464	4,176,367		3,421,000	14,508,798	29,258,885
20	48,486,681	0			1,005,652	9,897,751	4,468,712		3,421,000	14,508,798	29,551,231
21	48,486,681	0			692,843	5,116,229	4,781,522		3,421,000	14,508,798	29,864,041
22	48,486,681	0			358,136	0	5,116,229		3,421,000	14,508,798	30,198,747
23	48,486,681	0							3,421,000	14,508,798	30,556,883
24	48,486,681	0							3,421,000	14,508,798	30,556,883
25	48,486,681	0							3,421,000	14,508,798	30,556,883
26	48,486,681	0							3,421,000	14,508,798	30,556,883
27	48,486,681	0							3,421,000	14,508,798	30,556,883
28	48,486,681	0							3,421,000	14,508,798	30,556,883
29	48,486,681	0							3,421,000	14,508,798	30,556,883
30	48,486,681	0							3,421,000	14,508,798	30,556,883
31	48,486,681	0							3,421,000	14,508,798	30,556,883
32	48,486,681	0						(22,500,000)	3,421,000	14,508,798	53,056,883
33											
34											
35											
36											
37											

				Project Internal Rate of Return	
				Rate of Return Estimate	
COE	6.71	cents/kWh			30.00%
PROD CRI	0.00	cents/kWh		Internal Rate of Return	
TAX CREL	0.00	cents/kWh			20.00%
				Desired Return	20.00%
				NPV	0

Table 5.14 (cont.)

Deprec	Pre-tax Calculation Income	Tax	Federal Tax Credit	After-Tax Income	Corporate Tax Credit	Cash Flow	Cum Cash Flow
G	F - G						
	(46,541,389)	0		(46,541,389)		(46,541,389)	(46,541,389)
	(18,558,560)	0		(18,558,560)		(18,558,560)	(65,099,949)
0	(4,497,273)	0	0	(4,497,273)	0	(5,911,952)	(71,011,901)
26,596,226	0	0	0	0	0	25,082,518	(45,929,383)
24,661,584	2,040,602	816,241	0	1,224,361	0	24,266,278	(21,663,105)
12,000,083	14,815,479	5,926,192	0	8,889,288	0	19,156,327	(2,506,779)
8,936,902	17,999,973	7,199,989	0	10,799,984	0	17,882,529	15,375,751
8,810,756	18,255,924	7,302,370	0	10,953,555	0	17,780,149	33,155,899
8,709,640	18,495,932	7,398,373	0	11,097,559	0	17,684,146	50,840,045
4,923,124	22,431,061	8,972,425	0	13,458,637	0	16,110,094	66,950,139
1,229,147	26,284,055	10,513,622	0	15,770,433	0	14,568,896	81,519,035
1,228,872	26,454,478	10,581,791	0	15,872,687	0	14,500,727	96,019,762
1,229,147	26,636,261	10,654,504		15,981,756		14,428,014	110,447,776
1,228,872	26,831,339	10,732,535		16,098,803		14,349,983	124,797,759
1,229,147	27,039,501	10,815,801		16,223,701		14,266,718	139,064,477
1,228,872	27,262,806	10,905,122		16,357,684		14,177,396	153,241,873
1,229,147	27,501,172	11,000,469		16,500,703		14,082,050	167,323,923
1,228,872	27,756,793	11,102,717		16,654,076		13,979,801	181,303,724
1,229,147	28,029,738	11,211,895		16,817,843		13,870,623	195,174,347
1,228,872	28,322,359	11,328,944		16,993,416		13,753,575	208,927,922
1,229,147	28,634,894	11,453,957		17,180,936		13,628,561	222,556,483
1,228,872	28,969,876	11,587,950		17,381,925		13,494,568	236,051,051
614,574	29,942,310	11,976,924		17,965,386		18,579,959	254,631,010
	30,556,883	12,222,753		18,334,130		18,334,130	272,965,140
	30,556,883	12,222,753		18,334,130		18,334,130	291,299,270
	30,556,883	12,222,753		18,334,130		18,334,130	309,633,400
	30,556,883	12,222,753		18,334,130		18,334,130	327,967,530
	30,556,883	12,222,753		18,334,130		18,334,130	346,301,660
	30,556,883	12,222,753		18,334,130		18,334,130	364,635,790
	30,556,883	12,222,753		18,334,130		18,334,130	382,969,920
	30,556,883	12,222,753		18,334,130		18,334,130	401,304,050
	53,056,883	21,222,753		31,834,130		31,834,130	433,138,180

Figure 5.10: Biomass CHP - Sensitivity to Feed Cost
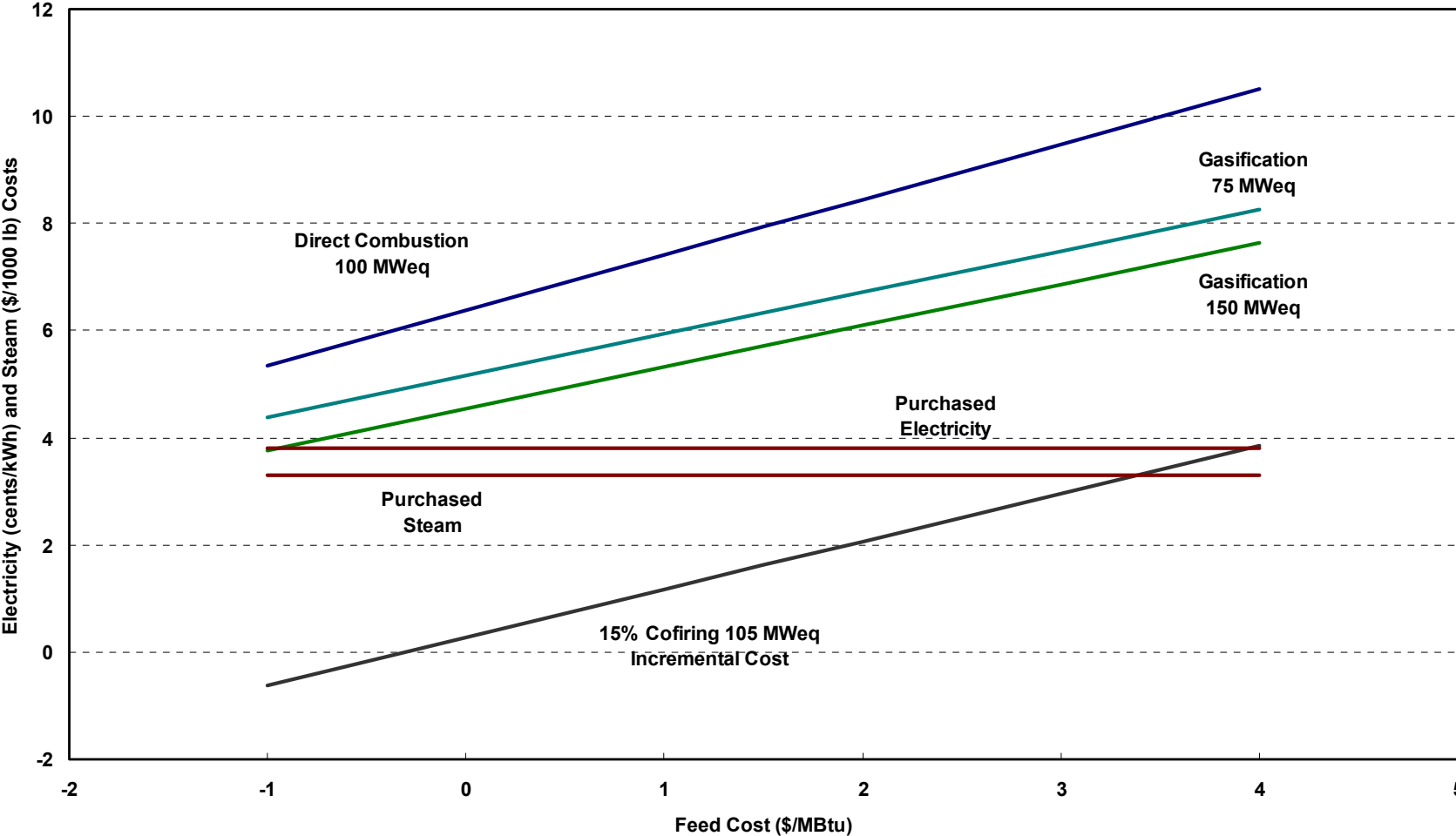
Figure 5.11: Biomass CHP - Effect of Plant Size on Cost of Electricity and Steam

Feed Cost = $2/MBtu
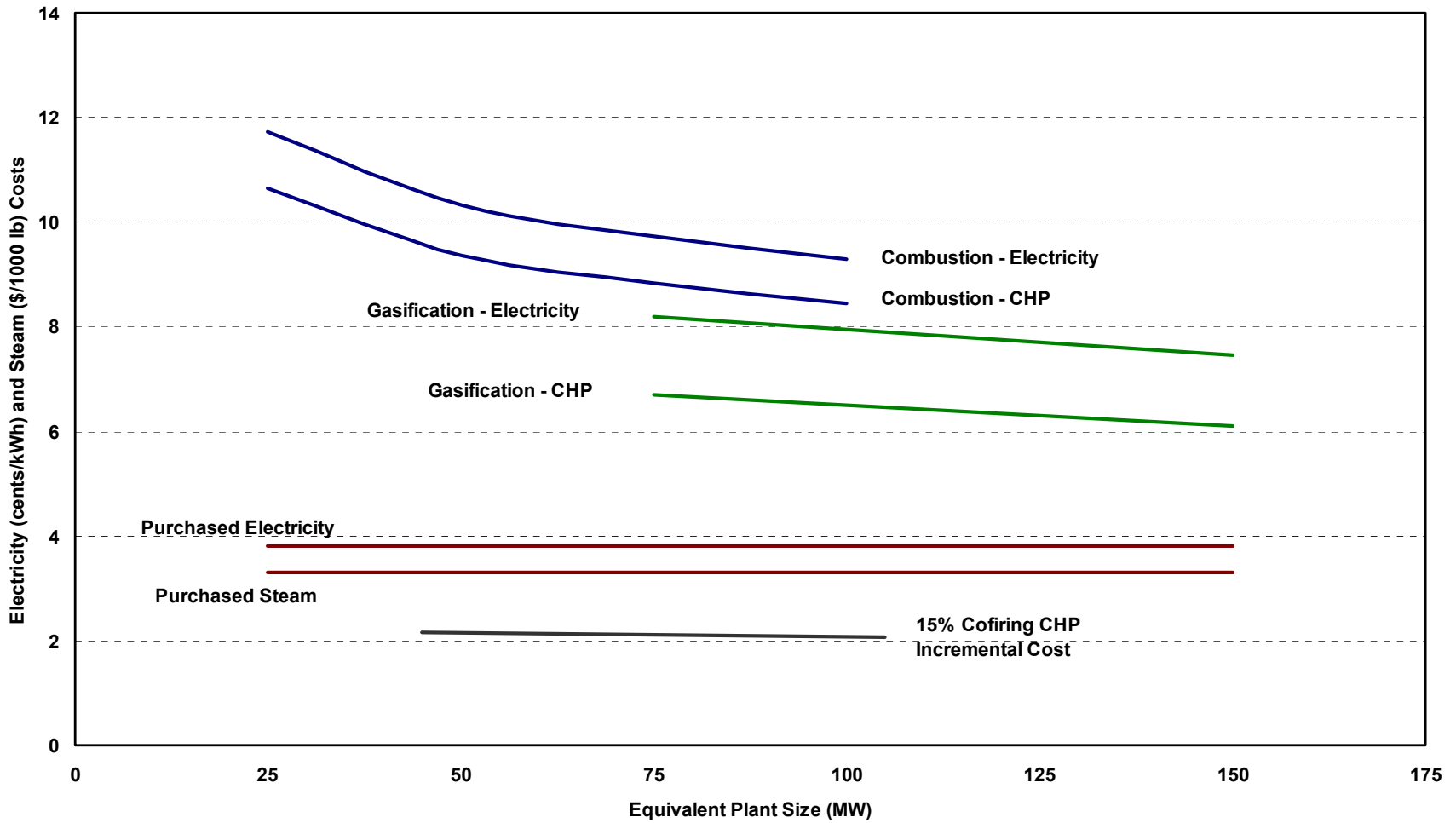
Figure 5.12: Biomass CHP - Sensitivity to Capital Cost

Feed Cost = $2/MBtu
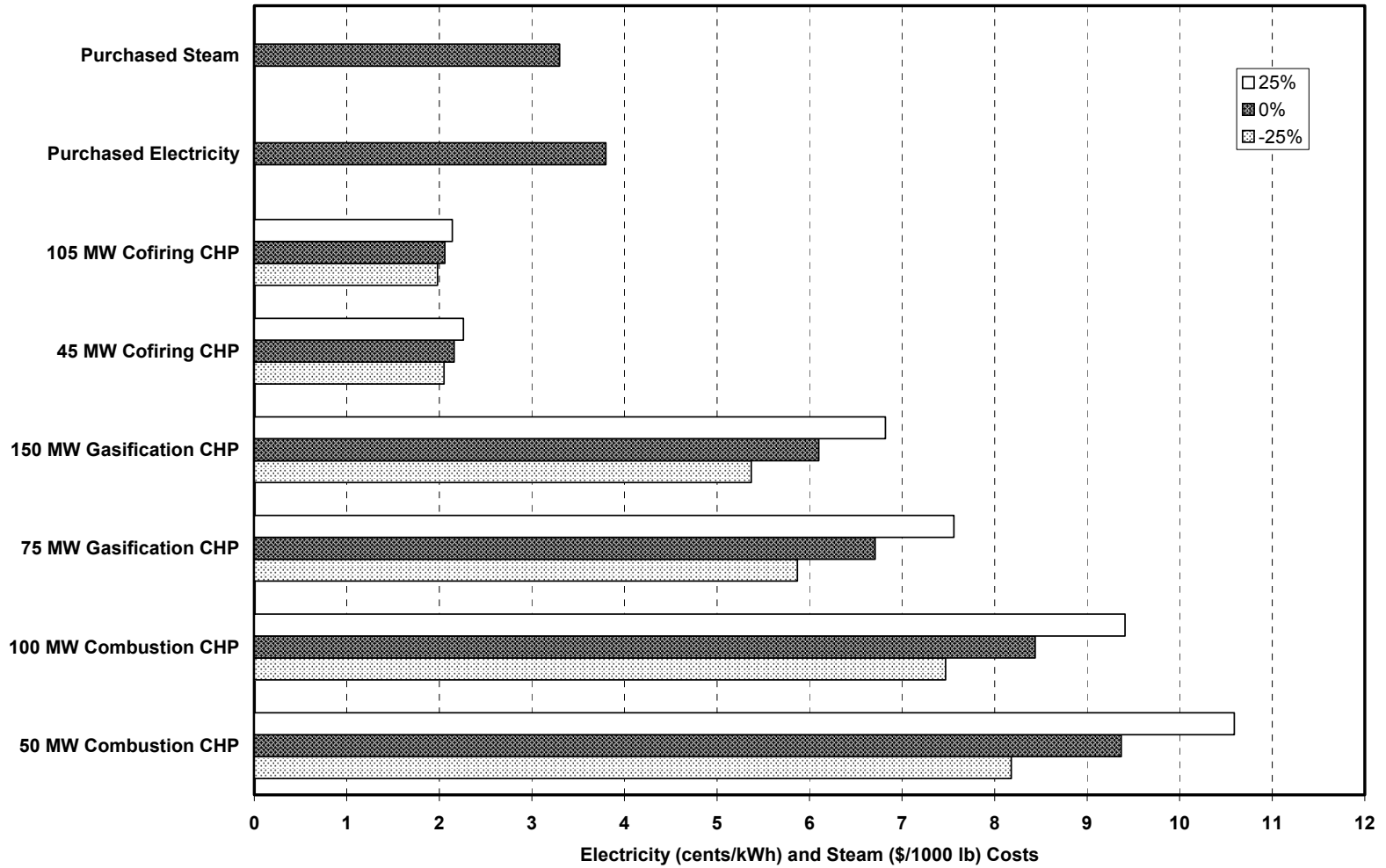
Figure 5.13: Biomass CHP - Sensitivity to Discount Rate

Feed Cost = $2/MBtu

50 MW eq

75 MW eq

Gasification

Direct Combustion

100 MW eq

150 MW eq

Purchased Electricity

Purchased Steam

45 MW eq

15% Cofiring
Incremental Cost

100 MW eq

Electricity (cents/kWh) and Steam ($/1000 lb) Costs (y-axis)

Discount Rate (Percent) (x-axis)
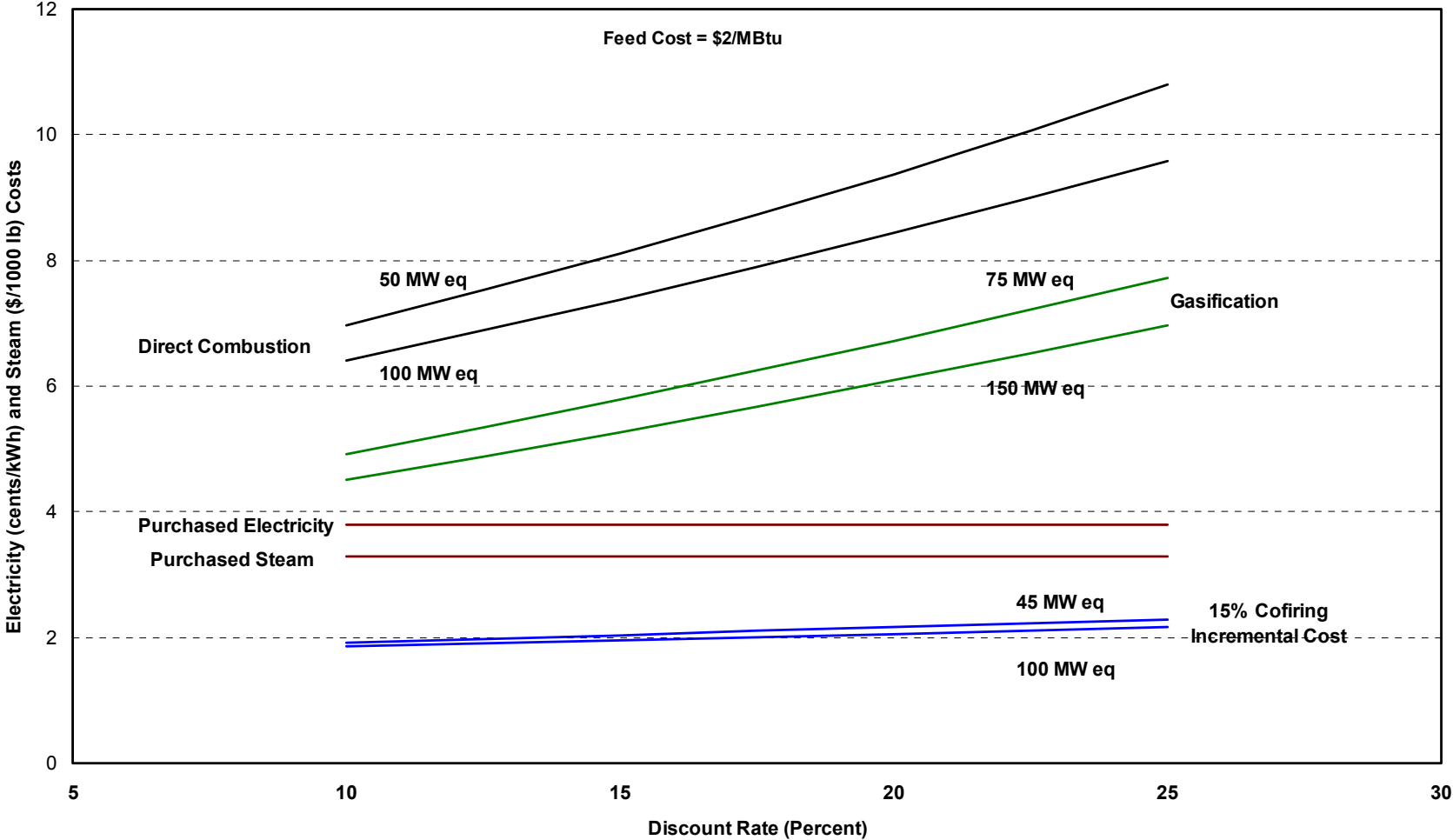
Figure 5.14: Biomass CHP - Debt Sensitivity

Feed Cost = $2/MBtu
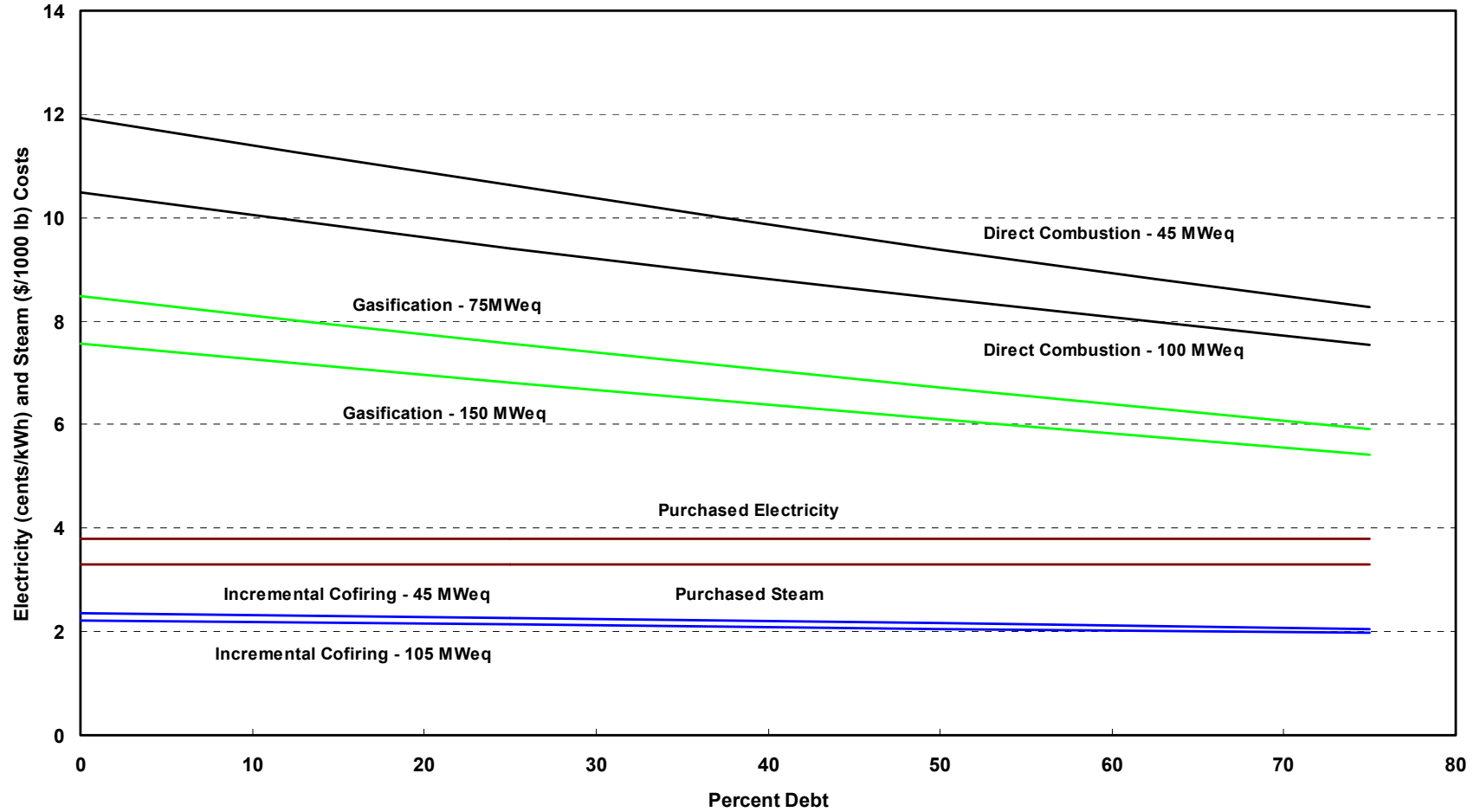
Figure 5.15: Biomass CHP - Impact of Carbon Allowances

5-44
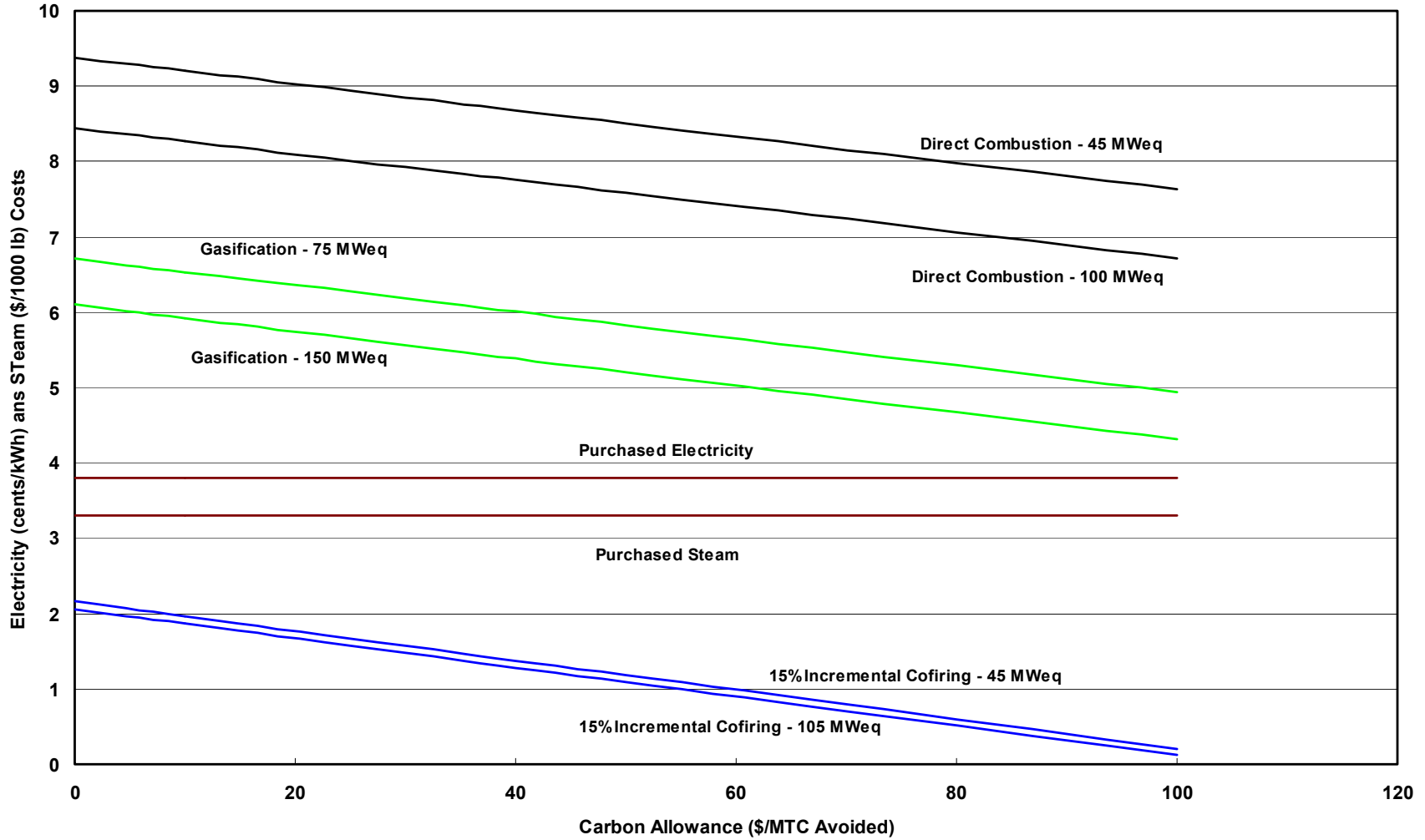
Figure 5.16: Biomass Combustion and Gasification CHP Impact of Tax Credit

Feed Cost = $2/MBtu
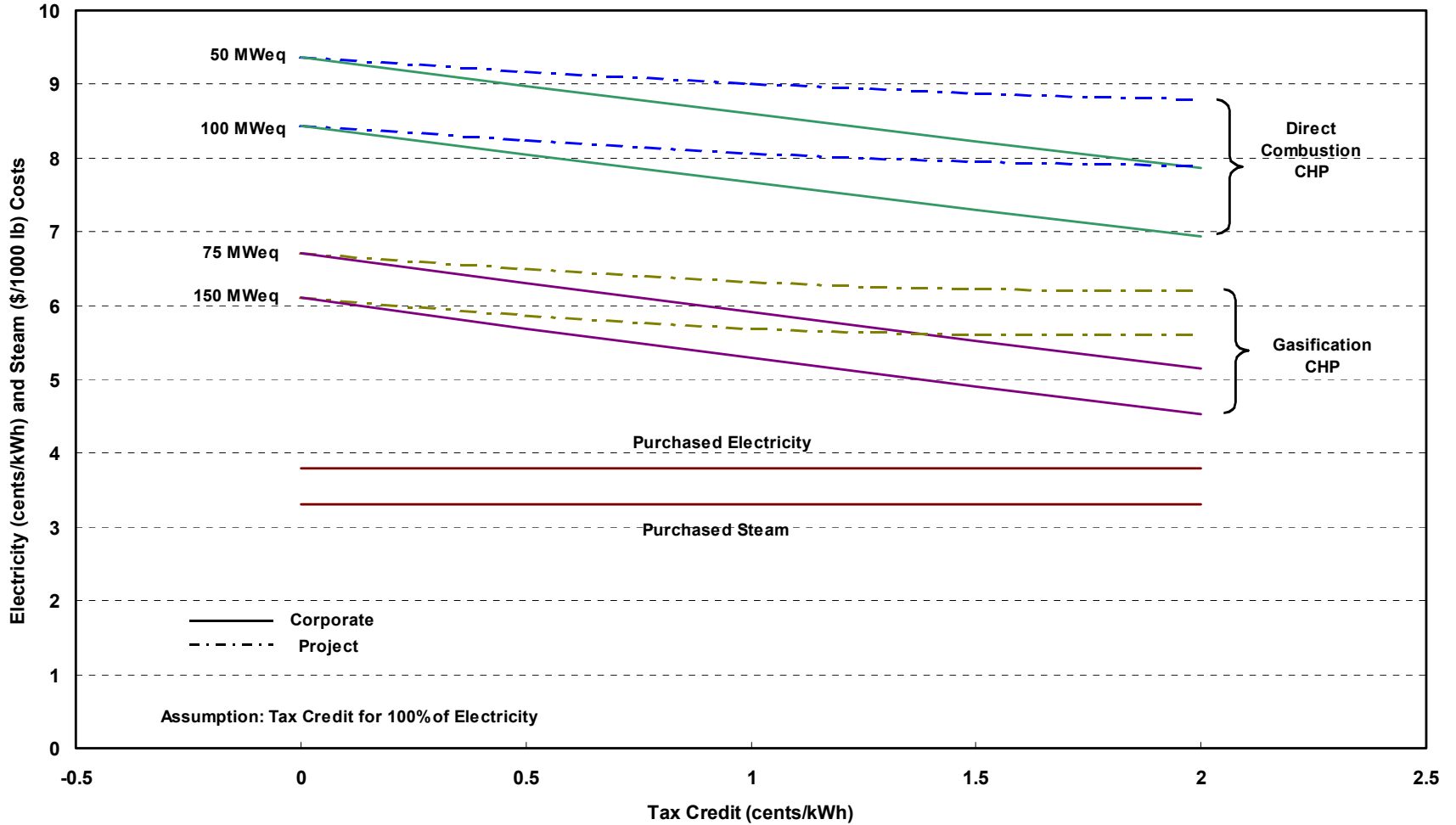
Figure 5.17: Biomass Cofiring CHP Incremental Costs, Impact of Tax Credit
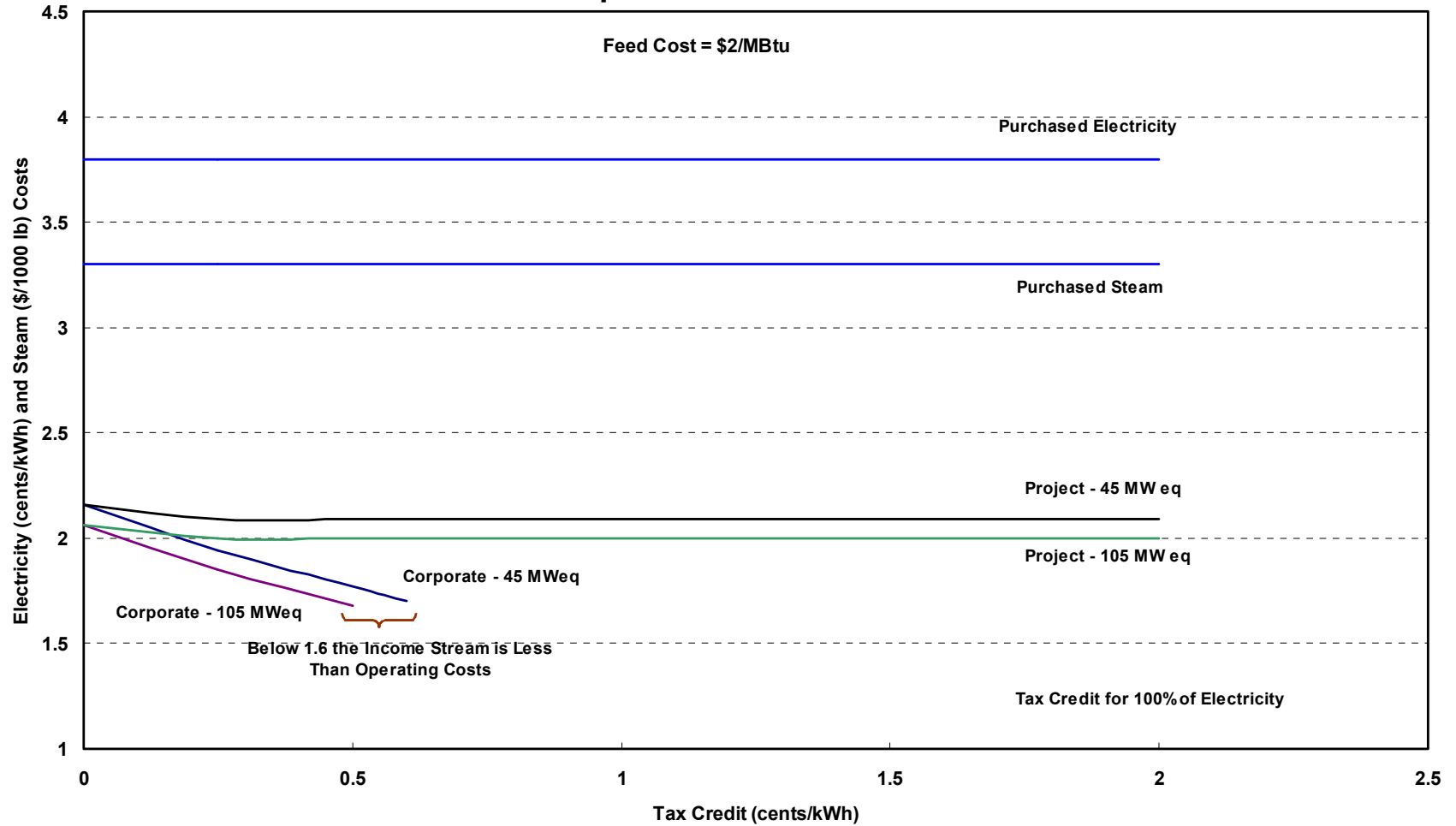
Figure 5.18: Biomass Cofiring CHP - Effect of Tax Credit on Return on Investment, Corporate Basis

Feed Cost = $2/MBtu

105 MWeq

45 MWeq

Assumption: Tax Credit for 100% of Electricity
Incremental Cost of Electricity = 2 cents/kWh
Incremental Cost of Steam = $2/1000 lb

Return on Investment (%)

Tax Credit (cents/kWh)
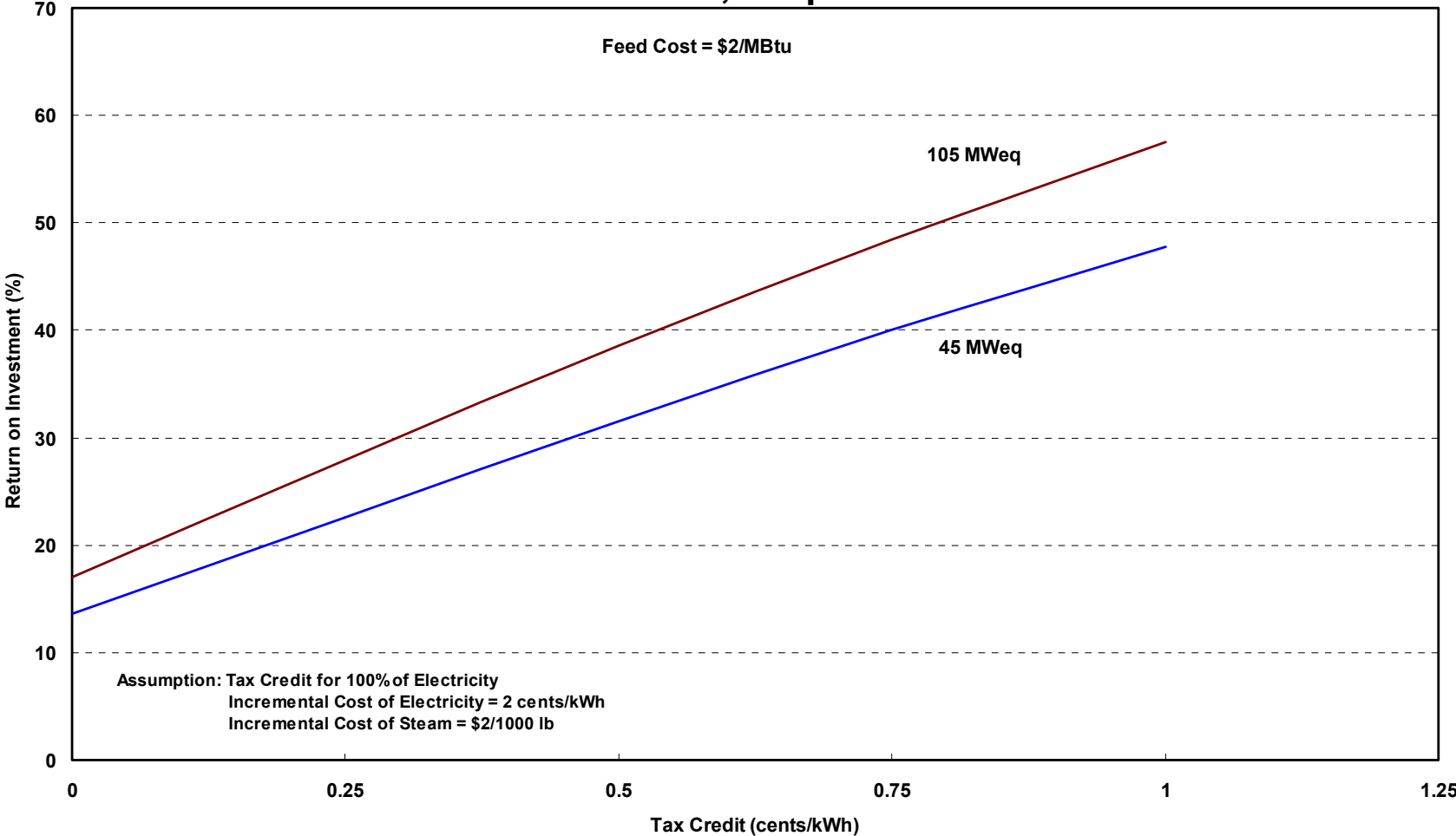
Figure 5.19: Comparison of CHP and Steam-Only Costs
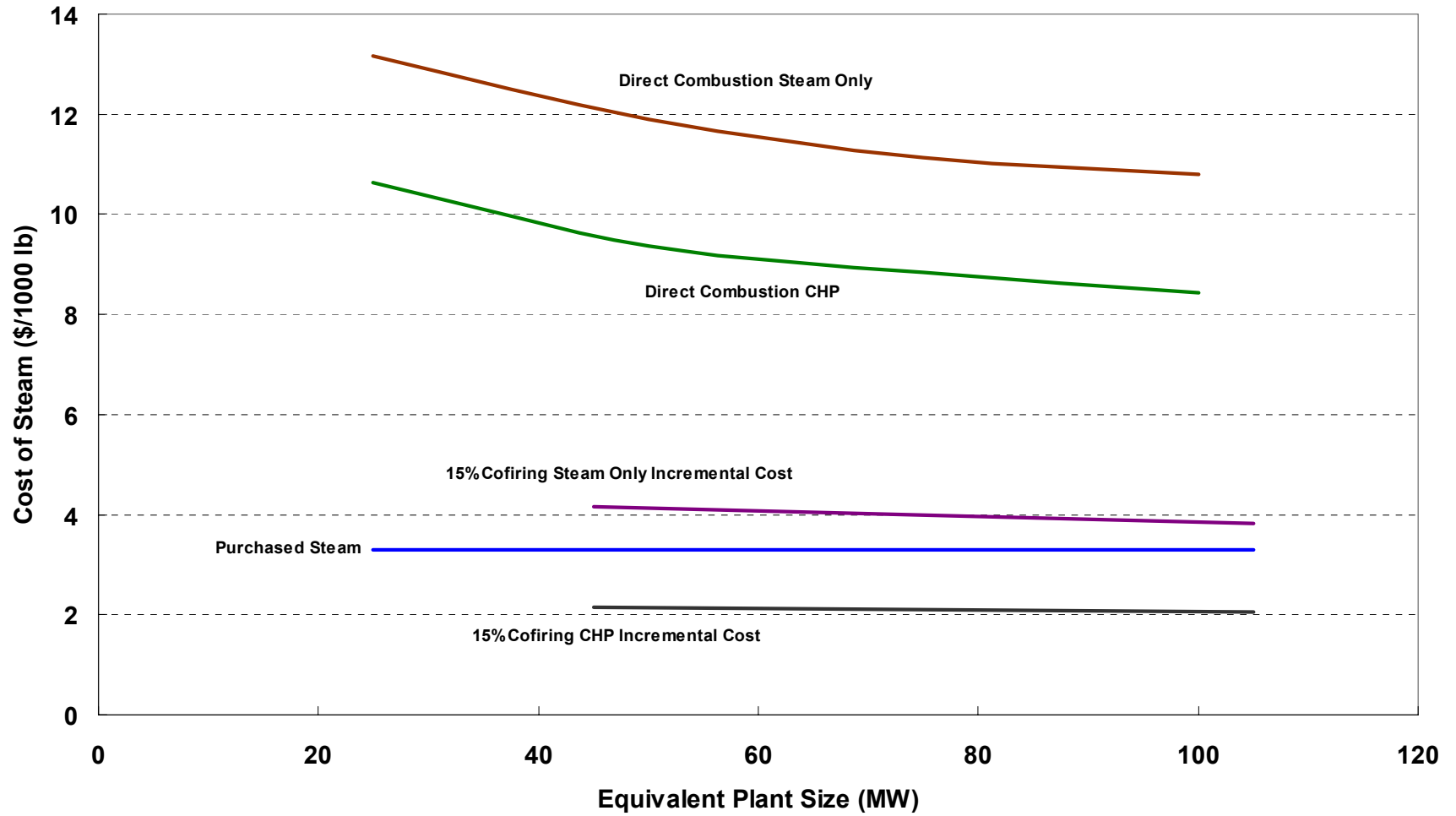
Figure 5.20: Gasification CHP - Site Impact with Incentives

Basis: 15% Discount Rate
25 $/ton carbon allowance
$0.015/kWh tax credit
Corporate

Legend:
- 75MWeq
- 150MWeq
- U.S.-Purchase
- NE U.S. - Purchase

Y-axis: Cost of Electricity (cents/kWh) and Steam ($/1000 lb)

X-axis: Electricity, Steam
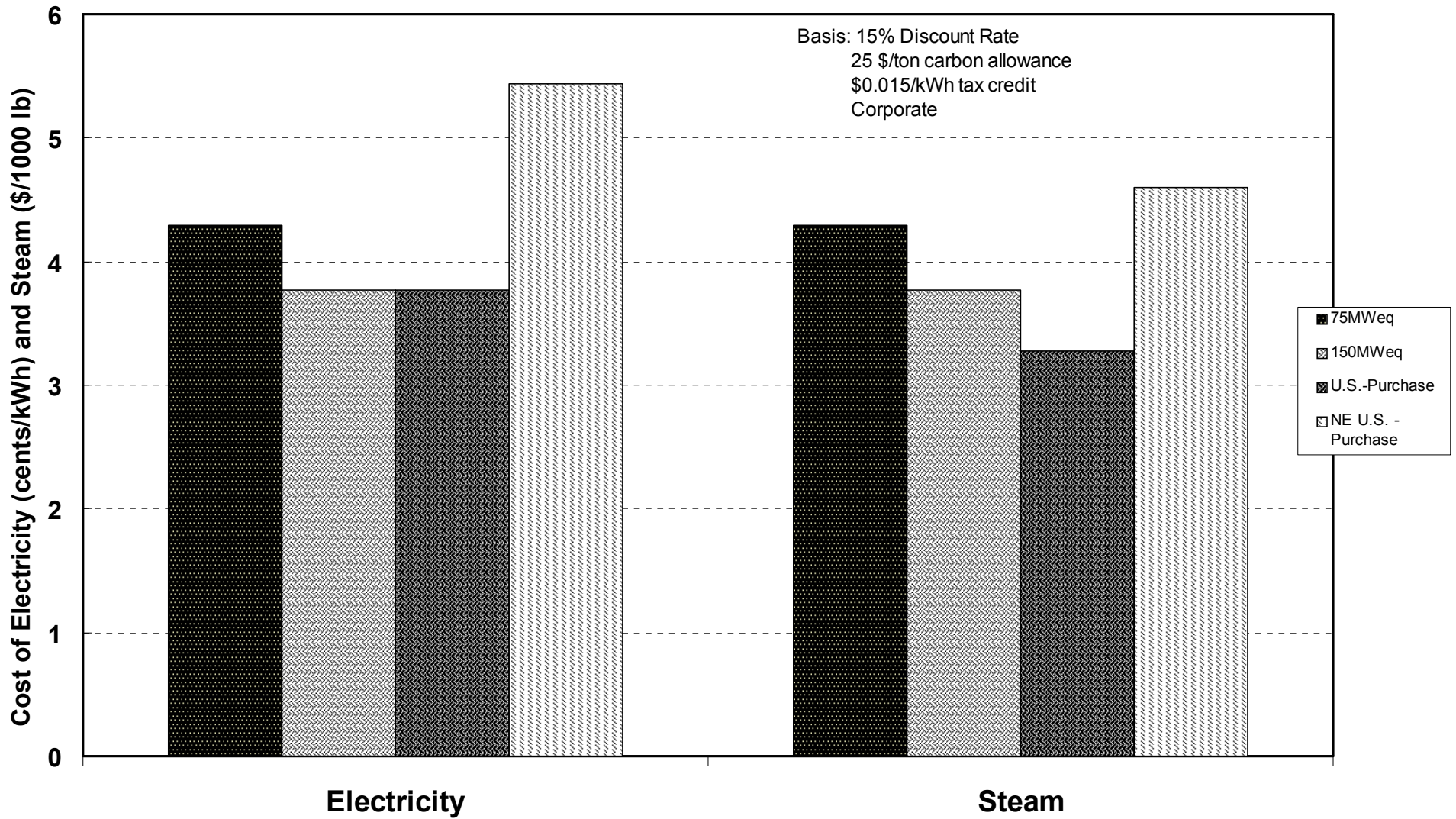
Table 5.15: Cost and Required Cash Flow Summary

CHP Case	Capital Cost		Operating Cost[a]		Cumulative Required Cash Flow
	Million $	$/kW	Million $/yr	¢/kWh	Million $
Cofiring - 105 MW	16.4	156	(2.02)[b]	(0.23)[b]	72
Direct Combustion - 75 MW	131.0	1,747	10.22	1.73	479
Direct Combustion - 100 MW	160.5	1,605	13.49	1.71	593
IGCC - 75 MW	149.3	2,070	6.71	1.14	433
IGCC - 150 MW	196.7	1,312	11.75	0.99	767

(a) incremental cost
(b)exclusive of feed

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6.   ENVIRONMENTAL PERFORMANCE

Two primary issues that could create a tremendous opportunity for biomass are global warming and the implementation of Phase II of Title IV of the Clean Air Act Amendments of 1990 (CAAA). Biomass offers the benefit of reducing NO_x, SO_2, and CO_2 emissions. The environmental benefits of biomass technologies are among its greatest assets. Global warming is gaining greater salience in the scientific community. There now appears to be a consensus among the world's leading environmental scientists and informed individuals in the energy and environmental communities that there is a discernable human influence on the climate, and that there is a link between the concentration of carbon dioxide (i.e., greenhouse gases) and the increase in global temperatures. Biomass use can play an essential role in reducing greenhouse gases, thus reducing the impact on the atmosphere. Cofiring biomass and fossil fuels and using integrated biomass gasification combined cycle systems can be an effective strategy for electric utilities to reduce their emissions of greenhouse gases.

The use of biomass crops also has the potential to mitigate water pollution. Since many dedicated crops under consideration are perennial, soil disturbance, and thus erosion can be substantially reduced. The need for agricultural chemicals is often lower for dedicated energy crops as well leading to lower stream and river pollution by agrichemical run-off.

Air Pollution

Biomass power has long been a source of heat and power in the United States and throughout the world. and is unique among renewables because it is a combustion technology that releases air pollutants. This environmental overview reviews air emissions from traditional biomass (wood and agriculture residues) and landfill methane biomass projects, and compares those emissions with conventional fossil-fuel generating plants. Greenhouse gas emissions will be discussed in the life cycle analysis section.

Major emissions of concern from traditional biomass power plants are particulate matter (PM), carbon monoxide (CO), volatile organic compounds (VOC), and nitrogen oxides (NO_x). Biomass releases very little sulfur dioxide because of the low amount of sulfur typically found in biomass. Actual amounts and the type of air emissions depend on several factors, including the type of biomass combusted, the furnace design, and operating conditions.

For larger biomass projects, two types of boilers are commonly used. One boiler type is the spreader stoker. Biomass enters the furnace through a fuel chute and is distributed either pneumatically or mechanically across the furnace, where the biomass burns in suspension. At the same time, larger pieces of biomass are spread on a stationary or moving grate and combusted. A second boiler type used is the fluidized bed combustion (FBC) boiler. The fluidized bed is comprised of inert particles through which air is blown so that the fluidized bed behaves as a fluid. The biomass is combusted faster and more completely because of the immediate contact with the hot bed material, and uncontrolled air emissions are correspondingly lower.

Table 6.1 compares air emissions from biomass facilities, using different feedstocks and boilers, with representative coal and natural gas systems. The table illustrates that biomass FBC boilers, as presently permitted, have lower emissions than biomass systems with stoker boilers. Biomass systems using stoker

boilers emit less SO_2 than coal and natural gas units (except for natural gas combined cycle units, which are characterized by extremely low SO_2 emissions), and less NO_x than stoker boilers combusting coal and reciprocating engines burning natural gas. Biomass systems with FBC boilers are even cleaner, with lower SO_2 and NO_x emissions than coal and natural gas combustion turbines and lower PM-10 emissions than coal systems. When comparing emissions, it is very important to understand that all the power systems reported–both fossil and biomass–meet the air emission standards governing permitting and operation that were in effect when the facilities were constructed, and represent not only differences in fuel, but also differences in emission control systems. Future systems will meet the emissions standards in place at the time of permitting, and choices of system and fuel will largely be governed by costs associated with meeting those standards.

Table 6.1 Direct Air Emissions from Wood Residue Facilities by Boiler Type

	SO_X	NO_X	CO	PM-10[1]	Comments
Biomass Technology					
Stoker Boiler, Wood Residues (1,4)	0.08	2.1 (biomass type not specified)	12.2 (biomass type not specified)	0.50 (total particulates) (biomass type not specified)	Based on 23 California grate boilers, except for SO_2 (uncontrolled)
Fluidized Bed, Biomass (4)	0.08 (biomass type not specified)	0.9 (biomass type not specified)	0.17 (biomass type not specified)	0.3 (total particulates) (biomass type not specified)	11 FBC boilers in California
Energy Crops (Poplar) Gasification (a,b)	0.05 (**suggested** value based on SOx numbers for Stoker and FBC, adjusted by a factor of 9,180/13,800 to account for heat rate improvement)	1.10 to 2.2 (0.66 to 1.32 w/SNCR; 0.22 to 0.44 with SCR)	0.23	0.01 (total particulates)	Combustor flue gas goes through cyclone and baghouse. Syngas goes through scrubber and baghouse before gas turbine. No controls on gas turbine.
Coal Technology					
Bituminous Coal, Stoker Boiler (f)	20.2 1 wt% S coal	5.8	2.7	0.62	PM Control only (baghouse)
Pulverized Coal Boiler (d)	14.3	6.89	0.35	0.32 (total particulates)	Average US PC boiler (typically:baghouse, limestone FGC)
Cofiring 15% Biomass (d2)	12.2	6.17	0.35	0.32 (total particulates)	?
Fluidized Bed, Coal (f)	3.7 (1 wt% S coal Ca/S = 2.5)	2.7	9.6	0.30	Baghouse for PM Control, Ca sorbents used for SO_x
Natural Gas Technology					
4-Stroke NG Reciprocating Engine (g)	0.006	7.96-38.3 (depends on load and air:fuel ratio)	2.98-35.0 (depends on load and air:fuel ratio)	0.09-0.18 (depends on load and air:fuel ratio)	No control except PCC at high-end of PM-10 range
Natural Gas Turbine (e)	0.009 (0.0007 wt% S)	1.72	0.4	.09 (total particulates)	Water-steam injection only
Natural Gas Combined Cycle (c,e)	0.004	0.91 (0.21 w/ SCR)	0.06	0.14 (total particulates)	Water-steam injection only

Sources:

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b. Spath and Mann (1997), "Life Cycle Assessment of a Biomass Gasification Combined-Cycle System." NREL.

c. Spath and Mann (2000), "Life Cycle Assessment of a Natural Gas Combined-Cycle Power Generation System." NREL.

d. Spath, Mann, and Kerr (1999), "Life Cycle Assessment of Coal-Fired Power Production." NREL.

d2. Mann???!5% wood residue on a heat basis (on Exh3 cofire sheet)

e. AP-42 Chapter 3.1

f. AP-42 Chapter 1.1

g. AP-42 Chapter 3.2

1 & 4 from References

Notes: [1]PM10 emission factors are not always available. Total particulates are specified in some cases (includes PM larger than 10 microns). Condensible PM is included in the direct emissions factors for Bituminous Coal Stoker Boiler, Fluidized Bed Coal Boiler, NG Reciprocating Engine, and the NG Turbine. In general, all particulates from

Additional emissions data for wood combustion systems from the Environmental Protection Agency, 5th Edition of AP-42, Compilation of Air Pollution Emission Factors are given in Appendix 4.

Table 6.2 presents averaged permitted and actual emission levels from 34 operating wood-fired generating plants in California. Of these, 23 are spreader stoker facilities and 11 are FBCs . These facilities were built prior to the new emissions standards. New facilities are subject to the new and much stricter Clean Air Act emissions standards. Air emission standards for the most recently constructed stand-alone biomass plant in the New England region, Pine Tree Power in Westminster, Massachusetts, are included for comparison. This facility was permitted to burn clean construction/demolition wood and has the most restrictive permit conditions of any wood-fired power plant in New England. The facility can meet these requirements using a high-efficiency fluidized bed boiler (low CO and VOC emissions), an SNCR system for NOx reduction, and a mechanical collector and baghouse for particulate control. No SO_2 controls are required.

Table 6.2 Air Pollutant Emissions Limits for Biomass Power Plants (lb/MWh)

	Boiler Type	SO_2		NOx		CO		PM	
		Permitted	Measured	Permitted	Measured	Permitted	Measured	Permitted	Measured
Existing California Biomass Facilities[1]	**All**	1.0	0.08	2.2	1.7	9.6	8.6	0.7	0.4
	Stokers	0.8	0.08	2.6	2.1	13.6	12.2	0.8	0.5
	FBCs	1.4	0.08	1.3	0.8	1.7	0.2	0.5	0.3
New Massachussetts Biomass Facility[2]	**FBC**	0.78 (BACT)	N/A	0.74 (LAER)	N/A	0.88 (BACT)	N/A	0.20 (BACT)	N/A

[1][4air] Data averaged for 34 California biomass facilities (23 stokers and 11 FBCs). Based on a heating value for biomass of 8,293 BTU/lb, and an average heat rate of 13,800 BTU/kWh.

[2][2air]Permitted emissions levels for new Pine Tree Biomass Power Plant in Westminster, MA. BACT=Best Available Control Technology; LAER=Lowest Achievable Emissions Rate

A number of states–including Texas, California, and Connecticut–have enacted or are considering type certification standards for distributed generation units less than 50 MW_e to ensure that emissions from small electric generating units to do not exceed BACT standards for central generating stations, and to simplify and reduce the time and cost of permitting such units. The majority of existing biopower plants would be covered by such standards if permitted today.

The Texas air quality standard became effective in 2001 for distributed generation units less than 50 MW_e installed or permitted after June 1, 2001, to provide a streamlined permitting method to encourage the use of clean electric generating units. The standard provides a certification method for emissions based on test results from EPA reference methods, California Air Resources Board methods, or equivalent testing to verify certification, and requires re-certification of the unit after 16,000 hours, or three years, of operation. The standard only requires certification of NO_x under the decision that CO and VOC emissions will be controlled if the NO_x limits are reached. To control SO_x, only gases containing less than 10 grains total sulfur per 100 standard cubic feet are allowed. Systems are required to display the certification on the unit, much like an automobile emissions sticker. Certification permit costs are $450 for units larger than 1 MW_e, and $100 for units smaller than 1 MW_e. Units that use combined heat and power may take credit for heat at a rate of 1 MWh for each 3.4 million Btu if the heat recovered is greater than 20% of the total CHP output. Emissions have been established for ozone attainment (West Texas) and non-

attainment (East Texas) areas, for units larger and smaller than 10 MW$_e$, for units that operate less than 300 hours per year, and for certain gases that would otherwise be vented to the atmosphere. A summary of emission limits are given in Table 6.3.

Table 6.3: Texas Distributed Generation Certification Standards

Size	Area	> 300 hours per year	< 300 hours per year	Landfill gas, digester gas
> 10 MW	All	0.14 lb NO$_x$/MWh	0.38 lb NO$_x$/MWh	1.77 lb NO$_x$/MWh (a)
< 10 MW	East Texas	0.44 lb NO$_x$/MWh (b) 0.14 lb NO$_x$/MWh (c)		
< 10 MW	West Texas	1.6 lb NO$_x$/MWh	21 lb NO$_x$/MWh	

(a) must contain less than 1.5 grains of H$_2$S or 30 grains of total sulfur
(b) prior to December 31, 2004
(c) after January 1, 2005

California has issued a draft standard, to become effective January 1, 2003, for any distributed generation system sold, leased, or offered for sale or lease, for use or operation in the State of California. CHP units may take credit for heat recovery if the unit achieves a minimum efficiency of 60 percent (useful energy out/fuel in). Unit emissions must be certified by California Air Resources Board reference methods; and the certification fee is $500 (60 day processing period). Units must meet the emission standards for 15,000 hours of operation when operated and maintained according to the manufacturer's instructions; and must be re-certified every 4 years. A summary of the proposed standard is given in Table 6.4.

Table 6.4: Proposed California Distributed Generation Certification Standards.

Pollutant	Emission Standard (lb/MWh)		
	Power Only Jan 2003 - Dec 2006	CHP Jan 2003 - Dec 2006	All Units After Jan 1, 2007
NO$_x$	0.5	0.7	0.05
CO	6.0	6.0	0.08
VOCs	1.0	1.0	0.02

To evaluate the potential of biopower systems, a simple analysis has been performed to compare existing and potential biopower system performance relative to the proposed standards. NO$_x$ emissions for existing systems are given in Figure 6.1[1] on both a life cycle and point-source plant emission basis. A national average coal station has NO$_x$ emissions of about 6.75 lb NO$_x$/MWh, a NSPS coal plant emits

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[1]Mann, M.K.; Spath, P.L. (2001). Comparison of Environmental Consequences of Power from Biomass, Coal and Natural Gas. Kyritsis, S., et al., eds. 1st World Conference on Biomass for Energy and Industry: Proceedings of the Conference held 5-9 June 2000, Sevilla, Spain. London, UK: James & James Ltd.; Vol. I: pp. 65-68; NREL NICH Report No. 31172.
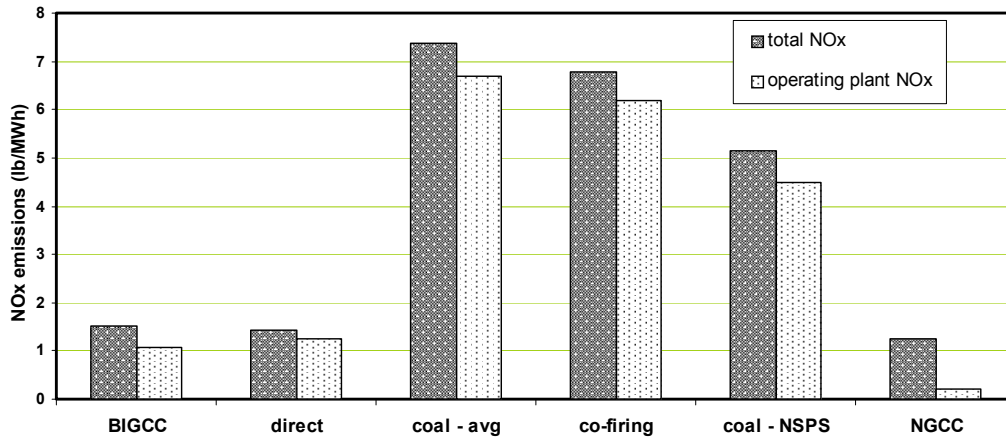
Figure 6.1: NO$_x$ Emissions-Life Cycle Total and Plant Operating Emissions

about 4.5 lb NO$_x$/MWh, a natural gas combined cycle plant emits about 0. 2 lb NO$_x$/MWh, and a biopower direct combustion system emits about 1.2 lb NO$_x$/MWh.

Figure 6.2 gives a comparison of four existing biopower direct combustion plant emissions relative to the proposed standards for East and West Texas. CHP emissions have also been estimated, assuming that the existing systems could be modified to give a 60% CHP efficiency. Two out of the four operating biopower plants meet the West Texas standard. All CHP systems meet the West Texas standard, but additional NO$_x$ control would be required for the systems to meet the East Texas standard.
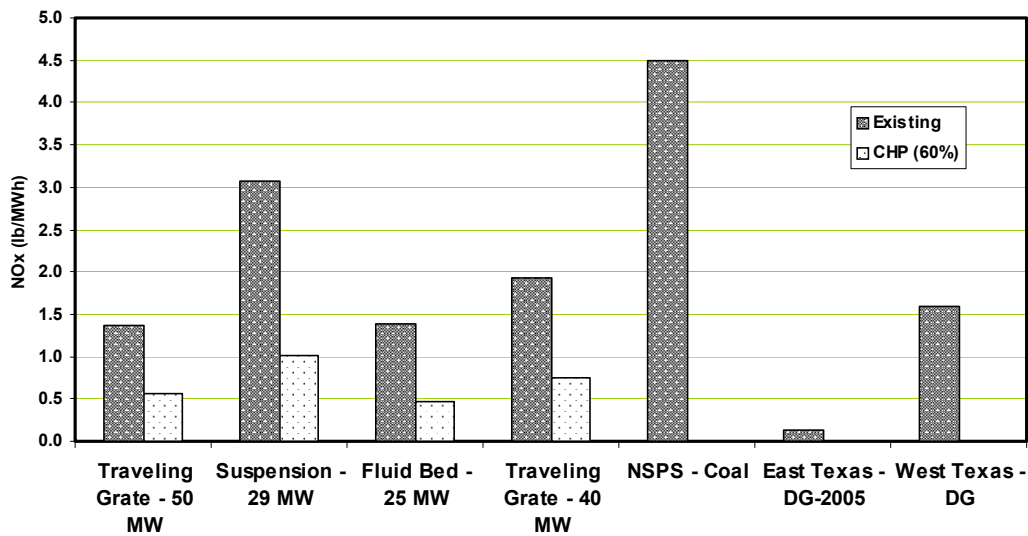
Figure 6.2: Biomass Combustion -Comparison of NO$_x$ Emissions to 2001 Texas DG Standard

The potential for a CHP system to meet standards is shown in Figure 6.3. A existing system with flue gas recycle (FGR) has emissions of about 1.4 lb NO_x/MWh. Since FGR and selective catalytic reduction (SCR) are additive, SCR is also used, assuming an additional 80% reduction. This lowers the NO_x to about 0.25 lb NO_x/MWh. CHP is then assumed (60% total efficiency), bringing the level down to 0.12 lb NO_x/MWh. The existing system meets the West Texas standard, and the CHP system with both FGR and SCR meets the East Texas standard. The system with FGR and SCR meets the 2003 California standard, but additional optimization would be required for the CHP system to meet the 2007 California standard.

Figure 6.3: Biomass Combustion - Potential for NO_x Reduction
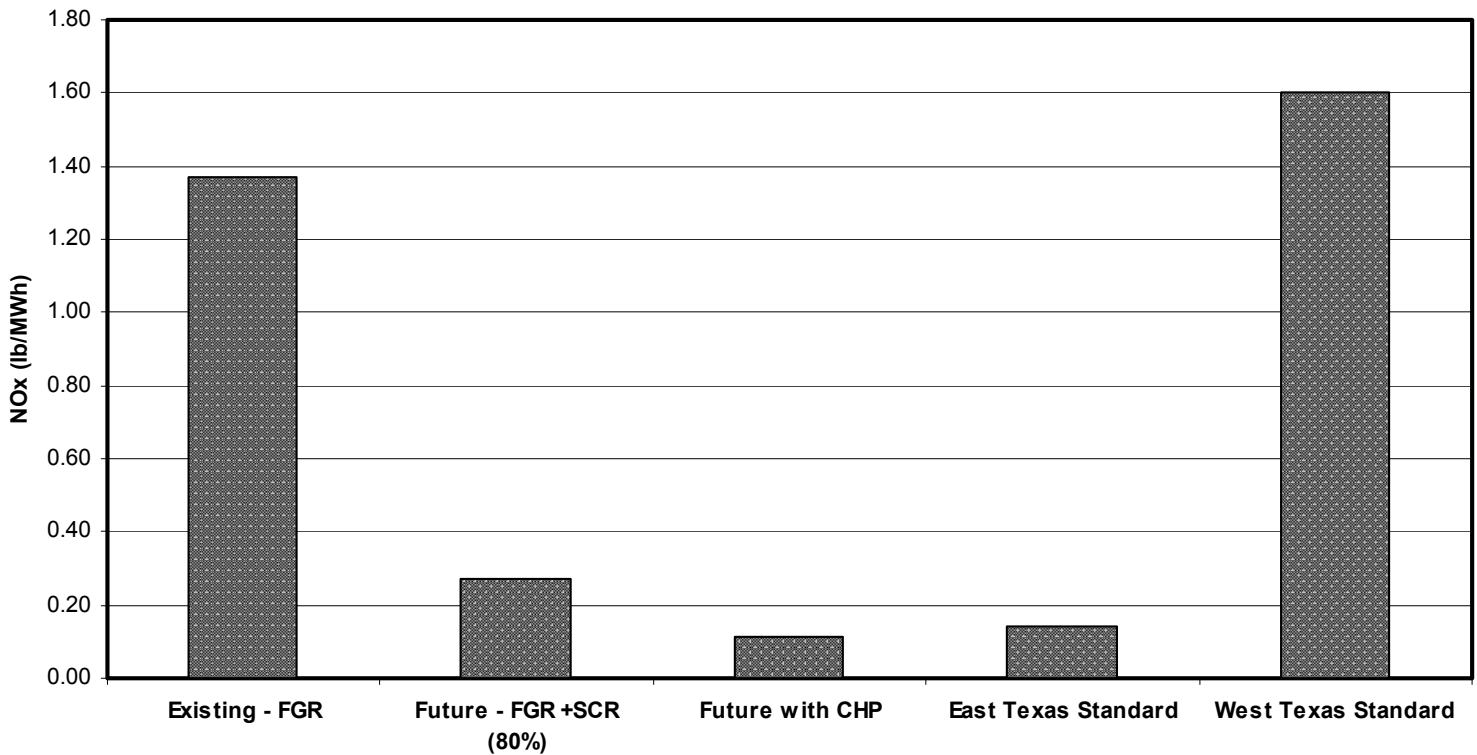
There are about 2,500 active landfills in the United States that receive over 200 million tons of municipal solid waste every year, with 55 to 60 percent from household waste, and 35 to 45 percent as commercial waste. Landfill gas is produced during the bacterial decomposition of this waste. The amount of landfill gas that is generated depends on the composition of waste in the landfill, the age of the landfill, the moisture content in the waste, pH levels, oxygen availability, and the temperature in the landfill.

Air emissions from landfills consist of roughly 50 percent methane, 48 percent carbon dioxide, small amounts of hydrogen, oxygen and nitrogen, and trace amounts of more than 100 non-methane organic compounds (NMOCs) like ethane, toluene, and benzene. The NMOC emissions include VOCs, hazardous air pollutants (HAPs), and odorous compounds. The VOCs present in NMOC emissions from landfills contribute to the formation of ozone that can reduce or damage growth in vegetables as well as exacerbate respiratory problems in humans. The health effects of HAPs include cancerous and non-cancerous illnesses like respiratory irritation and damage of the central nervous system. In 1996, the EPA issued New Source Performance Standards (NSPS) under the Clean Air Act for landfills with a capacity

of greater than 2.75 million tons that emit more than 50 Mg/year of NMOC emissions. These landfills have to install gas collection and combustion systems capable of controlling 98 percent or more of the NMOC emissions. The landfill gas can either be flared or converted to direct energy use or electrical energy.

Nationwide, there are over 325 landfill gas projects, with about two-thirds generating electricity for sale. The other one-third is for direct use, particularly for heating. Air emissions from landfill gas electric generating projects include CO, NO_x, SO_2, hydrogen chloride (HCI), PM, and other combustion products. Representative emissions are given in Table 6.5. PM emissions may also result from fugitive dust created by garbage trucks traveling along paved and unpaved roads. Gas collection systems are typically 60 to 85 percent efficient, so emissions of methane and NMOCs still occur. SO_2 emissions are site-specific and depend on the sulfur content of the waste in the landfill, and so are not included in the table.

Table 6.5: Air Emission Rates from Landfill Gas Combustion and Electric Generation (lb/MWh)

	NO_x	CO	PM-10
Flare (Btu Equivalent)	0.38	7.13	0.16
Internal Combustion Engine	2.37-4.73	4.45-8.9	0.45-0.91
Gas Turbine	0.98-1.93	2.55-5.10	0.24-0.49
Gas Boiler with low-NOx burners	0.33-0.66	0.06-0.11	0.08-0.16

Landfill gas systems with internal combustion (IC) engines generally have lower emissions than coal with stoker boilers, but higher emissions than most natural gas systems (except with reciprocating engines) and coal with FBC boilers. Landfill systems with gas turbines tend to have lower NO_x and CO emissions than coal systems with stoker boilers and natural gas combustion turbines, but higher NO_x and CO emissions than natural gas combined cycle systems. Landfill gas systems using gas turbines with low-NO_x burners have lower NO_x emissions than most of the generating technologies except natural gas combined cycle plants. All three landfill gas systems have relatively low levels of PM-10 emissions that are comparable to natural gas systems and lower than most coal systems.

Air emissions for landfill gas tend to be higher from facilities using IC engines, which are used at about 75 percent of the landfill gas electric facilities in the country. Because of tighter air emission standards, future landfill gas systems may need to use low-NO_x engines or gas turbines and may need CO and NO_x removal systems as well. Air emissions from landfill gas can be reduced through selective catalytic reduction to reduce NO_x emissions by injecting ammonia into the exhaust stream. Significant fuel pretreatment must be done at landfill gas generators to remove trace contaminants that can ruin the catalyst.

Some concern has been raised about possible dioxin production from landfill gas facilities. However, the EPA believes the potential is small for dioxin emissions from the combustion of landfill gas. Previous EPA analysis found that dioxin emissions from the combustion of landfill gas are comparable to dioxin emissions from oil or coal combustion, and significantly less than dioxin emissions from municipal waste combustion.

LIFE CYCLE ANALYSES[2]

The generation of electricity, and the consumption of energy in general, result in consequences to the environment. Using renewable resources and incorporating advanced technologies such as integrated gasification combined cycle (IGCC) may result in less environmental damage, but to what degree, and with what trade-offs? Life cycle assessment studies have been conducted on various power generating options in order to better understand the environmental benefits and drawbacks of each technology. Material and energy balances were used to quantify the emissions, energy use, and resource consumption of each process required for the power plant to operate. These include feedstock procurement (mining coal, extracting natural gas, growing dedicated biomass, collecting residue biomass), transportation, manufacture of equipment and intermediate materials (e.g., fertilizers, limestone), construction of the power plant, decommissioning, and any necessary waste disposal.

The systems chosen are:
*   a biomass-fired integrated gasification combined cycle (IGCC) system using a biomass energy crop (hybrid poplar)
*   a direct-fired biomass power plant using biomass residue (urban, primarily)
*   a pulverized coal boiler with steam cycle, representing the average for coal-fired power plants in the U.S. today
*   a system cofiring biomass residue with coal (15% by heat input will be presented here)
*   a natural gas combined cycle power plant.

Each study was conducted independently and can therefore stand alone, giving a complete picture of each power generation technology. However, the resulting emissions, resource consumption, and energy requirements of each system can ultimately be compared, revealing the environmental benefits and drawbacks of the renewable and fossil based systems.

System Energy Balance
The total energy consumed by each system includes the fuel energy consumed plus the energy contained in raw and intermediate materials that are consumed by the systems. Examples of the first type of energy use are the fuel spent in transportation, and fossil fuels consumed by the fossil-based power plants. The second type of energy is the sum of the energy that would be released during combustion of the material (if it is a fuel) and the total energy that is consumed in delivering the material to its point of use. Examples of this type of energy consumption are the use of natural gas in the manufacture of fertilizers and the use of limestone in flue-gas desulfurization. The combustion energy calculation is applied where non-renewable fuels are used, reflecting the fact that the fuel has a potential energy that is being consumed by the system. The combustion energy of renewable resources, those replenished at a rate equal to or greater than the rate of consumption, is not subtracted from the net energy of the system. This is because, on a life cycle basis, the resource is not being consumed. To determine the net energy balance of each system, the energy used in each process block is subtracted from the energy produced by the power plant. The total system energy consumption by each system is shown in Table 6.6.

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[2]Excerpted from Mann, M.K.; Spath, P.L. (2000). A Comparison of the Environmental Consequences of Power from Biomass, Coal, and Natural Gas. First World Conference and Exhibition on Biomass for Energy and Industry. June 5-9, Seville, Spain.

Table 6.6: Total System Energy Consumption

System	Total energy consumed (kJ/kWh)
Biomass-fired IGCC using hybrid poplar	231
Direct-fired biomass power plant using biomass residue	125
Average coal	12,575
Biomass / coal cofiring (15% by heat input)	10,118
Natural gas IGCC	8,377

To examine the process operations that consume the largest quantities of energy within each system, two energy measurement parameters were defined. First, the energy delivered to the grid divided by the total fossil-derived energy consumed by each system was calculated. This measure, known as the net energy ratio, is useful for assessing how much energy is generated for each unit of fossil fuel consumed. The other measure, the external energy ratio, is defined to be the energy delivered to the grid divided by the total non-feedstock energy to the power plant. That is, the energy contained in the coal and natural gas used at the fossil-based power plants is excluded. The external energy ratio assesses how much energy is generated for each unit of upstream energy consumed. Because the energy in the biomass is considered to be both generated and consumed within the boundaries of the system, the net energy ratio and external energy ratio will be the same for the biomass-only cases (biomass-fired IGCC and direct-fired biomass). In calculating the external energy ratio, we are essentially treating the coal and natural gas fed to the fossil power plants as renewable fuels, so that upstream energy consumption can be compared. Figure 6.4 shows the energy results for each case studied.

As expected, the biomass-only plants consume less energy overall, since the consumption of non-renewable coal and natural gas at the fossil plants results in net energy balances of less than one. The direct-fired biomass residue case delivers the most amount of electricity per unit of energy consumed. This is because the energy used to provide a usable residue biomass to the plant is fairly low. Despite its higher plant efficiency, the biomass IGCC plant has a lower net energy balance than the direct-fired plant because a significant amount of energy was required to grow the biomass as a dedicated crop. Resource limitations, however, may necessitate the use of energy crops in the future. Cofiring biomass with coal slightly increases the energy ratios over those for the coal-only case, even though the plant efficiency was derated by 0.9 percentage points.

In calculating the external energy ratios, the feedstocks to the power plants were excluded, essentially treating all feedstocks as renewable. Because of the perception that biomass fuels are of lower quality than fossil fuels, it was expected that the external energy ratios for the fossil-based systems would be substantially higher than those of the biomass-based systems. The opposite is true, however, due to the large amount of energy that is consumed in upstream operations in the fossil-based systems.
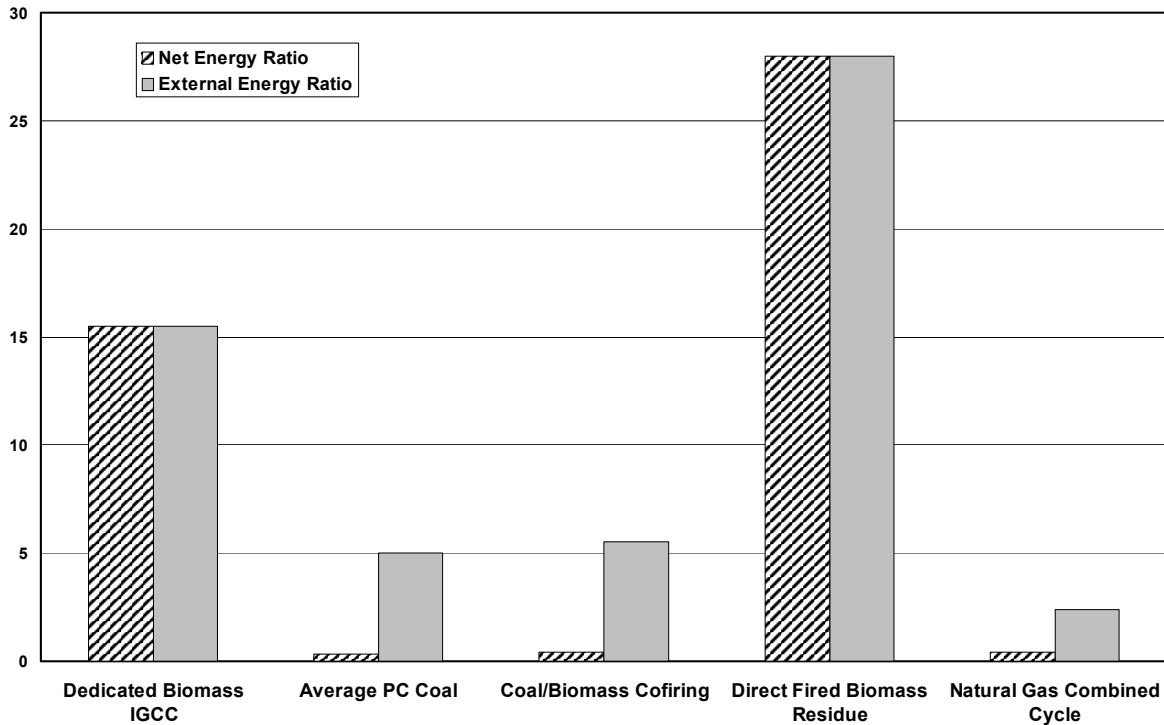
Figure 6.4: Life Cycle Energy Balance

The total non-feedstock energy consumed by the systems is shown in Table 6.7. In the coal case, 35% of this energy is consumed in operations relating to flue-gas cleanup, including limestone procurement. Mining the coal consumes 25% of this energy, while transporting the coal is responsible for 32%. Greater than 97% of the upstream energy consumption related to the natural gas IGCC system is due to natural gas extraction and pipeline transport steps, including fugitive losses. Although upstream processes in the biomass systems also consume energy, shorter transportation distances and the fact that flue-gas desulfurization is not required, reduce the total energy burden.

Table 6.7: Non-feedstock Energy Consumption

System	Non-feedstock energy consumed (kJ/kWh)
Biomass-fired IGCC using hybrid poplar	231
Direct-fired biomass power plant using biomass residue	125
Average coal	702
Biomass / coal cofiring (15% by heat input)	614
Natural gas IGCC	1,718

Global Warming Potential

Figure 6.5 shows the net emissions of greenhouse gases, using the 100-year values from the Intergovernmental Panel on Climate Change. CO_2, CH_4, and N_2O were quantified for these studies. The biomass IGCC system has a much lower GWP than the fossil systems because of the absorption of CO_2 during the biomass growth cycle. The direct-fired biomass system has a highly negative rate of greenhouse gas emissions because of the avoided methane generation associated with biomass decomposition that would have occurred had the residue not been used at the power plant.

Figure 6.5: Net Life Cycle Greenhouse Gas Emissions
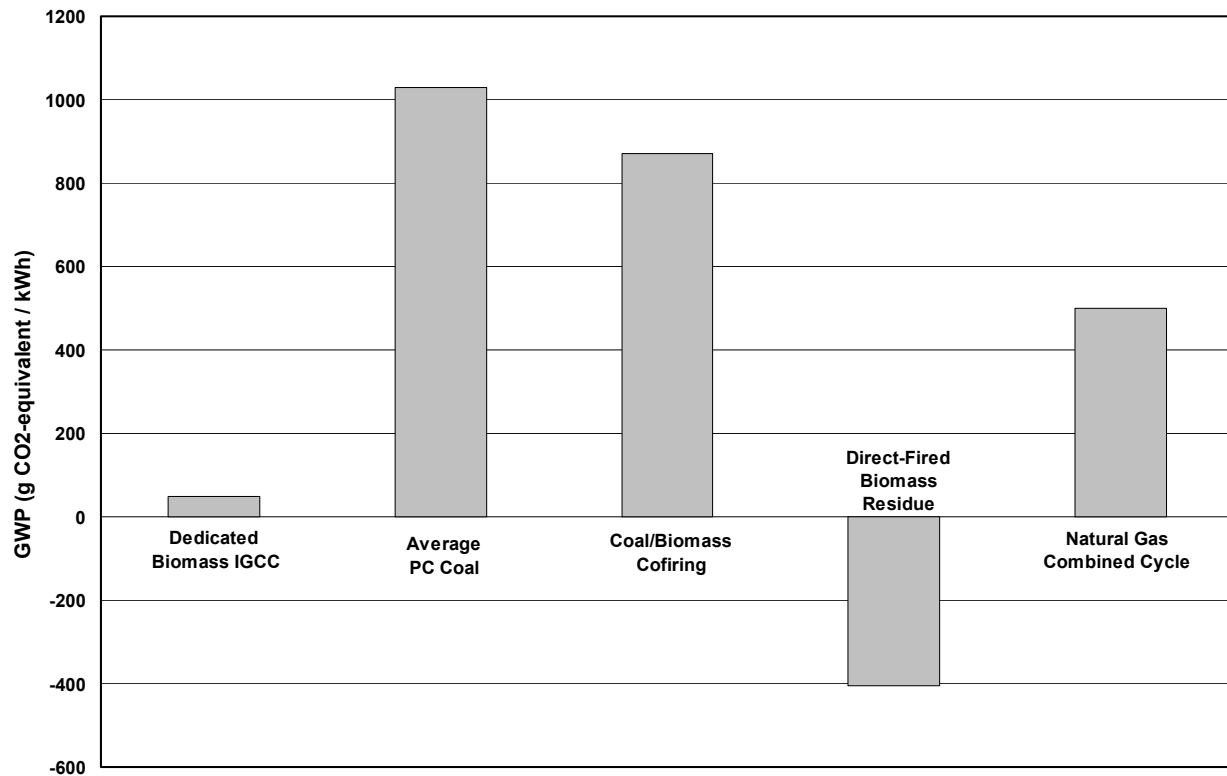
Based on current disposal practices, it was assumed that 46% of the residue biomass used in the direct-fired and cofiring cases would have been sent to a landfill and that the remainder would end up as mulch and other low-value products. Decomposition studies reported in the literature were used to determine that approximately 9% of the carbon in the biomass residue would end up as CH_4 were it not used at the power plant, while 61% would end up as CO_2. The remaining carbon is resistant to decomposition in the landfill, either due to inadequate growth conditions for the microbes or because of the protective nature of the lignin compounds.

Sensitivity analyses demonstrated that even moderate amounts of soil carbon sequestration (1,900 kg/ha/seven-year rotation) would result in the biomass IGCC system having a zero-net greenhouse gas balance. Sequestration amounts greater than this would result in a negative release of greenhouse gases, and a system that removes carbon from the atmosphere overall. The base case presented here assumes that there will be no net change in soil carbon, as actual gains and losses will be very site specific.

The natural gas combined cycle has the lowest GWP of all fossil systems because of its higher efficiency, despite natural gas losses that increase net CH_4 emissions. Cofiring biomass with coal at 15% by heat input reduces the GWP of the average coal-fired power plant by 18%.

Air Emissions

Emissions of particulates, SO_x, NO_x, CH_4, CO, and NMHCs are shown in Figure 6.6. Methane emissions are high for the natural gas case due to natural gas losses during extraction and delivery. The direct-fired biomass and coal/biomass cofiring cases have negative methane emissions, due to avoided decomposition processes (landfilling and mulching). CO and NMHCs are higher for the biomass case because of upstream diesel combustion during biomass growth and preparation. Cofiring reduces the coal system air emissions by approximately the rate of cofiring, with the exception of particulates, which are generated during biomass chipping.

Figure 6.6: Other Air Emissions
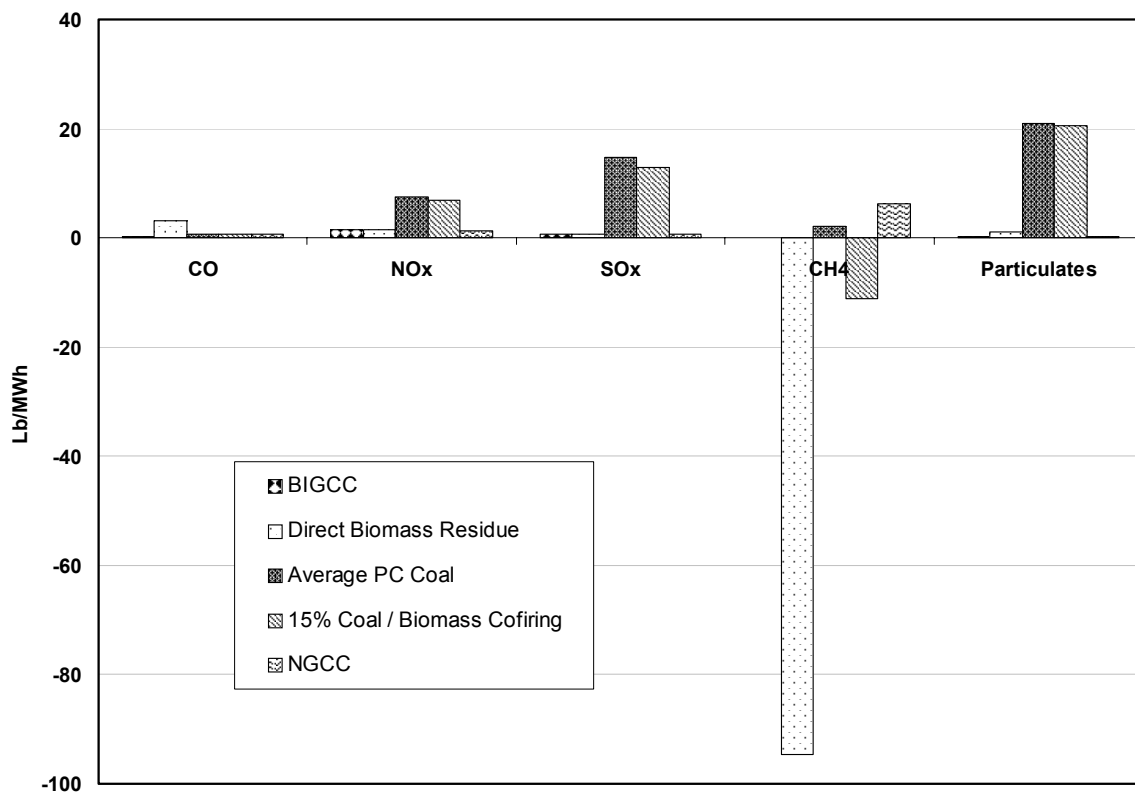
Resource Consumption

Figure 6.7 shows the total amount of non-renewable resources consumed by the systems. Limestone is used in significant quantities by the coal-fired power plants for flue-gas desulfurization. The natural gas combined cycle plant consumes almost negligible quantities of resources, with the exception of the feedstock itself. The natural gas consumed in this case includes a 1.4% loss to the atmosphere during extraction and delivery.

Figure 6.7 Resource Consumption
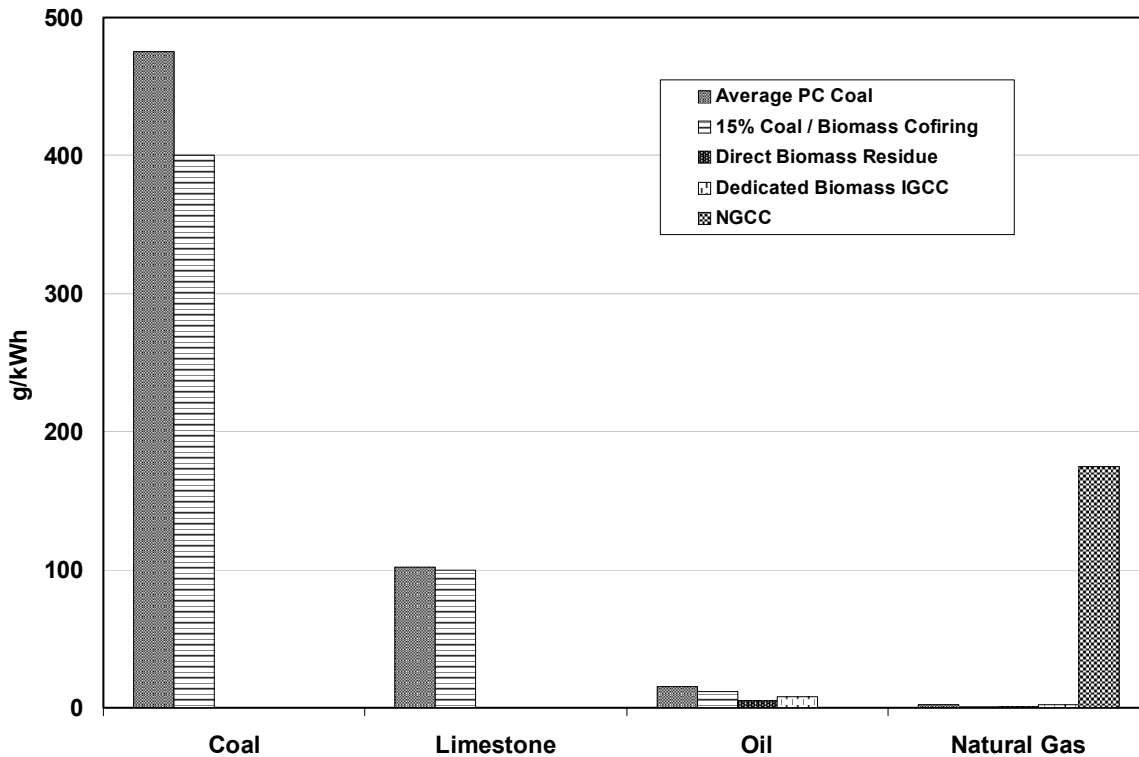
Summary

Completing several life cycle assessment studies has allowed us to determine where biomass power systems reduce the environmental burden associated with power generation. The key comparative results can be summarized as follows:

- The GWP of generating electricity using a dedicated energy crop in an IGCC system is 4.7% of that of an average U.S. coal power system.
- Cofiring residue biomass at 15% by heat input reduces the greenhouse gas emissions and net energy consumption of the average coal system by 18% and 12%, respectively.
- The life cycle energy balances of the coal and natural gas systems are significantly lower than those of the biomass systems because of the consumption of non-renewable resources.
- Not counting the coal and natural gas consumed at the power plants in these systems, the net energy balance is still lower than that of the biomass systems because of the energy used in processes related to flue gas clean-up, transportation, and natural gas extraction and coal mining.
- The biomass systems produce very low levels of particulates, NO_x, and SO_x compared to the fossil systems.
- System methane emissions are negative when residue biomass is used because of avoided decomposition emissions.
- The biomass systems consume very small quantities of natural resources compared to the fossil systems.
- Other than natural gas, the natural gas IGCC consumes almost no resources.

These results demonstrate quite clearly that, overall, biomass power provides significant environmental benefits over conventional fossil-based power systems. In particular, biomass systems can significantly reduce the amount of greenhouse gases that are produced per kWh of electricity generated. Additionally, because the biomass systems use renewable energy instead of non-renewable fossil fuels, they consume very small quantities of natural resources and have a positive net energy balance. Cofiring biomass with coal offers us an opportunity to reduce the environmental burdens associated with the coal-fired power systems that currently generate over half of the electricity in the United States. Finally, by reducing NO_x, SO_x, and particulates, biomass power can improve local air quality.

7.   POLICY

U.S. government policies are used to advance energy strategies such as energy security and environmental quality. In the case of renewable energy, and bioenergy in particular, a variety of policies have been implemented—research, development, and demonstration of new technologies, financial incentives, and regulatory mandates—to advance the use of renewables in the energy marketplace and thus realize the benefits of renewable energy. Many of the benefits of renewable energy are not captured in the traditional marketplace economics. Government policies are a means of converting non-economic benefits to an economic basis, often referred to as "internalizing externalities." This may be accomplished by supporting the research, development, and demonstration of new technologies that are not funded by industry because of projected high costs or long development time lines. To facilitate the introduction and market penetration of renewable technologies, the government may establish financial incentives such as tax credits for new technology or additional taxes on existing technology to make the product economically competitive. The government may also mandate the use of renewable energy or products through regulatory actions that override market economics. A Renewable Portfolio Standard that requires a given percentage of renewable generation of electricity is an example of regulatory policy. This chapter briefly reviews the pertinent Federal government policies.

Research, Development and Demonstration/Deployment[1]

Biomass research, development, and demonstration/deployment (RD&D) power, heat, fuels, and chemicals has been the subject of United States government programs since the early 1970s. In 1972, the Research Applied to National Needs (RANN) Directorate of the National Science Foundation (NSF) held several workshops to define the Fuels from Biomass Program (Ward 1976). In parallel, the Department of Interior had several activities funding urban wastes and industry residues uses, including energy (Phillips 1998).

To frame biomass RD&D in the context of the 1970s, the Environmental Protection Agency was formed at the end of 1970:

> *As concern with the condition of our physical environment has intensified, it has become increasingly clear that we need to know more about the total environment--land, water, and air. It also has become increasingly clear that only by reorganizing our Federal efforts can we develop that knowledge, and effectively ensure the protection, development and enhancement of the total environment itself* (President Nixon on the establishment of the Agency).

At that time, the United States had nearly 200 million inhabitants in 60 million households. Schools had no computers. Each person generated more than 1.5 kg of MSW per day in the United States. Paper companies recycled less than 20% of their fiber. Each person used about 350 GJ y^{-1}; and each dollar of the US GDP required 18 MJ of energy. Vehicles had an average fuel economy of less than 15.7 L per 100 km (15 miles/gallon), and the disposable income used to purchase motor fuels was about 4%.

Households spent half of that amount to purchase electricity. A trillion vehicle miles were traveled in the United States in that year (NSTC 1995).

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[1] Excerpted from Chum, H.C. and R.P. Overend (2002?) "Biomass and Bioenergy in the United States," <u>Advances in Solar Energy, Volume 15</u>

The oil embargo and related crises of the 1970s brought urgency to solve energy and security issues. A series of changes in government structure gave energy higher importance and consolidated activities that were previously conducted by a number of agencies. The NSF's RANN research activities were transferred to the Federal Energy Administration. In Fiscal Year 1974, a comprehensive 5-year plan, "Fuels from Biomass Energy Program," was developed as part of the Project Independence Blueprint. The early vision, Figure 7.1, presented by Martin Wolf at a Congressional hearing on bioconversion, guided much of the subsequent developments (Wolf 1974). In 1975, biomass energy activities were transferred to the Energy Research and Development Authority (ERDA). The Fuels from Biomass program at ERDA was funded at $600,000 in 1975. Urban waste activities were transferred from the Department of Interior and funded at the level of $400,000. The total funding for these activities corresponds to $3 million in constant 1999$ (we will mainly use year 1999$ and 2000$ to express the expenditures in constant dollars, through a calculation using the GDP deflator).

Figure 7.1: The Bioenergy "Vision" in 1974
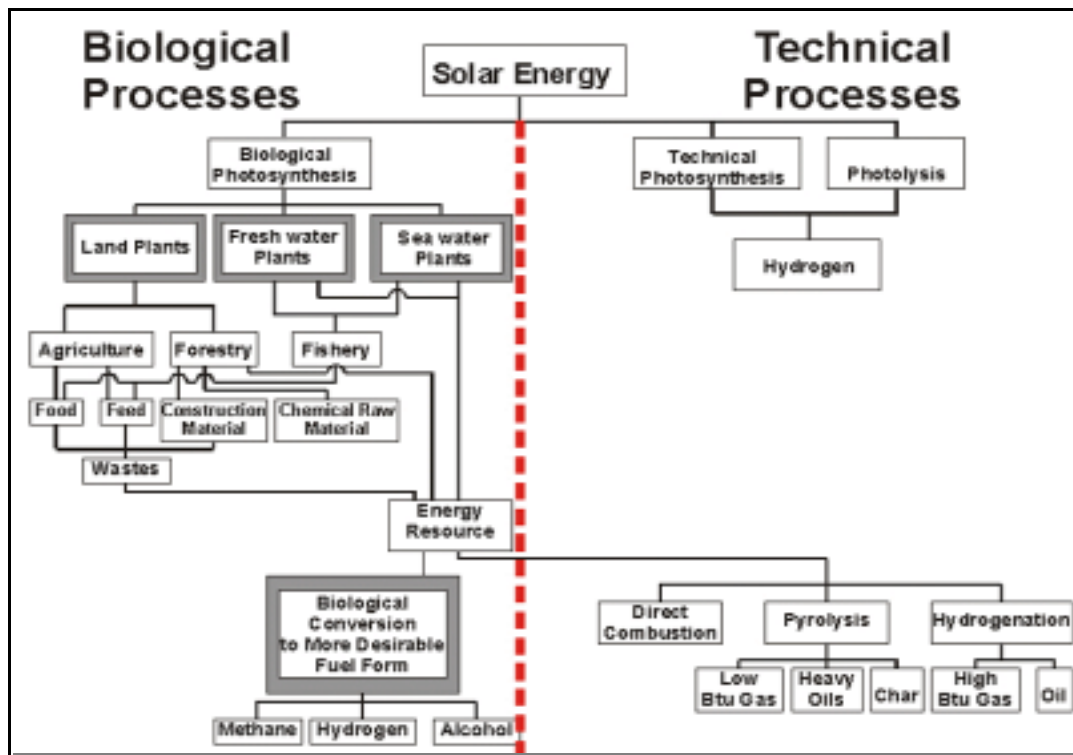
By 1977, all energy RD&D activities were consolidated in a new cabinet, the U.S. Department of Energy (USDOE). This department had then, and has now, multiple missions, including energy, energy security, defense-related activities such as nuclear weapons development and production, their safety and security, and advancement of the related science and technology (USDOE 2001).

Biomass and bioenergy funding from the USDOE can be framed in the context of the overall energy RD&D appropriations since 1978. A comparison of the major energy producing expenditures is shown in Figure 7.2, where funding for each of the technologies is in the order: nuclear>>coal>renewables >>oil, gas, and shale. Renewable RD&D investments over this period have been one-quarter to one-third of those in the nuclear area. Within the renewable energy technologies Figure 7.3, biomass and biofuels represent 12% of the overall investment (1978-2000) or $1.2 billion (2000$). Additional biomass

investments are found in the industrial activities funded under energy efficiency such as pulp and paper, agriculture, alternative feedstocks to chemicals, etc., as shown in Figure 7.4; energy efficiency activities in transportation, buildings, industry, and the Federal Energy Management Program (FEMP) are also included. For comparison, Figure 7.5 shows related investments in major fossil energy and component areas.

Figure 7.2: United States Appropriations for Energy R&D 1978 - 1998
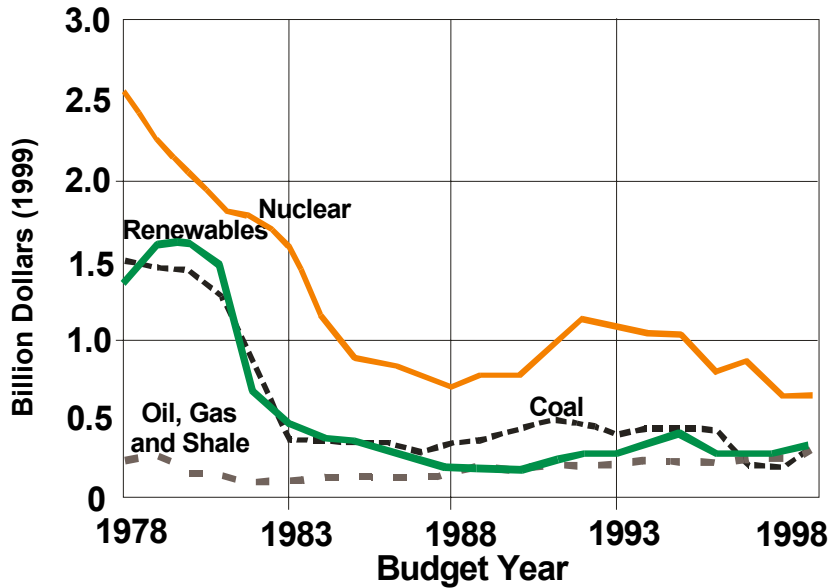
Figure 7.3: United States Appropriations for Renewable Energy R&D 1978 - 1998
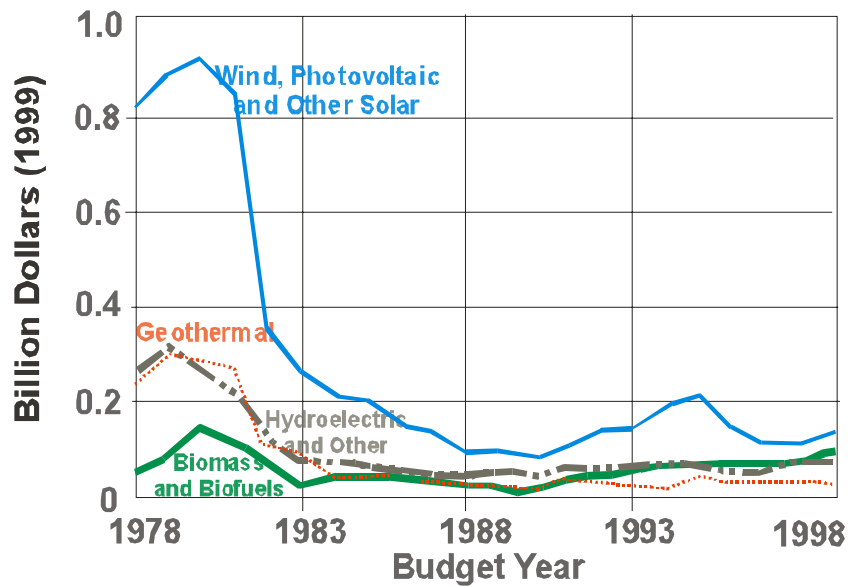
Figure 7.4: United States Appropriations for Energy Efficiency R&D 1978 - 1998
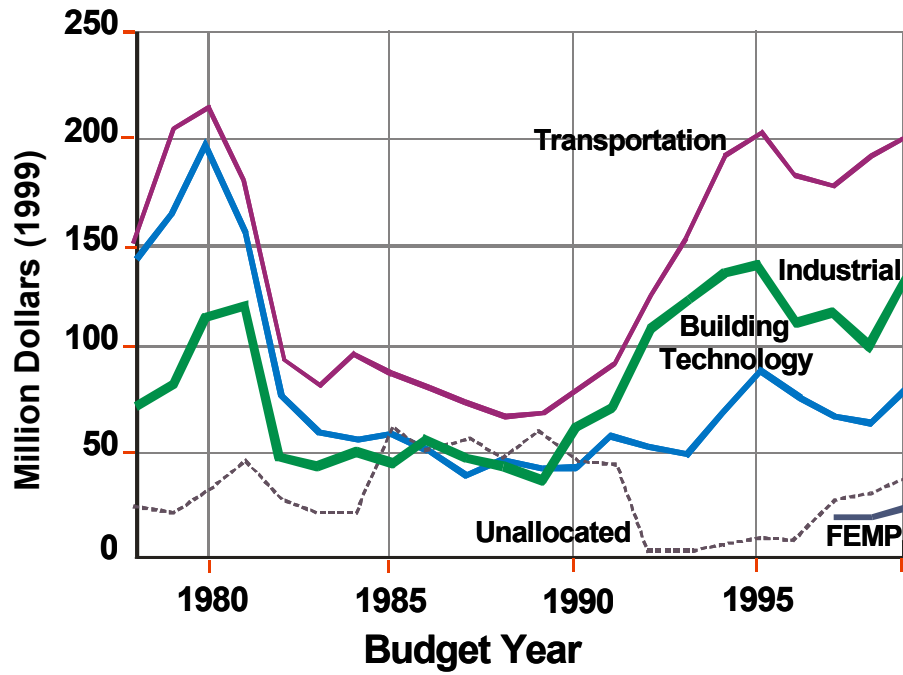
Figure 7.5: United States Appropriations for Fossil Energy R&D 1978 - 1998
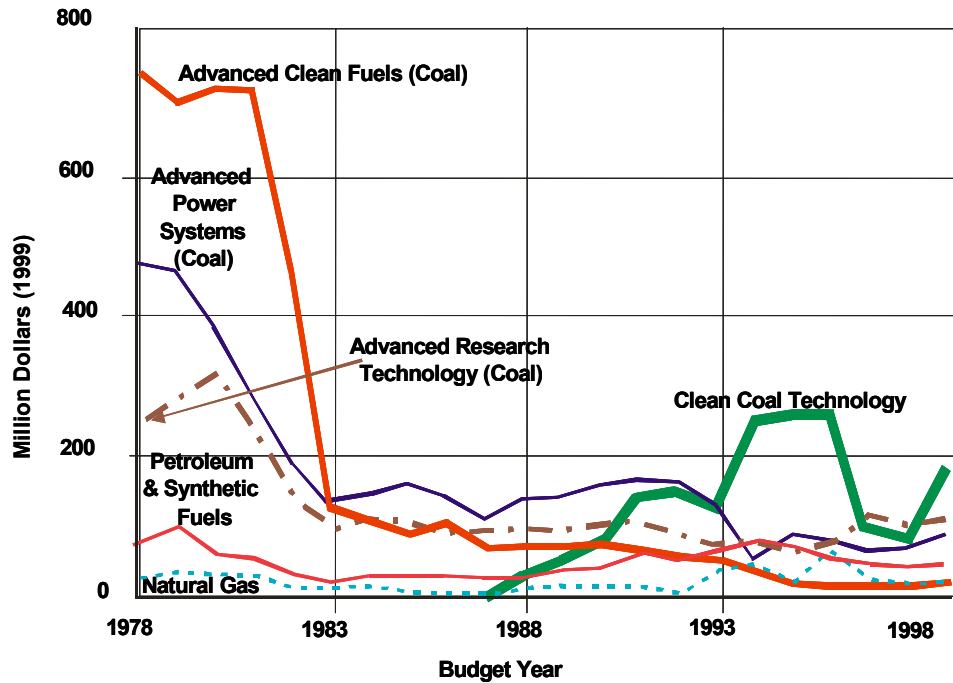
The total investment in this period for all biomass and bioenergy expenditures, including urban waste energy and management and related energy efficiency activities, is $1.4-1.5 billion (2000$), or 14%-15% of total Federal energy RD&D expenditures. Funding for non-RD&D activities is not included (EIA 1999; EIA 2000).

Government actions to increase biomass use for energy varied significantly over the past 25 years. Many of these actions responded to crude oil price signals, as shown in Figure 7.6 in constant 2000 $. In 1977-1983, the goal was primarily to reduce the dependence of the United States on energy imports—mainly oil. The programs focused on the development of alternative fuels and activities included RD&D from exploratory to pioneer plants for a wide range of technology options. Significant outreach activities helped increase the energy self-sufficiency of the existing biomass industry and speed the replacement of some oil applications with biomass, e.g., home heating.

Figure 7.6: Crude Oil Prices 1970 – 2000 in 2000$
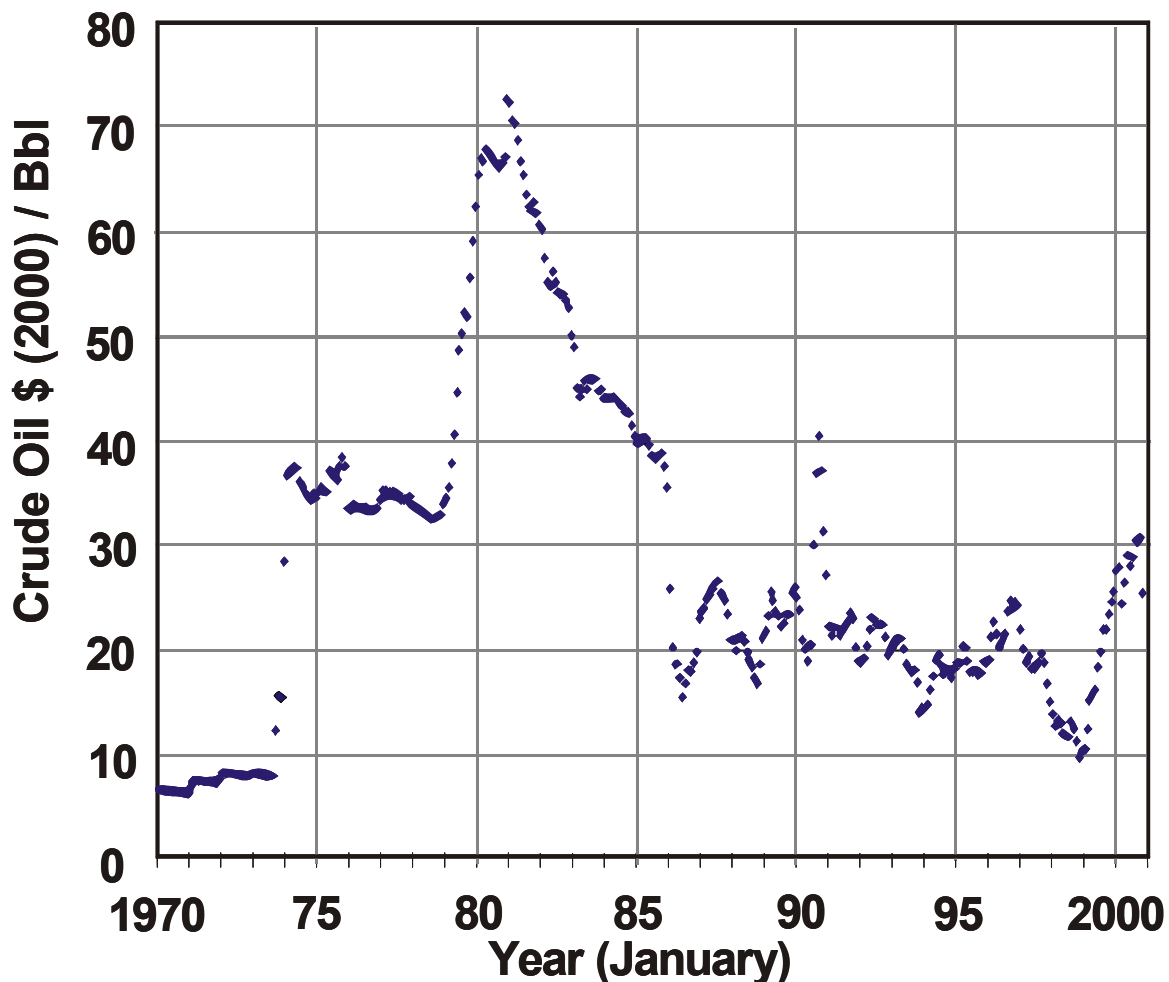
Crudedefl

During 1977-1983, a technology-driven RD&D approach responded to the wide diversity of biomass resources and product possibilities, including a range of gaseous, liquid, and solid fuels, power, heat, value added products, and the use of many different biomass sources. The biomass resources included agricultural and forestry residues, urban wastes, and dedicated feedstocks to be produced on land or

water. Freshwater and seawater plants were considered for their biomass as well as for the direct production of hydrogen fuel from sunlight and water. Deployment was fostered in many ways, including studies facilitating the construction of commercial plants to produce alternative fuels—mainly ethanol. A few of the late 1970s technologies were advanced sufficiently to become commercially viable. Direct combustion improvements were implemented in areas such as the forest products industry, pulp and paper mills, and home heating equipment.

In the period 1983-1990, there was a marked change in the approach of the Federal government towards energy supply. Supply and demand imbalances were to be resolved by market forces and supporting federal government policies, many of which were also applied at state and local levels. This alignment amplified federal actions and afforded significant penetration of several renewable technologies and, in particular, biomass combustion and ethanol from corn starch. RD&D continued to develop technologies to expand supply and reduce demand through increased efficiency RD&D. The priority of government funding was to conduct long-term high-risk R&D. Companies could not be expected to carry out such R&D because the benefits were not immediate nor could the benefits be captured by individual firms. The focus on the production of liquid fuels and energy from municipal waste was maintained, though other ways to recover resources and safely manage solid waste were investigated.

The 1990s saw the U.S. federal government increase renewable energy and energy efficiency RD&D as a priority. Cost-shared RD&D was conducted through a wide range of public-private partnerships in defined sectors—power, transportation fuels, forest products, and agriculture. Government sponsored some outreach activities and the development of selected pioneer plants for new biomass technologies. The overall approach combined market forces with technology development. The focus was specific products—electricity, ethanol from lignocellulosic biomass, biodiesel, specific model terrestrial feedstocks, and efforts to make energy and value-added products from biomass. In addition, RD&D in the forest products and agricultures sectors was reconfigured. Industry associations in these sectors developed Agenda 2020 visions and technology roadmaps to guide the selection of DOE efforts in this area (Agenda 2020, Agriculture Vision 2020 Anon 1998 and 1999).

A baseline (essentially a single snapshot) inventory of the overall government funding for bioenergy and biobased products for the United States federal government was prepared for fiscal year 1998 (Chum, Elam et al. 2000) . In that year the U.S. federal government invested $253 million in RD&D activities, including investments in basic research at the DOE Office of Science and at the Ntional Science Foundation. Of the $253 million, $153 million were devoted to bioenergy. Approximately 90% of the total bioenergy and biobased products amount, nearly $230 million (2000$), was appropriated through DOE and USDA programs. Other agencies—the NSF, EPA, and the Department of Commerce (Advanced Technology Program)—funded specific activities in support of these areas.

In fiscal year 2001, the government investment in RD&D at DOE and USDA was $239 million. The total R&D investment level by these two departments was similar to the previous numbers, but there were major changes in emphasis and scope. These totals do not include R&D investments at the NSF on the Plant Genome Research Program. The NSF plant genome activities began in 1998, and a portion of the $25 million annual budget is certainly applicable to biomass activities. The NSF also funds bioprocessing, metabolic engineering, separations technologies, fermentation and enzyme-catalyzed systems, chemistry, materials, and engineering programs, which include biobased products and bioenergy. In fiscal year 2001, the EPA invested $7 million in biomass-related activities, according to a report to Congress on Biomass Research and Development Act of 2000 (USDA/USDOE 2001).

Throughout these 25 years, funding for specific bioenergy areas was discontinued while focusing on specific products. Market and business considerations, funding availability, policy changes (e.g., deregulation of the electricity sector), and Congressional directions on specific projects to fund all played

a role in the process of selecting areas to be maintained or discontinued. For example, the efforts in high-pressure liquefaction to produce oil replacements did not reach product quality or cost effectiveness goals and was terminated in 1983. Macroalgae sometimes known as giant kelp were explored in several concepts but they were not cost effective in light of the declining oil price trend of that period. Similarly, during the "lean funding years" of the mid-to late-1980s, when the United States was in the process of balancing its budget, discretionary spending was significantly curtailed and much of the R&D in thermochemical fuels was discontinued in favor of ethanol from lignocellulosic biomass, which became, respectively, the fuel and feedstock of choice. All thermochemical fuels activities including methanol, other transportation fuels, or thermal depolymerization concepts that could have led to multiple products (1988-1989) were discontinued. By 1993, investigations on microalgae accumulating large fractions of their body mass as lipids were also discontinued primarily because of difficulties reaching cost effectiveness. Finally, towards the mid-1990s, the programs on wastes-to-energy or products from a wide range of "wastes" (municipal, urban, industrial, and agricultural) were also discontinued.

Incentives[2]

The major Federal legislation on financial incentives for renewable energy and renewable transportation fuels has been structured as tax credits and production incentive payments. See Tables 7.1 and 7.2 for a summary of major Federal provisions that affect renewable energy and renewable-based transportation fuels, respectively. For renewable energy, tax credits for purchases of renewable energy equipment were aimed at both the residential and business sectors. Accelerated depreciation of renewable energy equipment and production incentives were aimed at investors. From 1978 through 1998, similar types of tax credits have been in existence. Over time, the various laws have usually expanded the technologies covered, increased the credit amount, or extended the time period.

Two new types of financial incentives were introduced as part of the Energy Policy Act of 1992 (EPACT)—a production tax credit (PTC) and a renewable energy production incentive (REPI). The PTC is a 1.5 cents-per- kilowatthour (kWh) payment, payable for 10 years, to private investors as well as to investor-owned electric utilities for electricity from wind and closed-loop biomass facilities. The PTC is also known as the Section 45 tax credit, and was modified in 1999 to include chicken litter as well as closed-loop biomass. Closed-loop biomass is defined as biomass grown and harvested specifically for energy purposes. As far as is known today, no organization has applied for the PTC for closed-loop biomass. The REPI provides a 1.5 cents-per-kWh incentive, subject to annual congressional appropriations for generation from biomass (except municipal solid waste), geothermal (except dry steam), wind and solar from tax-exempt publicly owned utilities, local and county governments, and rural cooperatives.

For renewable transportation fuels, tax credits and tax exemptions are used to promote the use of renewable fuels, with the goal of displacing petroleum use in the transportation sector. There are four Federal tax subsidies for the production and use of alcohol transportation fuels: (1) a 5.4-cents-per-gallon excise tax exemption, (2) a 54-cents-per-gallon blender's tax credit, (3) a 10-cents-per-gallon small ethanol production tax credit, and (4) the alternative fuels production tax.

However, only the partial exemption from motor fuels excise tax is used to any extent. It is important to note that there are important financial incentive issues in the form of tax equity regarding all of the

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[2] Excerpted from: Gielecki, M. Mayes, F. and L. Prete "Incentives, Mandates, and Government Programs for Promoting Renewable Energy," USDOE Energy Information Agency, http://www.eia.doe.gov/cneaf/solar.renewables/rea_issues/incent.html, 4/18/2002

"alternate transportation fuels." However, only the alcohol fuels are renewable, so this discussion is confined to those. The primary incentive is the ethanol excise tax exemption.

Table 7.1: Time Line - Major Tax Provisions Affecting Renewable Energy

1978	**Energy Tax Act of 1978** (ETA) (P.L.95-618) Residential energy (income) tax credits for solar and wind energy equipment expenditures: 30 percent of the first $2,000 and 20 percent of the next $8,000. Business energy tax credit: 10 percent for investments in solar, wind, geothermal, and ocean thermal technologies; (in addition to standard 10 percent investment tax credit available on all types of equipment, except for property which also served as structural components, such as some types of solar collectors, e.g., roof panels). In sum, investors were eligible to receive income tax credits of up to 25 percent of the cost of the technology. Percentage depletion for geothermal deposits: depletion allowance rate of 22 percent for 1978-1980 and 15 percent after 1983.
1980	**Crude Oil Windfall Profits Tax Act of 1980** (WPT) (P.L.96-223) Increased the ETA residential energy tax credits for solar, wind, and geothermal technologies from 30 percent to 40 percent of the first $10,000 in expenditures. Increased the ETA business energy tax credit for solar, wind, geothermal, and ocean thermal technologies from 10 percent to 15 percent, and extended the credits from December 1982 to December 1985. Expanded and liberalized the tax credit for equipment that either converted biomass into a synthetic fuel, burned the synthetic fuel, or used the biomass as a fuel. Allowed tax-exempt interest on industrial development bonds for the development of solid waste to energy (WTE) producing facilities, for hydroelectric facilities, and for facilities for producing renewable energy.
1981	**Economic Recovery Tax Act of 1981** (ERTA) (P.L.97-34) Allowed accelerated depreciation of capital (five years for most renewable energy-related equipment), known as the Accelerated Cost Recovery System (ACRS); public utility property was not eligible. Provided for a 25 percent tax credit against the income tax for incremental expenditures on research and development (R&D).
1982	**Tax Equity and Fiscal Responsibility Act of 1982** (TEFRA) (P.L.97-248) Canceled further accelerations in ACRS mandated by ERTA, and provided for a basis adjustment provision which reduced the cost basis for purposes of ACRS by the full amount of any regular tax credits, energy tax credit, rehabilitation tax credit.
1982-1985	**Termination of Energy Tax Credits** In December 1982, the 1978 ETA energy tax credits terminated for the following categories of non-renewable energy property: alternative energy property such as synfuels equipment and recycling equipment; equipment for producing gas from geopressurized brine; shale oil equipment; and cogeneration equipment. The remaining energy tax credits, extended by the WPT, terminated on December 31, 1985.

1986	**Tax Reform Act of 1986** (P.L.99-514) Repealed the standard 10 percent investment tax credit. Eliminated the tax-free status of municipal solid waste (MSW) powerplants (WTE) financed with industrial development bonds, reduced accelerated depreciation, and eliminated the 10 percent tax credit (P.L.96-223). Extended the WPT business energy tax credit for solar property through 1988 at the rates of 15 percent for 1986, 12 percent for 1987, and 10 percent for 1988; for geothermal property through 1988 at the rates of 15 percent for 1986, and 10 percent for 1987 and 1988; for ocean thermal property through 1988 at the rate of 15 percent; and for biomass property through 1987 at the rates of 15 percent for 1986, and 10 percent for 1987. (The business energy tax credit for wind systems was not extended and, consequently, expired on December 31, 1985.) Public utility property became eligible for accelerated depreciation.
1992	**Energy Policy Act of 1992** (EPACT) (P.L.102-486) Established a permanent 10 percent business energy tax credit for investments in solar and geothermal equipment. Established a 10-year, 1.5 cents per kilowatthour (kWh) production tax credit (PTC) for privately owned as well as investor-owned wind projects and biomass plants using dedicated crops (closed-loop) brought on-line between 1994 and 1993, respectively, and June 30, 1999. Instituted the Renewable Energy Production Incentive (REPI), which provides 1.5 cents per kWh incentive, subject to annual congressional appropriations (section 1212), for generation from biomass (except municipal solid waste), geothermal (except dry steam), wind and solar from tax exempt publicly owned utilities and rural cooperatives. Indefinitely extended the 10 percent business energy tax credit for solar and geothermal projects.
1999	**Tax Relief Extension Act of 1999** (P.L. 106-170) Extends and modifies the production tax credit (PTC in EPACT) for electricity produced by wind and closed-loop biomass facilities. The tax credit is expanded to include poultry waste facilities, including those that are government-owned . All three types of facilities are qualified if placed in service before January 1, 2002. Poultry waste facilities must have been in service after 1999. A nonrefundable tax credit of 20 percent is available for incremental research expenses paid or incurred in a trade or business.
Notes: The residential energy credit provided a credit (offset) against tax due for a portion of taxpayer expenditures for energy conservation and renewable energy sources. The general business credit is a limited non-refundable credit (offset) against income tax that is claimed after all other non-refundable credits.	

Table 7.2. Timeline - Major Tax Provisions Affecting Renewable Transportation Fuels

1978	**Energy Tax Act of 1978** (ETA) (P.L.95-618) Excise tax exemption through 1984 for alcohol fuels (methanol and ethanol): exemption of 4 cents per gallon (the full value of the excise tax at that time) of the Federal excise tax on "gasohol" (gasoline or other motor fuels that were at least 10 percent alcohol (methanol and ethanol))
1980	**Crude Oil Windfall Profits Tax Act of 1980** (WPT) (P.L.96-223) Extended the gasohol excise tax exemption from October 1, 1984, to December 31, 1992. Introduced the alternative fuels production tax credit. The credit of $3 per barrel equivalent is indexed to inflation using 1979 as the base year, and is applicable only if the real price of oil is bellow $27.50 per barrel. The credit is available for fuel produced and sold from facilities placed in service between 1979 and 1990. The fuel must be sold before 2001. Introduced the alcohol fuel blenders' tax credit; available to the blender in the case of blended fuels and to the user or retail seller in the case of straight alcohol fuels. This credit of 40 cents per gallon for alcohol of at least 190 proof and 45 cents per gallon for alcohol of at least 150 proof but less that 190 proof was available through December 31, 1992. Extended the ETA gasohol excise tax exemption through 1992. Tax-exempt interest on industrial development bonds for the development of alcohol fuels produced from biomass, solid waste to energy producing facilities, for hydroelectric facilities, and for facilities for producing renewable energy.
1982	**Surface Transportation Assistance Act** (STA) (P.L. 97-424) Raised the gasoline excise tax from 4 cents per gallon to 9 cents per gallon, and increased the ETA gasohol excise tax exemption from 4 cents per gallon to 5 cents per gallon. Provided a full excise tax exemption of 9 cents per gallon for "neat" alcohol fuels (fuels having an 85 percent or higher alcohol content).
1984	**Deficit Reduction Act of 1984** (P.L.98-369) The STA excise tax exemption for gasohol was raised from 5 cents per gallon to 6 cents per gallon. Provided a new exemption of 4.5 cents per gallon for alcohol fuels derived from natural gas. The alcohol fuels "blenders" credit was increased from 40 cents to 60 cents per gallon of blend for 190 proof alcohol. The duty on alcohol imported for use as a fuel was increased from 50 cents to 60 cents per gallon
1986	**Tax Reform Act of 1986** (P.L.99-514) Reduced the tax exemption for "neat" alcohol fuels (at least 85 percent alcohol) from 9 cents to 6 cents per gallon. Permitted alcohol imported from certain Caribbean countries to enter free of the 60 cents per gallon duty. Repealed the tax-exempt financing provision for alcohol-producing facilities.

1990	**Omnibus Budget Reconciliation Act of 1990** (P.L. 101-508) Allows ethanol producers a 10 cent per gallon tax credit for up to 15 million gallons of ethanol produced annually. Reduced the STA gasohol excise tax exemption to 5.4 cents per gallon.
1992	**Energy Policy Act of 1992 (EPACT)** (P.L. 102-486) Provides: (1) a tax credit (variable by gross vehicle weight) for dedicated alcohol-fueled vehicles; (2) a limited tax credit for alcohol dual-fueled vehicles; and (3) a tax deduction for alcohol fuel dispensing equipment.
1998	**Energy Conservation Reauthorization Act of 1998** (ECRA) (P.L. 105-388) Amended EPACT to include a credit program for biodiesel use by establishing Biodiesel Fuel Use Credits. An EPACT-covered fleet can receive one credit for each 450 gallons of neat (100 percent) biodiesel purchased for use in vehicles weighing in excess of 8500 lbs (gross vehicle weight (GVW)). One credit is equivalent to one alternative fueled vehicle (AFV) acquisition. To qualify for the credit, the biodiesel must be used in biodiesel blends containing at least 20 percent biodiesel (B20) by volume. If B20 is used, 2,250 gallons must be purchased to receive one credit. **Transportation Equity Act for the 21ˢᵗ Century** (TEA-21) (P.L. 105-178) Maintains, through 2000, the 5.4 cent per gallon (of gasoline) excise tax exemption for fuel ethanol set by the Omnibus Budget Reconciliation Act of 1990 (P.L. 101-508). Extends the benefits through September 30, 2007, and December 31, 2007, but cuts the ethanol excise tax exemption to 5.3, 5.2, and 5.1 cents for 2001-2002, 2003-2004, and 2005-2007, respectively, and the income tax credits by equivalent amounts. The exemption is eliminated entirely in 2008.

Regulatory

The Public Utility Regulatory Policies Act of 1978 (PURPA) was the most significant section of the National Energy Act in fostering the development of facilities to generate electricity from renewable energy sources. However, with the electric power industry challenging its legality and implementation issues, the broad application of PURPA did not occur until after the legality of PURPA was upheld in 1981. PURPA opened the door to competition in the U.S. electricity supply market by requiring utilities to buy electricity from qualifying facilities (QFs). QFs are defined as nonutility facilities that produce electric power using cogeneration technology, or power plants no greater than 80 megawatts of capacity that use renewable energy sources. There is no size restriction for cogeneration plants; however, at least 5 percent of the energy output from a qualifying cogeneration facility must be dedicated to "useful" thermal applications.

Under PURPA, utilities are required to purchase electricity from QFs at the utilities' "avoided cost." The Federal government, in formulating regulations, often delegates implementation to the States. This occurred with PURPA, as the Federal Energy Regulatory Commission (FERC) delegated the authority for the determination of avoided cost to the States. In several States including California, avoided cost purchase contracts were very favorable to non-utility generators. For example, between 1982 and 1988, Standard Offer 4 (SO4) contracts written in California allowed QFs to sell renewable energy under 15-to-30 year terms. The contract guarantees fixed payment rates (based on forecasted short-run avoided costs) for up to 10 years if the QF has signed a contract for at least 20 years. After the 10ᵗʰ year, energy prices moved to the short-run avoided cost of the purchasing utility. The 10-year provisions were tied to

forecasts of increases in oil and gas prices, and were the basis for the fixed payments for the first ten years of the contracts. The forecasts were much higher than prices actually turned out to be. Therefore, a price and revenue drop occurred in the eleventh year when the fixed contract energy prices converted to variable prices (based on short-term avoided cost), greatly lessening the economic viability of affected projects.

This assessment of the effectiveness of PURPA is actually an assessment of PURPA in combination with various tax incentives in place between 1978 and 1998. Under PURPA, qualifying facilities (QF) not only sold electricity to electric utilities at the utility's avoided cost rates–these facilities were also granted tax benefits described in, which lowered their overall costs. PURPA's QF status applied to existing as well as new projects. Together, by year end 1998, existing and new projects totaled 12,658 megawatts of QF renewable capacity (Table 3). Of this, two-thirds (8,219 megawatts) of QF capacity was biomass. Some of these biomass QFs, however, were not "new" facilities, but rather had gone into commercial operation prior to PURPA. PURPA enabled these facilities to connect to the grid, if they chose to become QFs, and sell any generation beyond their own use at avoided cost rates.

Table 7.3: Nonutility Qualifying Facilities Using Renewable Resources as of December 31, 1998		
Fuel Source	Nameplate Capacity (megawatts)	Gross Generation (thousand megawatthours)
Biomass	8,219	45,032
Geothermal	1,449	9,882
Hydroelectric[a]	1,263	5,756
Wind	1,373	2,568
Solar Thermal	340	876
Photovoltaic	14	11
Total Renewable QF	12,658	64,126
Total QF, All Sources	60,384	327,977
Total Nonutility, All Sources	98,085	421,364
[a]Conventional; excludes pumped storage. Notes: Totals may not equal sum of components due to independent rounding. Source: Form EIA-860B, "Annual Electric Generator Report - Nonutility		

Two of the criteria for evaluating the effectiveness of incentives and mandates such as PURPA are renewable capacity and generation growth. The EIA began collecting data from nonutility companies in 1989 (Table 4), 11 years after the passage of PURPA. However, between 1989 and 1998, renewable capacity increased by 11.9 percent. At the national level, non-hydroelectric renewable generating capacity rose by 4,426 MW; the increase in hydroelectric capacity was 5,703 MW. Renewable generation rose by 22 percent (Table 5). Most of the increase in electricity generation from renewable energy is in the utility hydropower sector, including net imports. Nearly all of the increase in biomass, geothermal, solar, and wind generation occurred between 1989 and 1993. Non-hydro renewable generation, excluding imports, actually declined by more than 5 percent between 1993 and 1998, due primarily to California replacing Standard Offer 4 contract "avoided cost" provisions with competitive bidding mechanisms, and declining production at The Geysers geothermal plant. Also, in 1992, New York amended its Six-Cent Rule, which established a 6-cents-per-kilowatt hour floor on avoided costs for projects less than 80 MW in size, such that it was not applicable to any future power purchase agreements.

Table 7.4: U.S. Electric Power Sector Net Summer Capability, 1989-1998 (Megawatts)

Source	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Hydroelectric[a]	74,587	73,964	76,179	74,773	77,405	78,042	78,563	76,437	79,788	79,573
Geothermal	2,603	2,669	2,632	2,910	2,978	3,006	2,968	2,893	2,853	2,917
Biomass	7,840	8,796	9,627	9,701	10,045	10,465	10,280	10,557	10,535	10,266
Solar/PV	264	339	323	339	340	333	333	333	334	365
Wind	1,697	1,911	1,975	1,823	1,813	1,745	1,731	1,678	1,579	1,698
Total Renewables	**86,990**	**87,679**	**90,736**	**89,547**	**92,582**	**93,591**	**93,874**	**91,897**	**95,090**	**94,819**
Non Renewables	637,275	647,241	649,741	657,016	662,373	670,423	675,643	683,975	683,412	681,065
Total	**724,265**	**734,920**	**740,477**	**746,563**	**754,955**	**764,014**	**769,517**	**775,872**	**778,502**	**775,884**

[a]Conventional; excludes pumped storage.
Notes: Biomass capability does not include capability of plants where the Btu of the biomass consumed represents less than 50 percent of the Btu consumed from all energy sources. Totals may not equal sum of components due to independent rounding.
Sources: Energy Information Administration, Form EIA-860A, "Annual Electric Generator Report - Utility" and predecessor forms, and estimated data using Form EIA-860B, "Annual Electric Generator Report - Nonutility," and predecessor form.

Table 7.5: Electricity Generation From Renewable Energy by Energy Source, 1989-1998 (Thousand Kilowatthours)

Source	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Nonutility Sector (Gross Generation)										
Biomass	36,350,275	42,499,581	48,259,818	53,606,891	55,745,781	57,391,594	57,513,666	57,937,058	55,144,102	53,744,724
Geothermal	5,416,495	7,235,113	8,013,969	8,577,891	9,748,634	10,122,228	9,911,659	10,197,514	9,382,646	9,881,958
Hydroelectric	7,124,418	8,152,891	8,180,198	9,446,439	11,510,786	13,226,934	14,773,801	16,555,389	17,902,653	14,632,521
Solar	488,527	663,387	779,206	746,277	896,796	823,973	824,193	902,830	892,892	886,553
Wind	1,832,537	2,250,846	2,605,505	2,916,379	3,052,416	3,481,616	3,185,006	3,399,642	3.248,140	3,015,497
Total	51,212,252	60,801,818	67,838,696	75,293,877	80,954,413	85,046,345	86,208,325	88,992,433	86,569,433	82,161,253
Electric Utility Sector (Net Generation)										
Biomass	1,959,864	2,064,331	2,038,229	2,088,109	1,986,535	1,985,463	1,647,247	1,912,472	1,983,532	2,024,377
Geothermal	9,341,677	8,581,228	8,087,055	8,103,809	7,570,999	6,940,637	4,744,804	5,233,927	5,469,110	5,176,280
Hydroelectric	265,063,067	283,433,659	280,060,621	243,736,029	269,098,329	247,070,938	296,377,840	331,058,055	341,273,443	308,843,770
Solar	2,567	2,448	3,338	3,169	3,802	3,472	3,909	3,169	3,481	2,518
Wind	479	398	285	308	243	309	11,097	10,123	5,977	2,957
Total	276,367,654	294,082,064	290,189,528	253,931,424	278,659,908	256,000,819	302,784,897	338,217,746	348,734,543	316,050,902
Imports and Exports										
Geothermal (Imports)	533,261	538,313	736,980	889,864	877,058	1,172,117	884,950	649,514	16,493	45,145
Conventional Hydroelectric (Imports)	19,148,542	16,302,116	22,318,562	26,948,408	28,558,134	30,478,863	28,823,244	33,359,983	27,990,905	26,031,784
Conventional Hydroelectric (Exports)	5,464,824	7,543,487	3,138,562	3,254,289	3,938,973	2,806,712	3,059,261	2,336,340	6,790,778	6,158,582
Total Net Imports	**14,216,980**	**9,296,942**	**19,916,921**	**24,583,983**	**25,496,219**	**28,844,268**	**26,648,933**	**31,673,157**	**21,216,620**	**19,918,347**
Total Renewable Electricity Generation	341,796,886	364,180,824	377,945,145	353,809,284	385,110,540	369,891,432	415,642,155	458,883,336	456,520,167	418,129,367

Note: Totals may not equal sum of components due to independent rounding.
Sources: **Nonutility Sector - 1989-1997**: Energy Information Administration, Form EIA-867, "Annual Nonutility Power Producer Report." **Nonutility Sector - 1998**: Energy Information Administration, Form EIA-860B, "Annual Electric Generator Report - Nonutility." **Electric Utility Sector - 1989-1997**: Energy Information Administration, Form EIA-860, "Annual Electric Generator Report." **Electric Utility Sector- 1998**: Form EIA-860A "Annual Electric Generator Report - Utility." **Imports and Exports**: Energy Information Administration, *Renewable Energy Annual*, DOE/EIA-0603(95-99) (Washington, DC).

Data on renewable capacity in California were available for years prior to 1989. These data, for 1980 through 1996 (Table 6), more clearly show the growth in renewable capacity owned by nonutilities since the passage of PURPA. Renewable-based nonutility capacity (excluding cogeneration) rose from 187 megawatts in 1980 to 3,777 megawatts (excluding small hydropower and cogeneration plants) in 1996.

Table 7.6: California Nonutility Power Plants Installed Capacity, 1980-1996 (Megawatts)							
Year	Cogeneration[a]	Waste-to-Energy[b]	Geothermal	Small Hydro	Solar	Wind	Total
1980	227	14	0	0	0	173	414
1981	261	14	0	0	0	176	451
1982	412	32	0	48	1	176	669
1983	658	46	9	59	8	227	1,007
1984	893	79	96	67	27	496	1,658
1985	1,444	140	178	107	57	1,015	2,941
1986	1,788	275	188	144	122	1,235	3,752
1987	3,063	396	319	176	155	1,366	5,475
1988	3,662	513	587	229	221	1,378	6,590
1989	4,942	783	806	298	301	1,382	8,512
1990	5,315	878	870	321	381	1,647	9,412
1991	5,838	883	813	330	374	1,698	9,936
1992	5,684	804	831	371	408	1,729	9,827
1993	5,778	845	863	370	373	1,797	10,026
1994	5,857	795	863	410	373	1,629	9,927
1995	6,280	709	846	349	368	1,630	10,182
1996	6,177	823	885	362	360	1,709	10,316

[a]Includes gas-fired facilities and biomass co-firing and cogeneration.
[b]Waste-to-Energy includes wood and wood waste, municipal solid waste, landfill gas, and other biomass. However, biomass co-firing and cogeneration capacity is included under cogeneration.
Source: California Energy Commission, Draft Final Report, *California Historical Energy Statistics*, January 1998, Publication Number: P300-98-001.
Notes: Data exlude facilities rated less than 5 megawatts. Some data in this table are inconsistent with national data in Table 4 due to different sources, categories, and coverage. Also, these data represent installed capacity, while the data in Table 4 represent net summer capability.

Most of the growth had occurred by 1990. Between 1990 and 1993, California nonutility renewable capacity (excluding small hydropower and cogeneration plants) increased just 3% to 3,878 megawatts, and between 1993 and 1995, capacity actually dropped to 3,553 megawatts; generation followed a similar pattern. The principal reasons for this decline were the lower PURPA "avoided costs" when the long-term energy payment provisions of the contracts (usually 10-years), mostly signed in the early 1980s, expired. Natural gas prices in nominal dollars paid by electric utilities in California declines from a high of $6.77 per million Btu in 1982 to between $2.50 to $3.00 in 1986 through 1993. By 1995, the price declined further to $2.22.

This, along with the repeal of the standard investment tax credits in 1986, caused some wind, biomass, and solar facilities to reduce output or cease operation. Also, there was a substantial slowdown in the construction of new capacity. This slowdown transpired despite substantial decreases in short-run average costs of renewables because the operating costs were not reduced enough to be competitive in the market conditions of the mid-to-late 1990s.

Another criterion in evaluating the effectiveness of PURPA, in addition to expansion of renewable energy capacity and generation, is the cost competitiveness of the renewable facilities in the market. Utility wholesale power purchases from other utilities, which are more often made on a mutually agreeable economic basis between utilities and may be regarded as reflecting "wholesale" prices, averaged 3.53 cents per kWh nationwide in 1995. Although EIA has not attempted to estimate the cost of PURPA directly, it has examined the prices that utilities paid in 1995 to purchase power from nonutilities and, in particular, PURPA QF nonutilities using renewable resources. The average price utilities paid all nonutilities was 6.31 cents per kWh nationwide, considerably higher than the average wholesale price. Higher still was the price utilities paid nonutilities for renewable-based electricity. Utilities paid an average of 9.05 cents per kWh for nearly 42,800 million kWh of power from renewable QFs in 1995, compared with just 5.17 cents per kWh for 3,300 million kWh of power from non-QF renewables. This difference was even more extreme in California, where the renewable QF/non-QF purchased power costs were 12.79 and 3.33 cents per kWh, respectively. All non-QF purchases of renewable energy, however, were from hydropower facilities, the lowest cost renewable resource–and the lowest cost of all electricity resources. In analyzing these data, the reader should bear in mind that by 1995, many of the original PURPA power purchase contracts between utilities and nonutilities had expired. Therefore, the data reflect a mixture of the original avoided cost contracts and newer contracts.

Renewable-based generation costs would obviously have compared much more favorably with other generation costs during 2000, when California experienced severe electricity and natural gas shortages. Natural gas prices--the primary basis for determining alternative generation cost--rose sharply during 2000. Through September, the average cost of gas delivered to electric utilities in California increased to $4.32 per million Btu as compared to $2.68 for deliveries through September 1999.

Appendix 1

Biomass Feedstock Availability in the United States

Biomass Feedstock Availability in the United States: 1999 State Level Analysis

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I. Introduction

Interest in using biomass feedstocks to produce power, liquid fuels, and chemicals in the U.S. is increasing. Central to determining the potential for these industries to develop is an understanding of the location, quantities, and prices of biomass resources. This paper describes the methodology used to estimate biomass quantities and prices for each state in the continental U.S. An [Excel™ spreadsheet](#) contains estimates of biomass quantities potentially available in five categories: mill wastes, urban wastes, forest residues, agricultural residues and energy crops. Availabilities are sorted by anticipated delivered price. A [presentation](#) that explains how this information was used to support the goal of increasing biobased products and bioenergy 3 times by 2010 expressed in Executive Order 13134 of August 12, 1999 is also available.

II. Biomass Feedstock Availability

For the purpose of this analysis, biomass feedstocks are classified into five general categories: forest residues, mill residues, agricultural residues, urban wood wastes, and dedicated energy crops. Forestry is a major industry in the United States encompassing nearly 559 million acres in publicly and privately held forest lands in the continental U.S. (USDA, 1997). Nearly 16 million cubic feet of roundwood are harvested and processed annually to produce sawlogs, paper, veneers, composites and other fiber products (USDA, 1998a). The extensive forest acreage and roundwood harvest generate logging residues and provide the potential to harvest non-merchantable wood for energy. Processing of the wood into fiber products creates substantial quantities of mill residues that could potentially be used for energy. Agriculture is another major industry in the United States. Approximately 337 million acres of cropland are currently in agricultural production (USDA, 1997). Following the harvest of many of the traditional agricultural crops, residues (crop stalks) are left in the field. A portion of these residues could potentially be collected and used for energy. Alternatively, crop acres could be used to grow dedicated energy crops. A final category of biomass feedstocks includes urban wood wastes. These wastes include yard trimmings and other wood materials that are generally disposed of in municipal solid waste (MSW) and construction/demolition (C/D) landfills. Following is a description of the potential availability of these biomass feedstocks in the United States.

A. Forest Residues

Forest wood residues can be grouped into the following categories--logging residues; rough, rotten, and salvable dead wood; excess saplings; and small pole trees[1]. The forest wood residue supplies that could potentially be available for energy use in the U.S. are estimated using an updated version of a model originally developed by McQuillan et al. (1984). The McQuillan model estimates the total quantities of forest wood residues that can be recovered by first classifying the total forest inventory by the above wood categories (for both softwood and

hardwood), and by volume, haul distances, and equipment operability constraints. This total inventory is then revised downward to reflect the quantities that can be recovered in each class due to constraints on equipment retrieval efficiencies, road access to a site, and impact of site slope on harvest equipment choice[2].

The costs of obtaining the recoverable forest wood residues are estimated for each category. Prices include collection, harvesting, chipping, loading, hauling, and unloading costs, a stumpage fee, and a return for profit and risk. Prices are in 1995 dollars. For the purposes of this analysis, we have included only logging residues and rough, rotten, and salvable dead wood quantities. The potential annual forest waste residues available by state for three price scenarios are presented in Table 1. Quantities are cumulative quantities at each price (i.e., quantities at $50/dt include all quantities available at $40/dt plus quantities available between $40 and $50/dt).

Polewood, which represent the growing stock of merchantable trees, has not been included in the analysis due to the fact that it could potentially be left to grow and used for higher value fiber products. It is doubtful that these trees will be harvested for energy use. However, if harvested, they could add another 17 million dry tons at less than $30/dt delivered; 37.7 million dry tons at less than $40 delivered; and 65 million dry tons at less than $50/dt delivered. For a more detailed explanation of the methodology used to estimate the forest wood residue quantities and prices, see Walsh et al, 1998.

Table 1: Estimated Annual Cumulative Forest Residues Quantities (dry tons), by Delivered Price and State		
	< $30/dry ton delivered	< $40/dry ton delivered	< $50/dry ton delivered
Alabama	1009000	1475000	1899000
Arizona	134000	200000	261400
Arkansas	928000	1352000	1737800
California	1231000	1819000	2364400
Colorado	373000	554000	720300
Connecticut	109000	159000	204100
Delaware	26000	37000	48400
Florida	515000	755000	9757000
Georgia	1041000	1525000	1967800
Idaho	605000	902000	1179500
Illinois	228000	330000	423300
Indiana	253000	367000	470100
Iowa	72000	105000	135000

Kansas	47000	68000	88100
Kentucky	475000	690000	883500
Louisiana	872000	1275000	1641800
Maine	806000	1182000	1529100
Maryland	189000	273000	351200
Massachusetts	196000	284000	366200
Michigan	710000	1034000	1327900
Minnesota	468000	682000	874900
Mississippi	946000	1380000	1774600
Missouri	505000	733000	938700
Montana	676000	1007000	1316700
Nebraska	19000	27000	34400
Nevada	8000	11000	14400
New Hampshire	299000	438000	564400
New Jersey	70000	102000	130700
New Mexico	125000	185000	241900
New York	933000	1360000	1746400
North Carolina	1068000	1557000	2004900
North Dakota	11000	17000	21700
Ohio	232000	335000	430100
Oklahoma	156000	228000	292200
Oregon	1299000	1928000	2515900
Pennsylvania	948000	1377000	1763000
Rhode Island	20000	27000	35900
South Carolina	613000	898000	1158400
South Dakota	33000	49000	64300
Tennessee	930000	1351000	1732600
Texas	557000	814000	1050700

Utah	90000	133000	173000
Vermont	265000	386000	497200
Virginia	959000	1397000	1793600
Washington	1230000	1825000	2379600
West Virginia	727000	1056000	1352500
Wisconsin	609000	886000	1138400
Wyoming	132000	196000	256100
U.S. Total	23747000	34771000	44871800

B. Primary Mill Residues

The quantities of mill residues generated at primary wood mills (i.e., mills producing lumber, pulp, veneers, other composite wood fiber materials) in the U.S. are obtained from the data compiled by the USDA Forest Service for the 1997 Resource Policy Act (RPA) Assessment (USDA, 1998a). Mill residues are classified by type and include bark; coarse residues (chunks and slabs); and fine residues (shavings and sawdust). Data is available for quantities of residues generated by residue type and on uses of residues by residue type and use category (i.e., not used, fuel, pulp, composite wood materials, etc.). Data is available at the county, state, subregion, and regional level. In cases where a county has fewer than three mills, data from multiple counties are combined to maintain the confidentiality of the data provided by individual mills. Data represent short run average quantities.

Because primary mill residues are clean, concentrated at one source, and relatively homogeneous, nearly 98 percent of all residues generated in the United States are currently used as fuel or to produce other fiber products. Of the 24.2 million dry tons of bark produced in the U.S., 2.2 percent is not used while 79.4 percent is used for fuel and 18 percent is used for such things as mulch, bedding, and charcoal. Only about 1.4 percent of the 38.7 million dry tons of coarse residues are not used. The remainder are used to produce pulp or composite wood products such as particle board, wafer board, and oriented strand board (78 percent) and about 13 percent are used for fuel. Of the 27.5 million dry tons of fine wood residues, approximately 55.6 percent are used for fuel, 23 percent are used to produce pulp or composite wood products, 18.7 percent are used for bedding, mulch and other such uses, and about 2.6 percent are unused.

The residues, while currently used, could potentially be available for energy use if utilities could pay a higher price for the residues than their value in their current uses. Data regarding the value of these residues in their current uses are difficult to obtain. Much of the residues used for fuel are used on site by the residue generator in low efficiency boiler systems to produce heat and steam. Conversations with those in the industry and other anecdotal evidence suggests that these residues could be purchased for $15-25/dry ton for use in higher efficiency fuel systems. Similar anecdotal evidence suggests that residues used to produce fiber products (pulp, composite wood materials) sell for about $30-40/dry ton. For the purposes of this analysis, we assume that the residues not currently used could potentially be available for energy uses at delivered prices of less than $20/dry ton (assuming transportation distances of less than 50 miles). For similar

transportation distances, we assume that residues currently used for fuel could be available at less than $30/dry ton delivered and residues currently used for pulp, composite wood materials, mulch, bedding, and other such uses could potentially be available at delivered prices of less than $50/dry ton. Table 2 presents the cumulative annual quantities of mill residues by delivered price for each state.

Table 2: Estimated Annual Cumulative Mill Residue Quantities (dry tons), by Delivered Price and State			
	< $20/dry ton delivered	< $30/dry ton delivered	< $50/dry ton delivered
Alabama	17000	4581000	7802000
Arizona	0	75000	251000
Arkansas	2000	2497000	4705000
California	8000	2294000	4823000
Colorado	86000	121000	180000
Connecticut	0	40000	91000
Delaware	0	4000	16000
Florida	4000	1412000	2678000
Georgia	72000	3913000	7969000
Idaho	69000	1629000	4400000
Illinois	19000	117000	282000
Indiana	31000	213000	699000
Iowa	2000	46000	158000
Kansas	1000	9000	20000
Kentucky	109000	421000	1940000
Louisiana	64000	1943000	3245000
Maine	43000	209000	504000
Maryland	0	13000	166000
Massachusetts	0	44000	135000
Michigan	10000	932000	1564000
Minnesota	71000	916000	1121000
Mississippi	128000	3178000	6029000
Missouri	162000	315000	1196000
Montana	17000	659000	2173000

Nebraska	12000	21000	69000
Nevada	0	0	0
New Hampshire	23000	439000	1109000
New Jersey	0	8000	21000
New Mexico	25000	61000	125000
New York	28000	495000	1274000
North Carolina	33000	2060000	5028000
North Dakota	0	3000	4000
Ohio	0	0	0
Oklahoma	0	318000	698000
Oregon	10000	1738000	6834000
Pennsylvania	172000	591000	1628000
Rhode Island	0	11000	25000
South Carolina	4000	1706000	3382000
South Dakota	8000	46000	124000
Tennessee	202000	1325000	2018000
Texas	18000	1649000	4043000
Utah	20000	67000	102000
Vermont	0	59000	124000
Virginia	80000	1234000	2860000
Washington	5000	2262000	5689000
West Virginia	136000	459000	967000
Wisconsin	42000	1202000	192000
Wyoming	47000	124000	255000
U.S. Total	1780000	41459000	90418000

C. Agricultural Residues

Agriculture is a major activity in the United States. Among the most important crops in terms of average total acres planted from 1995 to 1997 are corn (77 million acres), wheat (72 million acres), soybeans (65 million acres), hay (60.5 million acres), cotton (15 million acres), grain sorghum (10 million acres), barley (7 million acres), oats (5 million acres), rice (3 million acres), and rye (1.5 million acres) (USDA, 1998b). After harvest, a portion of the stalks could potentially be collected for energy use. The analysis in this paper is limited to corn stover and wheat straw. Large acreage is dedicated to soybean production, but in general, residue production is relatively small and tends to deteriorate rapidly in the field, limiting the usefulness of soybean as an energy feedstock. However, additional residue quantities could be available from this source that have not been included in this analysis. Similarly, additional residue quantities could be available if barley, oats, rice, and rye production were included. Production of some of these crops (rice in particular) tends to be concentrated in a relatively small geographic area, and thus these crops could be an important local source of resources. Another potential source in the southern U.S. is cotton. A recent study (NEOS, 1998) suggests that approximately 500,000 dry tons of cotton gin trash is currently produced in the United States and this material is generally given away to farmers for use as a soil amendment. Another 171,000 dry tons of textile mill residues are produced, but much of this material is used to make other textiles and sells for prices in excess of $100/dry ton. These quantities are not included in this analysis.

The quantities of corn stover and wheat straw residues that can be available in each state are estimated by first calculating the total quantities of residues produced and then calculating the total quantities that can be collected after taking into consideration quantities that must be left to maintain soil quality (i.e., maintain organic matter and prevent erosion). Residue quantities generated are estimated using grain yields, total grain production, and a ratio of residue quantity to grain yield.[3] The net quantities of residue per acre that are available for collection are estimated by subtracting from the total residue quantity generated, the quantities of residues that must remain to maintain quality (Lightle, 1997). Quantities that must remain differ by crop type, soil type, typical weather conditions, and the tillage system used. A state average was used for this analysis. In general, about 30 to 40 percent of the residues can be collected.

The estimated prices of corn stover and wheat straw include the cost of collecting the residues, the premium paid to farmers to encourage participation, and transportation costs.

The cost of collecting the agricultural residues are estimated using an engineering approach. For each harvest operation, an equipment complement is defined. Using typical engineering specifications, the time per acre required to complete each operation and the cost per hour of using each piece of equipment is calculated (ASAE, 1995; NADA, 1995; USDA, 1996; Doanes, 1995). For corn stover, the analysis assumes 1x mow, 1x rake, 1x bale with a large round baler, and pickup, transport, and unloading of the bales at the side of the field where they are stored until transport to the user facility. The same operations are assumed for wheat straw minus the mowing. The operations assumed are conservative--mowing is often eliminated and the raking operation is also eliminated in some circumstances. The method used to estimate collection costs is consistent with that used by USDA to estimate the costs of producing agricultural crops (USDA, 1996).

An additional cost of $20/dry ton is added to account for the premium paid to farmers and the transportation cost from the site of production to the user facility. Currently, several companies purchase corn stover and/or wheat straw to produce bedding, insulating materials, particle board, paper, and chemicals (Gogerty, 1996). These firms typically pay $10 to $15/dry ton to farmers to compensate for any lost nutrient or environmental benefits that result from harvesting residues. The

premium paid to farmers depends, in part, on transportation distance with farmers whose fields are at greater distances from the user facility receiving lower premiums. Studies have estimated that the cost of transporting giant round bales of switchgrass are $5 to $10 per dry ton for haul distances of less than 50 miles (Bhat et al, 1992; Graham et al, 1996; Noon et al, 1996). Agricultural residue bales are of similar size, weight, and density as switchgrass bales, and a similar transportation cost is assumed. This cost is similar to the reported transportation costs of facilities that utilize agricultural residues (Schechinger, 1997). Prices are in 1995$. For a more detailed explanation of the methodology used to estimate agricultural residue quantities and prices, see Walsh et al, 1998. The estimated annual cumulated agricultural residues quantities, by delivered price and state are contained in Table 3. Table 3 also contains by state, the percent of the total available residues that are corn stover.

	< $30/dry ton delivered		< $40/dry ton delivered		< $50/dry ton delivered	
Table 3: Estimated Annual Cumulative Agricultural Residue Quantities (dry tons), by Delivered Price and State						
	Quantity	% Corn	Quantity	% Corn	Quantity	% Corn
Alabama	0	0	0	0	19267	0
Arizona	0	0	221864	24	221864	24
Arkansas	0	0	859361	0	984495	13
California	0	0	1478283	40	1478283	40
Colorado	0	0	2523820	90	2523820	90
Connecticut	0	0	0	0	0	0
Delaware	0	0	88077	0	300736	0
Florida	0	0	14824	0	14824	0
Georgia	0	0	344423	0	779871	56
Idaho	0	0	1248120	10	1248120	10
Illinois	0	0	24270757	94	24270757	94
Indiana	0	0	11883845	94	11883845	94
Iowa	0	0	23911214	99	23911214	99
Kansas	0	0	8570003	48	8570003	48
Kentucky	0	0	471819	0	2280603	49
Louisiana	0	0	80930	0	380557	79
Maine	0	0	0	0	0	0
Maryland	0	0	272468	0	802298	66
Massachusetts	0	0	0	0	0	6
Michigan	0	0	680783	0	4265671	84
Minnesota	0	0	11935896	88	11935896	88
Mississippi	0	0	0	0	37877	0
Missouri	0	0	1204353	0	4081358	70
Montana	0	0	406592	9	406592	9

Nebraska	0	0	16326915	98	16326915	98
Nevada	0	0	15350	0	15350	0
New Hampshire	0	0	0	0	0	0
New Jersey	0	0	32723	0	32723	0
New Mexico	0	0	476529	55	476529	55
New York	0	0	129515	0	129515	0
North Carolina	0	0	473229	0	1130744	58
North Dakota	0	0	14015	0	3715404	0
Ohio	0	0	7634476	82	7634476	82
Oklahoma	3214403	0	3440745	7	3440745	7
Oregon	0	0	155855	40	155855	40
Pennsylvania	0	0	197689	0	1031195	0
Rhode Island	0	0	0	0	0	0
South Carolina	0	0	239680	0	239680	0
South Dakota	0	0	3686246	71	2852740	71
Tennessee	0	0	300849	0	1004781	70
Texas	0	0	4497784	66	4497784	66
Utah	0	0	216546	29	216546	29
Vermont	0	0	0	0	0	0
Virginia	0	0	297986	0	585717	21
Washington	0	0	1364254	30	1364254	30
West Virginia	0	0	12008	0	51295	77
Wisconsin	0	0	5179618	97	5179618	97
Wyoming	0	0	171585	51	171585	51
U.S. Total	3214403	0	135331029	81	150651402	80

D. Dedicated Energy Crops

Dedicated energy crops include short rotation woody crops (SRWC) such as hybrid poplar and hybrid willow, and herbaceous crops such as switchgrass (SG). Currently, dedicated energy crops are not produced in the United States, but could be if they could be sold at a price that ensures the producer a profit at least as high as could be earned using the land for alternative uses such as producing traditional agricultural crops. The POLYSYS model is used to estimate the quantities of energy crops that could potentially be produced at various energy crop prices. POLYSYS is an agricultural sector model that includes all major agricultural crops (wheat, corn, soybeans, cotton, rice, grain sorghum, barley, oats, alfalfa, other hay crops); a livestock sector; and food, feed, industrial, and export demand functions. POLYSYS was developed and is maintained by the Agricultural Policy Analysis Center at the University of Tennessee and is used by the USDA Economic Research Service to conduct economic and policy analysis. Under a joint project between USDA and DOE, POLYSYS is being modified to include dedicated energy crops. A workshop consisting of USDA and DOE experts was held in November, 1997 to review the energy crop data being incorporated into the POLYSYS model.

The analysis includes cropland acres that are presently planted to traditional crops, idled, in pasture, or are in the Conservation Reserve Program. Energy crop production is limited to areas climatically suited for their production--states in the Rocky Mountain region and the Western Plains region are excluded. Because the CRP is an environmental program, two management scenarios have been evaluated--one to optimize for biomass yield and one to provide for high wildlife divesity. Energy crop yields vary within and between states, and are based on field trial data and expert opinion. Energy crop production costs are estimated using the same approach that is used by USDA to estimate the cost of producing conventional crops (USDA, 1996). Recommended management practices (planting density, fertilizer and chemical applications, rotation lengths) are assumed. Additionally, switchgrass stands are assumed to remain in production for 10 years before replanting, are harvested annually, and are delivered as large round bales. Hybrid poplars are planted at a 8 x 10 foot spacing (545 trees/acre) and are harvested in the 10th year of production in the northern U.S., after 8 years of production in the southern U.S., and after 6 years of production in the Pacific Northwest. Poplar harvest is by custom operation and the product is delivered as whole tree wood chips. Hybrid willow varieties are suitable for production in the northern U.S. The analysis assumes 6200 trees/acre, with first harvest in year 4 and subsequent harvests every three years for a total of 7 harvests before replanting is necessary. Willow is delivered as whole tree chips.

The estimated quantities of energy crops are those that could potentially be produced at a profit at least as great as could be earned producing traditional crops on the same acres, given the assumed energy crop yield and production costs, and the 1999 USDA baseline production costs, yields, and traditional crop prices (USDA, 1999b). In the U.S., switchgrass production dominates hybrid poplar and willow production at the equivalent (on an MBTU basis) market prices. The POLYSYS model estimates the farmgate price; an average transportation cost of $8/dt is added to determine the delivered price. Prices are in $1997. Table 4 presents the estimated annual cumulative quantities of energy crops by state by delivered price. For a more detailed explanation of the methodology used to estimate dedicated energy crop prices and quantities, see Walsh et al, 1998 and de la Torre Ugarte et al, 1999.

Table 4: Estimated Annual Cumulative Energy Crop Quantities (dry tons), by Delivered Price and State			
	< $30/dry ton delivered	< $40/dry ton delivered	< $50/dry ton delivered
Alabama	0	3283747	6588812
Arizona	0	0	0
Arkansas	0	1709915	5509780
California	0	0	0
Colorado	0	0	0
Connecticut	0	0	199646
Delaware	0	0	31454
Florida	0	0	1268290
Georgia	0	1321438	3958181
Idaho	0	0	0
Illinois	0	1427349	7689694
Indiana	0	418042	5026234
Iowa	0	234292	8295486
Kansas	0	2859261	11438271
Kentucky	0	3598827	5128780
Louisiana	0	3923954	5813200
Maine	0	0	0
Maryland	0	0	298653
Massachusetts	0	0	235908
Michigan	0	1154228	4179308
Minnesota	0	427467	5783002
Mississippi	0	5330671	9304782
Missouri	0	5251442	12780923
Montana	0	0	2778386
Nebraska	0	1922058	5172860

Nevada	0	0	0
New Hampshire	0	0	158757
New Jersey	0	0	142902
New Mexico	0	0	0
New York	0	0	3388035
North Carolina	0	639228	1632077
North Dakota	0	1928463	16757889
Ohio	0	3808089	9657080
Oklahoma	0	3644173	8083722
Oregon	0	0	0
Pennsylvania	0	0	2338243
Rhode Island	0	0	4943
South Carolina	0	1338745	2438152
South Dakota	0	5613863	12757734
Tennessee	0	6616717	9350856
Texas	0	4549899	9139885
Utah	0	0	0
Vermont	0	0	333465
Virginia	0	1260668	2609867
Washington	0	0	0
West Virginia	0	269250	1190299
Wisconsin	0	3595636	6114270
Wyoming	0	0	487361
U.S. Total	0	66127422	188067187

E. Urban Wood Wastes

Urban wood wastes include yard trimmings, site clearing wastes, pallets, wood packaging, and other miscellaneous commercial and household wood wastes that are generally disposed of at municipal solid waste (MSW) landfills and demolition and construction wastes that are generally disposed of in construction/demolition (C/D) landfills. Data regarding quantities of these wood wastes is difficult to find and price information is even rarer. Additionally, definitions differ by states. Some states collect data on total wastes deposited at each MSW and C/D landfill in their states, and in some states, the quantities are further categorized by type (i.e., wood, paper and cardboard, plastics, etc.). However, not all states collect this data. Therefore, the quantities presented are crude estimates based on survey data (Glenn, 1998; Bush et al, 1997; Araman et al, 1997).

For municipal solid wastes (MSW) a survey by Glenn, 1998 is used to estimate total MSW generated by state. These quantities are adjusted slightly to correspond to regional MSW quantities that are land-filled as estimated by a survey conducted by Araman et al, 1997. Using the Araman survey, the total amount of wood contained in land-filled MSW is estimated. According to this survey, about 6 percent of municipal solid waste in the Midwest is wood, with 8 percent of the MSW being wood in the South, 6.6 percent being wood in the Northeast and 7.3 percent being wood in the West. Estimated quantities were in wet tons; they were corrected to dry tons by assuming a 15 percent moisture content by weight.

To estimate construction and demolition wastes (C/D), the Glenn study and the Bush et al, 1997 survey were used. The Glenn study provided the number of C/D landfills by state, and the Bush et al survey provided the average quantity of waste received per C/D landfill by region as well as the regional percent of the waste that was wood. According to the Bush et al survey, C/D landfills in the Midwest receive an average 25,700 tons of waste per year with 46 percent of that quantity being wood. In the South, C/D landfills receive an average 36,500 tons of waste/yr with 39 percent being wood. Northeastern C/D landfills receive an average 13,700 tons of waste/yr with 21 percent being wood and Western C/D landfills receive an average 28,800 tons of waste/yr with 18 percent being wood. Estimated quantities were in wet tons; they were corrected to dry tons by assuming a 15 percent moisture content by weight.

Yard trimmings taken directly to a compost facility rather than land-filled, were estimated from the Glenn study. This estimate was made by multiplying the number of compost facilities in each state by the national average tons of material received by site (2750 tons). The total compost material was then corrected for the percent that is yard trimmings (assumed to be 80 percent) and for the quantity that is wood (assumed to be 90 percent). Quantities were corrected to dry tons by assuming a 40 percent moisture by weight.

In an effort to reduce the quantities of waste materials that are land-filled, most states actively encourage the recycling of wastes. Quantities and prices of recycled wood wastes are not readily available. However, the Araman and Bush surveys report limited data on the recycling of wood wastes at MSW and C/D sites. They report that in the South, approximately 36 percent of C/D landfills and 50 percent of MSW landfills operate a wood/yard waste recycling facility and that about 34 percent of the wood at C/D landfills and 39 percent of the wood at MSW landfills is recycled. In the Midwest, about 31 percent of the MSW and 25 percent of the C/D landfills operate wood recycling facilities with 16 percent of the MSW wood and 1 percent of the C/D wood is recycled. In the West, 27 percent of the MSW and C/D landfills operate wood recycling facilities and recycle 25 percent each of their wood. In the Northeast, 39 percent of the MSW and 28 percent of the C/D landfills operate wood recycling facilities and recycle 39 percent of the MSW wood and 28 percent of the C/D wastes.

The surveys do not report the use of total recycled wood, but do report the uses of recycled pallets which represent about 7 percent of the total wood and 4 percent of the recycled wood at C/D landfills and about 24 percent of the total wood and about 13 percent of the recycled wood at MSW landfills. At C/D landfills, about 14 percent of the recycled pallets are re-used as pallets, about 39 percent are used as fuel, and the remainder is used for other purposes such as mulch and composting. About 69 percent of the recyclers reported that they gave away the pallet material. Of those selling the material, the mean sale price was $11.01/ton and the median sale price was $10.50/ton. At MSW landfills, about 3 percent of the recycled pallets are re-used as pallets, about 41 percent are used as fuel, and the remainder is used for other purposes such as mulch and composting. About 58 percent of the C/D recyclers reported that they gave away the pallet material. Of those selling the material, the mean sale price was $13.17/ton and the median sale price was $10.67/ton. Transportation costs must still be added to the sale price. Given the lack of information regarding prices, we assumed that of the total quantity available, 60 percent could be available at less than $20/dry ton and that the remaining quantities could be available at less than $30/dry ton. Table 5 presents the estimated annual cumulative quantities of urban wood wastes by state and price.

	< $20/dry ton	< $30/dry ton	< $40/dry ton	< $50/dry ton
Table 5: Estimated Annual Cumulative Urban Wood Waste Quantities (dry tons), by Delivered Price and State				
Alabama	823566	1372610	1372610	1372610
Arizona	219736	366227	366227	366227
Arkansas	400364	667273	667273	667273
California	1579813	2633022	2633022	2633022
Colorado	94661	157769	157769	157769
Connecticut	246938	411563	411563	411563
Delaware	38959	64931	64931	64931
Florida	2757950	4596584	4596584	4596584
Georgia	862094	1436823	1436823	1436823
Idaho	135265	338162	338162	338162
Illinois	416047	693411	693411	693411
Indiana	316610	527684	527684	527684
Iowa	171802	286337	286337	286337
Kansas	736289	1227148	1227148	1227148
Kentucky	345699	576165	576165	576165
Louisiana	452322	753870	753870	753870
Maine	108358	180597	180597	180597
Maryland	204643	341071	341071	341071
Massachusetts	419272	698787	698787	698787
Michigan	495734	826224	826224	826224
Minnesota	919517	1532529	1532529	1532529
Mississippi	470831	784719	784719	784719
Missouri	315547	525911	525911	525911
Montana	52060	86766	86766	86766
Nebraska	102073	170121	170121	170121

Nevada	184112	306853	306853	306853
New Hampshire	110579	184298	184298	184298
New Jersey	389089	648481	648481	648481
New Mexico	142896	238160	238160	238160
New York	1140080	1900133	1900133	1900133
North Carolina	636035	1060056	1060056	1060056
North Dakota	326510	544184	544184	544184
Ohio	744518	1240864	1240864	1240864
Oklahoma	111173	185289	185289	185289
Oregon	182532	304220	304220	304220
Pennsylvania	399963	666605	666605	666605
Rhode Island	29803	49671	49671	49671
South Carolina	1289900	2149833	2149833	2149833
South Dakota	123982	206637	206637	206637
Tennessee	676029	1126715	1126715	1126715
Texas	1209449	2015749	2015749	2015749
Utah	138765	231275	231275	231275
Vermont	40802	68004	68004	68004
Virginia	519454	865757	865757	865757
Washington	292432	487387	487387	487387
West Virginia	105236	175393	175393	175393
Wisconsin	383466	639110	639110	639110
Wyoming	177383	295638	295638	295638
U.S. Total	22040338	36846616	36846616	36846616

III. Summary

Table 6 summarizes the estimated total annual cumulative quantities of biomass resources available by state and delivered price. It is estimated that substantial quantities of biomass (510 million dry tons) could be available annually at prices of less that $50/dt delivered. However, several caveats should be noted. There is a great deal of uncertainty surrounding some of the estimates. For example, while there is substantial confidence in the estimated quantities of mill residues available by state, there is a great deal of uncertainty about the estimated prices of these residues. The value of these feedstocks in their current uses is speculative and based solely on anecdotal discussions. Given that the feedstock is already being used--much of it under contract or in-house by the generator of the waste--energy facilities may need to pay a higher price than assumed to obtain the feedstock. Additionally, both the quantity and price of urban wastes are highly speculative. The analysis is based solely on one national study and regional averages taken from two additional surveys. There is no indication of the quality of the material present (i.e., whether the wood is contaminated with chemicals, etc.). Because of the ways in which the surveys were conducted, there may be double counting of some quantities (i.e., MSW may contain yard trimmings and C/D wastes as well). Additionally, the analysis assumes that the majority of this urban wood is available for a minimal fee, with much of the cost resulting from transportation. Other industries have discovered that once a market is established, these "waste materials" become more valuable and are no longer available at minimal price. This situation could also happen with urban wastes used for energy if a steady customer becomes available. It should also be noted however, that some studies indicate that greater quantities of urban wastes are available, and are available at lower prices, than are assumed in this analysis (Wiltsee, 1998). Given the high level of uncertainty surrounding the quantity and price estimates of urban wastes and mill residues, and the fact that these wastes are estimated to be the least cost feedstocks available, they should be viewed with caution until a more detailed analysis is completed.

The analysis has assumed that substantial quantities of dead forest wood could be harvested. The harvest of deadwood is a particularly dangerous activity and not one relished by most foresters. Additionally, large polewood trees represent the growing stock of trees, that if left for sufficient time, could be harvested for higher value uses. These opportunity costs have not been considered. And, the sustainability of removing these forest resources has not been thoroughly analyzed.

We estimate the price of agricultural residues to be high largely because of the small quantities that can be sustainably removed on a per acre basis. Improvements in the collection/transport technologies and the ability to sustainably collect larger quantities (due to a shift in no-till site preparation practices for example) could increase quantities and decrease prices over time. Also, the inclusion of some of the minor grain crops (i.e., barley, oats, rye, rice) and soybeans could increase the total quantities of agricultural residues available by state. However, further elucidation of quantities that can sustainably be removed might lower available quantities.

Dedicated energy crops (i.e., switchgrass and short rotation wood crops) are not currently produced--the analysis is based on our best estimates of yield, production costs, and profitability of alternative crops that could be produced on the same land. Improving yields and decreasing production costs through improved harvest and transport technologies could increase available quantities at lower costs.

We have assumed a transportation cost of $8/dry ton for most feedstocks. This cost is based on a typical cost of transporting materials (i.e., switchgrass bales and wood chips) for less than 50 miles (Graham et al, 1996; Bhat et al, 1992; Noon et al, 1996). Finally, the analysis is conducted at a state level and the distribution of biomass resources within the state is not specifically considered. We

have simply assumed that the feedstock is available within 50 miles of a user facility. This may not be the case which would result either in the cost of the feedstock being higher to a user facility due to increased transportation costs, or the quantities of available feedstock being lower to a user facility if the material is simply too far away from the end-user site to be practical to obtain. Biomass resource assessments are needed at a lower aggregation level than the state. Any facility considering using the analysis need to conduct its own local analysis to verify feedstock quantity and prices.

	< $20/dry ton	< $30/dry ton	< $40/dry ton	< $50/dry ton
Table 6: Estimated Cumulative Biomass Quantities (dry ton/yr), by Delivered Price and State				
Alabama	840566	6962610	10712357	17681689
Arizona	219736	575227	863091	1100491
Arkansas	402364	4092273	7085549	13604348
California	1587813	6158022	8224305	11298705
Colorado	180661	651769	3356589	3581889
Connecticut	246938	560563	610563	906309
Delaware	38959	94931	194008	461521
Florida	2761950	6753122	6778408	9533398
Georgia	934094	6390823	8540684	16111675
Idaho	204265	2572162	4117282	7165782
Illinois	435047	1038411	26838517	33359162
Indiana	347610	993684	13409571	18606863
Iowa	173802	404337	24582843	32786037
Kansas	737289	1283148	12733412	21343522
Kentucky	454699	1472165	5757811	10809048
Louisiana	516322	3568870	7976754	11834427
Maine	151358	1195597	1571597	2213697
Maryland	204643	543071	899539	1959222
Massachusetts	419272	938787	1026787	1435895
Michigan	505734	2468224	4627235	12163103
Minnesota	990517	2916529	15493892	21247327
Mississippi	598831	4908719	10673390	17930978
Missouri	477547	1345911	8029706	19522892
Montana	69060	1421766	2159358	6761444
Nebraska	114073	210121	18467094	21773296

Nevada	184112	314853	333203	336603
New Hampshire	133579	922298	1061298	2016455
New Jersey	389089	726481	791204	975806
New Mexico	167896	424160	960689	1081589
New York	1168080	3328133	3884648	8438083
North Carolina	669035	4188056	5789513	10855777
North Dakota	326510	558184	2506662	21043177
Ohio	744518	1472864	13018429	18962520
Oklahoma	111173	3873692	7816207	12699956
Oregon	192532	3341220	4126075	9809975
Pennsylvania	571963	2205605	2832294	7427043
Rhode Island	29803	80671	87671	115514
South Carolina	1293900	4468833	6332258	9368065
South Dakota	131982	285637	9601746	16005411
Tennessee	878029	3381715	10720281	15232952
Texas	1227449	4221749	13526432	20747118
Utah	158765	388275	647821	722821
Vermont	40802	392004	513004	1022669
Virginia	599454	3058757	5055411	8714941
Washington	297432	3979387	5938641	9920241
West Virginia	241236	1361393	1971651	3736487
Wisconsin	425466	2450110	11502364	14963398
Wyoming	224383	551638	787223	1465684
U.S. Total	23820338	105496557	314535067	510855005

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1. Logging residues are the unused portion of the growing of stock trees (i.e., commercial species with a diameter breast height (dbh) greater than 5 inches, excluding cull trees) that are cut or killed by logging and left behind. Rough trees are those that do not contain a sawlog (i.e., 50 percent or more of live cull volume) or are not a currently merchantable species. Rotten trees are trees that do not contain a sawlog because of rot (i.e., 50 percent or more of the live cull volume). Salvable dead wood includes downed or standing trees that are considered currently or potentially merchantable. Excess saplings are live trees having a dbh of between 1.0 and 4.9 inches. Small pole trees are trees with a dbh greater than 5 inches, but smaller than saw timber trees. (back to report)

2. Retrieval efficiency accounts for the quantity of the inventory that can actually be recovered due to technology or equipment (assumed to be 40 percent). It is assumed that 50 percent of the resource is accessible without having to construct roads, except for logging residues for which 100 percent of the inventory is assumed accessible. Finally, inventory that lies on slopes greater than 20 percent or where conventional equipment cannot be used are eliminated for cost and environmental reasons. (back to report)

3. The assumed residue factors are--1 ton of corn stover for every 1 ton of corn grain produced; 1.7 tons of wheat straw for every 1 ton of winter wheat grain; and 1.3 ton of wheat straw for every 1 ton of spring and duram wheat grain (Heid, 1984). We assume a grain weight of 56 and 60 lb/bu for corn and wheat grain respectively. Grain moisture factors are assumed to be 1 for corn and .87 for wheat. (back to report)

Appendix 2

Chemical Industry Utilities Costs

Chemicals Industry Manufacturing Costs
Reference: Department of Energy (1998). "Chemicals Industry Costs," EIA Manufacturing Consumption of Energy 1998, Table N8.3

1998 Data   Dollars per physical unit

NAICS Code	Subsector and Industry	Electricity Total (kWh)	Electrical Components		Natural Gas Total (mscf)	Natural Gas Components		Steam Total (million Btu)	Steam Components	
			From Local Utility (kWh)	From Other Sources (kWh)		From Local Utility (mscf)	From Other Sources (mscf)		From Local Utility (Mbtu)	From Other Sources (Mbtu)
Total United States										
311	Food	0.051	0.051	W	3.03	3.24	2.87	2.53	2.8	2.15
311221	Wet Corn Milling	0.034	0.034	W	2.64	2.79	2.6	W	W	W
325	Chemicals	0.036	0.036	0.032	2.44	2.61	2.39	3.13	3.30	3.01
325110	Petrochemicals	0.039	0.041	W	2.42	2.22	2.51	2.68	W	W
325120	Industrial Gases	0.033	W	W	2.13	2.13	W	3.49	W	W
325181	Alkalies and Chlorine	0.026	0.027	W	2.32	W	2.48	W	W	W
325188	Other Basic Inorganic Chemicals	0.026	0.026	0.032	2.78	3.01	2.73	4.20	5.92	Q
325192	Cyclic Crudes and Intermediates	0.040	W	W	2.54	2.37	2.95	3.67	W	W
325199	Other Basic Organic Chemicals	0.037	0.039	0.028	2.34	2.58	2.31	2.90	3.19	2.85
325211	Plastics Materials and Resins	0.038	0.039	0.035	2.52	3.29	2.33	3.59	3.93	3.47
325212	Synthetic Rubber	0.041	0.041	0.049	2.45	2.78	2.41	4.06	W	3.70
325222	Noncellulosic Organic Fibers	0.036	0.038	0.030	2.72	W	W	W	W	W
325311	Nitrogeneous Fertilizers	0.035	0.035	0.044	2.29	2.40	2.28	W	0.00	W
325312	Phosphatic Fertilizers	0.037	0.037	0.000	2.33	2.36	2.33	W	0.00	W
326	Plastics and Rubber Products	0.053	0.053	0.045	3.58	3.80	3.23	3.45	3.62	2.74
326199	Other Plastics Products	0.056	0.056	0.050	4.06	4.64	3.33	W	W	W

A2-2

NAICS Code	Subsector and Industry	Electricity Total (kWh)	Electrical Components		Natural Gas Total (mscf)	Natural Gas Components		Steam Total (million Btu)	Steam Components	
			From Local Utility (kWh)	From Other Sources (kWh)		From Local Utility (mscf)	From Other Sources (mscf)		From Local Utility (Mbtu)	From Other Sources (Mbtu)
Northeast Census Region										
311	Food	0.073	0.074	0.060	3.88	4.09	3.76	2.60	2.47	2.99
311221	Wet Corn Milling	W	W	0.000	0.00	0.00	0.00	0.00	0.00	0.00
325	Chemicals	0.052	0.054	0.037	3.67	3.75	3.58	4.39	3.68	4.46
325110	Petrochemicals	W	W	0.000	W	W	0.00	0.00	0.00	0.00
325120	Industrial Gases	0.040	0.038	W	W	W	0.00	W	W	W
325181	Alkalies and Chlorine	0.019	0.022	W	W	W	W	W	0.00	W
325188	Other Basic Inorganic Chemicals	0.059	0.059	W	3.49	3.60	3.35	W	0.00	W
325192	Cyclic Crudes and Intermediates	0.048	0.047	W	3.45	W	3.62	W	0.00	W
325199	Other Basic Organic Chemicals	0.048	0.048	0	3.86	4.08	3.70	3.05	W	3.16
325211	Plastics Materials and Resins	0.055	0.055	0	3.72	4.08	3.24	3.98	W	3.97
325212	Synthetic Rubber	W	W	W	W	6.22	W	W	0.00	W
325222	Noncellulosic Organic Fibers	0.089	0.089	0.000	W	W	WW	0.00	0.00	0.00
325311	Nitrogeneous Fertilizers	0.065	0.071	W	4.25	W	3.60	0.00	0.00	0.00
325312	Phosphatic Fertilizers	W	W	0.000	0.00	0.00	0.00	0.00	0.00	0.00
326	Plastics and Rubber Products	0.070	0.070	0.060	4.35	4.65	3.96	W	W	0.00
326199	Other Plastics Products	0.067	0.068	0.050	4.90	5.25	4.48	0.00	0.00	0.00

NAICS Code	Subsector and Industry	Electricity Total (kWh)	Electrical Components		Natural Gas Total (mscf)	Natural Gas Components		Steam Total (million Btu)	Steam Components	
			From Local Utility (kWh)	From Other Sources (kWh)		From Local Utility (mscf)	From Other Sources (mscf)		From Local Utility (Mbtu)	From Other Sources (Mbtu)
Midwest Census Region										
311	Food	0.046	0.046	0.055	2.87	3.02	2.78	2.97	2.89	W
311221	Wet Corn Milling	0.034	0.034	W	2.64	2.77	2.60	W	W	W
325	Chemicals	0.035	0.035	0.037	2.73	3.26	2.56	3.21	3.92	2.77
325110	Petrochemicals	0.056	0.056	0	3.43	W	W	0	0	0
325120	Industrial Gases	0.034	0.034	W	2.87	2.87	W	W	W	W
325181	Alkalies and Chlorine	0.032	0.032	0.000	3.23	W	W	W	W	0.00
325188	Other Basic Inorganic Chemicals	W	W	0.000	3.00	2.99	3.00	3.43	W	W
325192	Cyclic Crudes and Intermediates	0.036	0.036	0.000	2.98	3.03	W	W	0.00	W
325199	Other Basic Organic Chemicals	0.040	0.040	W	2.92	2.80	2.99	2.34	0.00	2.34
325211	Plastics Materials and Resins	0.039	0.039	W	3.64	4.26	2.66	2.91	4.45	2.44
325212	Synthetic Rubber	0.046	0.042	W	2.91	3.28	W	W	W	0.00
325222	Noncellulosic Organic Fibers	0.000	0.000	0.000	0.00	0.00	0.00	0.00	0.00	0.00
325311	Nitrogeneous Fertilizers	0.035	0.035	W	2.30	W	2.28	W	0.00	W
325312	Phosphatic Fertilizers	W	W	0.000	W	W	W	0.00	0.00	0.00
326	Plastics and Rubber Products	0.051	0.051	0.034	3.38	3.66	3.11	W	W	0.00
326199	Other Plastics Products	0.054	0.054	W	3.59	4.06	3.12	W	W	0.00

NAICS Code		Subsector and Industry	Electricity Total (kWh)	Electrical Components		Natural Gas Total (mscf)	Natural Gas Components		Steam Total (million Btu)	Steam Components	
				From Local Utility (kWh)	From Other Sources (kWh)		From Local Utility (mscf)	From Other Sources (mscf)		From Local Utility (Mbtu)	From Other Sources (Mbtu)
South Census Region											
311		Food	0.049	0.049	0.047	3.13	3.36	2.85	2.77	2.79	2.66
	311221	Wet Corn Milling	0.032	0.032	0.000	2.71	W	2.60	0.00	0.00	0.00
325		Chemicals	0.034	0.035	0.030	2.35	2.38	2.34	2.99	3.22	2.80
	325110	Petrochemicals	0.039	0.040	W	2.42	2.22	2.50	2.68	W	W
	325120	Industrial Gases	0.031	0.031	0.000	1.99	1.94	W	W	W	W
	325181	Alkalies and Chlorine	0.028	0.028	W	2.31	W	W	W	0.00	W
	325188	Other Basic Inorganic Chemicals	0.026	0.026	W	2.80	2.90	2.76	W	W	W
	325192	Cyclic Crudes and Intermediates	0.040	0.040	0.000	2.35	2.23	2.87	W	W	0.00
	325199	Other Basic Organic Chemicals	0.035	0.037	0.027	2.30	2.47	2.28	2.92	3.21	2.88
	325211	Plastics Materials and Resins	0.036	0.036	0.034	2.35	2.69	2.30	3.81	3.76	3.83
	325212	Synthetic Rubber	0.038	0.038	W	2.36	2.65	2.33	3.59	W	3.49
	325222	Noncellulosic Organic Fibers	0.036	0.037	0.030	2.68	3.02	W	W	W	W
	325311	Nitrogeneous Fertilizers	0.035	0.035	W	2.28	W	2.29	W	0.00	W
	325312	Phosphatic Fertilizers	0.420	0.042	0.000	2.37	2.72	2.35	W	0.00	W
326		Plastics and Rubber Products	0.045	0.046	0.037	3.40	3.59	2.97	3.03	W	2.74
	326199	Other Plastics Products	0.050	0.050	0.000	4.68	5.36	2.98	0.00	0.00	0.00

NAICS Code		Subsector and Industry	Electricity Total (kWh)	Electrical Components		Natural Gas Total (mscf)	Natural Gas Components		Steam Total (million Btu)	Steam Components	
				From Local Utility (kWh)	From Other Sources (kWh)		From Local Utility (mscf)	From Other Sources (mscf)		From Local Utility (Mbtu)	From Other Sources (Mbtu)
West Census Region											
311		Food	0.054	0.054	0.056	2.89	3.16	2.71	1.94	2.93	1.76
	311221	Wet Corn Milling	0.041	0.041	0.000	2.71	W	2.70	W	W	W
325		Chemicals	0.039	0.038	0.048	2.62	2.99	2.53	2.59	W	2.43
	325110	Petrochemicals	0.000	0.000	0.000	0.00	0.00	0.00	0.00	0.00	0.00
	325120	Industrial Gases	0.040	0.040	W	2.59	W	W	0.00	0.00	0.00
	325181	Alkalies and Chlorine	0.023	0.023	0.000	W	0.00	W	W	W	0.00
	325188	Other Basic Inorganic Chemicals	0.029	0.028	W	2.55	W	2.56	W	0.00	W
	325192	Cyclic Crudes and Intermediates	0.067	0.067	0.000	2.77	2.84	W	0.00	0.00	0.00
	325199	Other Basic Organic Chemicals	0.056	0.061	W	3.28	Q	3.26	3.50	W	W
	325211	Plastics Materials and Resins	0.064	0.063	0.079	3.46	3.74	3.16	W	0.00	W
	325212	Synthetic Rubber	0.107	0.107	0.000	6.78	6.78	0.00	0.00	0.00	0.00
	325222	Noncellulosic Organic Fibers	W	W	0.000	0.00	0.00	0.00	0.00	0.00	0.00
	325311	Nitrogeneous Fertilizers	0.030	0.029	W	W	W	W	W	0.00	W
	325312	Phosphatic Fertilizers	W	W	0.000	W	W	W	0.00	0.00	0.00
326		Plastics and Rubber Products	0.061	0.061	Q	3.71	3.83	3.02	W	W	0.00

1998 Data   Dollars per physical unit

NAICS Code	Subsector and Industry	Electricity Total (kWh)	Electrical Components		Natural Gas Total (mscf)	Natural Gas Components		Steam Total (million Btu)	Steam Components	
			From Local Utility (kWh)	From Other Sources (kWh)		From Local Utility (mscf)	From Other Sources (mscf)		From Local Utility (Mbtu)	From Other Sources (Mbtu)
325										
al United States	Chemicals	0.036	0.036	0.032	2.44	2.61	2.39	3.13	3.30	3.01
rtheast Census Region	Chemicals	0.052	0.054	0.037	3.67	3.75	3.58	4.39	3.68	4.46
dwest Census Region	Chemicals	0.035	0.035	0.037	2.73	3.26	2.56	3.21	3.92	2.77
uth Census Region	Chemicals	0.034	0.035	0.030	2.35	2.38	2.34	2.99	3.22	2.80
st Census Region	Chemicals	0.039	0.038	0.048	2.62	2.99	2.53	2.59	W	2.43

Appendix 3

Properties of Biomass[1]

March 2002

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[1] Updated from Graboski, M. S. and Bain R. L. (1979). "Chapter 3: Properties of Biomass Relevant to Gasification," in A Survey of Biomass Gasification, Volume II - Principles of Gasification, Solar Energy Research Inst., Golden, CO, SERI/TR-33-239, July

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PROPERTIES OF BIOMASS RELEVANT TO GASIFICATION

An understanding of the structure and properties of biomass materials is necessary to evaluate their utility as feedstocks for conversion processes. This section summarizes available information on a variety of such properties including chemical analysis, heats of combustion and formation, physical structure, heat capacities, and transport properties of biomass feedstocks and chars. Much of the information reported is for wood materials; however, where data were available for other forms of biomass such as municipal solid waste and feedlot waste, they were included.

3.1   BULK CHEMICAL ANALYSIS OF BIOMASS

In evaluating gasification feedstocks, it is generally useful to have proximate and ultimate analyses, heats of combustion, and sometimes ash analyses. These provide information on volatility of the feedstock, elemental analysis, and heat content. The elemental analysis is particularly important in evaluating the feedstock in terms of potential pollution.

Table 3-1 lists the standard Methods for evaluating carbonaceous feedstocks.

A number of instruments have been developed for determining elemental composition, most often, in biomass conversion, for carbon, hydrogen, nitrogen, sulfur, and oxygen. Chlorine normally is not determined by such analyzers. Most of these systems employ a catalytic combustion or pyrolysis step to decompose the sample to carbon dioxide, water, hydrogen sulfide, and nitrogen, which are then determined quantitatively by as chromatography using flame ionization (FID) or thermal conductivity (TC) detectors. Oxygen is usually determined by catalytic conversion to carbon monoxide over a platinized carbon catalyst followed by GC analysis. A short list of some representative equipment is given in Table 3-2.

3.1.1   Proximate Analyses

The proximate analysis classifies the fuel in terms of its moisture (M), volatile matter (VM), ash, and (by difference) fixed carbon content. In the test procedure, the volatile material is driven off in an inert atmosphere at high temperatures (950°C) using a slow heating rate. The pyrolysis yield is representative of that for slow pyrolysis processes; fast pyrolysis techniques employing very rapid heating rates normally yield more volatile matter. The moisture determined by the proximate method represents physically bound water only; water released by chemical reactions during pyrolysis is classified with the volatiles. The ash content is determined by combustion of the volatile and fixed carbon fractions. The resulting ash fraction is not representative of the original ash, more appropriately termed mineral matter, due to the oxidation process employed in its determination. In the most exact analysis, small corrections to the ash weight are necessary to correct it to a mineral

Table 3-1: ASTM Standards Methods for Biomass and Coal

Method	Biomass Test No.	Coal Test No.	Repeatability[a] (wt%)	Reproducibility[b] (wt%)
Proximate Analysis				
Moisture	E871	D2013, D3173	0.5	1.0
Volatile Matter	E872, E897	D3175	0.5	1.0
Ash	D1102, E830	D3174	0.6	1.3
Fixed Carbon	Difference	Difference		
Ultimate Analysis		D3176		
C	E777	D3176	0.5	1.6
H	E777	D3178	0.2	0.5
N	E778	D3179	0.04	0.05
S	E775	D4239, D3177	0.03	0.06
O	Difference	Difference		
Chlorine	E776	D2361	0.03	0.11
Gross Heating Value	E711, D2015	D2015	27-111 Btu/lb[c]	68-250 Btu/lb[c]
Ash Analysis				
Ash in Biomass	E1755		2.7[d]	8.9[d]
Ash in wood	D1102		0.03 (6.6[d])	
Elemental Ash	D3682, D2795		5[d] See element	
Fusion temp	D1857		50°F	
Water soluble alkali	Soak overnight in H_2O @90 C, Analyze by AA			
Bulk Density	E873		TBD	TBD
Fuel size (based on RDF)	E828			

[a] within laboratory; [b] between laboratories; [c] dependent on magnitude of HHV
[d] % of average

matter basis. The fixed-carbon content of an as received sample is calculated by material balance. Thus:

$$FC = 1 - M - ASH - VM \qquad (3\text{-}1)$$

The fixed carbon is considered to be a polynuclear aromatic hydrocarbon residue resulting from condensation reactions which occur in the pyrolysis step.

Table 3-2: Elemental Analyzer Equipment

Instrument	Oxidant	Capability	Detection
Carlo Erba 1104	oxygen	C, H, N, O	FID & TIC
Chemical Data Systems (CDS 1200)	oxygen	C, H, N, O, S and functional groups	FID & TC
Hewlett-Packard HP-185	MNO_2 added	C, H, N	FID & TC
Perkin Elmer 240	oxygen	C, H, N, O, S	TC

The most useful basis for reporting proximate analysis is the dry basis. In this instance the compositions are normalized to a moisture-free basis (denoted by *):

$$VM^* + FC^* + ASH = 1, \qquad (3\text{-}2)$$

and, for example,

$$VM^* = VM/(1-M).$$

The moisture is reported as grams of moisture per gram of dry feedstock. Typical proximate analyses for solid fuels are given in Table 3-3, from which it is evident that common biomass materials are more readily devolatilized (pyrolyzed) than lignite and bituminous coals, yielding considerably less fixed-carbon residue. This is due to the much more aromatic structure of the coals which is produced by the geological coalification process. The higher volatile content of biomass materials makes them potentially useful feedstocks for pyrolysis processes. In general, the ash content of biomass materials is considerably lower than for coals. This is due to the fact that the bulk of the coal ash was deposited in coal beds by processes such as siltation and did not come from the parent carbonaceous material. An exception is municipal solid waste, which contains a high mineral content due to nonvolatile trash components such as metals and glass.

Table 3-3: Proximate Analysis Data for Selected Solid Fuels and Biomass
(Dry basis, wt%)

	Volatile Matter (VM)	Fixed Carbon (FC)	Ash	Reference
Coals				
Pittsburgh seam	33.9	55.8	10.3	Bituminous Coal Research 1974
Wyoming Elkol	44.4	51.4	4.2	
Lignite	43.0	46.6	10.4	
Oven Dry Woods				
Western hemlock	84.8	15.0	0.2	Howlett and Gamanche 1977
Douglas fir	86.2	13.7	0.1	
White fir	84.4	15.1	0.5	
Ponderosa pine	87.0	12.8	0.2	
Redwood	83.5	16.1	0.4	
Cedar	77.0	21.0	2.0	
Oven Dry Barks				
Western hemlock	74.3	24.0	1.7	Howlett and Gamance 1977
Douglas fir	70.6	27.2	2.2	
White fir	73.4	24.0	2.6	
Ponderosa pine	73.4	25.9	0.7	
Redwood	71.3	27.9	0.8	
Cedar	86.7	13.1	0.2	
Municipal Refuse and Major Components				
Nat'l Ave. Waste	65.9	9.1	25.0	Klass and Ghosh 1973
Newspaper (9.4%)	86.3	12.2	1.5	
Paper boxes (23.4%)	81.7	12.9	5.4	
Magazine paper (6.8%)	69.2	7.3	23.4	
Brown paper (5.6%)	89.1	9.8	1.1	
Selected Biomass				
Almond wood	77.28	15.94	6.78	Miles et. al. 1995
Red oak sawdust	86.22	13.47	0.31	
Hybrid poplar	84.81	12.49	2.70	
Alfalfa stems	78.92	15.81	5.27	
Wheat straw, Denmark	69.80	12.29	10.78	
Wheat straw, OR	81.24	17.06	4.32	
Rice straw	65.47	15.86	18.67	
Willow	85.23	13.82	0.95	
Sugar cane bagasse	85.61	11.95	2.44	
Switchgrass, MN	82.94	14.37	2.69	
Bana Grass	73.44	16.68	9.88	

3.1.2 Ultimate Analyses

Ultimate analyses generally report C, H, N, S and O (by difference) in the solid fuel. Table 3-1 lists the appropriate ASTM tests for these elements while Table 3-2 lists several manufacturers of modern elemental analyzers. Care must be exercised in using ultimate analyses for fuels containing high moisture content because moisture is indicated in the ultimate analysis as additional hydrogen and oxygen.

To avoid confusion and give a good representation of the fuel itself, ultimate analyses should be performed and reported on a dry basis; when this is done all hydrogen determined is truly a constituent of the fuel. For certain biomass materials like municipal solids and animal waste, the determination of chlorine is important because it represents a possible pollutant and corrosive agent in gasification and combustion systems.

Typical ultimate analyses for a variety of feedstocks are presented in Table 3-4.

All biomass materials have carbon contents considerably lower than coals; the atomic carbon to hydrogen ratio is much higher in coals than in biomass materials. For coal, the H/C ratio is unity, while for biomass the ratio is typically 1.5. The bound oxygen content of biomass materials is considerably higher, due to the ether, acid, and alcohol groups in the cellulose, hemicellulose, and lignin fractions of biomass, as will be discussed later in this section. The nitrogen and sulfur contents in coal are considerably higher than those in most biomass. Thus, in direct biomass combustion, pollutants resulting from bound nitrogen and sulfur in the fuel generally are present in small enough quantities to meet EPA standards, although the high chlorine contents that are found in animal wastes can pose a severe pollution problem. The nitrogen content, normalized by heating value, of selected samples from Table 3-4 is given in Figure 3-1. Alkali content of biomass is important also because of its potential impact on slagging and fouling in combustion and gasification systems. A recent study (Miles 1995) found that biomass feeds containing less than 0.5 lb K per million Btu did not cause fouling and slagging in commercial biomass boilers. The potassium content of selected biomass samples from Table 3-4 is shown in Figure 3-2.

The relative "quality" of the volatile matter can be estimated using the ultimate analysis and simple stoichiometry. If it is assumed that the fixed carbon contains only carbon, then all hydrogen and oxygen plus a portion of the carbon are associated with the volatile materials. Table 3-5 presents a typical calculation for the volatile fraction of lignite and Douglas fir bark.

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Table 3-4: Ultimate Analysis Data for Selected Solid Fuels and Biomass Materials
(Dry basis, wt %)

Material	C	H	N	S	O	Cl	Ash	HHV Btu/lb	HHV MJ/kg	Reference
Pittsburgh seam coal	75.5	5.0	1.2	3.1	4.9	--	10.3	13,650	31.68	Tillman 1978
West Kentucky No. 11 coal	74.4	5.1	1.5	3.8	7.9	--	7.3	13,460	31.24	Bituminous Coal Research 1974
Utah coal	77.9	6.0	1.5	0.6	9.9	--	4.1	14,170	32.89	Tillman 1978
Wyoming Elkol coal	71.5	5.3	1.2	0.9	16.9	--	4.2	12,710	29.50	Bituminous Coal Research 1974
Lignite	64.0	4.2	0.9	1.3	19.2	--	10.4	10,712	24.86	Bituminous Coal Reseach 1974
Charcoal	80.3	3.1	0.2	0.0	11.3	--	3.4	13,370	31.03	Tillman 1978
Alder, red	49.55	6.06	0.13	0.07	43.78		0.40	8,578	19.91	Rossi
Alder/fir sawdust	51.02	5.80	0.46	0.05	68.54	0.02	4.13	8,760	20.33	Miles et. al. 1995
Alfalfa Pellets	44.90	5.60	2.90	0.22	37.08	0.39	9.30	7,807	18.12	MN Project
Alfalfa Pellets	45.60	5.50	2.70	0.21	36.99	0.39	9.00	7,880	18.29	MN Project
Alfalfa seed straw	46.76	5.40	1.00	0.02	40.72		7.25	7,949	18.45	Jenkins and Ebeling
Almond hulls	45.79	5.36	0.96	0.01	40.60		5.78	7,850	18.22	Jenkins and Ebeling
Almond prunings	51.30	5.29	0.66	0.01	40.90		1.63	8,621	20.01	Jenkins and Ebeling
Almond shells	44.98	5.97	1.16	0.02	42.27		4.81	8,350	19.38	Jenkins and Ebeling
Almond wood	47.45	5.53	0.59	0.08	39.57	0.03	6.78	6,829	15.85	Miles et. al. 1995
Animal waste	42.7	5.5	2.4	0.3	31.3		17.8	7,380	17.13	Tillman 1978
Ash, white	49.70	6.90			43.00		0.30	8,940	20.75	Johnson and Auth
Bagasse	39.70	5.50	0.30		42.30		13.30	6,756	15.68	Mudge et al
Bagasse	44.80	5.35	0.38	0.01	39.55		11.27	7,467	17.33	Jenkins and Ebeling
Bagasse	46.27	5.27	0.12	0.05	42.41	0.05	5.83	7,885	18.30	Turn et. al.
Bagasse	48.64	5.87	0.16	0.04	42.85	0.03	2.44	8,166	18.95	Miles et. al. 1995
Bagasse	45.71	5.89			40.37		8.03	8,402	19.50	Grover and Anuradha
Bana Grass, HI	45.06	5.42	0.84	0.11	38.69	0.83	9.88	7,533	17.48	Miles et. al. 1995
Banagrass	47.10	5.29	0.44	0.16	41.93	0.61	4.47	7,897	18.33	Turn et. al.
Bark	47.27	5.20	0.40	0.05	37.68	0.03	9.37	7,721	17.92	Feldman et. al.
Bean straw	42.97	5.59	0.83	0.01	44.93		5.93	7,523	17.46	Jenkins and Ebeling
Beech	51.6	6.3	0.0	0.0	41.5		0.6	8,760	20.33	Tillman 1978
Birch and maple mix	49.86	6.12	0.10	0.09	43.45	0.03	0.36	8,453	19.62	Feldman et. al.
Birch, white	49.80	6.50			43.40		0.30	8,669	20.12	Johnson and Auth

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Material	C	H	N	S	O	Cl	Ash	HHV Btu/lb	HHV MJ/kg	Reference
Black locust	50.73	5.71	0.57	0.01	41.93		0.80	8,492	19.71	Jenkins and Ebeling
Black walnut prunings	49.80	5.82	0.22	0.01	43.25		0.78	8,544	19.83	Jenkins and Ebeling
Cabernet Sauvignon prunings	46.59	5.85	0.83	0.04	43.90		2.17	8,199	19.03	Jenkins and Ebeling
Casuarina	48.50	6.04	0.31	0.00	43.32		1.83	8,087	18.77	Channiwala
Casuarina	48.61	5.83	0.59	0.02	43.36		1.40	8,376	19.44	Jenkins and Ebeling
Cedar bark	51.00	5.70			38.20		5.10	8,630	20.03	Johnson and Auth
Cedar, white	48.80	6.40			44.40		0.40	8,018	18.61	Johnson and Auth
Chaparall	46.90	5.08	0.54	0.03	40.17		6.13	8,337	19.35	Jenkins and Ebeling
Chenin Blanc prunings	48.02	5.89	0.86	0.07	41.93		2.51	8,242	19.13	Jenkins and Ebeling
Cherry	48.52	5.81	0.31	0.02	42.97	0.02	1.35	8,408	19.51	Feldman et. al.
Chinkapin	49.68	5.93	0.07	0.01	44.03		0.30	8,337	19.35	Rossi
Christmas trees	51.59	5.58	0.52	0.40	36.70	--	5.21	9,009	20.91	Miles et. al. 1995
Cocoa hulls	48.23	5.23	2.98	0.12	33.19		8.25	8,203	19.04	Jenkins and Ebeling
Coconut fiber (coir)	50.29	5.05	0.45	0.16	39.63		3.72	8,639	20.05	Channiwala
Coconut shells	50.22	5.07	0.00	0.00	43.37		0.71	8,832	20.50	Channiwala
Corn cobs	46.58	5.87	0.47	0.11	45.46		1.36	8,087	18.77	Jenkins and Ebeling
Corn stover	43.65	5.56	0.61	0.01	43.31		5.58	7,604	17.65	Jenkins and Ebeling
Corn Stover	46.50	5.81	0.56	0.11	39.67		7.40	8,186	19.00	Gregory et al
Corn stover	46.51	5.81	0.56	0.11	39.67		7.00	8,782	20.38	Evans et. al.
Cotton gin trash	39.59	5.26	2.09	2.09	36.38		17.60	7,075	16.42	Jenkins and Ebeling
Cotton gin waste	42.66	6.05	0.18		49.50		1.61	7,531	17.48	Channiwala
Cotton stalk	39.47	5.07	1.25	0.02	38.09		17.20	6,820	15.83	Channiwala
Cotton stalk	43.64	5.81	0.00	0.00	43.87		6.68	7,867	18.26	Grover and Anuradha
Cypress	55.00	6.50			38.10		0.40	9,892	22.96	Johnson and Auth
Demolition wood	46.30	5.39	0.57	0.12	34.50	0.05	13.12	7,916	18.37	Miles et. al. 1995
Douglas fir	50.64	6.18	0.06	0.02	43.00		0.10	8,837	20.51	Rossi
Douglas fir	52.3	6.3	0.1	0.0	40.5		0.8	9,050	21.01	Tillman 1978
Douglas fir bark	56.2	5.9	0.0	0.0	36.7		1.2	9,500	22.05	Tillman 1978
Elm	50.40	6.60			42.30		0.70	9,039	20.98	Johnson and Auth
Eucalyptus Camaldulensis	49.00	5.87	0.30	0.01	43.97		0.76	8,367	19.42	Jenkins and Ebeling
Eucalyptus Globulus	48.18	5.92	0.39	0.01	44.18		1.10	8,285	19.23	Jenkins and Ebeling
Eucalyptus Grandis	48.33	5.89	0.15	0.01	45.13		0.52	8,337	19.35	Jenkins and Ebeling

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Material	C	H	N	S	O	Cl	Ash	HHV Btu/lb	HHV MJ/kg	Reference
Fir mill waste	51.23	5.98	0.06	0.03	42.29	0.19	0.41	8,779	20.38	Miles et. al. 1995
Fir, white	49.00	5.98	0.05	0.01	44.75		1.52	8,367	19.42	Jenkins and Ebeling
Forest residuals	50.31	4.59	1.03	0.11	39.99	0.04	3.97	8,670	20.12	Miles et. al. 1995
Furniture waste	49.87	5.91	0.29	0.03	40.29	<0.01	3.61	8,658	20.10	Miles et. al. 1995
Grape pomice	54.94	5.83	2.09	0.21	32.08		4.20	9,393	21.80	Grover and Anuradha
Groundnut shells	48.59	5.64	0.58	0.00	39.49		5.70	8,552	19.85	Johnson and Auth
Gum	50.88	6.06	0.15	0.04	41.57	0.02	1.28	8,475	19.67	Feldman et. al.
Hardwood	49.73	6.06	0.24	0.04	42.87	0.11	0.95	8,430	19.57	Feldman et. al.
Hemlock, western	50.4	5.8	0.1	0.1	41.4		2.2	8,620	20.01	Tillman 1978
Hickory	49.7	6.5	0.0	0.0	43.1		0.7	8,670	20.12	Tillman 1978
Hog fuel	45.36	5.63	0.18	0.02	42.13	0.03	16.89	7,681	17.83	Feldman et. al.
Kelp, brown, Soquel Point	27.80	3.77	4.63	1.05	23.69		42.10	4,632	10.75	Chynoweth et al
Kelp, giant brown, Monterey	26.60	3.74	2.55	1.09	20.22		45.80	4,421	10.26	Chynoweth et al
Macadamia shells	54.41	4.99	0.36	0.01	39.69		0.40	9,052	21.01	Jenkins and Ebeling
Madrone	48.56	6.05	0.05	0.02	45.08		0.30	8,246	19.14	Rossi
Madrone	48.94	6.03	0.05	0.02	41.74		0.20	8,406	19.51	Rossi
Mango wood	46.24	6.08	0.28		44.42		2.98	8,259	19.17	Johnson and Auth
Manzanita	48.18	5.95	0.17	0.02	44.68		0.82	8,315	19.30	Jenkins and Ebeling
Maple	49.54	6.11	0.10	0.02	49.54		0.50	8,306	19.28	Evans et. al.
Maple	50.6	6.0	0.3	0.0	41.7		1.4	8,580	19.91	Tillman 1978
Millet straw	43.71	5.85	0.01	0.00	45.16		5.27	7,777	18.05	Channiwala
Mixed waste paper	47.99	6.63	0.14	0.07	36.84		8.33	8,934	20.74	Miles et. al. 1995
Mixed wood	49.31	6.03	0.18	0.02	42.98	0.04	1.44	8,366	19.42	Feldman et. al.
Mixed wood (90% red oak)	48.51	6.17	0.12	0.04	44.22		0.94	8,210	19.06	Evans et. al.
Mixed wood	48.40	6.31	0.21	0.03	44.23		0.82	8,228	19.10	Evans et. al.
Municipal solid waste	47.6	8.0	1.2	0.3	32.9		12.0	8,546	19.84	Saner et. al. 1970
Napier grass	45.20	6.00			42.30		5.70	7,889	18.31	Elliot et al
Oak	49.83	5.87	0.32	0.04	41.82	0.03	2.09	8,373	19.43	Feldman et. al.
Oak, Alabama woodwaste	49.5	5.7	0.2	0.0	41.3	--	3.3	8,266	19.19	Boley and Landers 1969
Oak, Canyon	47.84	5.80	0.07	0.01	45.76		0.50	8,178	18.98	Rossi
Oak, red	49.34	5.93	0.07	0.13	41.74	0.03	2.76	8,220	19.08	Feldman et. al.
Oak, red, sawdust	49.96	5.92	0.03	0.01	43.77	0.07	0.31	8,374	19.44	Miles et. al. 1995

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Material	C	H	N	S	O	Cl	Ash	HHV Btu/lb	HHV MJ/kg	Reference
Oak, tan	48.67	6.03	0.06	0.04	44.99		0.20	8,156	18.93	Rossi
Oak, tan	48.34	6.12	0.03	0.03	44.99		0.50	8,238	19.12	Jenkins and Ebeling
Oak, white	49.48	5.38	0.35	0.01	43.13		1.52	8,367	19.42	Jenkins and Ebeling
Olive pits	48.81	6.23	0.36	0.01	43.48		3.20	9,216	21.39	Channiwala
Paper	43.4	5.8	0.3	0.2	44.3	--	6.0	7,572	17.57	Bowernan 1969
Peach pits	49.14	6.34	0.48	0.02	43.52		1.10	8,367	19.42	Rossi
Peach pits	53.00	5.90	0.32	0.05	39.14		1.03	8,970	20.82	Jenkins and Ebeling
Peanut hulls	45.77	5.46	1.63	0.12	39.56		5.89	8,031	18.64	Jenkins and Ebeling
Pine	51.27	6.19	0.13	0.13	42.13	0.02	0.13	8,748	20.30	Feldman et. al.
Pine bark	52.3	5.8	0.2	0.0	38.8		2.9	8,780	20.38	Tillman 1978
Pine needles	48.21	6.57			43.72		1.50	8,669	20.12	Grover and Anuradha
Pine, long leaf, bark	56.40	5.50			37.40		0.70	9,380	21.77	Risser
Pine, ponderosa	49.25	5.99	0.06	0.03	44.36		0.29	8,470	19.66	Jenkins and Ebeling
Pine, slash, bark	56.20	5.40			37.30		0.70	9,380	21.77	Risser
Pine, white	52.60	6.10			41.20		0.10	8,919	20.70	Johnson and Auth
Pine, yellow	52.60	7.00			52.60		1.31	9,668	22.44	Riser
Pine. Loblolly, bark	56.30	5.60			37.70		0.40	9,384	21.78	Risser
Pistachio shells	48.79	5.91	0.56	0.01	43.41		1.13	8,298	19.26	Jenkins and Ebeling
Poplar	48.45	5.85	0.47	0.01	43.69		1.33	8,350	19.38	Jenkins and Ebeling
Poplar	51.6	6.3	0.0	0.0	41.5		0.6	8,920	20.70	Tillman 1978
Poplar - coarse	50.82	5.89	0.59	0.02	41.08	0.04	1.60	8,139	18.89	Miles et. al. 1995
Poplar, hybrid	50.18	6.06	0.60	0.02	40.44	0.01	2.70	8,178	18.98	Miles et. al. 1995
Redwood	53.5	5.9	0.1	0.0	40.3		0.2	9,040	20.98	Tillman 1978
Redwood wastewood	53.4	6.0	0.1	0.1	39.9		0.6	9,163	21.27	Boley and Landers 1969
RDF - Tacoma, WA	39.70	5.78	0.80	0.35	27.24		26.13	6,679	15.50	Miles et. al. 1995
Rice hulls	38.30	4.36	0.83	0.06	35.45		20.60	6,415	14.89	Rossi
Rice hulls	38.5	5.7	0.5	0.0	39.8		15.5	6,610	15.34	Tillman 1978
Rice husk	38.92	5.10	2.17	0.12	37.89		15.80	6,751	15.67	Maheshwari
Rice husk bran	39.82	5.12	0.55	0.00	36.77		18.64	6,588	15.29	Channiwala
Rice straw	39.2	5.1	0.6	0.1	35.8		19.2	6,540	15.18	Tillman 1978
Rice straw	41.78	4.63	0.70	0.08	36.57		13.42	7,014	16.28	Jenkins and Ebeling
Sawdust	51.33	6.13	0.12	0.02	41.97	0.07	0.36	8,802	20.43	Feldman et. al.

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Material	C	H	N	S	O	Cl	Ash	HHV Btu/lb	HHV MJ/kg	Reference
Sawdust pellets	47.2	6.5	0.0	0.0	45.4		1.0	8,814	20.46	Wen et. al. 1974
Shredded currency	42.89	5.97	1.75	0.30	43.62		5.47	7,867	18.26	Miles et. al. 1995
Softwood	50.80	6.25	0.15	0.14	41.74	0.03	0.78	8,771	20.36	Feldman et. al.
Southern oak	49.94	5.30	0.16	0.00	42.77	0.02	0.81	8,500	19.73	Feldman et. al.
Spruce	51.80	5.70			38.30		3.80	8,759	20.33	Johnson and Auth
Sudan grass	44.58	5.35	1.21	0.01	39.18		8.65	7,492	17.39	Jenkins and Ebeling
Switchgrass, Columbus, OH	46.68	5.82	0.77	0.19	37.57	0.03	8.97	7,766	18.02	Miles et. al. 1995
Switchgrass, Dakota Leaf, MN	47.45	5.75	0.74	0.08	42.37	0.03	3.61	8,014	18.60	Miles et. al. 1995
Switchgrass, G Petersen 1	48.64	5.46	0.04	0.07	42.06	0.005	3.73	8,001	18.57	Iowa Project
Switchgrass, G Petersen 2	47.98	5.46	0.19	0.06	41.54	0.007	4.77	7,765	18.02	Iowa Project
Switchgrass, G Petersen 4	48.37	5.52	0.03	0.15	43.59	0.003	2.34	8,104	18.81	Iowa Project
Switchgrass, Joe Cross 1	47.11	5.39	0.23	0.06	43.19	0.007	4.02	7,934	18.41	Iowa Project
Switchgrass, Joe Cross 2	46.00	4.57	0.32	0.05	44.51	0.006	4.54	7,862	18.25	Iowa Project
Switchgrass, Joe Cross 4	48.00	5.54	0.16	0.07	42.61	0.004	3.61	8,017	18.61	Iowa Project
Switchgrass, Krutsinger 1	46.91	5.38	0.38	0.07	41.61	0.017	5.64	7,890	18.31	Iowa Project
Switchgrass, Krutsinger 2	44.97	5.10	0.69	0.09	42.43	0.024	6.72	7,812	18.13	Iowa Project
Switchgrass, Krutsinger 4	48.20	5.68	0.24	0.06	42.00	0.017	3.81	7,952	18.46	Iowa Project
Switchgrass, Lodge Land 1	47.71	5.43	0.38	0.04	41.53	0.007	4.91	7,953	18.46	Iowa Project
Switchgrass, Lodge Land 2	47.46	5.41	0.48	0.05	43.18	0.007	3.42	8,091	18.78	Iowa Project
Switchgrass, Lodge Land 4	47.72	5.48	0.15	0.06	43.10	0.003	3.49	8,034	18.65	Iowa Project
Switchgrass, Schulz 30	48.69	5.61	0.06	0.05	43.14	0.003	2.44	8,012	18.60	Iowa Project
Switchgrass, Sellers 1	48.69	5.50	0.34	0.06	41.28	0.004	4.14	8,021	18.62	Iowa Project
Switchgrass, Sellers 2	48.31	5.52	0.29	0.09	42.59	0.005	3.20	8,074	18.74	Iowa Project
Switchgrass, Sellers 32	49.10	5.71	0.17	0.05	42.21	0.002	2.76	7,983	18.53	Iowa Project
Switchgrass, Sellers 4	48.72	5.54	0.16	0.05	41.70	0.008	3.83	8,052	18.69	Iowa Project
Switchgrass, Summer, MN	47.51	5.02	0.65	0.07	37.02	0.03	2.69	7,979	18.52	Miles et. al. 1995
Switchgrass, SWG10	43.78	5.25	0.52	0.07	46.10	0.035	4.29	7,806	18.12	Iowa Project
Switchgrass, SWG12	43.20	5.23	0.50	0.10	47.19	0.046	3.78	7,735	17.95	Iowa Project
Switchgrass, SWG14	42.13	5.07	0.54	0.08	48.49	0.022	3.68	7,803	18.11	Iowa Project
Switchgrass, SWG16	42.89	5.05	0.57	0.10	47.68	0.015	3.71	7,837	18.19	Iowa Project
Switchgrass, SWG18	43.93	5.17	0.55	0.08	46.86	0.005	3.41	7,809	18.12	Iowa Project
Switchgrass, SWG20	44.21	5.07	0.64	0.09	46.23	0.004	3.75	7,793	18.09	Iowa Project

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Material	C	H	N	S	O	Cl	Ash	HHV Btu/lb	HHV MJ/kg	Reference
Switchgrass, SWG22	44.45	5.14	0.59	0.11	46.17	0.004	3.53	7,847	18.21	Iowa Project
Switchgrass, SWG26	44.86	5.15	0.57	0.09	46.20	0.005	3.13	7,852	18.22	Iowa Project
Switchgrass, SWG28	44.71	5.15	0.63	0.07	45.90	0.003	3.55	7,785	18.07	Iowa Project
Switchgrass, Van Patten 1	48.32	5.50	0.10	0.06	42.80	0.036	3.21	8,161	18.94	Iowa Project
Switchgrass, Van Patten 2	48.41	5.48	0.09	0.04	42.56	0.024	3.42	8,091	18.78	Iowa Project
Switchgrass, Van Patten 4	46.95	5.79	0.14	0.06	44.71	0.012	2.35	8,182	18.99	Iowa Project
Switchgrass, WG24	44.03	5.09	0.55	0.09	46.30	0.006	3.93	7,864	18.25	Iowa Project
Urban wood waste	48.77	5.76	0.27	0.07	39.59	0.05	2.50	8,361	19.41	Miles et. al. 1995
Walnut shells	49.98	5.35	0.21	0.01	43.35		0.56	8,695	20.18	Jenkins and Ebeling
Walnut, English, prunings	49.72	5.63	0.37	0.01	43.14		1.08	8,458	19.63	Jenkins and Ebeling
Water hyacinth	40.30	4.60	1.51		33.99		19.60	6,402	14.86	Klass and Ghosh
Water hyacinth	43.00	5.80	5.60		29.50		15.30	7,747	17.98	Elliot et al
Wheat dust	41.38	5.10	3.04	0.19	35.17		13.68	6,980	16.20	Jenkins and Ebeling
Wheat straw	43.20	5.00	0.61	0.11	39.40		8.90	7,199	16.71	Jenkins and Ebeling
Willow - SA22 -3 yr	49.90	5.90	0.61	0.07	41.81	<0.01	1.71	8,424	19.55	Miles et. al. 1995
Willow - SA22 Butt	48.95	6.05	0.36	0.04	43.54	0.01	1.06	8,326	19.32	Miles et. al. 1995
Willow - SA22 Top	49.42	5.89	0.96	0.12	41.27	<0.01	2.34	8,510	19.75	Miles et. al. 1995
Willow - SA22-1 yr	49.75	6.00	0.65	0.09	42.01	0.01	1.50	8,457	19.63	Miles et. al. 1995
Willow - SH3-1 yr	48.85	6.04	0.71	0.06	42.64	0.01	1.70	8,443	19.60	Miles et. al. 1995
Willow - SP3-1yr	50.29	6.01	0.50	0.07	41.93	<0.01	1.20	8,691	20.17	Miles et. al. 1995
Willow - SV1-1 yr	47.94	5.84	0.63	0.06	44.43	<0.01	1.10	8,325	19.32	Miles et. al. 1995
Willow - SV1-3 yr	49.09	5.89	0.35	0.03	46.39	<0.01	0.95	8,330	19.33	Miles et. al. 1995
Wood - land clearing	42.32	5.02	0.33	0.06	35.77	0.02	16.50	7,408	17.19	Miles et. al. 1995
Wood - yard waste	41.54	4.79	0.85	0.24	32.21	0.30	20.37	7,009	16.27	Miles et. al. 1995

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Figure 3-1: Nitrogen Content of Selected Biomass Samples

Nitrogen Content of Biomass

Bar chart of Nitrogen (lb/MBtu) for selected biomass samples (x-axis from 0.0 to 3.5):

- Alfalfa stems — ~3.0
- Rice straw — ~1.35
- Wood - yard waste — ~1.2
- RFD - Tacoma — ~1.2
- Forest residuals — ~1.15
- Bana Grass, HI — ~1.1
- Switchgrass, OH — ~1.0
- Switchgrass, D Leaf, MN — ~0.9
- Almond wood — ~0.85
- Switchgrass, MN — ~0.8
- Rice husks — ~0.75
- Willow - SV1-1 yr — ~0.75
- Hybrid poplar — ~0.7
- Imperial wheat straw — ~0.7
- Poplar - coarse — ~0.7
- Demolition wood — ~0.7
- California wheat straw — ~0.55
- Oregon wheat straw — ~0.5
- Alder/fir sawdust — ~0.5
- Danish wheat straw — ~0.5
- Wood - land clearing — ~0.45
- Willow - SV1-3 yr — ~0.4
- Miscanthus, Silberfeder — ~0.4
- Furniture waste — ~0.35
- Urban wood waste — ~0.3
- Sugar Cane Bagasse — ~0.2
- Mixed waste paper — ~0.15
- Fir mill waste — ~0.05
- Red oak sawdust — ~0.03

Nitrogen (lb/MBtu)

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Figure 3-2: Potassium Content of Selected Biomass Samples[3]

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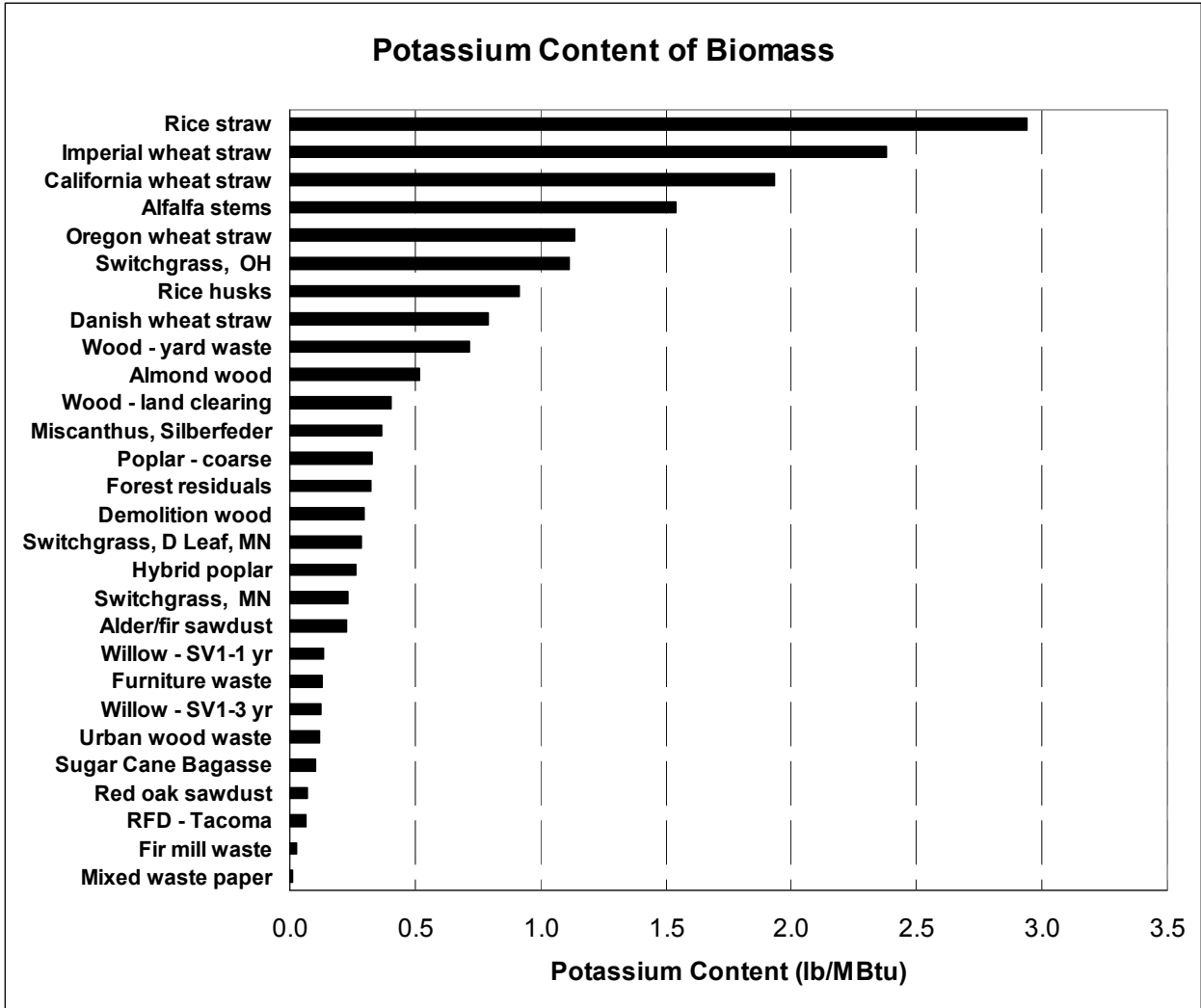
Table 3-5: Elemental Analysis of Volatiles Liberated by Pyrolysis for Two Selected Fuels

Fuel	wt% in volatile, dry basis			Molar ratio volatile		
	C	H	O	C	H	O
Lignite	17.4	4.22	19.17	1	2.91	0.83
Douglas fir bark	23.4	5.9	36.7	1	3.03	1.17

The C/H/O ratios of these volatile fractions are very similar despite the difference in feedstock. In the pyrolysis process, at relatively high temperatures,

$$\nearrow \quad CH_4 \tag{3-3}$$

$$\text{Volatiles} \quad \longrightarrow \quad CO + CO_2 \tag{3-4}$$

$$\searrow \quad H_2O \tag{3-5}$$

If we assume that CO is produced exclusively we can calculate the product analysis from pyrolysis.

Therefore, assuming:

$$C + 4H \longrightarrow CH_4 \tag{3-6}$$

$$2H + O \longrightarrow H_2 \tag{3-7}$$

$$C + O \longrightarrow CO, \tag{3-8}$$

let X be the moles of carbon converted to methane, Y the oxygen converted to water, and Z the carbon to CO.

The material balance equations yield:

$$X = [\, 2 + (H/C) - 2\,(O/C)\,]\,/\,6 \tag{3-9}$$

$$Z = 1 - X \tag{3-10}$$

$$Y = O/C - Z \tag{3-11}$$

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In the calculation for methane it should be pointed out that as long as water-gas shift reaction equilibrium is attained, it makes no difference whether the non-hydrocarbon products are CO and H_2O or a mixture of CO, CO_2, H_2, and H_2O.

Table 3-6 presents such an analysis on a dry basis of 100 lb of fuel.

Table 3-6: Evaluation of Feedstocks for Pyrolysis by Material Balance Calculation

Fuel	SCF Gas 100lb dry feed	Mole Fractions			Lb C in CH_4 100lb C in feed
		CH_4	CO	H_2O	
Lignite	754	0.395	0.334	0.271	14.7
Douglas fir bark	1196	0.277	0.341	0.382	18.7

The gas derived from lignite is higher in quality than that from the fir bark due to the bark's greater potential to form water. The quantity of gas produced is greater for the fir bark due to the greater quantity of volatiles present. The most important factor is the fraction of carbon converted to methane. The woody material shows a greater potential to form methane on a carbon feed basis, indicating that it is a higher quality feedstock for pyrolysis. This may be attributed to the higher degree of aromaticity exhibited in coals.

Table 3-7 presents ultimate analysis for typical pyrolysis chars derived from biomass feedstocks. Except for the municipal solid waste char, all contain considerable quantities of volatile constituents, including H and O, due to the low processing temperature.

The C/H and C/O ratios are greater in all chars than in the fresh feed materials. The high-temperature municipal waste char has been almost completely devolatized, as is evidenced by the low H and O contents.

3.1.3 Moisture Content of Fuels

Woody fuels and municipal solid waste samples are available with various moisture contents. The moisture is important in determining drying costs and as-received heat contents of the fuels.

Table 3-8 presents approximate ranges of moisture for typical biomass fuels. The effect of moisture on the recoverable heat is dramatic due to the heat requirements for vaporizing the moisture plus superheating the vapor.

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Table 3-7: Ultimate Analysis Data for Selected Pyrolysis Chars
(Dry Basis, Weight Percent)

Material	C	H	N	S	O	Ash	HHV Btu/lb	HHV MJ/kg	Reference
Fir bark char	49.9	4.0	0.1	0.1	24.5	21.4	8,260	19.17	Pober and Bauer 1977
Rice hull char	36.0	2.6	0.4	0.1	11.7	49.2	6,100	14.16	Pober and Bauer 1977
Grass straw char	51.0	3.7	0.5	0.8	19.7	24.3	8,300	19.26	Pober and Bauer 1977
Animal waste char[a]	34.5	2.2	1.9	0.9	7.9	48.8	5,450	12.65	Pober and Bauer 1977
MSW char	54.9	0.8	1.1	0.2	1.8	41.2	8,020	18.61	Sanner et al 1970
Redwood charcoal (421 - 549°C)	75.6	3.3	0.2	0.2	18.4	2.3	12,400	28.78	Boley and Landers 1969
Redwood charcoal (460 - 941°C)	78.8	3.5	0.2	0.2	13.2	4.1	13,100	30.41	Boley and Landers 1969
Oak charcoal (438 - 641°C)	67.7	2.4	0.4	0.2	14.4	14.9	10,660	24.60	Boley and Landers 1969
Oak charcoal (571°C)	64.6	2.1	0.4	0.1	15.5	17.3	9,910	23.00	Boley and Landers 1969

[a]Contains 3.7% Cl lumped with oxygen

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Table 3-8: Approximate Moisture Contents Of Typical Biomass Fuels

Biomass Fuel	Moisture Content (wt %)
Bark	25 - 75
Coarse wood residue	30 - 60
Manure, beef cattle	80 - 90
Manure, poultry	70 - 80
Shavings	16 - 40
Sawdust	25 - 40
Sander dust	2 - 8
Municipal refuse	20
Air dry feedlot waste	12
Baled switchgrass	10 - 15

3.1.4 Heating Values

The heating value of carbon feedstocks is determined by the ASTM method listed in Table 3-1. The experimental method employs an adiabatic bomb calorimeter which measures the enthalpy change between reactants and products at 25°C. The heating value obtained is termed the higher heating value because the water of combustion is present in the liquid state at the completion of the experimental determination.

The heating value may be reported on two bases. These are the gross or higher heating value and the net or lower heating value. The higher heating value (HHV) represents the heat of combustion relative to liquid water as the product. The lower heating value (LHV) is based on gaseous water. You may also see HHV and LHV referred to as gross calorific value (GCV) and net calorific value (NCV). The difference in the heating value is the latent heat of the water of combustion. Heating values often are reported on both wet and dry fuel bases. The conversion between bases is simple in the case of the higher heating value, involving only normalizing out the moisture (M). This is true because the moisture present in the raw fuel is in the same state before and after combustion.

$$HHV^* = HHV / (1 - M) \hspace{3cm} (3\text{-}12)$$

Lower (net) heating values depend on the moisture content in a more complicated

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fashion. Since both the product water and moisture are present as vapor after combustion, a portion of the heat of combustion is used to evaporate the moisture. Therefore, using the latent heat of water, $\lambda = 980$ Btu/lb,

$$HHV^* = (LHV - M\lambda) / (1 - M) \qquad\qquad (3\text{-}13)$$

To convert between higher (gross) and lower (net) heating values, the amount of water produced by combustion reactions, but not including moisture, must be known. If this is called W, lb water/lb fuel, then the heating values are related by:

$$HHV = LLV + W\lambda. \qquad\qquad (3\text{-}14)$$

All heats reported in this discussion are higher (gross) heating values on a dry basis.

Table 3-4 reports higher heating values on a dry basis for a variety of biomass fuels. Typically, the heating values for coals are much greater than for biomass materials, ranging from 10 MBtu/lb to 14 MBtu/lb (23.2 MJ/kg to 32.5 MJ/kg) and 5 MBtu/lb to 9 MBtu/lb (11.6 MJ/kg to 20.9 MJ/kg), respectively. This is principally due to the higher carbon content of the coals. Table 3-7 gives higher heating values for biomass chars. The values are low due to the high ash content of the chars; however, on a dry, ash-free basis, the heating values are similar to those of the coals.

A common method for estimating heating values of solid fuels is the Boie equation (Van Krevelan 1961) which permits the heating value to be estimated from the ultimate analysis. The Boie equation has been used to estimate the HHV of the biomass samples in Table 3-4. The average absolute error of the estimate is 4.70%, with a bias of 3.19%. A second method for estimating heating values is that of Tillman (1978). As shown in Table 3-9, the results for Tillman's equation, which uses only the carbon content, give comparable values. The average error is roughly 2.83% with a positive bias of 0.83%.

A third method of estimating gross heating values has been developed at IGT (Institute of Gas Technology 1978) using the experimental heating values and ultimate analyses of more than 700 coal samples. When this heating value correlation is used to estimate the higher heating values of fresh biomass materials, the average error is 3.34% with a negative 1.73% bias.

A linear least-squares regression has been performed on the biomass data set in Table 3-4 and the resulting regression equation is given in Table 3-9. The average error is 2.02%, with a positive bias of 0.09. R^2 for the fit is 0.900. A graphical representation of the correlation versus data is given in Figure 3.3. While this better represents the data in Table 3-4, it must be noted that the estimate has not been checked for biomass samples outside the given data set. The experimental error in the ASTM heating value is ± 100 Btu/lb while the regression yields an average error for chars and fresh biomass

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of about ± 160 Btu/lb. Experimental values should be used in cases where the elemental analysis is much different from materials previously tested.

Table 3-9: Comparison of Experimental and Calculated Higher (Gross) Heating Values

Name	Equation HHV [=] Btu/lb	Absolute Avg Error %	Bias %	R^2
Boie (1)	157.4 C + 520.4 H + 28.1 N + 46.9 S - 49.7 O	4.70	3.19	--
Tillman (2)	188 C - 718	2.83	0.83	--
IGT (3)	146.58 C + 568.78 H + 29.45 S - 6.58 A - 51.53 (O + N)	3.34	-1.73	--
Bain (4)	85.65 + 137.04 C + 217.55 H + 62.56 N + 107.73 S + 8.04 O - 12.94 A (Eq 3-15)	2.02	0.09	0.900

(1)   Van Krevelan, D.W. (1961). Coal; Coal Science and Technology 3, Elsevier Scientific Publishing Company, NY, NY, page 416
(2)   Tillman, D.A. (1978). Wood as an Energy Source, Academic Press, NY, NY.
(3)   Institute of Gas Technology (1978). "Coal Conversion Systems Technical Data Book," DOE Contract EX-76-C-01-2286, available from NTIS.
(4)   This publication

To convert to MJ/kg multiply by 0.00232

Nomenclature: All values are in weight percent, dry basis

     A = ash
     C = carbon
     H = hydrogen
     N = nitrogen
     O = oxygen
     S = sulfur

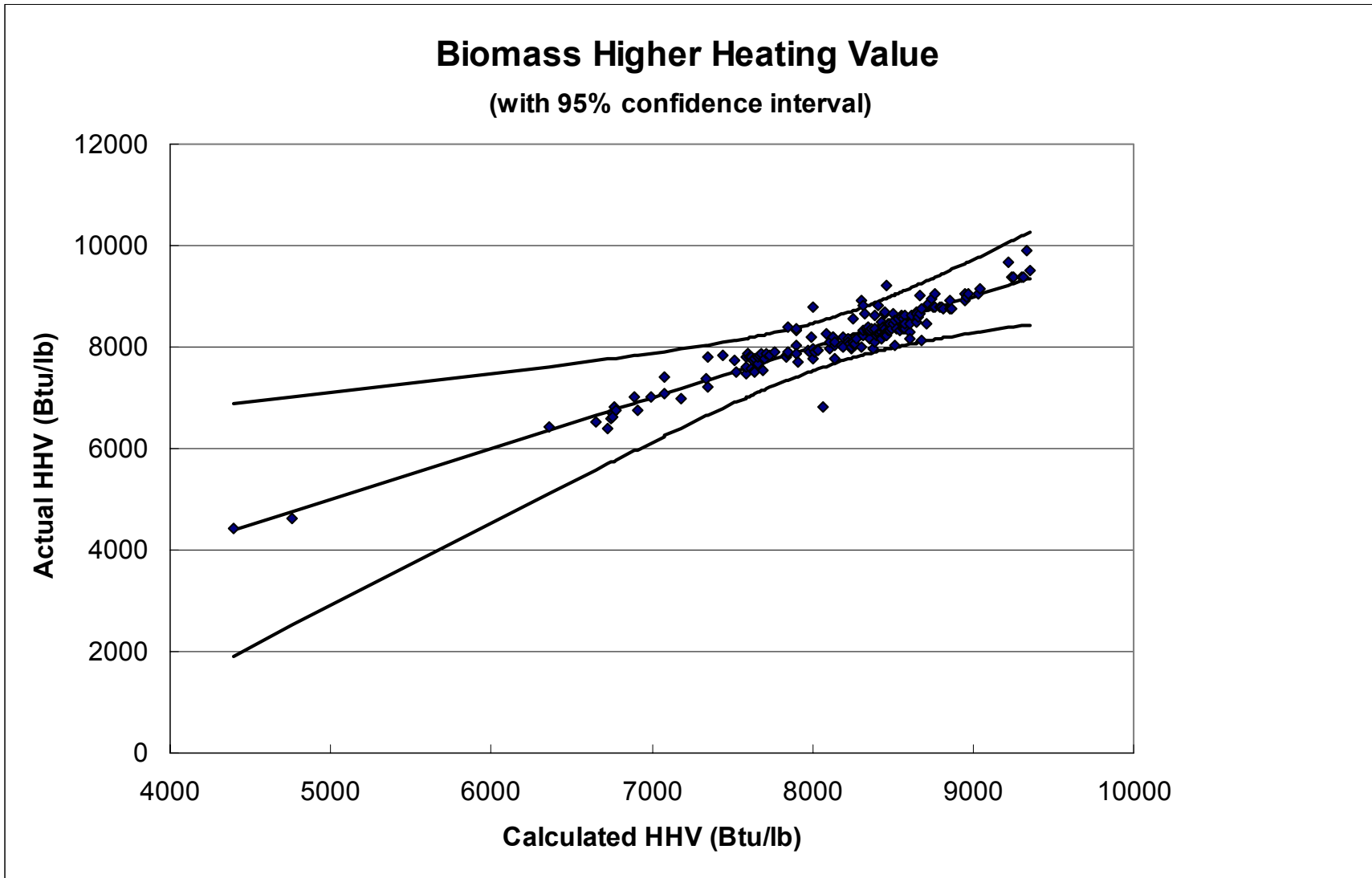% Error = 100 (calc. HHV - Exptl. HHV) / Exptl. HHV

Absolute Average Error = $\sum$(absoute error)$_i$ / n

Bias = $\sum$ (Error)$_i$ / n

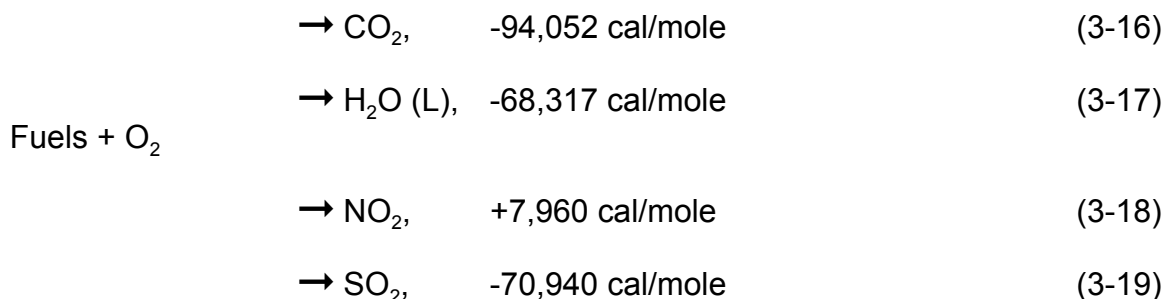where n =175

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Figure 3-3: Biomass Higher Heating Value

Biomass Higher Heating Value

(with 95% confidence interval)

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3.1.5 Heats of Formation

In thermodynamic calculations, the heat of formation of the feedstocks is required. Heats of formation may be calculated rigorously from the heats of combustion, assuming that the only materials oxidized are C, H, N, and S, by posing the following reactions:

$$\rightarrow CO_2, \qquad -94,052 \ cal/mole \qquad\qquad (3\text{-}16)$$

$$\rightarrow H_2O \ (L), \quad -68,317 \ cal/mole \qquad\qquad (3\text{-}17)$$

Fuels + O_2

$$\rightarrow NO_2, \qquad +7,960 \ cal/mole \qquad\qquad (3\text{-}18)$$

$$\rightarrow SO_2, \qquad -70,940 \ cal/mole \qquad\qquad (3\text{-}19)$$

The heat of formation of the fuel may be calculated as follows, assuming no chemical heat involving ash reactions:

$$H_f \ (25°C) = (HHV^* + 0.018 \ \textstyle\sum_{Prod} [\ H_{fi}n_{fi}\ ]) / (1 - Ash) \qquad\qquad (3\text{-}20)$$

in Btu/lb, dry, ash-free basis.

In this equation, n_{fi} is the moles of species i formed per 100 lb of dry biomass on combustion (i can be CO_2, $H_2O(L)$, NO_2, SO_2) while H_{fi} is the heat of formation of i at 25°C in cal/mole. The factor 0.018 puts the formation enthalpy on a Btu per pound of biomass basis. The HHV is treated as a positive number. The heat of formation is normalized to a dry, ash-free basis for purposes of comparison. Table 3-10 presents heat of formation for a variety of feedstocks. The data show a definite trend in terms of the rank (degree) of aromatization of the materials involved. Biomass is very low in rank since its structure consists of only single aromatic rings (benzene derivatives). Fuels of higher rank - peat, lignite, bituminous, and anthracite coals - have structures containing progressively larger aromatic clusters. Typical bituminous coal structures contain from four to six condensed aromatic rings. The fuel of highest rank is graphite. The coals tend to have low heats of formation which increase in the exothermic sense as the rank decreases. Most woody materials exhibit a constant heat of formation in the range of -2,200 Btu/lb. Materials such as straw and rice hulls have higher heats of formation, on the order of -2,700 Btu/lb. The biomass chars generally exhibit heats of formation intermediate between coals and fresh biomass materials. Figure 3-4 shows how the heats of formation depend on the H/C ratio of the feedstock. It is evident that the biomass chars, although similar in ultimate analysis to coals do not correlate with the coals in terms of H/C ratio. This is probably due to the coal's greater degree of aromatization, which is a result of the coalification process.

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Table 3-10: Heats of Formation for Typical Fuels and Biomass Materials
(Basis: Dry, Ash-Free Solid)

Material	Hf (77°F) (Btu/lb)	H'/C'
Charcoal	142	0.46
Pittsburgh seam coal	-209	0.79
Western Kentucky No. 11 coal	-323	0.82
Utah coal	-540	0.92
Wyoming Elkol	-648	0.88
Lignite	-1062	0.78
Douglas fir	-2219	1.45
Doulas fir bark	-2081	1.26
Pine bark	-2227	1.33
Western hemlock	-2106	1.38
Redwood	-2139	1.33
Beech	-2480	1.45
Hickory	-2344	1.57
Maple	-2203	1.43
Poplar	-2229	1.45
Rice hulls	-2747	1.78
Rice straw	-2628	1.56
Sawdust pellets	-1860	1.65
Animal waste	-2449	1.55
Muncipal solid waste	-2112	1.51
Fir bark char	-1580	0.96
Muncipal solid waste char	-1136	0.87
Grass straw char	-1581	0.87
Animal waste char	-1536	0.76
Municipal solid waste char	-214	0.18

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Figure 3-4: Heats of Formation of Carbonaceous Fuels

$Hf = -190.3 - 1407 (H/C)$, R2 = 0.86
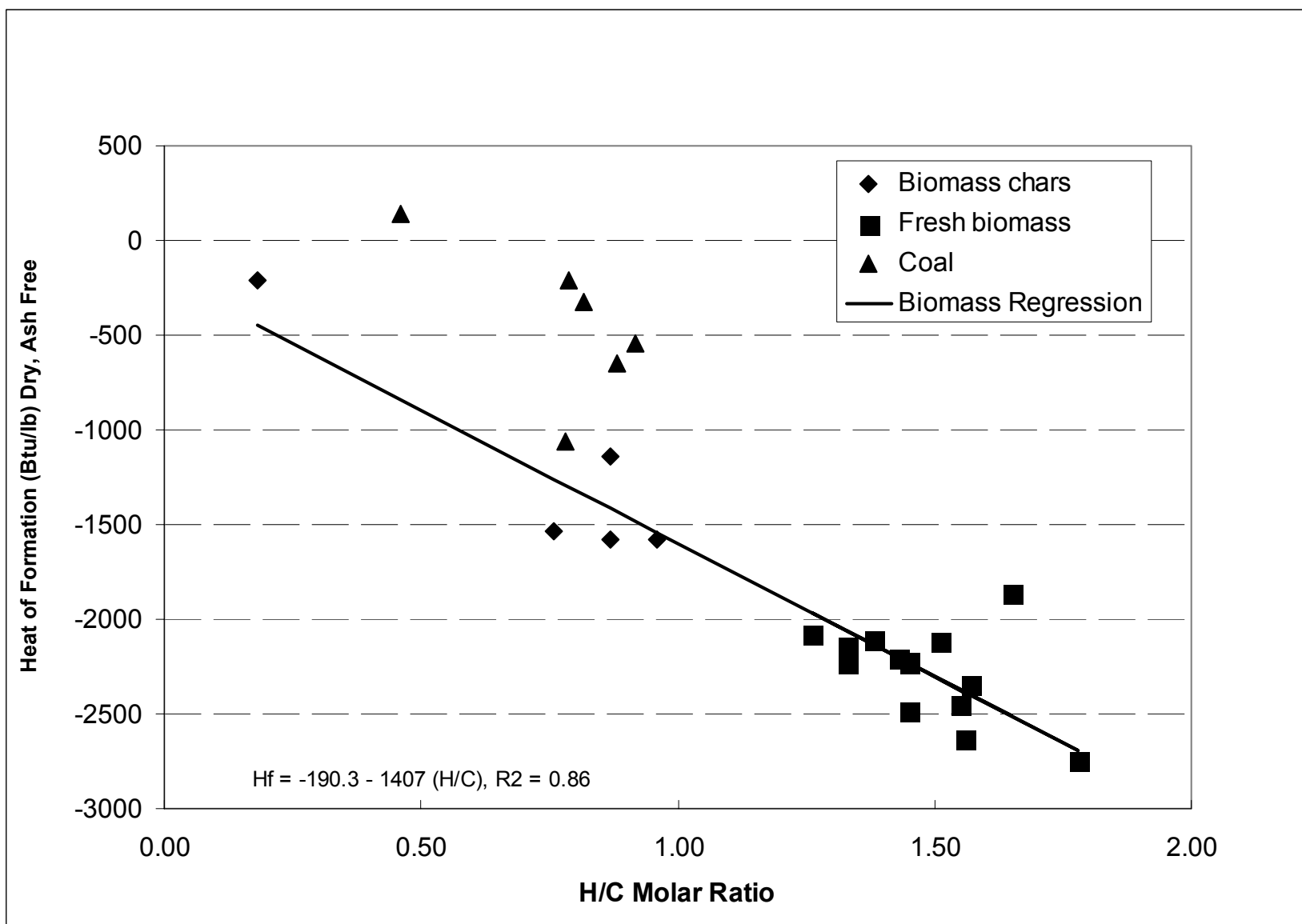
Heats of combustion for biomass materials can be calculated using the heat of formation data based on the following empirical correlation for biomass materials:

$$H_f (77° F) = - 190.3 - 1407 \ H'/C' \qquad (3-21)$$

with H'/C' as mole ratio, Btu/lb, dry ash-free basis.

For natural biomass materials and their chars, the following equation results, based on the ultimate analysis and the pertinent combustion reactions:

$$HHV^* = (141C + 615H - 10.2N + 39.8S) - (1 - A/100)[(16,769H/C) + 190] \qquad (3-22)$$

The HHV* is the gross heating value on a dry basis, Btu/lb, and the analytical data are expressed in weight percent. This equation cannot be expected to function for manmade materials such as plastics or for non-cellulose-derived materials like leather. For the biomass data set in Table 3-4, the average absolute error is 2.52% and the bias is -0.47%.

3.1.6 Ash

The ash content of selected biomass samples in given in Table 3-11. Biomass with high annual growth, such as herbaceous materials, annual crops, and woody prunings all have abundant alkali in the ash. Potassium is of primary importance because it volatilizes and reacts during combustion. In addition, biomass rich in both potassium and chlorine can cause large amounts of slagging and fouling during combustion. Biomass ash samples are typically low in sodium content because sodium is toxic to non-halophytic plants. Ash samples high in iron typically indicate presence of non-biomass materials such as dirt or soil.

Table 3-11: Ash Composition of Selected Biomass Samples

Material	Ash wt%	Elemental Composition, wt%											
		SiO2	Al2O3	TiO2	Fe2O3	CaO	MgO	Na2O	K2O	SO3	P2O5	CO2/Other	Undet.
Mixed waste paper	8.33	28.10	52.56	4.29	0.81	7.49	2.36	0.53	0.16	1.70	0.20		1.80
Fir mill waste	0.41	15.17	3.96	0.27	6.58	11.90	4.59	23.50	7.00	2.93	2.87	18.92	2.31
RFD - Tacoma	26.13	33.81	12.71	1.66	5.47	23.44	5.64	1.19	0.20	2.63	0.67		12.58
Red oak sawdust	0.31	20.97	2.99	0.27	2.94	10.90	4.15	1.40	22.40	2.69	1.33	14.30	15.66
Sugar Cane Bagasse	2.44	46.61	17.69	2.63	14.14	4.47	3.33	0.79	4.15	2.08	2.72		1.39
Urban wood waste	5.54	55.12	12.49	0.72	4.51	13.53	2.93	3.19	4.78	1.92	0.88		-0.07
Willow - SV1-3 yr	0.95	8.08	1.39	0.06	0.84	45.62	1.16	2.47	13.20	1.15	10.04	13.67	2.32
Furniture waste	3.61	57.62	12.23	0.50	5.63	13.89	3.28	2.36	3.77	1.00	0.50		-0.78
Willow - SV1-1 yr	1.10	16.76	3.01	0.07	0.85	34.83	2.46	3.05	12.20	1.70	10.36	17.58	-2.87
Alder/fir sawdust	4.13	35.36	11.54	0.92	7.62	24.90	3.81	1.71	5.75	0.78	1.90	1.85	3.86
Switchgrass, MN	2.69	61.64	1.32	0.19	1.08	11.11	4.86	0.64	8.24	0.80	3.09		7.03
Hybrid poplar	2.70	5.90	0.84	0.30	1.40	49.92	18.40	0.13	9.64	2.04	1.34	8.18	1.91
Switchgrass, D Leaf, MN	3.61	61.23	0.57	0.37	0.79	12.06	5.42	0.43	7.63	1.11	3.56		6.83
Demolition wood	13.12	45.91	15.55	2.09	12.02	13.51	2.55	1.13	2.14	2.45	0.94		1.71
Forest residuals	3.97	17.78	3.55	0.50	1.58	45.46	7.48	2.13	8.52	2.78	7.44		2.78
Poplar - coarse	1.60	0.88	0.31	0.16	0.57	44.40	4.32	0.23	20.08	3.95	0.15	19.52	5.43
Miscanthus, Silberfeder	3.05	61.84	0.98	0.05	1.35	9.61	2.46	0.33	11.60	2.63	4.20		4.95
Wood - land clearing	16.50	65.77	14.84	0.55	5.27	5.78	1.81	2.70	2.19	0.36	0.66	0.45	-0.38
Almond wood	6.78	45.60	10.75	0.54	4.06	18.96	4.22	3.08	6.26	2.06	1.47		3.00
Wood - yard waste	20.37	59.65	3.06	0.32	1.97	23.75	2.15	1.00	2.96	2.44	1.97		0.73
Danish wheat straw	3.89	55.32	0.84	0.22	1.05	12.27	2.48	1.51	12.90	2.49	4.30		6.62
Rice husks	20.26	91.42	0.78	0.02	0.14	3.21	0.01	0.21	3.71	0.72	0.43		
Switchgrass, OH	8.97	65.18	4.51	0.24	2.03	5.60	3.00	0.58	11.60	0.44	4.50		2.32
Oregon wheat straw	4.32	46.07	1.69	0.09	1.85	9.95	2.45	1.18	25.20	4.92	3.32		3.28
Alfalfa stems	5.27	5.79	0.07	0.02	0.30	18.32	10.38	1.10	28.10	1.93	7.64	14.80	11.55
California wheat straw	7.02	55.32	1.88	0.08	0.73	6.14	1.06	1.71	25.60	4.40	1.26		1.82
Imperial wheat straw	9.55	37.06	2.23	0.17	0.84	4.91	2.55	9.74	21.70	4.44	2.04		14.32
Rice straw	18.67	74.67	1.04	0.09	0.85	3.01	1.75	0.96	12.30	1.24	1.41		2.68
Bana Grass, HI	9.88	33.65	0.80	0.07	0.63	3.57	1.71	0.38	42.80	0.85	2.74	8.97	3.83

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3.2 CHEMICAL COMPOSITION OF WOODS

In characterizing and correlating reactivity data for pyrolysis and gasification, it is necessary to have some idea of the chemical structure of the reactant material. Woods can be analyzed in terms of fractions of differing reactivity by solvent extraction techniques. This discussion provides some of the relevant information on the structure and composition of these reactive fractions which will be useful in discussions of gasification kinetics and pyrolysis.

Woods can be separated into three fractions: extractables, cell wall components, and ash. The extractables, generally present in amounts of 4% to 20%, consist of materials derived from the living cell. The cell wall components, representing the bulk of wood, are principally the lignin fraction and the total carbohydrate fraction (cellulose and hemicellulose) termed holocellulose. Lignin, the cementing agent for the cellulose fibers, is a complex polymer of phenylpropane. Cellulose is a polymer formed from d (+)-glucose while the hemicellulose polymer is based on other hexose and pentose sugars. In woods, the cell wall fraction generally consists of lignin/cellulose in the ratio 43/57. Residues of the total wood, such as bark and sawdust, have differing compositions.

Table 3-12 presents some analyses of woods on a dry basis while Table 3-13 presents data for typical wood barks.

Table 3-12: Chemical Analyses of Representative Woods [a]
(wt % Dry Basis)

Sample	Ash	Extractables	Lignin	Holocellulose
Softwoods[b]				
Western white pine	0.20	13.65	26.44	59.71
Western yellow pine	0.46	15.48	26.65	57.41
Yellow cedar	0.43	14.39	31.32	53.86
Incense cedar	0.34	20.37	37.68	41.60
Redwood	0.21	17.13	34.21	48.45
Hardwoods[c]				
Tanbark oak	0.83	16.29	24.85	58.03
Mesquite	0.54	23.51	30.47	45.48
Hickory	0.69	19.65	23.44	56.22

[a]Encyclopedia of Chem. Tech. (1963), p. 358
[b]Softwood refers to conifer woods
[c]Hardwood refers to deciduous woods

Table 3-13: Chemical Analyses of Representative Wood Barks [a]
(% Dry Basis)

Sample	Ash	Extractables	Lignin	Holocellulose[b]
Black spruce	2.1	24.78	45.84	24.78
Fir	3.1	30.37	39.16	27.37
White birch	1.5	21.6	37.8	39.1
Yellow birch	2.9	19.9	36.5	40.7
Beech	8.3	18.3	37.0	36.4

[a]From Wise 1946
[b]By difference

In comparing the ultimate analysis data for barks and whole woods in Table 3-4, there is no indication that the chemical makeup of the feedstocks is different. However, from the extractable and cell wall analyses it is evident that the lignin and extractable contents of barks are much greater than those of whole woods. It should be expected that these materials would exhibit different overall reactivities due to their chemical differences.

3.2.1 Cellulose

The carbohydrate fraction of plant tissues is composed of cellulose and hemicelluloses, which are moderate to high molecular weight polymers based on simple sugars. Cellulose itself is derived from d-glucose while the hemicelluloses are principally polymers of d-xylose and d-mannose. The hemicellulose composed of pectin generally is present in only very small quantities in woody material but can be a substantially abundant constituent of the inner bark of trees. The cellulose polymer is shown in Fig. 3-5.
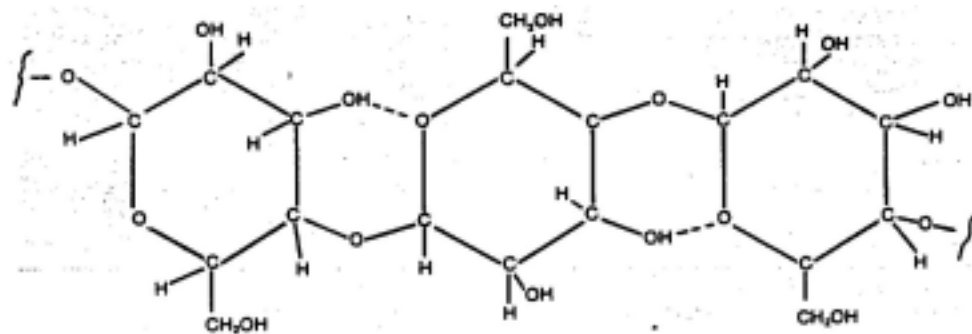

Figure 3-5: The Cellulose Molecule

Cellulose is composed of d-glucose units ($C_6H_{10}O_5$) bound together by ether-type linkages called glycosidic bonds. Glucose is a hexose, or six carbon sugar. In wood the polymers form thread-like chains of molecular weight greater than 100,000. In cotton, 3000 or more units with a combined molecular weight of 500,000 may be present in chains, yielding an extended length of 15,700 Å and cross section of 4 by 8 Å. These very long, thin molecules can be coiled and twisted but, because of the arrangement of the ether linkage, the chain is stiff and extended. An additional contribution to rigidity results from the hydrogen bonding between a hydroxyl hydrogen and the ring oxygen in the adjacent monomer. The threads are woven amongst each other in a random fashion, termed amorphous cellulose, and also fitted together in a crystalline arrangement. Strong van der Waals forces and hydrogen bonds between threads (termed secondary bonding) give rise to a lamellae structure, The weakest bond in the chain direction is the C-O glycosidic bond with an energy of 50 kcal. Cellulose fibers are thus very strong.

The dominant physical characteristic of cellulose is its extreme insolubility, which retards not only acid and enzymic hydrolysis but also the removal of lignins and hemicelluloses interspersed through the cellulose structures. The strong secondary bonding is responsible for the insolubility. Cellulose can be dissolved by strong acids such as hydrochloric, sulfuric, and phosphoric.

Pyrolysis of cell wall materials provides a mixture of volatile materials, tars, and char. The proportion of each fraction and its composition depends on the reaction conditions including temperature, pressure, heating rate, and atmospheric composition. Char results from the condensation of aromatic compounds formed from the primary decomposition products. Since aromatics are not present initially, the amount of char formed by condensation reactions is relatively small.

3.2.2 Principal Hemicelluloses

Interlaced with cellulose in the cell walls are a number of other polymeric sugars termed hemicelluloses. These are generally differentiated from true cellulose by their solubility in weak alkaline solutions. Figure 3-6 shows a sequence employed by Timell (1967) for isolating softwood polysaccharides. Hemicelluloses are not precursors of cellulose; they are distinctly different compounds that contain acidic and neutral molecules of low and high molecular weight. In contrast to cellulose, which appears to be universal and invariant as the structural polysaccharide of higher land plants, the hemicellulose polysaccharides show a significant variation in composition and structure among species. Several reviews of hemicellulose chemistry have been presented by Polglase (1955), Aspinall (1959), and Whistler and Richards (1970).

Most hemicelluloses contain two to four (and occasionally five to six) simpler sugar residues, d-xylose, d-glucose, d-mannose, d-galactose, 1-arabinose, d-glucuronic acid, and 4-O-methyl-d-glucuronic acid residues constitute the majority of hemicellulose monomers as shown in Fig. 3-7. The structure is similar to that of cellulose except that
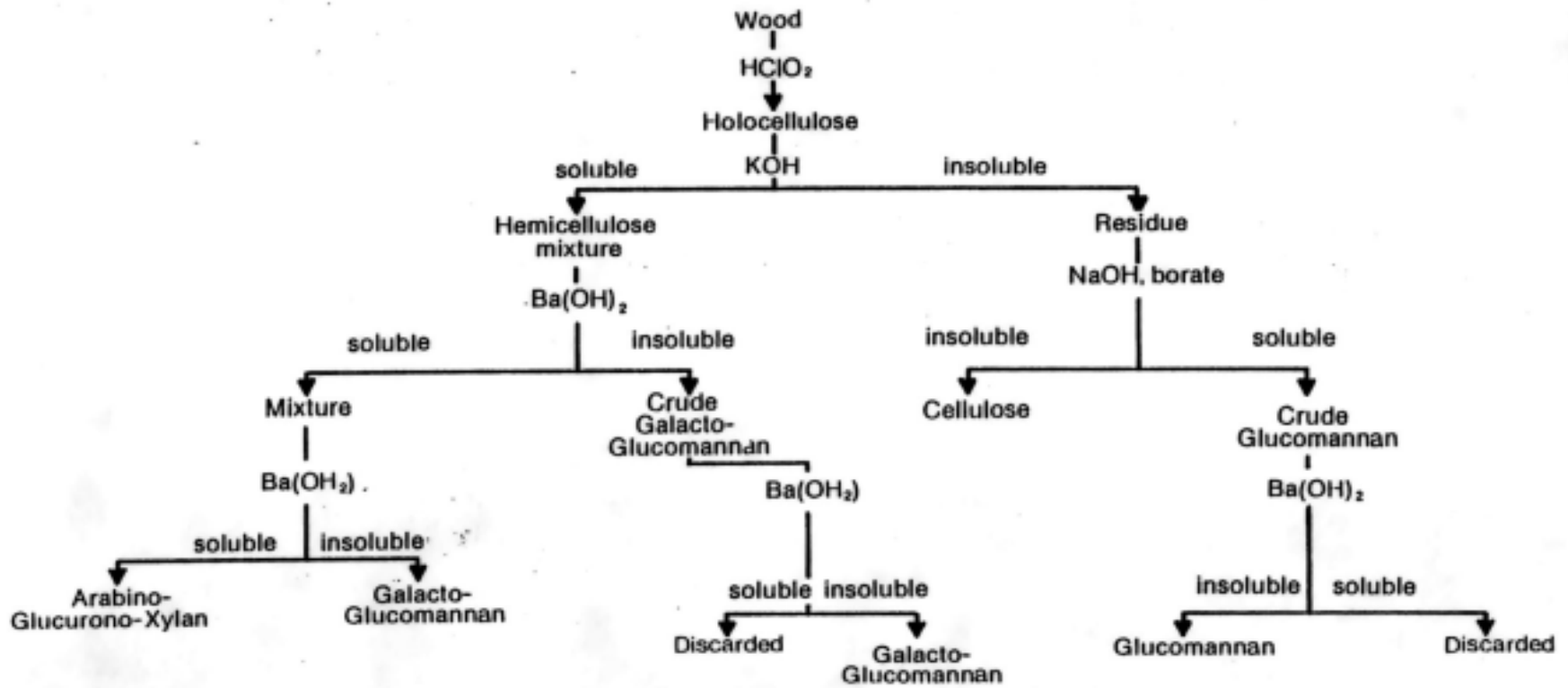
Figure 3-6: Extraction Sequence for Isolation of Softwood Polysaccharides

CHO
HO-C-H
HO-C-H
H-C-OH
H-C-OH
CH₂OH

D-mannose

CHO
H-C-OH
HO-C-H
HO-C-H
H-C-OH
H-CH₂OH

D-galactose

CHO
H-C-OH
HO-C-H
H-C-OH
H-C-OH
CH₂OH

D-glucose

CHO
H-C-OH
HO-C-H
H-C-O-CH₃
H-C-OH
COOH

4-O-methyl-
D-glucuronic
acid

CHO
H-C-OH
HO-C-H
HO-C-H
H-C-OH
COOH

D-galacturonic
acid

CHO
H-C-OH
HO-C-H
H-C-OH
H-C-OH
COOH

D-glucuronic
acid

CHO
H-C-OH
HO-C-H
HO-C-H
CH₂OH

L-arabinose

CHO
H-C-OH
HO-C-H
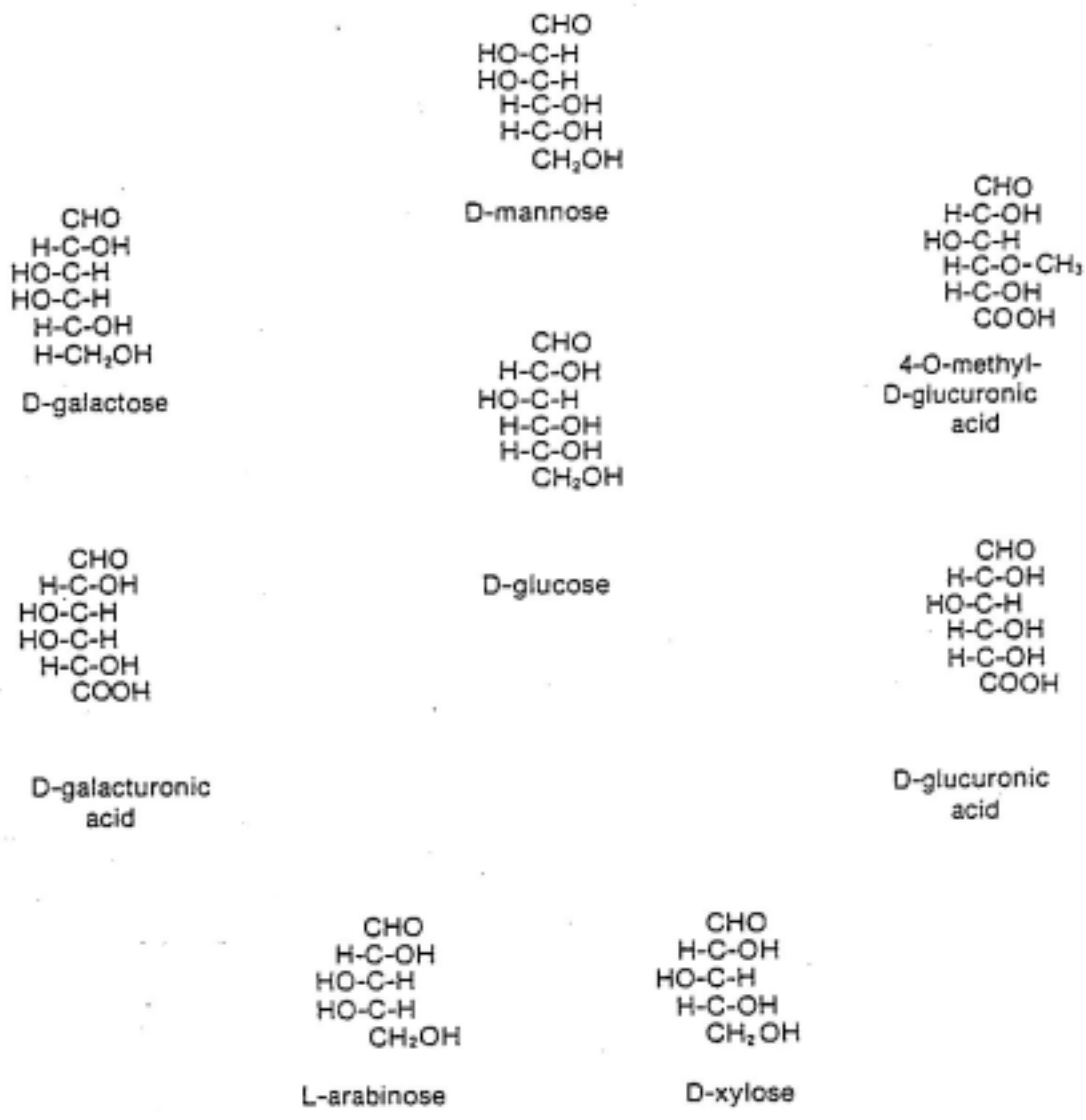H-C-OH
CH₂OH

D-xylose

**Figure 3-7: Structural Interrelationship of Commonly Occurring
Hemicellulose Component Sugars**

the hemicellulose polymers generally contain 50 units to 200 units and exhibit a branched rather than a linear structure.

These structural characteristics, as well as the number and proportion of different sugar residues present (degree of heteropolymerization), largely determine the observed physical properties of hemicelluloses. The heteropolymerization decreases the ability to form regular, tight-fitting crystalline regions and thus makes hemicellulose more soluble than cellulose. Solubility is also increased due to the branching, which decreases the number of intermolecular hydrogen bonds, and the decreased degree of polymerization compared to cellulose.

## 3.2.2.1	Xylans

Xylans, the most abundant of the hemicelluloses, are polymers of d-xylose ($C_5H_{10}O$). Xylose is a pentose sugar. The xylan fraction of cellulose is often termed pentosan. They are most abundant in agricultural residues such as grain hulls and corn stalks. Hardwoods (deciduous) and softwoods contain appreciable amounts of xylans. Xylan chains are short, exhibiting molecular weights on the order of 30,000 or less. In addition, some xylans contain carboxylic acid and methyl-ether groups. Typical xylans are shown in Fig. 3-8. The acidic xylans contain d-glucuronic acis or the methylate acid as terminal branch units.

Some of the acid xylans are of low molecular weight. They are known as hemicellulose-B and are differentiated from the normal xylans and other neutral hemicelluloses in that they are not precipitated from the alkaline extract by neutralization.

## 3.2.2.2	Mannans

Mannan-based hemicelluloses include glucomannans, which are built up from linked d-glucose and d-mannose residues in about a 30:70 ratio, and galactoglucomannans, made up of linked d-galactose, d-glucose, and d-mannose in 2:10:30 ratios. In softwoods, mannans are present in substantial amounts while in hardwoods there is generally very little mannan hemicellulose.

3.2.3 Cellulose Data for Woods

Table 3-14 presents some data on the cellulose content of woods. The holocellulose fraction of hardwoods is composed principally of cellulose and xylans. The total content of mannans and other hemicelluloses averages only 4.8% for the four samples. In softwoods, the cellulose fraction is about the same as in hardwoods. However, mannans are present to a much greater extent; the mannans equal or exceed the total xylans in the conifers. Other hemicelluloses are present at 5.4% on the average for the four samples.
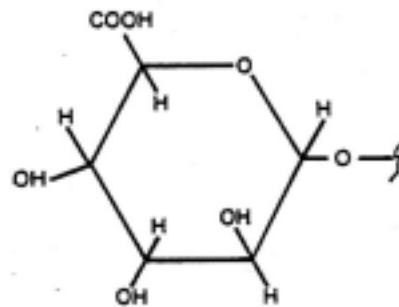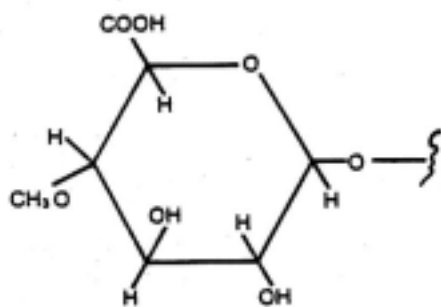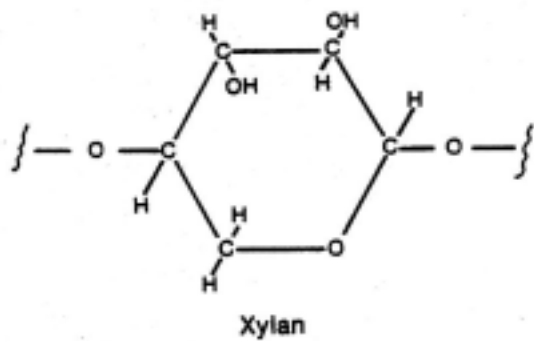
Xylan

Acid Xylans-Terminal Groups

Figure 3-8: Xylan Hemicellulose Structures

Table 3-14: Breakdown of Holocellulose Fraction of Woods [a]

	Wt% in Holocellulose				
	Cellulose	Xylans	Acidxylans	Mannans	Others
Hardwoods					
Trembling Aspen	71.5	20.0	4.1	2.9	1.5
Beech	64.5	23.8	6.5	2.9	2.3
Sugar Maple	69.8	20.0	5.9	3.1	1.2
Southern Red Oak	59.8	28.3	6.6	2.9	2.4
Softwoods					
Eastern hemlock	69.0	6.1	5.0	17.1	2.8
Douglas Fir	64.6	4.2	4.2	16.0	11.0
White spruce	65.2	9.5	5.0	16.3	3.9
Jack Pine	65.1	10.1	5.6	15.1	4.0

[a]From Encyclopedia of Chem. Tech., 1963, p. 358.

3.2.4 Lignin

The noncarbohydrate component of the cell wall, termed lignin, is a three-dimensional polymer based primarily on the phenylpropane unit. Lignin is deposited in an amorphous state surrounding the cellulose fibers and is bound to the cellulose directly by ether bonds. Its exact structure is not known, although considerable information is available based on its chemical reactivity. In solubility analyses, lignin is defined as the cell wall portion not soluble in 72% sulfuric acid. Table 3-15 gives typical elemental analyses of wood lignins.

Table 3-15: Elemental Analysis of Wood Lignin

Type	C (%)	H (%)	O(%)	OCH$_3$ (%)	Molecular Wt.
Softwood	63.8	6.3	29.9	15.8	10,000
Hardwood	59.8	6.4	33.7	21.4	5,000

It is assumed, based on much evidence, that the lignins are composed of several monomer groups as shown in Fig. 3-9. These are combined to form the polymer by a variety of linkages involving the aromatic rings and functional groups. The polymer formed contains only single aromatic rings as shown in 3-10 (structural formula).
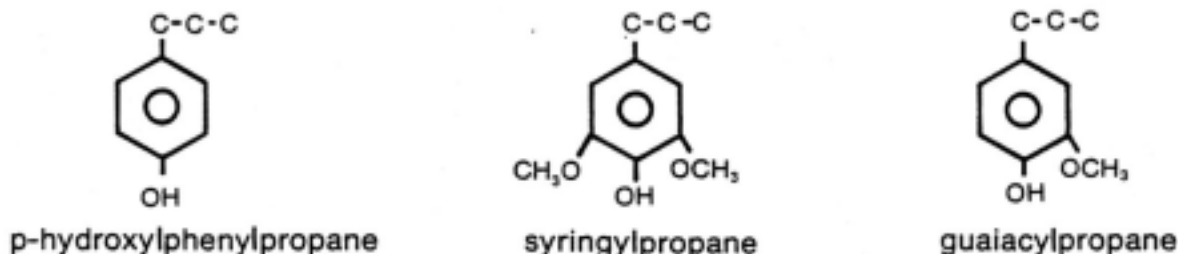
Figure 3-9: Several Monomer Units in Lignin

The representative structure contains the phenylpropane substituted as sinapyl, coniferyl, and p-coumaryl alcohols as shown in Fig. 3-11. Lignification, as discussed by Freudenberg (1965), is thought to occur by dehydration-ploymerization of these alcohol units. Thermal pyrolysis of lignin generally yields a considerable amount of char. It is likely that thermal pyrolysis and lignification follow the same route to yield a condensed polynuclear aromatic structure.

The amount of lignin present varies among materials. Typical amounts for woods and barks are given in Tables 3-12 and 3-13. Table 3-16 gives data for a variety of other biomass materials.

Table 3-16: Lignin in Miscellaneous Plant Material [a]

Material	Wt %, Dry Unextracted Material
Rice hulls	40.0
Bagasse	20.3
Peanut shells	28.0
Pine needles	23.9
Wheat straw	13.9
Corncobs	13.4

[a] From Encyclopedia of Chem. Tech., 1963, p.361

3.2.5 Extractables

The nature and quantity of extractables vary widely among woods. Table 3-17 lists the type of extractables found in a variety of wood materials. The resins and volatile oils

are fragrant and found most commonly in softwoods. Waxes, fatty acids, pigments, and carbohydrates are commonly found in all woods. Starches account for about 3% of the total wood. Since the quality and nature of extractables vary, the products after pyrolysis and gasification vary.

Table 3-17: Extractable Components of Wood

Volatile Oils (removed by steam of ether soluble

      Terpenes ($C_{12}H_{16}$)

      Sesquiterpene ($C_{15}H_{24}$)
          and their oxygenated derivatives

Resins and Fatty Acids (soluble in ether)

      Resin acids ($C_{20}H_{30}O_2$)

      Fatty acids (oleic, linoleic, palmitic)

      Glyceryl esters of fatty acids

      Waxes (esters of monohydroxyalcohols and fatty acids)

      Physterols (high molecular weight cyclic alcohols)

Pigments (soluble in alcohol)

      Flavonols (multi-ring naphthenic and aromatic alcohols, chlorides, ketones acids)

      Pyrones (multi-ring naphthenic and aromatic alcohols, chlorides, ketones acids)

      Antranols (multi-ring naphthenic and aromatic alcohols, chlorides, ketones acids

      Tannins (amorphous polyhydroxylic phenols)

Carbohydrate Components (water soluble)

      Starch

      Simple sugars

      Organic acids
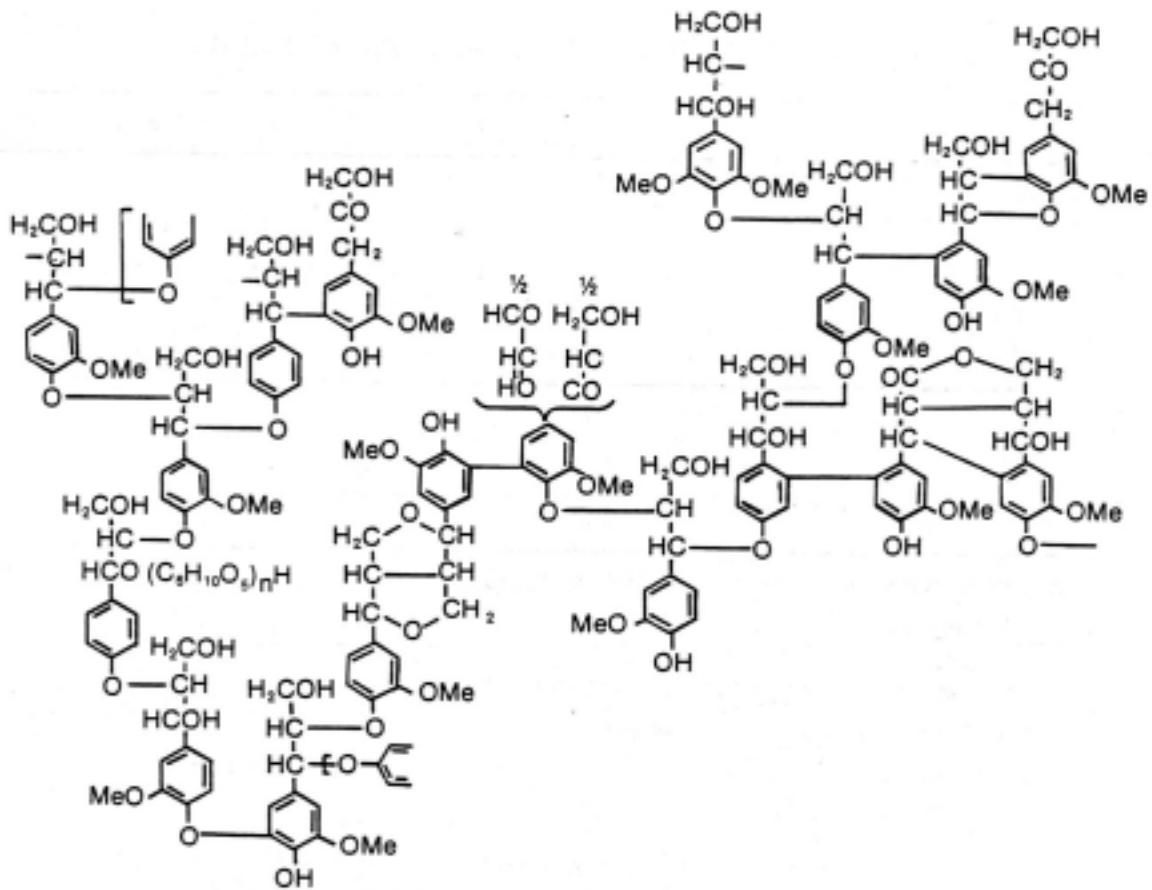
Figure 3-10: Representative Structure of Coniferous Lignin

p-coumaryl alcohol   coniferyl alcohol   sinapyl alcohol
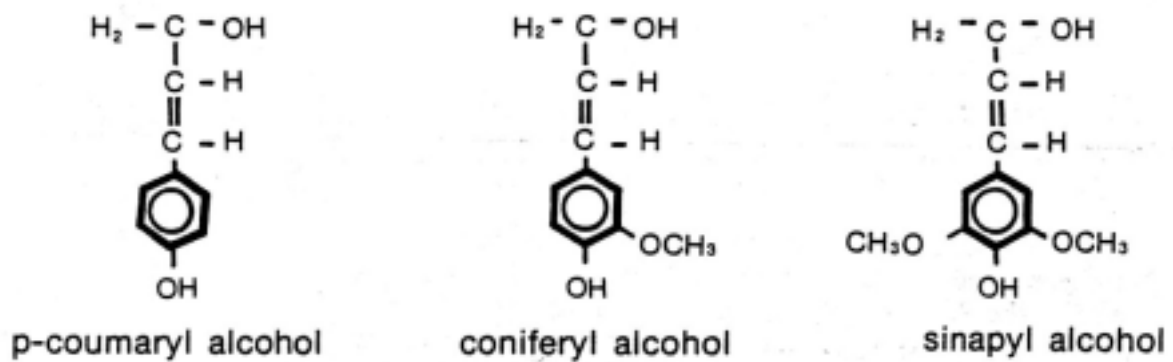
Figure 3-11: P-Hydroxycinnamyl Alcohols

Table 3-18 presents some typical extraction data on woods. The bulk of the extractables may be removed by hot water and ether. The ether-soluble portion is usually much greater for the softwoods, showing the higher content of volatile oils and resins. The hot water extraction, which leaches some tannins as well as the carbohydrates, gives yields approximately the same for the soft- and hardwoods.

Table 3-18: Extraction Data for Woods [a]

Sample	Wt % of Solubles	
	Hot Water	**Ether**
Softwoods		
Western yellow pine	5.05	8.52
Yellow cedar	3.11	2.55
Incense cedar	5.38	4.31
Redwood	9.86	1.07
Western white pine	4.49	4.26
Longleaf pine	7.15	6.32
Douglas fir	6.50	1.02
Western larch	12.59	0.81
White spruce	2.14	1.36
Hardwoods		
Tanbark oak	5.60	0.80
Mesquite	15.09	2.30
Hickory	5.57	0.63
Basswood	4.07	1.96
Yellow birch	3.97	0.60
Sugar Maple	4.36	0.25
Average—Softwoods	6.25	3.36
Average—Hardwoods	6.44	1.09

[a]From Enclyclopedia of Chem. Tech., 1963, p.358

3.3 WOOD STRUCTURE

Wood is composed of cells of various sizes and shapes. Long pointed cells are known as fibers; hardwood fibers are about 1mm in length, while softwood fibers vary in length from about 3mm to 8mm. The mechanical properties of wood depend largely on its density, which, in turn, is largely determined by the thickness of the cell walls.

3.3.1 Physical Structure of Softwoods

Figure 3-12 shows a typical softwood structure taken from Siau (1971). In softwoods, the fluid conducting elements are the longitudinal tracheids and ray tracheids. Longitudinal and horizontal resin canals are also present in many species.

Longitudinal tracheids, shown in Fig. 3-13, make up the bulk of the structure of softwoods. These are long, hollow, narrow cells having no openings that are tapered along the radial surfaces for a considerable portion of the lengths where they are in contact with other tracheids. The surfaces of the tracheids are dotted with pits, minute depressions in the plant tissue wall which permit the movement of water and dissolved materials between tracheids. The pit is covered with a semipermeable membrane. Pits are oriented in softwoods as adjacent pairs (pit pairs); fluid flow occurs between tracheids in the direction normal to the principal direction of flow.

The tracheid diameter varies from 15 to 80 μm according to species, with a length ranging from 1200 to 7500 μm. Average values of diameter and length, respectively, are 33 μm and 3500 μm. The inner diameter which is available for flow is typically 20-30 μm. The effective radius of the pit openings is 0.01 to 4 μm due to the restriction created by the membrane. Typically, a tracheid contains 50 pits. In addition to pit pairs allowing longitudinal flow, there are also pit pairs leading from longitudinal tracheids to ray tracheids, permitting radial flow.

The volumetric composition of a typical softwood is as follows:

Longitudinal tracheids	93%
Longitudinal resin canals	1%
Ray tracheids	6%

Since the principal voidage is oriented longitudinally, the magnitude of the permeability in the longitudinal direction is much greater than the radial permeability. Figure 3-14 shows a schematic model for flow through a softwood.

3.3.2 Physical Structure of Hardwoods

The structure of a typical hardwood is shown in Fig. 3-15. The dominant feature of the hardwood structure is the large open vessels or pores. Tracheids and pits are present but contribute significantly more resistance to flow. In a typical hardwood, the following structural composition is present:

Vessels	55%
Tracheids	26%
Woods rays	18%
Others	1%

Vessels are large, with diameters of 20 to 30 µm. The vessels are short, connected by "perforation plates" which offer very low flow resistance. Thus the vessels behave as long capillaries. Figure 3-16 shows the nature of flow through hardwoods.
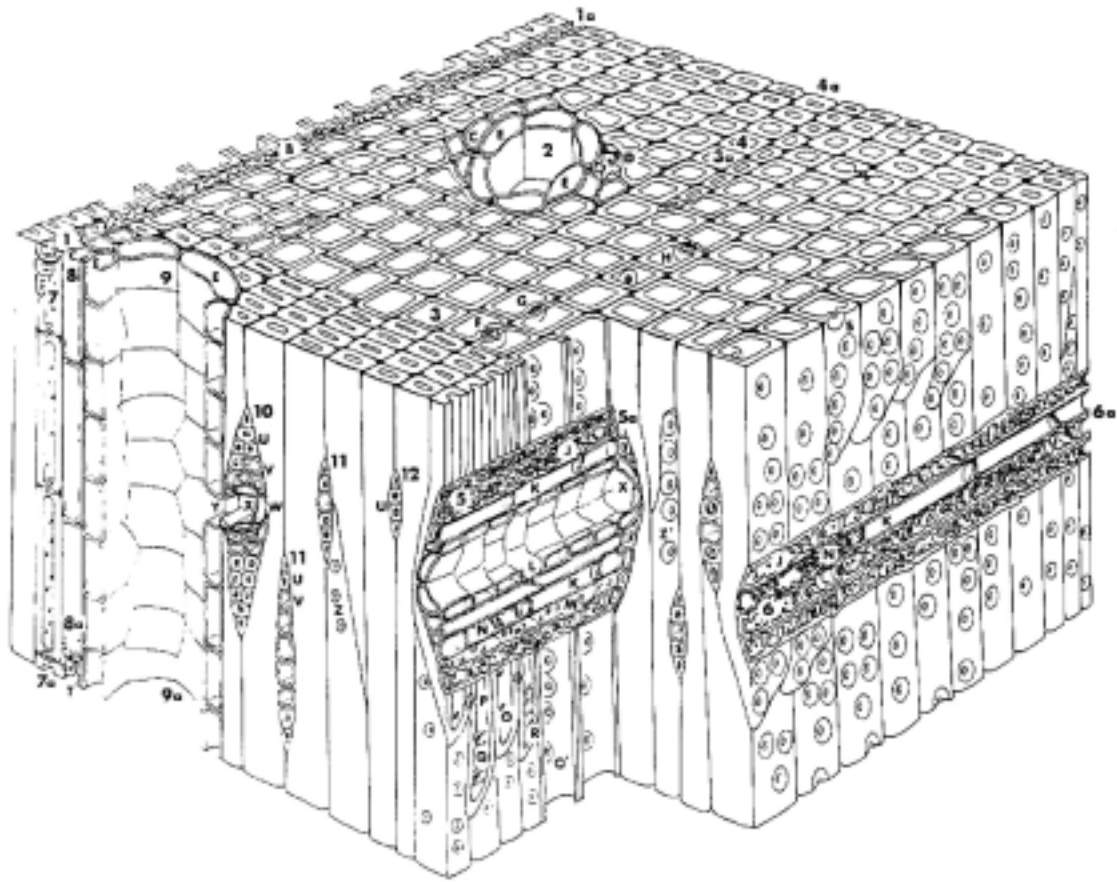
**Figure
3-12: Gross Structure of a Typical Southern Pine Softwood**

Transverse view: 1-1a, ray; B, dentate ray tracheid; 2, resin canal; C, thin-walled longitudinal parenchyma; D, thick-walled longitudinal parenchyma; E, epithelial cells; 3-3a, earlywood tracheids; F, radial bordered pit pair cut through torus and pit apertures; G, pit pair cut below pit apertures; H, tangential pit pair; 4-4a, latewood.

Radial view: 5-5a, sectioned fusiform ray; J, dentate ray tracheid; K, thin-walled parenchyma; L, epithelial cells; M, unsectioned ray tracheid; N, thick-walled parenchyma; O, latewood radial pit (inner aperture); O', earlywood radial pit (inner aperture); P, tangential bordered pit; Q, callitorid-like thickenings; R, spiral thickenings; S, radial bordered pits (the compound middle lamella has been stripped away removing crassulae and tori); 6-6a, sectioned uniseriate heterogenous ray.

Tangential view: 7-7a, strand tracheids; 8-8a, longitudinal parenchyma (thin-walled); T, thick-walled parenchyma; 9-9a, longitudinal resin canal; Y, opening between horizontal and vertical resin canals; 11, uniseriate homogeneous rays; 12, uniseriate homogeneous ray; Z, small tangential pits in latewood; Z', large tangential pits in earlywood.
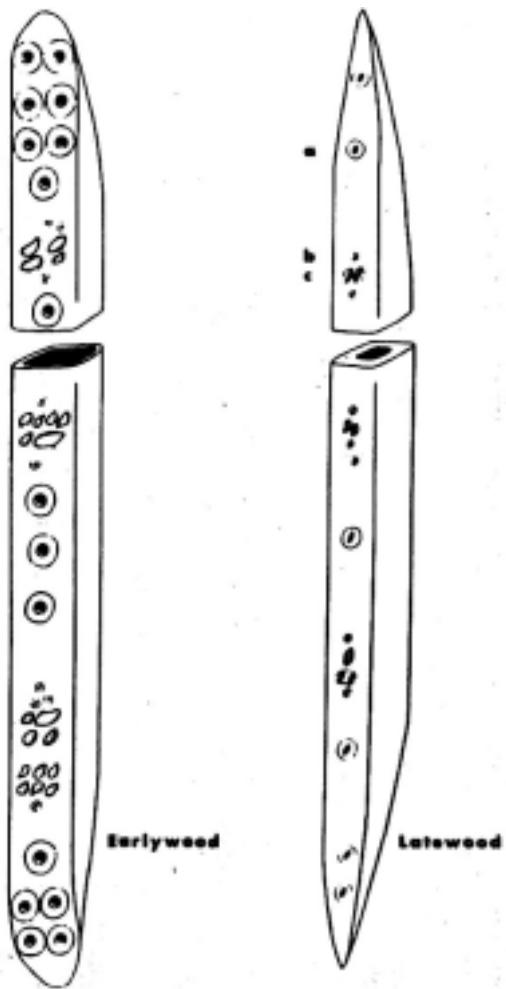
Figure 3-13: Radial Surfaces of Earlywood and Latewood Tracheids

(a) intertracheal bordered pits; (b) bordered pits to
tracheids; (c) pinoid pits to ray parenchyma
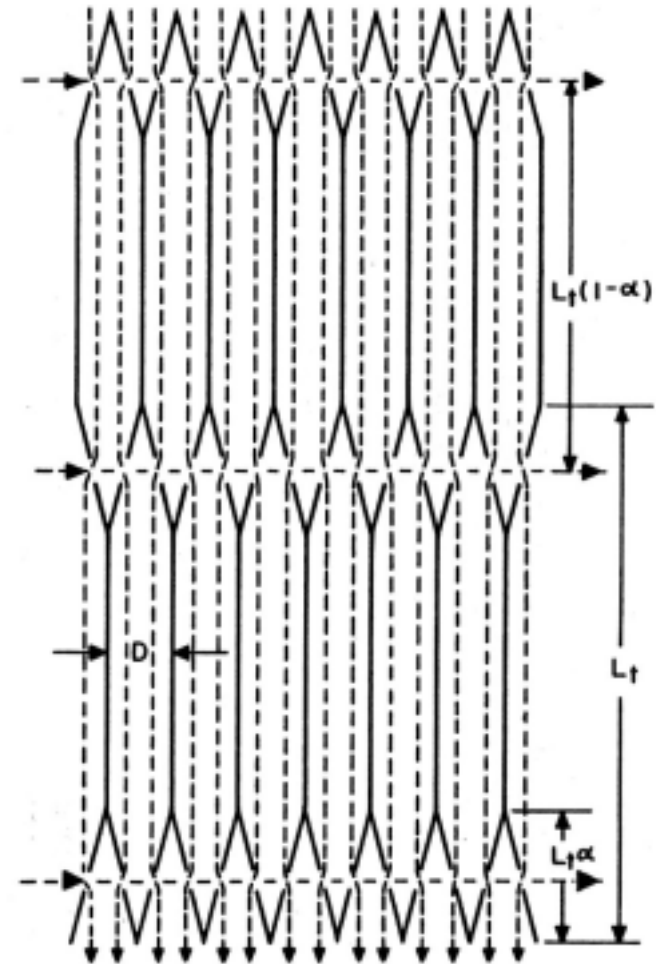
Figure 3-14: Softwood Flow Model
Tangential section showing pits on the radial surfaces
Of the tapered ends of the tracheids

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A3-45
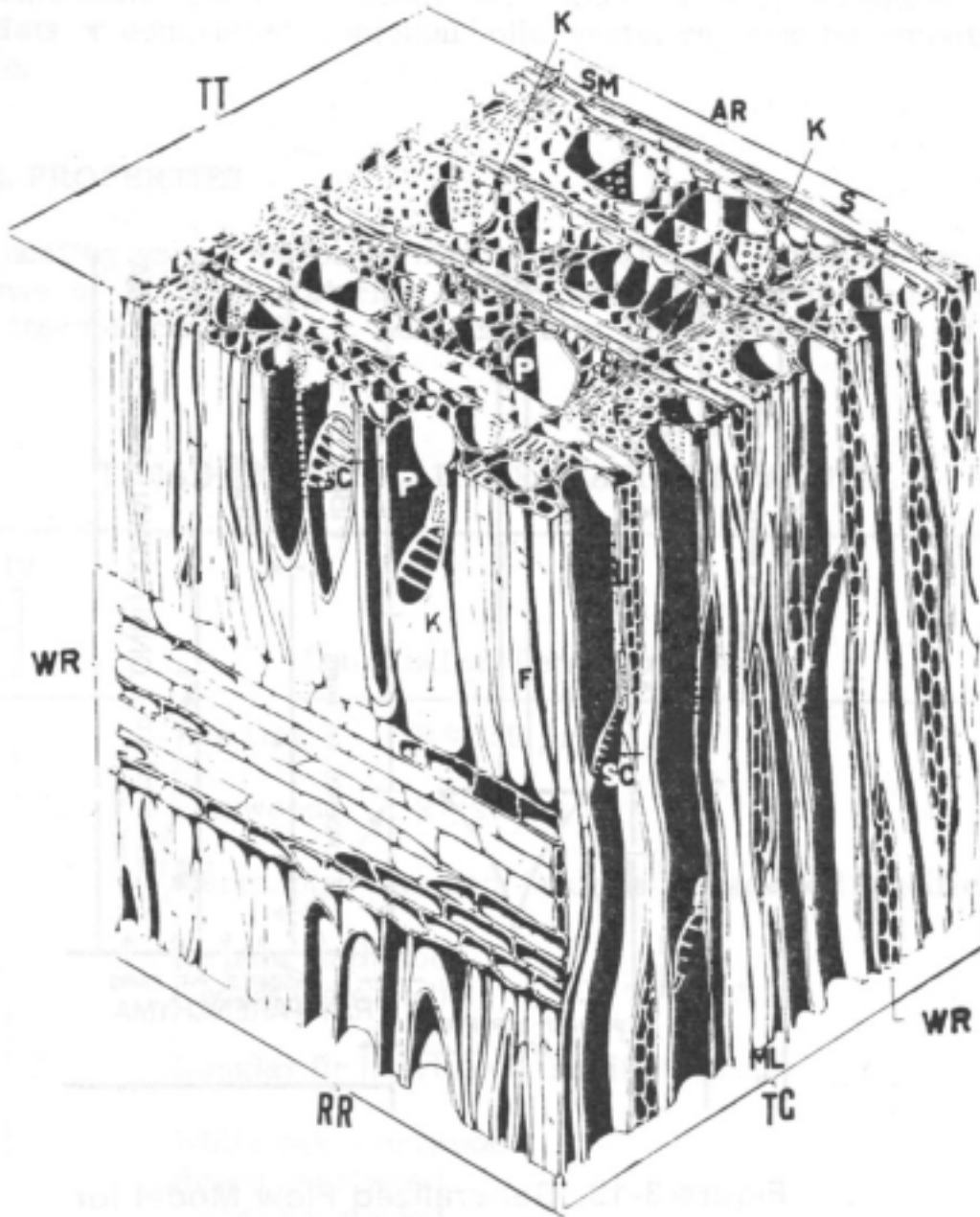
Figure 3-15: Gross Structure of a Typical Hardwood

Plane TT is the cross section, RR is the radial surface, and TG is the tangential surface. The vessels or pores are indicated by P, and the elements are separated by scalariform perforation plates, SC. The fibers, F, have small cavities and thick walls. Pits in the walls of the fibers and vessels, K, provide for the flow of liquid between the cells, The wood rays are indicated at WR. AR indicates one annual ring. The earlywood (springwood) is designated S, while the latewood (summerwood) is SM. The true middle lamella is located at ML.
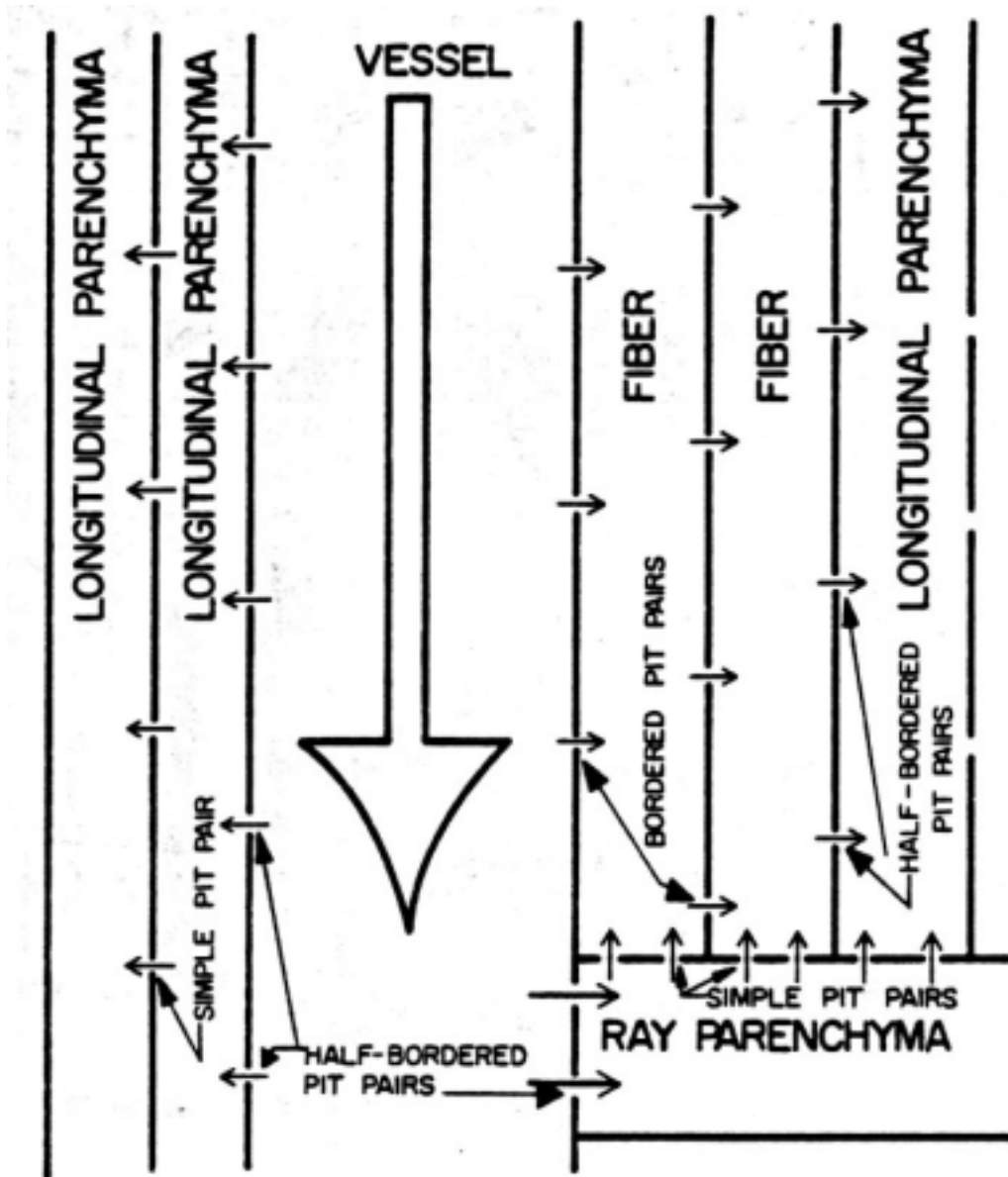
Figure 3-16: Generalized Flow Model for Hardwoods

3.3.3 Permeability

Permeability is important in pyrolysis. During heating, pyrolysis gases and liquids are generated within the particle and must pass through the porous structure to the surroundings. Low permeability may significantly affect the product distribution by increasing the residence time of the primary pyrolysis products in the hot zone, thereby increasing the probability that they will enter into secondary reactions. Pelletized, densified biomass will have a low permeability compared with natural woods. Table 3-19 shows the range of permeability for various natural woods.

In natural soft- and hardwood structures, it is evident that the porosity is directed principally in the vertical direction in the livewood. Physical properties such as thermal conductivity and diffusivity therefore depend on direction within fresh wood. Such a behavior is termed anisotropic (aeolotropic).

Table 3-19: Typical Permeability Values

Permeability $(cm^3 (air)cm^{-1}atm^{-1})$	Longitudinal Permeabilities	
10^4	Red Oak	$R \approx 150 \ \mu m$
10^3	Basswood	$R \approx 20 \ \mu m$
10^2	Maple, oine sapwood, Douglas fir sapwood (Pacific Coast)	
10^1	Spruces (sapwood), cedars (sapwood)	
10^0	Douglas fir heartwood (Pacific Coast)	
10^{-1}	White oak heartwood, Beech heartwood, Cedar heartwood	
	Douglas fir heartwood (intermountain)	
10^{-2}		Transverse permeabilities. (The species are in approximately the same order as for longitudinal permeabilties)
10^{-3}		
10^{-4}		

3.4   PHYSICAL PROPERTIES

In addition to heating value, the other major physical data necessary for predicting the thermal response of biomass materials under pyrolysis, gasification, and combustion processes are thermal conductivity, heat capacity, true density, and diffusion coefficients.

3.4.1 Thermal Conductivity

Thermal conductivity is defined in general terms as a proportionality factor which relates heat flow through a material to a temperature difference across a specified distance in that material. Mathematically, thermal conductivity is defined by Fourier's Law of Heat Conduction, given here for unidimensional heat flux in the x-direction in rectangular coordinates:

$$q_x = -k_x \frac{dT}{dx} \tag{3-23}$$

Most homogeneous materials are isotropic, and the thermal conductivity varies only with temperature

$$q = -k\nabla T \tag{3-24}$$

However, most naturally occurring biomass materials are anisotropic. For wood, the thermal conductivity is a function of temperature and spatial direction. Modified biomass materials, such as densified wood, probably do not exhibit the same type of anisotropic behavior as the naturally occurring biomass materials. Thermal conductivity should be related to the various materials present in a substance. Thus in biomass thermal conductivity should be a function of the major constituents, including moisture, cellulose, hemicellulose, and lignin.

Table 3-20 compiles available thermal conductivity data for biomass materials. No data are available for compacted biomass feedstocks. In general, no chemical analyses are presented with the data. The bulk of the data are probably effective thermal conductivities of powders rather than of the solids. The conductivities for solid woods, for example, are two to ten times greater than for many of the other biomass materials listed in Table 3-20 (e.g., sawdust and redwood shavings). Most data sources do not specify the state of the materials.

Steinhagen (1977) has summarized thermal conductivity data for several woods over the range -40° C to +100° C as a function of moisture content and has shown that moisture is an important parameter in wood conductivity. Since the moisture content is not known for the bulk of the entries in Table 3-20, the data presented are at best only semi-quantitative.

Completely lacking in the available data are thermal conductivities at higher temperatures. This is primarily because the majority of the data were determined by researchers in the forest products industry interested in the thermal properties of wood and insulating materials for home heating and cooling applications. If thermal conductivity values are to be used in modeling pyrolysis or gasification processes, then new data over the actual range of processing conditions must be developed, including data for densified materials.

Table 3-20: Thermal Conductivity of Selected Biomass Materials

Material	Bulk Density (lb/ft^3)	Temperature (°F)	Thermal Conductivity (Btu/ft-h-°F)	Reference
Ashes, wood	--	32 - 212	0.040	Kern 1950
Cardboard	--	--	0.037	Kern 1950
Carbon, porous, with grain				
Grade 60 48% porosity	65.5[a]	Room Temp.	0.083	Perry and Chilton 1973
Grade 45 47% porosity	64.9	Room Temp.	0.083	Perry and Chilton 1973
Grade 25 47% porosity		Room Temp.	0.083	Perry and Chilton 1973
Carbon Refractory brick - 17% porosity		Room Temp.	1.33	Perry and Chilton 1973
Celotex, sheet fiber from sugar cane	13.2	--	0.028	Handbook Chem. Phys, 1966
	14.8	--	0.028	Handbook Chem. Phys, 1966
	14.4	32	0.0253	McAdams 1954
	14.4	0	0.0242	McAdams 1954
	14.4	-100	0.0208	McAdams 1954
	14.4	-200	0.0175	McAdams 1954
	14.4	-300	0.0133	McAdams 1954
Charcoal - from maple, beech, birch				
Coarse	13.2	--	0.030	Handbook Chem. Phys, 1966
6 mesh	15.2	--	0.031	Handbook Chem. Phys, 1966
20 mesh	19.2	--	0.032	Handbook Chem. Phys, 1966
Charcoal flakes	11.9	176	0.043	McAdams 1954

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Material	Bulk Density (lb/ft³)	Temperature (°F)	Thermal Conductivity (Btu/ft-h-°F)	Reference
	15	176	0.051	McAdams 1954
	--	0 to 100	0.0133	Handbook Chem. Phys, 1966
Cork, regranulated				
Fine particles	9.4	--	0.025	Handbook Chem. Phys, 1966
1/16-in. Particles	8.1	--	0.026	Handbook Chem. Phys, 1966
Corkboard	5.4	--	0.021	Handbook Chem. Phys, 1966
	7.0	--	0.022	Handbook Chem. Phys, 1966
	10.6	--	0.025	Handbook Chem. Phys, 1966
	14.0	--	0.028	Handbook Chem. Phys, 1966
	6.9	32	0.0205	McAdams 1954
	6.9	0	0.0200	McAdams 1954
	6.9	-100	0.0183	McAdams 1954
	6.9	-200	0.0142	McAdams 1954
	6.9	-300	0.0100	McAdams 1954
Cork, pulverized	10.0	32	0.035	McAdams 1954
	10.0	100	0.039	McAdams 1954
	10.0	200	0.032	McAdams 1954
Cotton	5.0	200	0.037	McAdams 1954
	5.0	100	0.035	McAdams 1954
	5.0	32	0.0325	McAdams 1954
	5.0	-100	0.0276	McAdams 1954

Material	Bulk Density (lb/ft³)	Temperature (°F)	Thermal Conductivity (Btu/ft-h-°F)	Reference
	5.0	-200	0.0235	McAdams 1954
Cotton	5.0	-300	0.0198	McAdams 1954
Graphite - 2 ¾" Dia., ¾ " Thick, 30% porosity	98.6[a]	--	7.33	Handbook Chem. Phys, 1966
Porous, Grade 60 52% porosity	65.5[a]	--	4.17	Handbook Chem. Phys, 1966
Porous, Grade 45 53% porosity	64.9[a]	--	3.75	Handbook Chem. Phys, 1966
Porous, Grade 25 53% porosity	64.3[a]	--	3.33	Handbook Chem. Phys, 1966
Paper	--	--	0.075	McAdams 1954
Paper or pulp, macerated	2.5-3.5	--	0.0121	Lewis 1968
Sawdust, various	12.0	--	0.034	Handbook Chem. Phys, 1966
Redwood	10.9	--	0.035	Handbook Chem. Phys, 1966
(and shavings)	8-15	--	0.0375	Handbook Chem. Phys, 1966
Sawdust (soft pine and oak)				
10 - 40 mesh	--	-295	0.016	Chow 1948
	--	-180	0.0195	Chow 1948
		-105	0.0235	Chow 1948
		-55	0.0265	Chow 1948
		-20	0.0295	Chow 1948
		5	0.0325	Chow 1948
		30	0.0355	Chow 1948
		35	0.0385	Chow 1948
		62	0.040	Chow 1948

Material	Bulk Density (lb/ft³)	Temperature (°F)	Thermal Conductivity (Btu/ft-h-°F)	Reference
[a]Apparent density, defined in Section 3.4.3				
Shredded redwood bark	4.0	32	0.0290	McAdams 1954
	4.0	-100	0.0235	McAdams 1954
	4.0	-200	0.0196	McAdams 1954
	4.0	-300	0.0155	McAdams 1954
	--	-50	0.0168	Rowley et al. 1945
	--	-25	0.0180	Rowley et al. 1945
	--	25	0.0203	Rowley et al. 1945
	--	75	0.0226	Rowley et al. 1945
Sheet insulite, from wood pulp	16.2	--	0.028	Handbook Chem. Phys, 1966
	16.9	--	0.028	Handbook Chem. Phys, 1966
Wood fiber, mat	1.7	-50	0.016	Rowley et al. 1945
	1.7	0	0.018	Rowley et al. 1945
	1.7	50	0.020	Rowley et al. 1945
	1.7	100	0.023	Rowley et al. 1945
Wood fiber, blanket	3.5	-50	0.016	Rowley et al. 1945
	3.5	0	0.018	Rowley et al. 1945
	3.5	50	0.020	Rowley et al. 1945
	3.5	100	0.022	Rowley et al. 1945
Wood fiber, excelsier	1.64	-50	0.019	Rowley et al. 1945
	1.64	0	0.022	Rowley et al. 1945

Material	Bulk Density (lb/ft³)	Temperature (°F)	Thermal Conductivity (Btu/ft-h-°F)	Reference
	1.64	50	0.022	Rowley et al. 1945
Wood fiber, excelsier	1.64	100	0.024	Rowley et al. 1945
Solid woods				
Balsa	8 - 12	-300	0.0151	Gray et al. 1960
	8 - 12	-285	0.0150	Gray et al. 1960
	8 - 12	-260	0.0167	Gray et al. 1960
	8 - 12	-207	0.0183	Gray et al. 1960
	8 - 12	-190	0.0192	Gray et al. 1960
	8 - 12	-160	0.0233	Gray et al. 1960
	8 - 12	-130	0.0233	Gray et al. 1960
	8 - 12	-95	0.0232	Gray et al. 1960
Balsa, across grain	7.3	--	0.028	Handbook Chem. Phys, 1966
	8.8	--	0.032	Handbook Chem. Phys. 1966
	20	--	0.048	Handbook Chem. Phys. 1966
Cypress, across grain	29	--	0.056	Handbook Chem. Phys. 1966
Mahogany, across grain	34	--	0.075	Handbook Chem. Phys. 1966
Maple, across grain	44.7	122	0.11	McAdams 1954
Fir	26	75	0.063	Chapman 1974
Oak	30 - 38	86	0.096	Chapman 1974
Yellow pine	40	75	0.065	Chapman 1974
White pine	27	86	0.087	Chapman 1974

Material	Bulk Density (lb/ft^3)	Temperature (°F)	Thermal Conductivity (Btu/ft-h-°F)	Reference
Pine, white, across grain	34	59	0.087	McAdams 1954
	32	--	0.032	Handbook Chem. Phys, 1966
Pine, Virginia, across grain	34	--	0.082	Handbook Chem. Phys, 1966
Pine board, 1 ¼" thick	--	-50	0.0515	Gray et al. 1960
	--	0	0.054	Gray et al. 1960
	--	50	0.0575	Gray et al. 1960
	--	100	0.059	Gray et al. 1960
Pine, with grain	34.4	59	0.20	McAdams 1954
Oak, across grain	51.5	59	0.12	McAdams 1954

Equations have been developed for wood, expressing thermal conductivity as a function of of moisture and specific gravity for combined heat flow in the radial and tangential directions (McLean 1941). The expression was derived at ambient temperatures.

For moisture contents less than 40% the thermal conductivity is expressed as

$$k = S(0.116 + 0.00233M) + 0.01375 \qquad\qquad (3\text{-}25)$$

and for moisture contents greater than 40%

$$k = S(0.116 + 0.00317M) + 0.01375 \qquad\qquad (3\text{-}26)$$

where S = apparent specific gravity, as defined in Section 3.4.3
                M = Percent moisture content, oven dry basis, or

$$M = 100(W - D)/D, \qquad\qquad (3\text{-}27)$$

where W = Original weight
                D = Dry weight after oven drying

A plot of thermal conductivity as a function of moisture content and specific gravity using equation 3-25 is given in Figure 3-17.

Figure 3-17: Thermal Conductivity as a Function of Moisture and Specific Gravity (MacLean 1941)
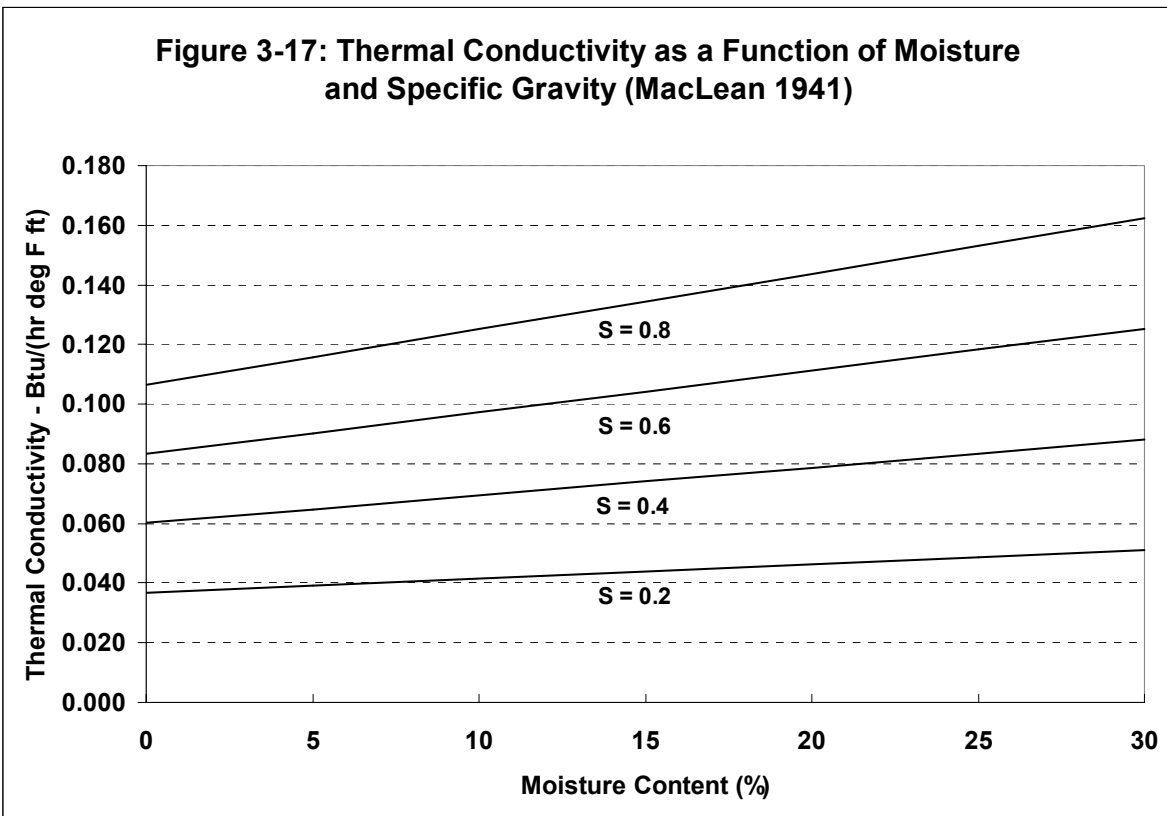
3.4.2 Heat Capacity

Heat capacity, as normally reported, is defined in terms of the enthalpy content of a material and represents the relative ability of a material to store energy. Enthalpy is a function of temperature and pressure.

$$H = H(T,P) \tag{3-28}$$

and

$$dH = (\partial H/\partial T)_P \, dT + (\partial H/\partial P)_T \, dP \tag{3-29}$$

For solids and liquids $\partial H/\partial P$ is very small and

$$dH = (\partial h/\partial T)_P \, dT \tag{3-30}$$

By definition the temperature dependency term $(\partial H/\partial P)_p$ is called heat capacity at constant pressure, C_p, and is reported on a per unit weight basis. The resulting equation for the enthalpy change is as follows:

$$\Delta H = \int_{T_O}^{T} C_P \, dT \tag{3-31}$$

This equation is normally used for materials of constant mass and no phase transitions. For example, if water is driven out of wood the apparent heat capacity may change very rapidly with temperature; the same is true for other phase transitions. Generally, if phase transitions are incorporated the enthalpy change will be:

$$\Delta H = \int_{T_O}^{T_P} C^\alpha{}_P \, dT \; + \; \Delta H_{PHASE\ CHANGE} \; + \; \int_{T_P}^{T} C^\beta{}_P \, dT \tag{3-32}$$

where

$C^a{}_P$, $C^\beta{}_P$ = heat capacities of phases 1 and 2

T_P = temperature at which phase change occurs

The heat capacity is a function of the composition and temperature but not the density of the material as long as compacting does not alter the chemical structure.

The data on heat capacity are limited. Some typical values are given in Table 3-21. No characterization data are reported for the samples.

Several C_P equations have been developed to predict the heat capacities of wood at temperatures to 100 °C. As an example of specific heat equations for woods, Beall (1968) shows the equation in which moisture is an important parameter in estimating the heat capacity:

$$C_p = 0.259 + (9.75 \times 10^{-4})M + 6.05 \times 20^{-4}T_1 + 1.3 \times 10^{-5}M\ T_1, \qquad (3-33)$$

where

M = % moisture, up to 27%.

Table 3-21: Heat Capacity

Material	Temperature (°F)	Heat capacity (Btu lb^{-1} °F^{-1})	Reference
Carbon	78-168	0.168	Perry 1973
	103-1640	0.314	Perry 1973
	132-2640	0.387	Perry 1973
Charcoal	50	0.16	Perry 1973
Cellulose	--	0.32	Perry 1973
Oak	--	0.57	Perry 1973
Fir	75	0.65	Chapman 1974
Yellow pine	75	0.67	Chapman 1974
Cork	68	0.45	Chapman 1974

Other methods are available and generally are for the same temperature range.

As with thermal conductivity, no references were readily available for heat capacity of biomass materials for the temperature range of thermal processing conditions needed for pyrolysis or gasification; new data are needed for applicable temperature ranges.

3.4.3 Density

The density of the material is important in considering energy contents of fuels on a volumetric basis, such as for transporting, solids handling, and sizing reaction vessels. There are three ways of reporting solid material density: bulk density, apparent particle

density, and skeletal density. These density values differ in the way in which the material volume is calculated. The bulk density volume basis includes the actual volume of the solid, the pore volume, and the void volume between solid particles. Apparent particle density includes solid volume and pore volume. Skeletal density, or true density, includes only solid volume. The three values are related as follows:

$$\rho_a = \rho_s(1-\epsilon_p) \qquad\qquad (3\text{-}34)$$

$$\rho_b = \rho_a(1-\epsilon_b), \qquad\qquad (3\text{-}35)$$

where

ρ_s = skeletal density, weight/volume
ρ_a = apparent density, weight/volume
ρ_b = bulk density, weight/volume

ϵ_p = particle porosity = $\dfrac{\text{Volume of pores}}{\text{Volume of pores and volume of solid}}$

ϵ_b = bed porosity = $\dfrac{\text{Volume of external voids}}{\text{Volume of external voids and volume of particles}}$

Densification of biomass is accomplished by reducing the particle porosity ϵ_p.

The density of biomass depends on the nature of the material, its moisture content, and degree of densification. Raw, over-dry biomass (with 7% to 8% moisture) has an apparent density of about 40 lb/ft^3 (hardwoods) and 28 lb/ft^3 (softwoods). The density of woods with high moisture contents can be as high as 60 lb/ft^3. Densification produces particles with apparent bone dry densities of 55 lb/ft^3 to 75 lb/ft^3. The skeletal density of over dry biomass has been reported to be 91 lb/ft^3 (Siau 1971). Bulk densities of a number of biomass materials are given in Table 3-20. Apparent densities of a number of biomass materials are given in Table 3-22.

3.4.3.1   Effect of Moisture Content on Density

The apparent density of wood and biomass depends on the moisture content. The dry and wet biomass apparent densities are related as follows from the moisture content obtained from the proximate analysis of the raw feedstock:

$$\rho_a(D) = (1-M)\,\rho_a(R), \qquad\qquad (3\text{-}36)$$

where

$\rho_a(D)$ = apparent density of dry biomass,
$\rho_a(R)$ = apparent density of raw biomass, and
    M = proximate moisture.

For a typical raw biomass with 50% moisture and apparent dry density of 30 lb/ft^3, the raw biomass sample has a density of 60 lb/ft^3.

Table 3-22: Apparent Density of Selected Woods
(Jenkins, 1989)

Wood Type	Specific Gravity	Density (lb/ft^3)
Almond	0.78	48.67
Alder (red)	0.38	23.71
Ash (white)	0.54	33.70
Aspen	0.36	22.46
Bald cypress	0.43	26.83
Beech	0.57	35.57
Birch, yellow	0.55	34.32
Cedar, incense	0.35	21.84
Cottonwood	0.37	23.09
Elm, American	0.46	28.70
Fir, balsam	0.32	19.97
Hemlock, mountain	0.42	26.21
Hickory, pecan	0.61	38.06
Maple, sugar	0.57	35.57
Oak, northern red	0.56	34.94
Oak, white	0.60	37.44
Pine, jack	0.40	24.96
lodgepole	0.39	24.34
ponderosa	0.39	24.34
sugar	0.34	21.22
Poplar, balsam	0.30	18.72
Redwood, old growth	0.39	24.34
Spruce, black	0.38	23.71
Tanoak	0.58	36.19
Yellow poplar	0.40	24.96

3.4.3.2   Densification

Densification by compaction reduces the internal voidage of the biomass material and reshapes the particles so that the bulk density is increased. The bulk density of green wood chips is typically 20 lb/ft^3, while the apparent density is on the order of 60 lb/ft^3. The typical external void fraction, ϵ_b, for chips is therefore about 0.67. The high voidage is due to the shape of the particles. Reshaping the particles to cylinders typically reduces the void fraction ϵb to about 0.5 and thus raises the bulk density to about 30 lb/ft^3. Thus the weight per unit volume is increased 50% by reshaping, and more material can be transported in the same carrier volume.

Densification of biomass by decreasing the particle porosity further improves handling. For raw, dry biomass of apparent density of 30 lb/ft^3, the particle porosity, ϵ_p, is typically 0.67 assuming 91 lb/ft^3 for the skeletal density. For densified samples, with reported apparent bone dry densities of 55 lb/ft^3 to 75 lb/ft^3, the particle porosity has decreased to 0.4 to 0.18. Thus in densification a large fraction of the internal voidage is removed.

3.4.4 <u>Diffusion Coefficients in Biomass Materials</u>

No data are readily available in the literature on gas diffusion coefficients in either natural or pelleted biomass materials or in the pyrolysis chars.

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Appendix 4

Wood Residue Combustion in Boilers

1.6 Wood Residue Combustion In Boilers

1.6.1 General[1-6]

The burning of wood residue in boilers is mostly confined to those industries where it is available as a byproduct. It is burned both to obtain heat energy and to alleviate possible solid residue disposal problems. In boilers, wood residue is normally burned in the form of hogged wood, bark, sawdust, shavings, chips, mill rejects, sanderdust, or wood trim. Heating values for this residue range from about 4,500 British thermal units/pound (Btu/lb) of fuel on a wet, as-fired basis, to about 8,000 Btu/lb for dry wood. The moisture content of as-fired wood is typically near 50 weight percent for the pulp, paper and lumber industries and is typically 10 to 15 percent for the furniture industry. However, moisture contents may vary from 5 to 75 weight percent depending on the residue type and storage operations. Generally, bark is the major type of residue burned in pulp mills; either a mixture of wood and bark residue or wood residue alone is burned most frequently in the lumber, furniture, and plywood industries.

1.6.2 Firing Practices[5, 7, 8]

Various boiler firing configurations are used for burning wood residue. One common type of boiler used in smaller operations is the Dutch oven. This unit is widely used because it can burn fuels with very high moisture content. Fuel is fed into the oven through an opening in the top of a refractory-lined furnace. The fuel accumulates in a cone-shaped pile on a flat or sloping grate. Combustion is accomplished in two stages: (1) drying and gasification, and (2) combustion of gaseous products. The first stage takes place in the primary furnace, which is separated from the secondary furnace chamber by a bridge wall. Combustion is completed in the secondary chamber before gases enter the boiler section. The large mass of refractory helps to stabilize combustion rates but also causes a slow response to fluctuating steam demand.

In another boiler type, the fuel cell oven, fuel is dropped onto suspended fixed grates and is fired in a pile. Unlike the Dutch oven, the refractory-lined fuel cell also uses combustion air preheating and positioning of secondary and tertiary air injection ports to improve boiler efficiency. Because of their overall design and operating similarities, however, fuel cell and Dutch oven boilers have many comparable emission characteristics.

The firing method most commonly employed for wood-fired boilers with a steam generation rate larger than 100,000 lb/hr is the spreader stoker. In this boiler type, wood enters the furnace through a fuel chute and is spread either pneumatically or mechanically across the furnace, where small pieces of the fuel burn while in suspension. Simultaneously, larger pieces of fuel are spread in a thin, even bed on a stationary or moving grate. The burning is accomplished in three stages in a single chamber: (1) moisture evaporation; (2) distillation and burning of volatile matter; and (3) burning of fixed carbon. This type of boiler has a fast response to load changes, has improved combustion control, and can be operated with multiple fuels. Natural gas, oil, and/or coal, are often fired in spreader stoker boilers as auxiliary fuels. The fossil fuels are fired to maintain constant steam production when the wood residue moisture content or mass rate fluctuates and/or to provide more steam than can be generated from the residue supply alone. Although spreader stokers are the most common stokers among larger wood-fired boilers, overfeed and underfeed stokers are also utilized for smaller units.

Another boiler type sometimes used for wood combustion is the suspension-fired boiler. This boiler differs from a spreader stoker in that small-sized fuel (normally less than 2 mm and normally low moisture) is blown into the boiler and combusted by supporting it in air rather than on fixed grates. Rapid changes in combustion rate and, therefore, steam generation rate are possible because the finely divided fuel particles burn very quickly.

A later innovation in wood firing is the fluidized bed combustion (FBC) boiler. A fluidized bed consists of inert particles through which air is blown so that the bed behaves as a fluid. Wood residue enters in the space above the bed and burns both in suspension and in the bed. Because of the large thermal mass represented by the hot inert bed particles, fluidized beds can handle fuels with moisture contents up to near 70 percent (total basis). Fluidized beds can also handle dirty fuels (up to 30 percent inert material). Wood fuel is pyrolyzed faster in a fluidized bed than on a grate due to its immediate contact with hot bed material. As a result, combustion is rapid and results in nearly complete combustion of the organic matter, thereby minimizing the emissions of unburned organic compounds.

1.6.3 Emissions And Controls[7-12]

The major emission of concern from wood boilers is particulate matter (PM). These emissions depend primarily on the composition of the residue fuel burned, and the particle control device. Oxides of nitrogen (NO_x) may also be emitted in significant quantities when certain types of wood residue are combusted or when operating conditions are poor.

1.6.3.1 Criteria Pollutants

The composition of wood residue and the characteristics of the resulting emissions depend largely on the industry from which the wood residue originates. Pulping operations, for example, produce great quantities of bark that may contain more than 70 weight percent moisture, sand, and other non-combustibles. As a result, bark boilers in pulp mills may emit considerable amounts of particulate matter to the atmosphere unless they are controlled. On the other hand, some operations, such as furniture manufacturing, generate a clean, dry wood residue (2 to 20 weight percent moisture) which produces relatively low particulate emission levels when properly burned. Still other operations, such as sawmills, burn a varying mixture of bark and wood residue that results in PM emissions somewhere between these two extremes. Additionally, NO_x emissions from wet bark and wood boilers are typically lower (approximately one-half) in comparison to NO_x emissions from dry wood-fired boilers.

Furnace operating conditions are particularly important when firing wood residue. For example, because of the high moisture content that may be present in wood residue, a larger than usual area of refractory surface is often necessary to dry the fuel before combustion. In addition, sufficient secondary air must be supplied over the fuel bed to burn the volatiles that account for most of the combustible material in the residue. When proper drying conditions do not exist, or when secondary combustion is incomplete, the combustion temperature is lowered, and increased PM, CO, and organic compound emissions may result from any boiler type. Significant variations in fuel moisture content can cause short-term emissions to fluctuate.

1.6.3.2 Greenhouse Gases[13-18]

Carbon dioxide (CO_2), methane (CH_4), and nitrous oxide (N_2O) emissions are all produced during wood residue combustion. Nearly all of the fuel carbon (99 percent) in wood residue is converted to CO_2 during the combustion process. This conversion is relatively independent of firing configuration. Although the formation of CO acts to reduce CO_2 emissions, the amount of CO produced is insignificant compared to the amount of CO_2 produced. The majority of the fuel carbon not converted to CO_2, due to incomplete combustion, is entrained in the bottom ash. CO_2 emitted from this source is generally not

counted as greenhouse gas emissions because it is considered part of the short-term CO_2 cycle of the biosphere.

Formation of N_2O during the combustion process is governed by a complex series of reactions and its formation is dependent upon many factors. Formation of N_2O is minimized when combustion temperatures are kept high (above 1475ºF) and excess air is kept to a minimum (less than 1 percent).

Methane emissions are highest during periods of low-temperature combustion or incomplete combustion, such as the start-up or shut-down cycle for boilers. Typically, conditions that favor formation of N_2O also favor emissions of CH_4.

1.6.4 Controls

Currently, the four most common control devices used to reduce PM emissions from wood-fired boilers are mechanical collectors, wet scrubbers, electrostatic precipitators (ESPs), and fabric filters. The use of multitube cyclone (or multiclone) mechanical collectors provides particulate control for many wood-fired boilers. Often, two multiclones are used in series, allowing the first collector to remove the bulk of the dust and the second to remove smaller particles. The efficiency of this arrangement varies from 25 to 65 percent. The most widely used wet scrubbers for wood-fired boilers are venturi scrubbers. With gas-side pressure drops exceeding 15 inches of water, particulate collection efficiencies of 85 percent or greater have been reported for venturi scrubbers operating on wood-fired boilers.

ESPs are employed when collection efficiencies above 90 percent are required. When applied to wood-fired boilers, ESPs are often used downstream of mechanical collector precleaners which remove larger-sized particles. Collection efficiencies of 90 to 99 percent for PM have been observed for ESPs operating on wood-fired boilers.

A variation of the ESP is the electrostatic gravel bed filter. In this device, PM in flue gases is removed by impaction with gravel media inside a packed bed; collection is augmented by an electrically charged grid within the bed. Particulate collection efficiencies are typically over 80 percent.

Fabric filters (i. e., baghouses) have had limited applications to wood-fired boilers. The principal drawback to fabric filtration, as perceived by potential users, is a fire danger arising from the collection of combustible carbonaceous fly ash. Steps can be taken to reduce this hazard, including the installation of a mechanical collector upstream of the fabric filter to remove large burning particles of fly ash (i. e., "sparklers"). Despite complications, fabric filters are generally preferred for boilers firing salt-laden wood. This fuel produces fine particulates with a high salt content having a quenching effect, thereby reducing fire hazards. Particle collection efficiencies are typically 80% or higher.

For stoker and FBC boilers, overfire air ports may be used to lower NO_x emissions by staging the combustion process. In those areas of the U. S. where NO_x emissions must be reduced to their lowest levels, the application of selective noncatalytic reduction (SNCR) to residue wood-fired boilers has been accomplished; the application of selective catalytic reduction (SCR) is being contemplated. Both systems are postcombustion NO_x reduction techniques in which ammonia (or urea) is injected into the flue gas to selectively reduce NO_x to nitrogen and water. In one application of SNCR to an industrial wood-fired boiler, NO_x reduction efficiencies varied between 35 and 75 percent as the ammonia-to-NO_x ratio increased from 0.4 to 3.2.

Emission factors and emission factor ratings for wood residue boilers are summarized in Tables 1.6-1, 1.6-2, 1.6-3, 1.6-4. The factors are presented on an energy basis (pound of pollutant per million Btu of heat input). Factors for wet wood represent facilities that burn wood residue with a

moisture content of 20 percent or greater. Factors for dry wood represent wood residue with less than 20 percent moisture content. Cumulative particle size distribution data and associated emission factors are presented in Table 1.6-5. Uncontrolled and controlled size-specific emission factors are plotted in Figure 1.6-1.

1.6.5 Updates Since the Fifth Edition

The Fifth Edition was released in January 1995. Revisions to this section since that date are summarized below. For further detail, consult the background report for this section. This and other documents can be found on the CHIEF Web Site at http://www.epa.gov/ttn/chief/, or by calling the Info CHIEF Help Desk at (919)541-1000.

Supplement A, February 1996

- Significant figures were added to some PM and PM-10 emission factors.

- In the table with NO_x and CO emission factors, text was added in the footnotes to clarify meaning.

Supplement B, October 1996

- SO_x, CH_4, N_2O, CO_2, speciated organics, and trace elements emission factors were corrected.

- Several HAP emission factors were updated.

Supplement D, February 1998

- Table 1.6-1, the PM-10 and one PM emission factors were revised to present two significant figures and the PM-10 emission factor for wood-fired boilers with mechanical collectors without flyash reinjection was revised to 2.6 lb/ton to reflect that these values are based on wood with 50% moisture. A typographical error in the wet scrubber emission factor for PM-10 was corrected.

- Table 1.6-2, the SO_x emission factors for all boiler categories were revised to 0.075 lb/ton to reflect that these factors are based on wood with 50% moisture.

- Tables 1.6-4 and 1.6-5 were re-titled to reflect that the speciated organic and trace element analysis presented in these tables are compiled from wood-fired boilers equipped with a variety of PM control technologies.

Supplement D, August 1998

- Table 1.6-4, the emission factor for trichlorotrifluoroethane was removed. The phenol emission factor was corrected to 1.47E-04; the phenanthrene factor was corrected to 5.02E-05; the chrysene factor was corrected to 4.52E-07; and, the polychlorinated dibenzo-p-furans factor was corrected to 2.9E-08.

Supplement E, February 1999

- In the footnotes of tables 1.6-1, 2, 3, 4, 5, 6, 7, some text was removed that described how to adjust the factors when burning wood with moisture and thermal content significantly different from 50% or 4500 Btu/lb, respectively. The EPA is revising Section 1.6 and, in the interim, consistent with EPA's recommendations regarding proper use of AP-42, the EPA encourages users of the wood combustion emission factors to account for the specific assumptions included in the factors and to convert the factors to a thermal content basis (i.e., lb/MMBtu) to estimate emissions when burning wood that differs significantly from 4500 Btu/lb or 50% moisture.

Supplement G, July 2001

- All emission factors were revised and new factors were added. In some cases separate factors were developed for wet wood (greater than or equal to 20 percent moisture content) and dry wood (less than 20 percent moisture).

- Separate PM and NOx emission factors are provided for dry wood combustion.

- All emission factors have been converted to units of lb/MMBtu.

- PM emission factors are specified by fuel type and control device type but not by boiler type.

- NOx, SOx and CO emission factors are specified by fuel type and not by boiler type.

- Additional toxic emission factors have been added.

- The general quality rating for PM factors are higher than before.

- TOC and CO2 emission factors are specified by all wood types and not by boiler type.

- New Source Classification Codes (SCC) were assigned for dry wood.

March 2002
- The VOC and TOC emission factors in Table 1.6-3 were calculated incorrectly. This has been corrected. The correct factors are 0.013 and 0.039, respectively.

Table 1.6-1. EMISSION FACTORS FOR PM FROM WOOD RESIDUE COMBUSTION[a]

Fuel	PM Control Device	Filterable PM		Filterable PM-10[b]		Filterable PM-2.5[b]	
		Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING
Bark/Bark and Wet Wood	No Control[c]	0.56[d]	C	0.50[e]	D	0.43[e]	D
Dry Wood	No Control[c]	0.40[f]	A	0.36[e]	D	0.31[e]	D
Wet Wood	No Control[c]	0.33[g]	A	0.29[e]	D	0.25[e]	D
Bark	Mechanical Collector	0.54[h]	D	0.49[e]	D	0.29[e]	D
Bark and Wet Wood	Mechanical Collector	0.35[i]	C	0.32[e]	D	0.19[e]	D
Dry Wood	Mechanical Collector	0.30[j]	A	0.27[e]	D	0.16[e]	D
Wet Wood	Mechanical Collector	0.22[k]	A	0.20[e]	D	0.12[e]	D
All Fuels[m]	Electrolyzed Gravel Bed	0.1[m]	D	0.074[e]	D	0.065[e]	D
All Fuels[m]	Wet Scrubber	0.066[n]	A	0.065[e]	D	0.065[e]	D
All Fuels[m]	Fabric Filter	0.1[o]	C	0.074[e]	D	0.065[e]	
All Fuels[m]	Electrostatic Precipitator	0.054[p]	B	0.04[e]	D	0.035[e]	
		<u>Condensible PM</u>					
All Fuels[m]	All Controls/No Controls	0.017[q]	A				

Table 1.6-1. (cont.)

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. CPM = Condensible Particulate Matter. These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[b] PM-10 = particulate matter less than or equal to 10 microns in aerodynamic diameter. PM-2.5 = particulate matter less than or equal to 2.5 microns in aerodynamic diameter. Filterable PM = PM captured and measured on the filter in an EPA Method 5 (or equivalent) sampling train. Condensible PM = PM captured and measured in an EPA Method 202 (or equivalent) sampling train.

[c] Factor represents boilers with no controls, Breslove separators, Breslove separators with reinjection, and mechanical collectors with reinjection. Mechanical collectors include cyclones and multiclones.

[d] References 19-21, 88.

[e] Cumulative mass % provided in Table 1.6-6 for Bark and Wet Wood-fired boilers multiplied by the Filterable PM factor.

[f] References 22-32, 88.

[g] References 26, 33-36, 88.

[h] References 37, 38, 88.

[i] References 26, 39-41, 88.

[j] References 26, 27, 34, 42-54, 88.

[k] Reference 55-57, 88.

[l] All fuels = Bark, Bark and Wet Wood, Dry Wood, and Wet Wood.

[m] References 27, 58, 88.

[n] References 26, 59-66, 88.

[o] References 26, 67-70, 88.

[p] References 26, 71-74, 88.

[q] References 19-21, 25, 28, 29, 31, 32, 36-41, 46, 51, 53-60, 62 - 65, 67-69, 72-75, 88.

Table 1.6-2. EMISSION FACTORS FOR NO$_x$, SO$_2$, AND CO FROM WOOD RESIDUE COMBUSTION[a]

Source Category[c]	NO$_x$[b]		SO$_2$[b]		CO[b]	
	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING	Emission Factor (lb/MMbtu)	EMISSION FACTOR RATING
Bark/bark and wet wood/wet wood-fired boiler	0.22[d]	A	0.025[e]	A	0.60[f,g,i,j]	A
Dry wood-fired boilers	0.49[h]	C	0.025[e]	A	0.60[f,g,i,j]	A

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. To convert lb/MMBtu to kg/J, multiply by 4.3E-10. NO$_x$ = Nitrogen oxides, SO$_2$ = Sulfur dioxide, CO = Carbon monoxide.

[b] Factors represent boilers with no controls or with particulate matter controls.

[c] These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[d] References 19, 33, 34, 39, 40, 41, 55, 62-64, 67, 70, 72, 78, 79, 88-89.

[e] References 26, 45, 50, 72, 88-89.

[f] References 26, 59, 88-89.

[g] References 19, 26, 39-41, 60-64, 67, 68, 70, 75, 79, 88-89.

[h] References 30, 34, 45, 50, 80, 81, 88-89.

[i] References 26, 30, 45-51, 80-82, 88-89.

[j] Emission factor is for stokers and dutch ovens/fuel cells. References 26, 34, 36, 55, 60, 65, 71, 72, 75. **CO Factor for fluidized bed combustors is 0.17 lb/MMbtu.** References 26, 72, 88-89.

Table 1.6-3. EMISSION FACTORS FOR SPECIATED ORGANIC COMPOUNDS, TOC, VOC, NITROUS OXIDE, AND CARBON DIOXIDE FROM WOOD RESIDUE COMBUSTION[a]

Organic Compound	Average Emission Factor[b] (lb/MMBtu)	EMISSION FACTOR RATING
Acenaphthene	9.1 E-07[c]	B
Acenaphthylene	5.0 E-06[d]	A
Acetaldehyde	8.3 E-04[e]	A
Acetone	1.9 E-04[f]	D
Acetophenone	3.2 E-09[g]	D
Acrolein	4.0 E-03[h]	C
Anthracene	3.0 E-06[i]	A
Benzaldehyde	<8.5 E-07[j]	D
Benzene	4.2 E-03[k]	A
Benzo(a)anthracene	6.5 E-08[l]	B
Benzo(a)pyrene	2.6 E-06[m]	A
Benzo(b)fluoranthene	1.0 E-07[l]	B
Benzo(e)pyrene	2.6 E-09[r]	D
Benzo(g,h,i)perylene	9.3 E-08[n]	B
Benzo(j,k)fluoranthene	1.6 E-07[o]	D
Benzo(k)fluoranthene	3.6 E-08[p]	B
Benzoic acid	4.7 E-08[q]	D
bis(2-Ethylhexyl)phthalate	4.7 E-08[g]	D
Bromomethane	1.5 E-05[f]	D
2-Butanone (MEK)	5.4 E-06[f]	D
Carbazole	1.8 E-06[f]	D
Carbon tetrachloride	4.5 E-05[r]	D
Chlorine	7.9 E-04[s]	D
Chlorobenzene	3.3 E-05[f]	D
Chloroform	2.8 E-05[f]	D
Chloromethane	2.3 E-05[f]	D
2-Chloronaphthalene	2.4 E-09[f]	D
2-Chlorophenol	2.4 E-08[u]	C
Chrysene	3.8 E-08[c]	B
Crotonaldehyde	9.9 E-06[j]	D
Decachlorobiphenyl	2.7 E-10[r]	D
Dibenzo(a,h)anthracene	9.1 E-09[l]	B
1,2-Dibromoethene	5.5 E-05[f]	D
Dichlorobiphenyl	7.4 E-10[r]	C
1,2-Dichloroethane	2.9 E-05[r]	D
Dichloromethane	2.9 E-04[v]	D
1,2-Dichloropropane	3.3 E-05[f]	D
2,4-Dinitrophenol	1.8 E-07[w]	C
Ethylbenzene	3.1 E-05[f]	D
Fluoranthene	1.6 E-06[x]	B
Fluorene	3.4 E-06[i]	A
Formaldehyde	4.4 E-03[y]	A
Heptachlorobiphenyl	6.6E-11[r]	D

A4-10

Table 1.6-3. (cont.)

Organic Compound	Average Emission Factor[b] (lb/MMBtu)	EMISSION FACTOR RATING
Hexachlorobiphenyl	5.5 E-10[r]	D
Hexanal	7.0 E-06[z]	D
Heptachlorodibenzo-p-dioxins	2.0 E-09[aa]	C
Heptachlorodibenzo-p-furans	2.4 E-10[aa]	C
Hexachlorodibenzo-p-dioxins	1.6 E-06[aa]	C
Hexachlorodibenzo-p-furans	2.8 E-10[aa]	C
Hydrogen chloride	1.9 E-02[j]	C
Indeno(1,2,3,c,d)pyrene	8.7 E-08[l]	B
Isobutyraldehyde	1.2 E-05[z]	D
Methane	2.1 E-02[f]	C
2-Methylnaphthalene	1.6 E-07[z]	D
Monochlorobiphenyl	2.2 E-10[r]	D
Naphthalene	9.7 E-05[ab]	A
2-Nitrophenol	2.4 E-07[w]	C
4-Nitrophenol	1.1 E-07[w]	C
Octachlorodibenzo-p-dioxins	6.6 E-08[aa]	B
Octachlorodibenzo-p-furans	8.8 E-11[aa]	C
Pentachlorodibenzo-p-dioxins	1.5 E-09[aa]	B
Pentachlorodibenzo-p-furans	4.2 E-10[aa]	C
Pentachlorobiphenyl	1.2 E-09[r]	D
Pentachlorophenol	5.1 E-08[ac]	C
Perylene	5.2 E-10[f]	D
Phenanthrene	7.0 E-06[ad]	B
Phenol	5.1 E-05[ae]	C
Propanal	3.2 E-06[z]	D
Propionaldehyde	6.1 E-05[f]	D
Pyrene	3.7 E-06[af]	A
Styrene	1.9 E-03[f]	D
2,3,7,8-Tetrachlorodibenzo-p-dioxins	8.6 E-12[aa]	C
Tetrachlorodibenzo-p-dioxins	4.7 E-10[ag]	C
2,3,7,8-Tetrachlorodibenzo-p-furans	9.0 E-11[aa]	C
Tetrachlorodibenzo-p-furans	7.5 E-10[aa]	C
Tetrachlorobiphenyl	2.5 E-09[r]	D
Tetrachloroethene	3.8 E-05[t]	D
o-Tolualdehyde	7.2 E-06[j]	D
p-Tolualdehyde	1.1 E-05[z]	D
Toluene	9.2 E-04[v]	C
Trichlorobiphenyl	2.6 E-09[r]	C
1,1,1-Trichloroethane	3.1 E-05[t]	D
Trichloroethene	3.0 E-05[t]	D
Trichlorofluoromethane	4.1 E-05	D
2,4,6-Trichlorophenol	<2.2 E-08[ak]	C

Table 1.6-3. (cont.)

Organic Compound	Average Emission Factor[b] (lb/MMBtu)	EMISSION FACTOR RATING
Vinyl Chloride	**1.8 E-05[r]**	D
o-Xylene	**2.5 E-05[v]**	D
Total organic compounds (TOC)	**0.039[ai]**	D
Volatile organic compounds (VOC)	**0.013[aj]**	D
Nitrous Oxide (N_2O)	**0.013[ak]**	D
Carbon Dioxide (CO_2)	**195[al]**	A

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. To convert lb/MMBtu to kg/J, multiply by 4.3E-10. These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[b] Factors are for boilers with no controls or with particulate matter controls.

[c] References 26, 34, 36, 59, 60, 65, 71-73, 75.

[d] References 26, 33, 34, 36, 59, 60, 65, 71-73, 75.

[e] References, 26, 35, 36, 46, 50, 59, 60, 65, 71-75.

[f] Reference 26.

[g] Reference 33.

[h] Reference 26, 50, 83.

[i] References 26, 34, 36, 59, 60, 65, 71-73, 75.

[j] References 26, 50.

[k] References 26, 35, 36, 46, 59, 60, 65, 70, 71-75.

[l] References 26, 36, 59, 60, 65, 70-75.

[m] References 26, 33, 36, 59, 60, 65, 70-73, 75.

[n] References 26, 33, 36, 59, 60, 65, 71-73, 75.

[o] Reference 34.

[p] References 26, 36, 60, 65, 71-75.

[q] References 26, 33.

[r] References 26.

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[t] References 26, 72.

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[v] References 26, 72.

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[x] References 26, 33, 34, 59, 60, 65, 71-75.

[y] References 26, 28, 35, 36, 46 - 51, 59, 60, 65, 70, 71-75, 79, 81, 82.

[z] Reference 50.

[aa] Reference 26, 45.

[ab] References 26, 33, 34, 36, 59, 60, 65, 71-75, 83.

[ac] References 26, 35, 60, 65, 71, 72.

[ad] References 26, 33, 34, 36, 59, 60, 65, 71 - 73.

[ae] References 26, 33, 34, 35, 60, 65, 70, 71, 72.

[af] References 26, 33, 34, 36, 59, 60, 65, 71 - 73, 83.

[ag] References 26, 45.

[ah] References 26, 35, 60, 65, 71.

[ai] TOC = total organic compounds. Factor is the sum of all factors in table except nitrous oxide and carbon dioxide.

[aj] VOC volatile organic compounds. Factor is the sum of all factors in table except hydrogen chloride, chlorine, formaldehyde, tetrachloroethene, 1,1,1,-trichloroethane, dichloromethane, acetone, nitrous oxide, methane, and carbon dioxide.

[ak] Reference 83.

[al] References 19 - 26, 33 - 49, 51- 57, 77, 79 - 82, 84 - 86.

Table 1.6-4. EMISSION FACTORS FOR TRACE ELEMENTS FROM WOOD RESIDUE COMBUSTION[a]

Trace Element	Average Emission Factor (lb/MMBtu)[b]	EMISSION FACTOR RATING
Antimony	**7.9 E-06**[c]	C
Arsenic	**2.2 E-05**[d]	A
Barium	**1.7 E-04**[c]	C
Beryllium	**1.1 E-06**[e]	B
Cadmium	**4.1 E-06**[f]	A
Chromium, total	**2.1 E-05**[g]	A
Chromium, hexavalent	**3.5 E-06**[h]	C
Cobalt	**6.5 E-06**[i]	C
Copper	**4.9 E-05**[g]	A
Iron	**9.9 E-04**[k]	C
Lead	**4.8 E-05**[l]	A
Manganese	**1.6 E-03**[d]	A
Mercury	**3.5 E-06**[m]	A
Molybdenum	**2.1 E-06**[c]	D
Nickel	**3.3 E-05**[n]	A
Phosphorus	**2.7 E-05**[c]	D
Potassium	**3.9 E-02**[c]	D
Selenium	**2.8 E-06**[o]	A
Silver	**1.7 E-03**[p]	D
Sodium	**3.6 E-04**[c]	D
Strontium	**1.0 E-05**[c]	D
Tin	**2.3 E-05**[c]	D
Titanium	**2.0 E-05**[c]	D
Vanadium	**9.8 E-07**[c]	D
Yttrium	**3.0 E-07**[c]	D
Zinc	**4.2 E-04**[o]	A

[a] Units of lb of pollutant/million Btu (MMBtu) of heat input. To convert from lb/MMBtu to lb/ton, multiply by (HHV * 2000), where HHV is the higher heating value of the fuel, MMBtu/lb. To convert lb/MMBtu to kg/J, multiply by 4.3E-10. These factors apply to Source Classification Codes (SCC) 1-0X-009-YY, where X = 1 for utilities, 2 for industrial, and 3 for commercial/institutional, and where Y = 01 for bark-fired boiler, 02 for bark and wet wood-fired boiler, 03 for wet wood-fired boiler, and 08 for dry wood-fired boiler.

[b] Factors are for boilers with no controls or with particulate matter controls.

[c] Reference 26.

[d] References 26, 33, 36, 46, 59, 60, 65, 71-73, 75, 81.

[e] References 26, 35, 36, 46, 59, 60, 65, 71-73, 75.

[f] References 26, 35, 36, 42, 46, 59, 60, 65, 71-73, 75, 81.

[g] References 26, 34, 35, 36, 42, 59, 60, 65, 71-73, 75, 81.

[h] References 26, 36, 46, 59, 60, 71, 72, 73, 75.

[i] References 26, 34, 83.

[j] References 26, 33-36, 46, 59, 60, 65, 71-73, 75, 81.

[k] References 26, 71, 72, 81.

[l] References 26, 33-36, 46, 59, 60, 65, 71-73, 75.

[m] References 26, 35, 36, 46, 59, 60, 65, 71-73, 75, 81.

[n] References 26, 33 - 36, 46, 59, 60, 65, 71-73, 75, 81.

[o] References 26, 33, 35, 46, 59, 60, 65, 71-73, 75, 81.

[p] Reference 34.

Table 1.6-5. CUMULATIVE PARTICLE SIZE DISTRIBUTION AND SIZE-SPECIFIC
EMISSION FACTORS FOR WOOD/BARK-FIRED BOILERS[a]

EMISSION FACTOR RATING: E

Particle Size[b] (µm)	Cumulative Mass % ≤ Stated Size				
	Uncontrolled[c]	Controlled			
		Multiple Cyclone[d]	Multiple Cyclone[e]	Scrubber[f]	Dry Electrostatic Granular Filter (DEGF)
15	94	96	35	98	77
10	90	91	32	98	74
6	86	80	27	98	69
2.5	76	54	16	98	65
1.25	69	30	8	96	61
1.00	67	24	6	95	58
0.625	ND	16	3	ND	51
Total	100	100	100	100	100

[a] Reference 89.
[b] Expressed as aerodynamic equivalent diameter.
[c] From data on underfeed stokers. May also be used as size distribution for wood-fired boilers.
[d] From data on spreader stokers with flyash reinjection.
[e] From data on spreader stokers without flyash reinjection.
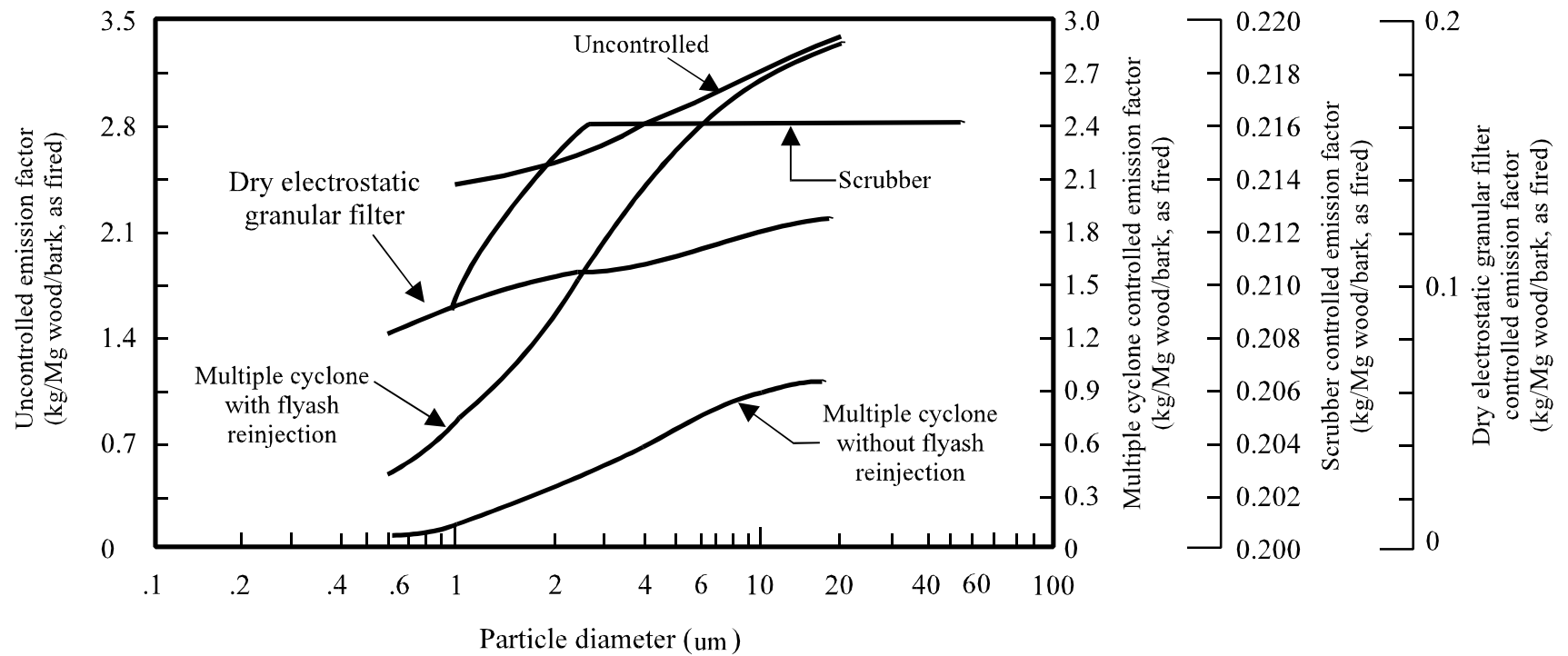[f] From data on Dutch ovens. Assumed control efficiency is 94%.

Figure 1.6-1. Cumulative size-specific particulate matter emission factors for wood/bark-fired boilers.

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