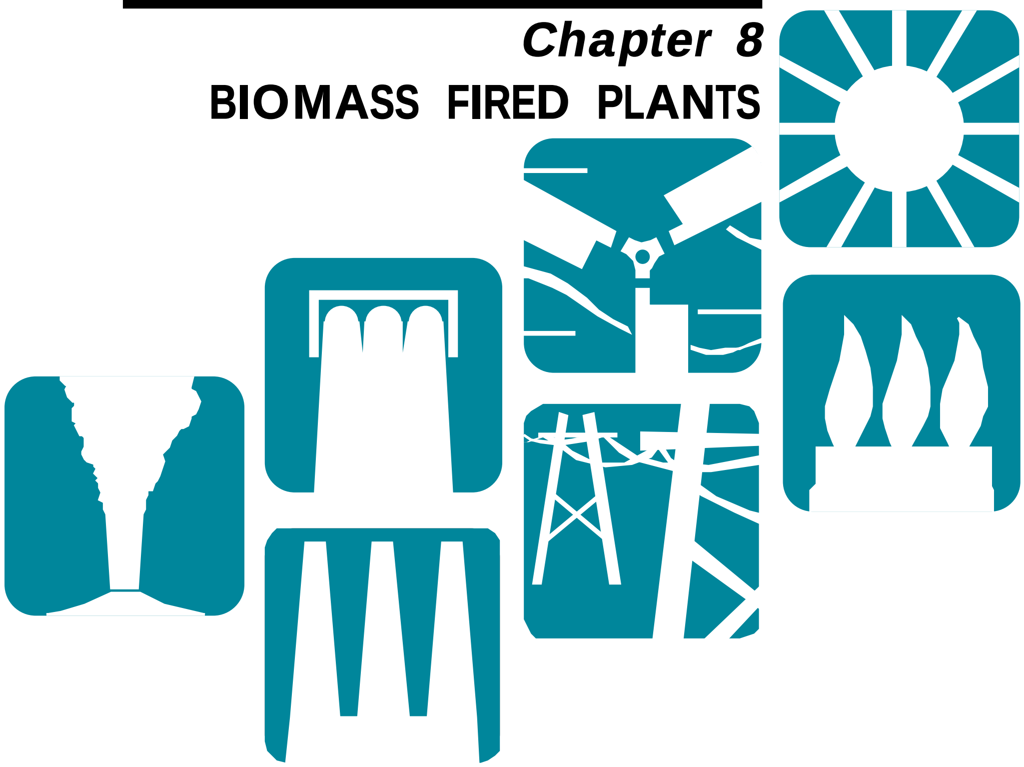
STAFF REPORT

1996
ENERGY TECHNOLOGY STATUS REPORT

Detailed Technology Evaluations

Chapter 8

BIOMASS FIRED PLANTS



MARCH 1999

CALIFORNIA ENERGY COMMISSION

STATE OF CALIFORNIA ENERGY COMMISSION

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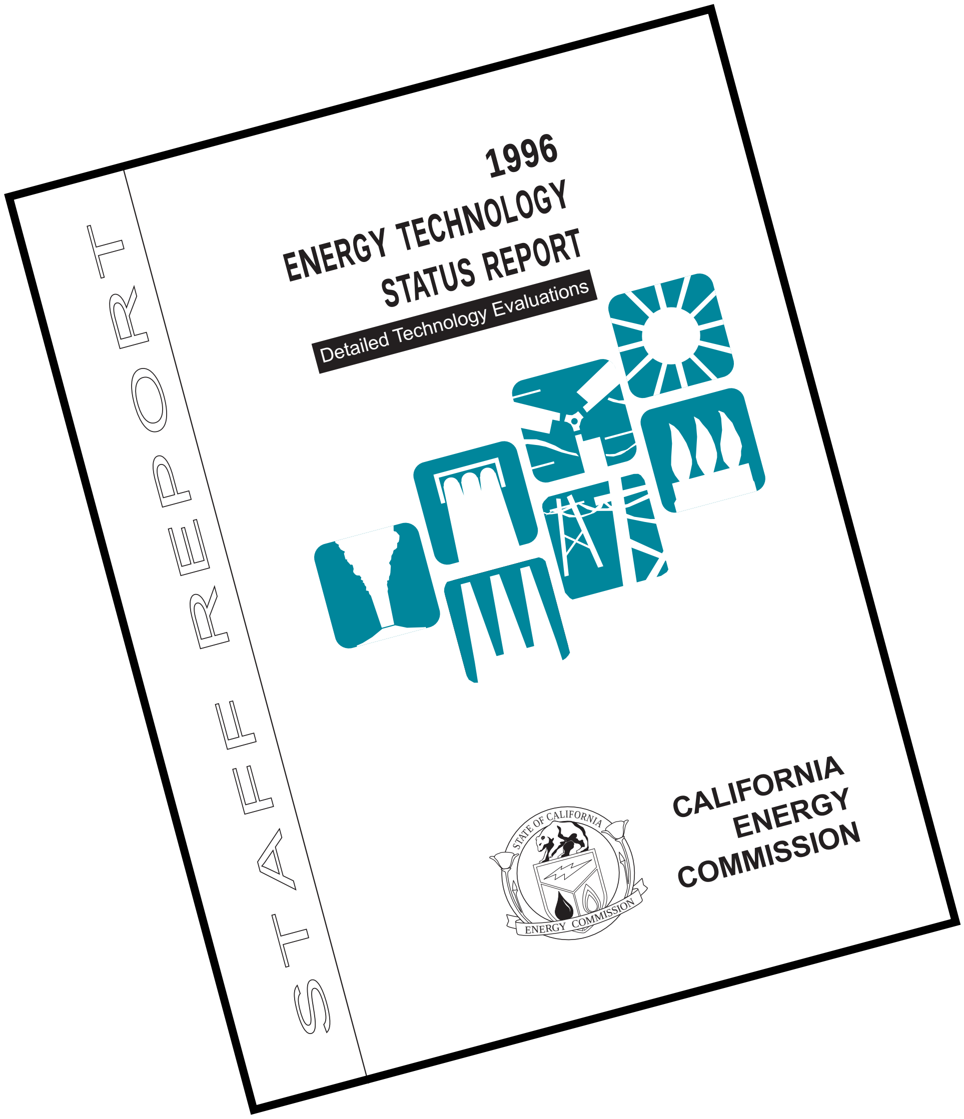

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ABSTRACT

The California Energy Commission's ***Energy Technology Status Report (ETSR)*** is a staff report that responded to the legislative requirements specified in Public Resources Code Section 25604, starting in 1988. This statute called for the Commission to publish and submit biennially to the Governor and Legislature a report on energy development trends in the state, including the status of new and existing technologies. In response to this mandate, the ***ETSR*** provided critical input to the Commission's ***Energy Development Report*** which fulfilled these legislative requirements and established state energy policy recommendations. The ***ETSR*** served additionally as a support document in new power plant siting evaluations involving demonstration project exemptions, and it still serves as an important reference for use both internally at the Commission and by other research, government, and industry organizations.

With the restructuring of the electric utility industry in 1996, the Commission assumed a number of new, critical responsibilities for implementation of Assembly Bill 1890, the restructuring legislation. Commission staff resources were shifted to the effort, the publication of the 1994 and 1996 ***ETSR*** was delayed, and the ***Energy Development Report*** was discontinued, at least temporarily. Even though the information in this document, the 1996 version of the ***ETSR,*** is dated, the Commission believes the need for it is still strong. In the future, energy technology status reports may take a different form, in response to the changing needs for technology evaluation for public interest energy research under restructuring.

When the 1996 ***ETSR*** is completed, it will consist of several parts:

- The ***Report Summary*** (completed and available from the Commission's Publications Office or from the web site at <www.energy.ca.gov/etsr/reportsu.html>). The ***Summary*** explains the parameters for determining commercial status, research and development (R&D) goals, and deployment issues. The ***Summary*** also depicts this information in at-a-glance matrix format and shows the levelized costs of key energy technologies in chart form;
- Detailed evaluations and levelized costs of the technologies, including electricity generation and storage technologies, end-use, and electricity transmission and distribution (T&D) technologies. In earlier versions of the ***ETSR***, generation and storage comprised Appendix A, Volumes I and II, and end-use and T&D comprised Appendix B, Volumes I and II. For the 1996 ***ETSR***, the chapters will be available individually, and those most in demand will be made available first*; and
- Explanations of the economic assumptions and the levelized cost computer spreadsheet model used for the levelized cost analyses.

The ***ETSR*** represents an effort to compile the best available published information and data on energy technologies; as a result, the level of detail presented varies for each technology evaluation based on the amount of information available.

* The eleven chapters in greatest demand are Chapter 2, Oil and Gas Combustion; 6, Geothermal; 8, Biomass; 9, Municipal Solid Waste; 11, Wind; 12, Solar Thermal Electric; 13, Photovoltaics; 14, Ocean Energy; 15, Fuel Cells; 16, Storage Systems; and 29, T&D. For a complete list of chapters, see the following page.

LIST OF ALL ETSR CHAPTERS

The following is a list of the chapter titles for the Energy Technology Status Report, Detailed Technology Evaluations. Not all chapters were updated in 1995, and not all that were updated in 1995 will be available at once. The 1992 versions of the Detailed Technology Evaluations are available as Appendix A, Volumes I and II (containing Chapters 1-9 and 10-16, respectively) and Appendix B, Volumes I and II (Chapters 17-22 and 23-29, respectively).

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1996 Energy Technology Status Report

Editor's note: California's Assembly Bill 1890, passed in the fall of 1996, ended electricity monopolies in California and restructured the electric utility industry. This legislation gave the California Energy Commission a number of new and important responsibilities for implementation of AB 1890. Commission staff resources were limited, and publication of this document, the **Energy Technology Status Report (ETSR)**, *was delayed. Even though the information in the* **ETSR** *is dated, the Commission believes the need for it is still strong, and we welcome your feedback and assistance in future updates. We may change the format of the* **ETSR** *to meet the needs of the restructuring effort or for other purposes in the public interest.*

This chapter of the **ETSR**, *Chapter 8 -- Biomass Fired Plants, was updated in 1995 and 1996. The approximate revision date of each subsection is included on the bottom of each page.*

8.0 BIOMASS FIRED PLANTS

8.1 BIOMASS DIRECT-COMBUSTION

DESCRIPTION

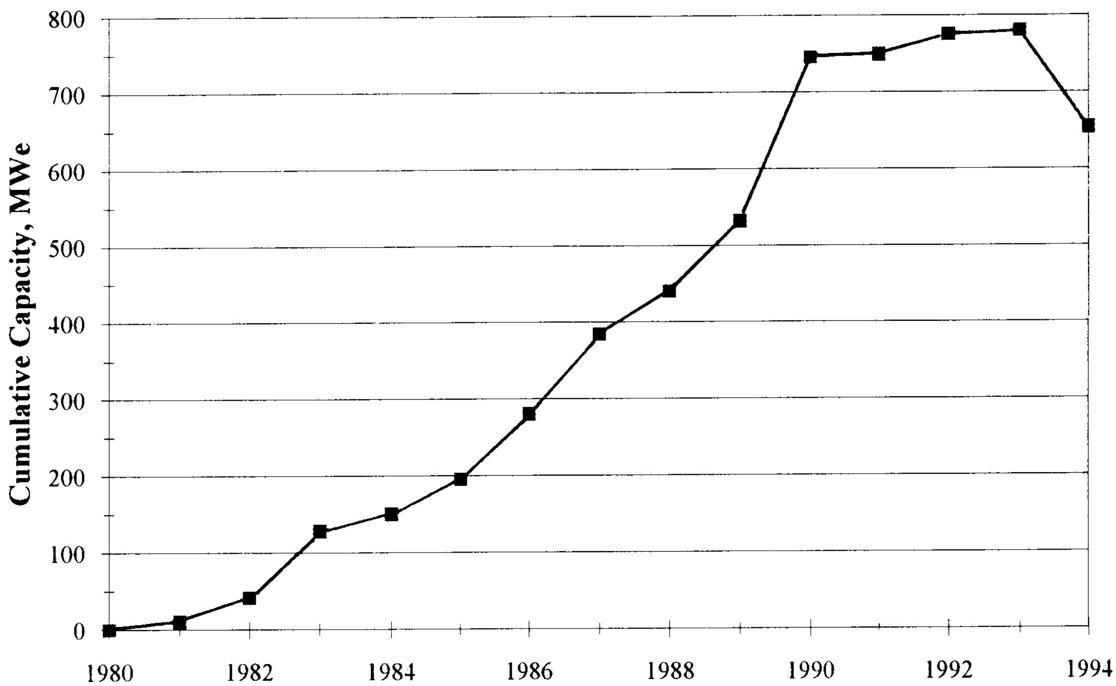
Of all the various types of biomass-to-energy conversion technologies in California today, direct-combustion is the leading technology in electrical power capacity. In 1991, the overall estimated biomass resource potential annually produced in California was about 47 million bone dry tons (bdt). [3,19,20,21] Approximately seven million bdt of residue, mostly wood, was used by biomass facilities to produce about 860 megawatts (MW) of gross power capacity in California in 1990. This was about 2 percent of the total electric capacity of California. [4,19,20,21]

Figure 8.1-1 illustrates the trend in direct-combustion biomass power capacity from 1980 to 1994, and Figure 8.1-2 shows the trend in the average retail cost of biomass feedstocks supplied to direct-combustion facilities in California from 1980 to 1995. In 1995, the power capacity had dwindled to about 600 MW, mainly due to contract curtailments negotiated between utilities and power plant owners and the expiration of the fixed energy price portion of the Standard Offer 4 (SO4) contracts. Beginning in year 11 of the SO4 contracts, biomass plant owners are paid energy prices based on the marginal cost of natural gas-fired power plants. Some of the curtailed facilities may eventually switch back to operating status.

Direct-combustion biomass facilities currently generating electricity in California fall into two broad categories: electricity-only and cogeneration plants. Electricity-only plants produce electricity which is sold to power utilities. Cogeneration facilities produce both steam and electricity either for internal use, for sale, or both. Out of approximately 30 operating direct-combustion biomass facilities in California, 15 produce electricity only and the others are cogenerators. These plants have a combined total gross capacity of approximately 600 MW.

FIGURE 8.1-1

DIRECT-COMBUSTION BIOMASS POWER CAPACITY IN CALIFORNIA
FROM 1980 TO 1994



Source: Adapted from [14], pp. 4-8.

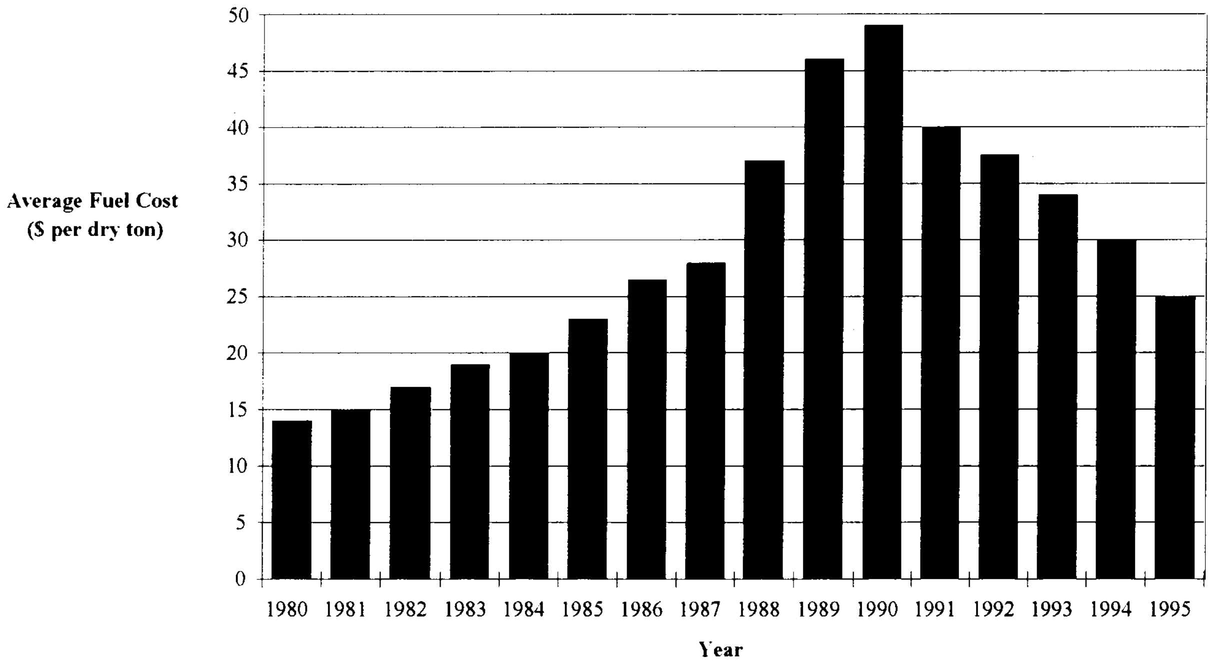
Direct-combustion equipment generally employs conventional steam boiler technology. Commonly, there are four different types of combustors used in direct-combustion biomass energy production: pile burners, spreader-stokers, suspension and cyclone burners, and fluidized bed combustors. Figures 8.1-3 through 8.1-8 illustrate some of the more prevalently used burners in California: Pile Burner-Dutch Oven, Sloped Grate Boiler, Pinhole Fixed Grate Boiler, Traveling Grate Combustor, Bubbling Fluidized Bed Combustor, and Circulating Fluidized Bed Combustor.

Biomass fuels currently used in direct combustion in California include urban wood waste, forest slash, orchard prunings, mill wastes, pits and nut shells, and various types of agricultural wastes. Pile burners, spreader-stokers, suspension burners, and cyclone burners generally burn wood residues exclusively; fluidized bed combustors can burn both wood and agricultural residues.

For electricity-producing facilities, those employing fluidized bed combustors have the highest cumulative gross power output of the different combustor technologies with 289 MW, or 36 percent. This is followed by fixed grate boilers with 250 MW (31 percent) and moving grates with 203 MW (25 percent). These three combustion technologies comprise over 92 percent of the total biomass gross power capacity in California. On a per facility basis, the three combustor

FIGURE 8.1-2

AVERAGE RETAIL COST OF BIOMASS SUPPLIED TO DIRECT-COMBUSTION FACILITIES IN CALIFORNIA



Source: Adapted from [14], pp. 4-8.

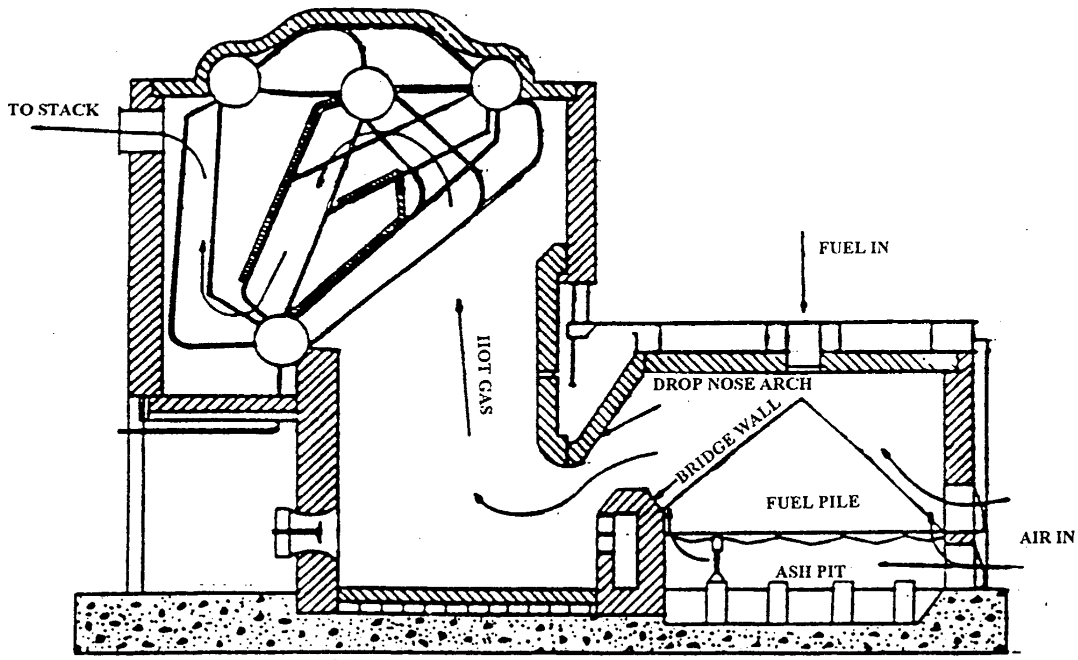
technologies with the highest average power output are the suspension burner with 29 MW per facility, the fluidized bed at 20 MW per facility, and the moving grate at 20 MW per facility. The older combustion technologies have significantly lower average power capacities and, as a consequence, the capacity of the average biomass facility has increased significantly in recent years. Combustors built for electricity production from 1980 to 1985 average 11 MW, while those built from 1986 to 1990 have an average gross power output of 22 MW.

All of the previously mentioned combustion technologies, except fluidized bed combustors, have an average availability of 87 percent or greater. The facilities with pile burners, moving grates, inclined grates, or suspension burners have availabilities of 85 percent or more. Only one fixed grate boiler facility has an availability of less than 80 percent. In contrast, the average availability of fluidized bed combustors is 72 percent, with four facilities in California having availabilities of less than 50 percent. [4]

One reason for this low availability is that fluidized beds, in general, burn lower quality and generally lower cost fuel and a wider variety of fuels. Agricultural residues tend to have a higher ash content and contaminant concentration, leading to longer forced and scheduled outages. Another reason for the low availability is that fluidized beds, as a newer technology, have experienced many initial start-up problems. It is interesting to note that if the low availabilities of

FIGURE 8.1-3

PILE BURNER-DUTCH OVEN



Source: [25]

the fluidized bed combustors and the single lowest fixed grate burner are eliminated, the overall average availability would be about 9l percent.

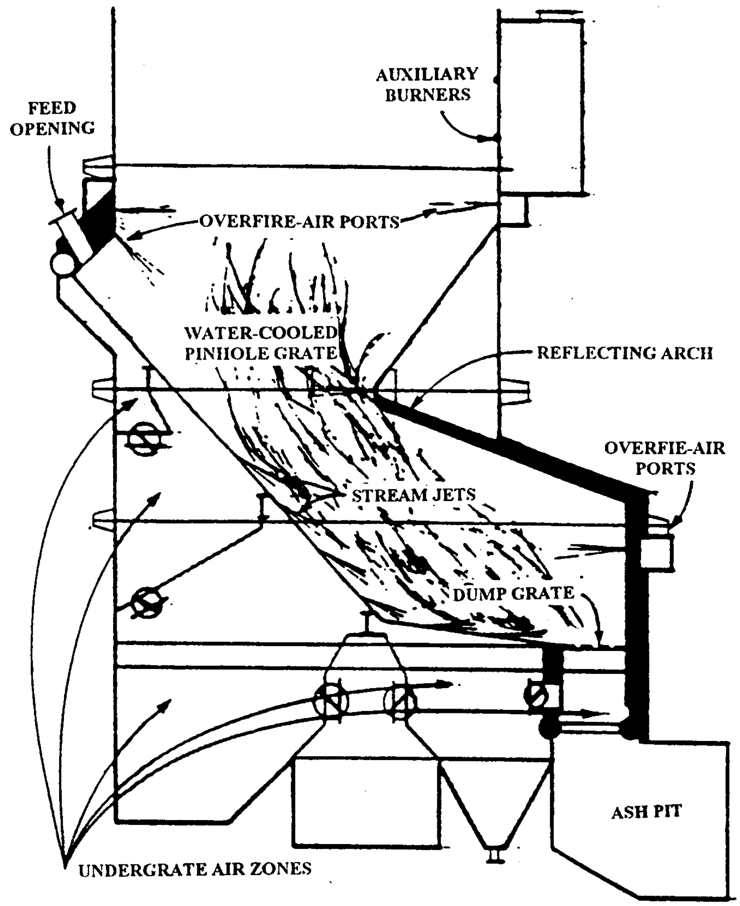
COMMERCIAL AVAILABILITY

Technology Maturity:
In the early 1980s, stokers were used as the main prime movers for direct-combustion biomass energy production; whereas in the mid 1980s, fluidized bed combustors became more popular. Both technologies have relatively low cycle efficiencies ranging from 17 to 23 percent [high heating value, (HHV)] (heat rates from 20,000 to 15,000 Btu/kWh). However, the fluidized bed technology generally results in higher efficiency than the stoker technology, but at a higher capital cost. The low cycle efficiencies associated with biomass fuel combustion are primarily a consequence of the type of direct-combustion technology, the fuel moisture content, and the ash deposition problems of the biomass fuel.

Several developing technologies generally show promise to either increase low plant efficiency or decrease fuel costs associated with direct-combustion. These technologies include gasification and hot gas clean-up, the use of gas turbines with direct-combustion gases and whole-tree burning. Other technologies that provide for revenue streams from value-added products, such as

FIGURE 8.1-4

SLOPED GRATE BOILER



Source: [25]

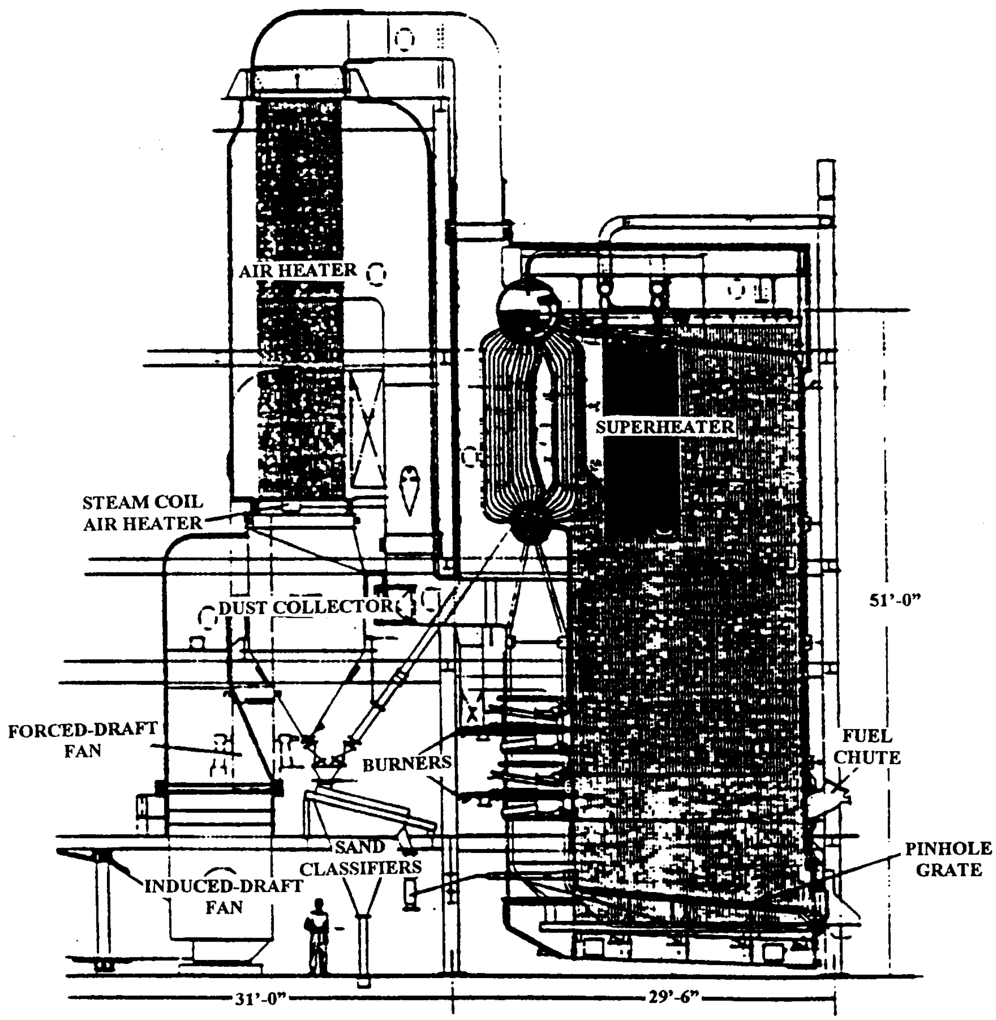
add-on ethanol production facilities, hold out the promise of improved economics. All of these technologies are currently in the development stage.

Existence of Supplier(s):
More than 50 companies in the United States manufacture wood-fired boilers suitable for use in generating 250 kWe to 50 MWe of electric power from biomass. These firms include Babcock and Wilcox, Combustion Engineering, Energy Products of Idaho, Zurn, Riley, Peabody, Wellons, Detroit Stoker, Keeler Dorr-Oliver, and Coen. [2]

Competitive Cost:
Life-cycle cash-flow analyses have been performed with a spreadsheet computer model to determine the cost competitiveness of biomass direct-combustion technology. The parameters used for this analysis are included on the Electric Generation Economic Input Worksheet

FIGURE 8.1-5

PINHOLE FIXED GRATE BOILER



Source: [25]

provided at the end of this section. The computer model printouts for low- and high-cost cases are also included at the end of this section for utility, municipal government, and non-utility ownership for baseload load duty cycles. The costs calculated are reported in both levelized constant (or real) dollars and nominal dollars referenced to a 1993 base year. Note that the results in nominal dollars are higher than those in real dollars because they include real escalation and annual inflation at 3.2 percent. Results of the cash-flow analyses indicate that the levelized cost for the conventional combined cycle technology ranges from 5.8 to 11.8 cents per kilowatt hour (cents/kWh). Based on an acceptable cost to utility decision-makers for baseload power of 3.9 to 4.4 cents/kWh in real 1993 dollars, biomass direct-combustion is a cost competitive energy option under limited conditions.

FIGURE 8.1-6

TRAVELING GRATE COMBUSTOR

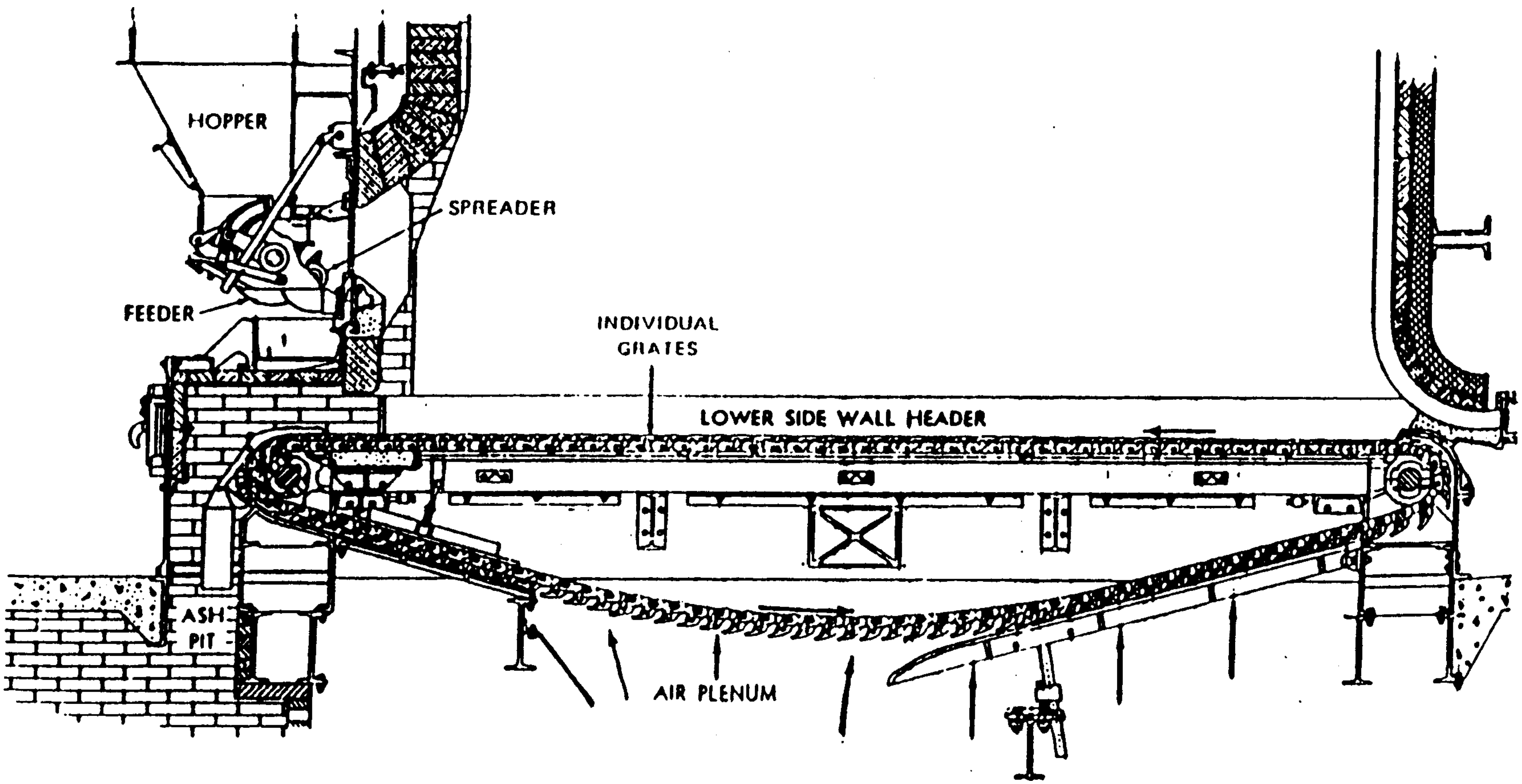


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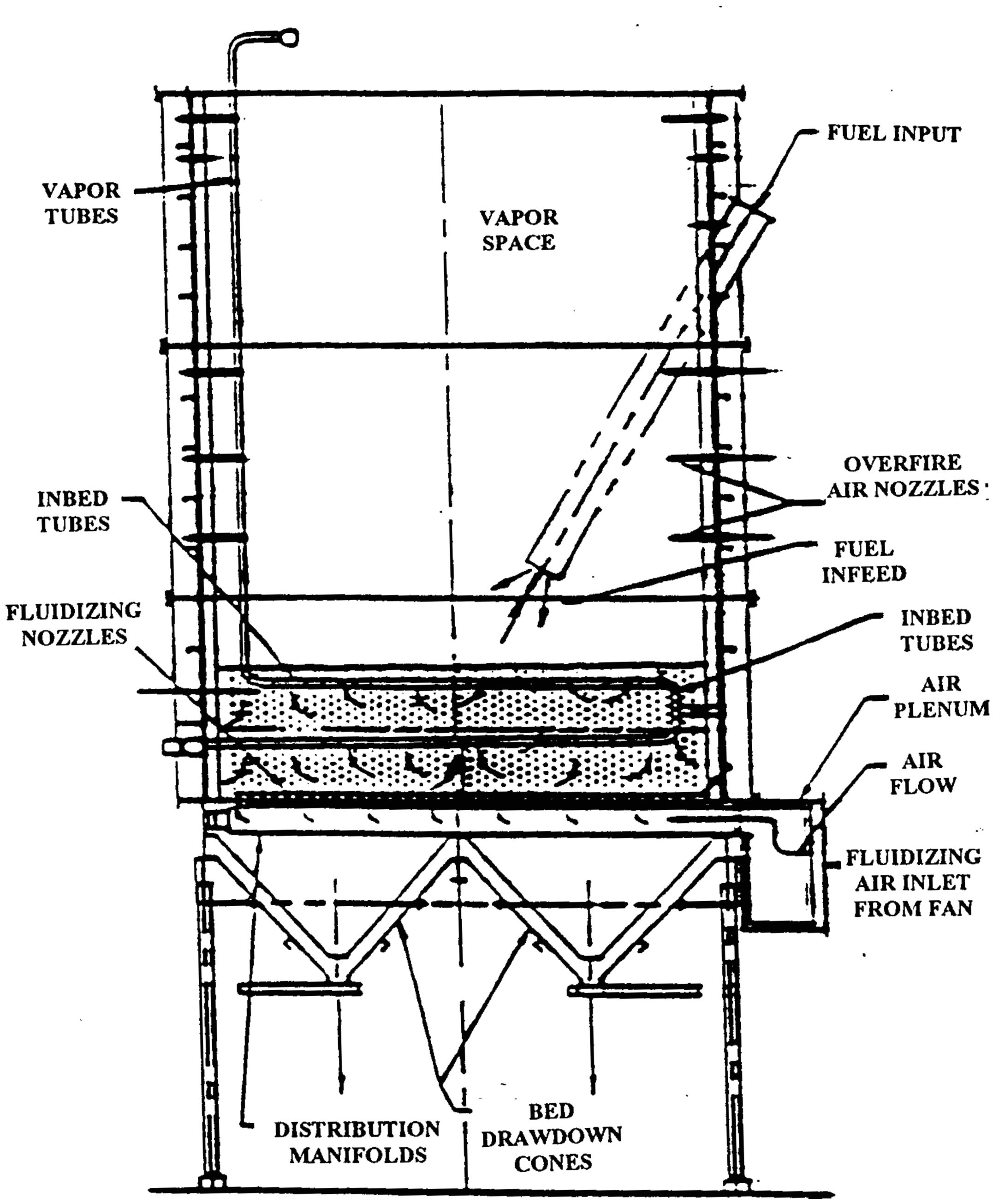
FIGURE 8.1-7

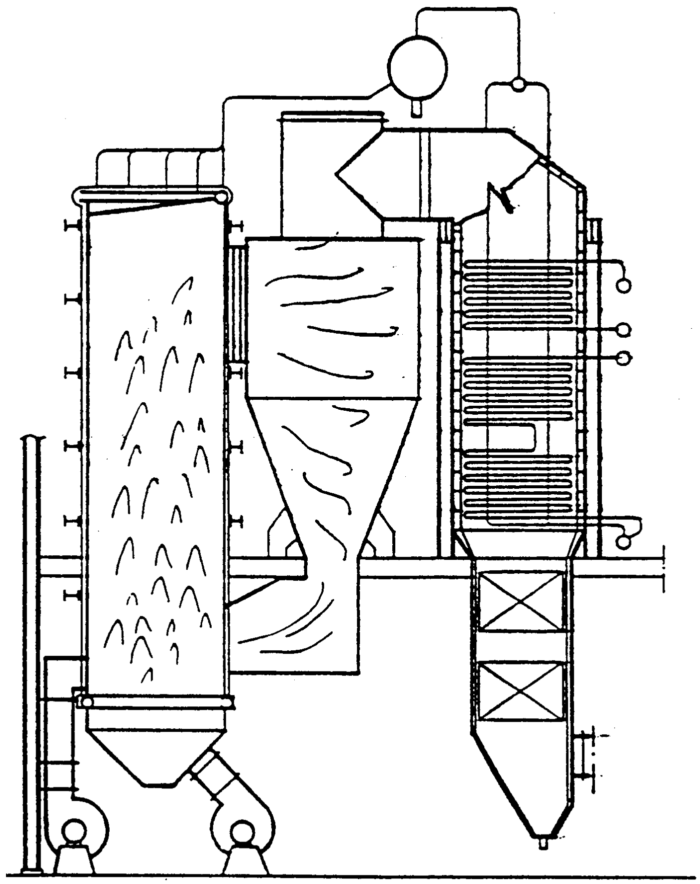
BUBBLING FLUIDIZED BED COMBUSTOR



Source: [25]

FIGURE 8.1-8

CIRCULATING FLUIDIZED BED COMBUSTOR

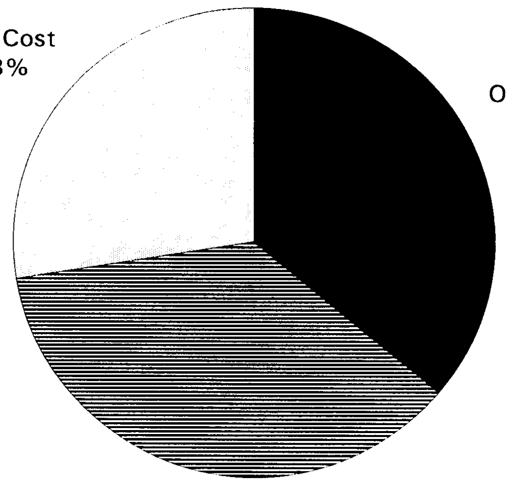


Source: California Energy Commission, R&D Office, Sacramento, Calif.

Figure 8.1-9 represents a typical breakdown of costs for a direct-combustion facility. Capital costs typically range from 3 to 5 cents/kWh (including financing costs), fuel costs from 2 to 4 cents/kWh, and operation and maintenance costs from 3 to 5 cents/kWh. Overall, the Cost of Electricity (COE) ranges from 6 to 14 cents/kWh. [23] The COE for direct-combustion biomass energy production is significantly higher than the cost of electricity for natural gas energy production. The COE for cogeneration plants, especially those associated with host sawmill operations, is significantly less than for electricity-only plants. A key reason for this cost discrepancy is the generation of a second product, steam. Steam has an estimated retail value of 4 cents/kWh when translated into electricity units. [23] As shown in Figure 8.1-1, the electricity capacity of the direct-combustion industry has been declining and will likely further decline if technology improvements and institutional remedies are not found to enable this industry to be competitive in a deregulated electricity market.

FIGURE 8.1-9

TYPICAL BREAKDOWN OF COSTS IN DIRECT-COMBUSTION BIOMASS ENERGY PRODUCTIONS



Source: [5]

Purchase Order and Construction Lead Time:
Various considerations in the scheduling of a biomass-fired facility are site selection, financing, licensing and permitting, design engineering, major equipment procurement, construction, testing and startup. Other important issues include obtaining fuel supply contracts, obtaining the power purchase agreement, and financing a suitable site. Once a site is selected, permitting takes approximately six months for a typical 5 MW plant and one year for a 25 MW plant. [2] The balance of engineering required to bring the plans to start-up and commercial operation requires approximately one to two years for 5 MW and 25 MW plants. The plant size only slightly affects the schedule, while the permitting stage has a significant effect. As a result, a 5 MW plant and a 25 MW plant require approximately two and three years, respectively, to complete the site selection process through commercial operation.

Conclusion:
The biomass power industry in California is in a period of shakeup. A typical direct-combustion biomass facility's COE ranges from approximately 6 to 14 cents/kWh. [23] Although this cost is not competitive with prices of natural gas power generation (about 2.5 cents/kWh), various mitigation approaches may be taken to decrease the negative economic impacts of the technical and environmental barriers associated with biomass energy production and hence decrease a plant's COE. These technical and environmental barriers are discussed in this section's "Research and Development Goals."

The institutional issues, however, have often been targeted as the most vital point to the longevity of the direct-combustion biomass industry. For the direct-combustion industry, issues of governmental policy, deregulation, market supply and demand, and environmentally driven regulations create many challenges but also some opportunities in the process of transitioning from a price-supported industry to a cost-competitive industry.

RESEARCH AND DEVELOPMENT GOALS (Significant Impact)

Reduced Capital Costs: (Significant Impact)
Systems/Design Development: The capital costs associated with biomass energy production are slightly higher than conventional technologies, such as steam power plants, since the fuel collection, processing, and handling systems require more attention. These systems must be economically optimized in the future so that the industry can be more competitive. The development of a comprehensive fuels infrastructure could potentially decrease the COE. Fuel preparation/handling systems, including fuel receiving, storage, and feeding systems, usually account for much of the capital investment in biomass power plants. [7] If the preparation/handling equipment capital costs of a typical biomass power plant are reduced by 10 percent, a 0.9 percent decrease in the total cost is expected, according to an Electric Power Research Institute economic model. [5]

Another strategy to reduce costs is to increase revenues through the production of value-added products, thus allowing capital costs allocated to power production to be reduced. Factors to consider include the following: (1) site selection and production optimization of feedstocks, transport, and marketing; (2) integrated studies of indigenous biomass species for highest end-use values; (3) co-production of ethanol and other higher-value non-fuel products from the biomass crops to the extent that they are marketable; and (4) integrated management of biomass systems. An idealized example of integrated management might be the use of set-aside and damaged farm land for dedicated feedstocks; municipal and agricultural processing waste water for irrigation; and the sale of value-added products such as ash for fertilizer, and compost from municipal, agricultural, and other residues.

In connection with the strategy to increase revenues, theoretically, there are several advantages to the integration of an ethanol plant with a cogeneration facility. It provides a convenient and cost-effective way to dispose of byproducts of the biomass-to-ethanol conversion process that may not be readily marketable or easily disposable as waste materials. One of these products, lignin, can be used as fuel in an on-site cogeneration plant.

Another potential byproduct from the ethanol plant that can be used as cogeneration plant fuel is biogas, which is a mixture of methane and CO_2 produced from anaerobic digestion of xylose, furfural, and glycerol contained in the waste water from the ethanol plant. Other byproducts that may be fed to the cogeneration plant are unconverted cellulose and hemicellulose, and yeast cells carried over from the reactors. Depending on the ethanol yields achieved (i.e., the efficiency of conversion of the feedstock to ethanol), the lignin plus biogas account for 80 to 95 percent of the total fuel energy that can be delivered to the cogeneration boiler from the ethanol plant. [24] Any energy generated in excess of the ethanol plant's needs can be sold as electricity.

In addition to the use of steam in an ethanol plant, a number of steam-consuming processing facilities can be located with the ethanol/cogeneration facility to produce various value-added products. Some of those products are steam-flaked sorghum, silica glass from rice straw, kenaf paper, rope, compost, and sterilized biosolids "super soil." These products may have profitable "niche" markets which in turn would help support the viability of the overall enterprise and provide low-cost residues for energy conversion.

Improved Performance: (Significant Impact)
Efficiency: Along with other negative results, poorly controlled flame temperature and high alkali content of many biomass fuels lead to ash deposition. Accumulated ash often acts as an insulator to the boiler tubes inhibiting the heat transfer between the hot gases and the water, which reduces the boiler efficiency. Ash deposition also has had an impact upon the development of the biomass industry because it limits the types of fuel that can be combusted on a sustainable basis. To maintain efficient combustion, the moisture content of the fuel should be in the range of 25 to 35 percent. Wood used by the direct-combustion biomass industry has the following moisture contents: forestry wood ranges between 40 and 55 percent, sawdust averages less than 10 percent, urban wood wastes averages 24 percent, animal wastes have an average of 30 percent, and most agricultural residues have moisture contents less than 20 percent. Biomass fuels, obviously, must either be dried or properly manipulated before combustion. [5]

A reduction in the moisture content of a fuel would increase the thermal efficiency of the combustion system. A boiler's efficiency can increase beyond 5 percent with the addition of a fuel dryer to the plant. [7] The extra expense of the dryer will be somewhat offset by reductions in the boiler cost, fuel preparation cost, flue gas handling cost, and particulate removal cost of the plant. If the fuel moisture content is reduced from 33 to 20 percent, a typical biomass power plant's COE could be reduced by about 3 percent.

Availability/Reliability/Durability: Direct-combustion biomass energy production was initially hailed as an environmentally sound alternative to open-fired burning of agricultural residues. Its potential, however, has never been realized since the burning of these fuels has caused serious ash deposition problems in boilers. A mixture of only 10 percent of rice straw can cause an unscheduled plant shutdown in a few hours from severe slagging or bed agglomeration. This barrier prevents biomass facilities from burning some of the more readily available and least expensive residues. For instance, none of the biomass power plants built to date in California can economically burn straws. The University of California at Davis, through a contract with the California Energy Commission, is currently investigating the feasibility of using leached rice straw in direct combustion facilities. Initial results are promising.

Corrosion is a serious problem in the boiler system because it can easily damage the boiler tubes. Water-side corrosion is a common type of corrosion failure and is pervasive in all steam power plants, including coal, petroleum, natural gas and biomass power plants. Fire-side corrosion, on the other hand, is more prevalent in the biomass industry than other power plants because various biomass fuels possess different acid dew point temperatures. Fire-side corrosion is generally due to the formation of acids when the metal and gas temperatures fall below the acid dew point temperature. The problem in trying to maintain temperature above the dew point is that there are many different types of biomass fuels with different metal and gas temperatures. The temperatures must be closely monitored in order to prevent serious boiler tube damage, taking into account the different ranges in acid dew point temperature in the fuels. Various preventive methods include careful design of differential expansion locations, removal of the residual stress concentrations, heat treatment of the tube bends, cleanliness of the boiler tubes and the internal surface, and regular scouring of the deposited feed water corrosion products. [8]

Erosion of boiler walls and superheater tubes provides yet another challenge to biomass plant designers and operators. Not only does it necessitate regular maintenance of boiler tubes and walls, but erosion may also lower the capacity factor of biomass facilities when boiler tube blowouts force unscheduled shutdowns for repairs. The abrasive nature of biomass residues contribute to erosion. Sand and other foreign matter inevitably find their way into the boiler even when the fuel is carefully screened. [22] Furthermore, abrasive fuels such as those with high silica content may abrade boiler surfaces.

Lower Operation and Maintenance Cost: (Significant Impact)
Ash deposits inevitably build up in even optimally designed boilers, so regular maintenance is an unavoidable necessity for smooth biomass plant operation. Most fouling build-up may be removed with well-positioned soot blowers, but slagging and agglomeration deposits on the grate or in the bed generally necessitate periodic boiler shutdown so that they can be chiseled away. Biomass facilities that have finely tuned their combustion process may require this maintenance only once or twice a year. Facilities that have poor designs or that use high alkali content fuels may require boiler maintenance every seven to 10 days. [22]

Another problem leading to higher operation and maintenance costs is fuel impurities which can cause excessive wear on biomass processing equipment. Since most biomass facilities have had to resort to dirtier fuels in recent years, their processing equipment has been exposed to higher concentrations of abrasive particles than the systems were originally designed to handle. In addition, some types of agricultural residues that have been recently utilized as fuels have been found to be abrasive, even without contamination, due to high silica content of the residues. Biomass facility managers have had to make tradeoffs between having economical, readily available fuels, and minimizing the wear to their processing equipment.

Reduced Environmental Impacts: (Minor Impact)
Process Modifications: Affordable emission control depends predominantly on the type and amount of emissions limitations imposed by the federal and state governments on the direct-combustion industry and not on the technological advancements in the industry. Currently, emission control technology has sufficiently matured so that if NOx emission control, for example, was needed for a typical direct-combustion facility, the plant cost would not increase significantly (on a percentage basis). The institutional effects of emission controls will be discussed in the “Deployment Issues” section.

DEPLOYMENT ISSUES (Potential "Show Stoppers")

Environmental Constraints: (Minor Impact)
Air Pollution: When dry fuels with high concentrations of fines (particulate matter) are moved about with front-end loaders or other heavy equipment, or when winds blow across dry storage piles, the airborne fines become a problem. Although dry fuel is generally considered ideal for combustion, it is most likely to emit dust when handled or blown by the wind. Airborne fines can travel beyond plant boundaries into neighboring properties, raising complaints from the public. A rather obvious way to control the dust emission from fuel is to water down the fuel piles. Although high fuel moisture content, as discussed in earlier sections, typically reduces boiler efficiency, moderate spraying to the tops of fuel piles during summer months and other periods when dust emissions become critical may be unavoidable. [22]

Particulate emissions are a primary concern in wood combustion. The ash content in wood, sand, dirt, and unburned carbon contributes to particulate emissions. The impact of biomass on particulates is significantly less than that of coal because the ash content from wood burning is less: from 0.5 to 2.2 percent. For coal, the ash content can reach 10 percent.

Various mechanisms such as wet collection devices and electrostatic precipitators can help remove the particulates from flue gas emissions. Another emission control device is the cyclone collector. These devices have high filtration efficiencies on materials greater than 20 microns in diameter. Fabric filter is another control mechanism but has not been used widely in wood-fired power plants. One problem with fabric filters is the fire hazard caused by still-burning particles. Even if the mechanical collector is located upstream, the particles tend to find their way back to the inlets. [8]

Water Pollution: A major contaminant of biomass fuels is top soil. Tree wastes become contaminated when logs or branches are dragged through the forest; urban wood wastes and mill wastes gather dirt when they are moved about with heavy machinery on the collection site; and agricultural wastes can become contaminated with soil during collection and when moved in the storage yard. In general, each time the fuel is allowed to touch the ground, additional dirt is accumulated on the fuel. These various contaminants can degrade the water quality from leaching of the storage piles. Run-off from exposed woodpiles can contribute to high biological oxygen demand in surface waters resulting from inorganic compounds, such as potassium, total phosphate, ammonia, and nitrogen, being leached from wood. One obvious way to resolve fuel quality problems that affect the water quality is to avoid combusting unclean fuels if possible. Fuel samples should be inspected for excessive dirt and contamination, and payments should be tied to fuel quality.

Ash Disposal: Normally, ash is not considered a hazardous waste, but ash characterization can be required by state or federal officials or by potential purchasers of ash to ensure a consistent quality of the product. Ash from municipal incinerators, however, can be considered hazardous by some states. The concern is the potential for ash to leach heavy metals and other contaminants into ground or surface waters.

According to Title 22, biomass ash is classified as a designated waste and if sent to a landfill, it must be disposed by using the designated waste methodology. [18] The implication then for biomass ash disposal is that it must be determined on a case-by-case basis. A high concentration of toxic contaminants in the biomass ash may require the ash to be disposed of in a more expensive Class I landfill instead of the usual Class II.

Financial Constraints: (Significant Impact)
High Capital Costs: High front-end capital costs make direct-combustion less economically attractive, especially under the direct-access deregulation proposal. [5]

Along with the 1992 National Energy Policy Act, tax incentive programs are available for different types of biomass energy production. [12] These incentives are generally applicable to liquid or gaseous biomass fuels, but some existing biomass plants in California may be able to modify their operations to gain these economic incentives. Table 8.1-1 summarizes these incentives. Currently, no biomass power plant in California qualifies for this 1.5 cents/kWh income tax credit. Various parties have suggested that this federal tax credit should be amended to allow California biomass plants to qualify. [6]

Fuel and Resource Constraints: (Significant Impact)
High Cost of Fuel: Figure 8.l-2 shows that in 1990 the cost of biomass fuel reached a peak value of about 50 $/bdt, but currently the retail cost of fuel is near 25 $/bdt. The main reason for the elevated cost of fuel in the late 1980s and early 1990s was the great competition for the biomass fuel supply in California among the 65 direct-combustion facilities. With the closure or curtailment of many direct-combustion facilities, there is now a surplus of biomass fuels on the market, and the price has decreased to 25 $/bdt and is still decreasing. If the fuel cost is reduced from 30 $/bdt, representing the current average cost of woody biomass in California, to 15 $/bdt, the electricity generation cost savings would be 13 percent for a typical biomass power plant in California. [5] Wood fuel prices far below 30 $/bdt have been reported by various direct-combustion biomass power plants in California. Such low prices may have resulted from being offset by tipping fees, or they may have been obtained by securing premium captive fuel supplies such as mill waste and, in some cases, urban wood waste.

Variation of Fuel and Resource Quality: Biomass energy potential is lost during fuel storage through three mechanisms: evaporation of volatiles, adsorption of water and decomposition. As much as 15 percent of the potential energy of the fuel may be lost from evaporation during storage. [9] The rate of evaporation of volatiles is difficult, if not impossible, to control and the damages can be costly to facilities that store fuel for extended periods of time. Therefore, the best means for minimizing the losses from evaporation is to use the fuel as quickly as possible.

Governmental Constraints: (Significant Impact)
Agency-Government Coordination: A major institutional barrier surrounding the biomass industry is the lack of state biomass policy. California's direct-combustion biomass industry has received mixed signals from different state agencies. Hence, a biomass collaborative was initiated by the state in the latter part of 1994 to help establish the state's perspectives on the direct-combustion industry and to provide a discussion platform between the state and the

TABLE 8.1-1

FEDERAL BIOMASS TAX CREDITS

Title	Code	Fuel Type	Incentive	Period	Limits
Production Tax Credit	IRC 45	Biomass	$0.015/kWh	Online:1993-99 10 years	Closed-loop
Incentive Payment	42 USC 1331	Renewable	$0.015/kWh	On-line: 1993-2002, 10 years	Non-profit
Unconventional Fuel Credit	IRC 29	Biogas	$0.953/MMBTU	On-line: by 1996, 10 years	Separate sales
Accelerated Depreciation		Biomass, waste fuels	DDB, 5 years and 7 years		<80 MW QF
Tax Exempt Financing		All energy	Tax-exempt	Tax life	2-counties or 65% waste
Investment Tax Credit	TRA 1986	Waste fuel	6.5% ITC	Commit: 1986 on-line by 1996	$200k by 3/1/86
Excise Tax Exemption	IRC 4041, 4081, 4091	Alcohol	$0.054/gal	Expires 2001	% content
Alcohol Mixture Credit	IRC 40(a)(1)	Ethanol	$0.54/gal	Expires 2001	Proof limits
Alcohol Production Credit	IRC 40(a)(2)	Ethanol	$0.54/gal	Expires 2001	Proof limits
Small Producers Credit	IRC 40(a)(3)	Ethanol	$0.10/gal	Expires 2001	<15 MMgal/yr
Alcohol Fuels Property	IRC 179A	Clean Fuels	$2-50k/vehicle $100k/pump	Expires 2005	Phased out

Source: [12]

biomass industry. Initially, heads of the following state agencies were involved in a biomass collaborative: California Environmental Protection Agency, Public Utilities Commission (CPUC), Energy Commission, Air Resources Board, Department of Forestry, Integrated Waste Management Board, Resources Agency, Department of Water Resources, and Department of Food and Agriculture.

The biomass industry in the past had failed to represent itself with a collective voice to express its concerns to state officials and legislators. California's biomass industry had formed groups such as California Biomass Energy Alliance, Biomass Processors' Association, Independent Energy Producers, and others to attempt to voice the industry's concerns. A working group composed of staff level representatives of the agencies listed above was established to address the institutional issues in detail. Initially, this group worked solely with the California Biomass Energy Alliance, the trade association representing most of the power plant owners. In November 1995, the working group was expanded to include representatives of all major biomass stakeholders. The mission statement of this group is "to optimize and further develop sustainable and beneficial uses of biomass in California." One of the key needs identified by the Collaborative is a comprehensive, quantitative analysis of the benefits. The dialogue between state officials and the industry is ongoing, through the Collaborative and through other efforts.

Undependable Avoided Cost Contracts: For most biomass facilities with SO4 contracts, the fixed 10-year period ends in the next few years. Biomass qualifying facilities are now receiving combined energy and capacity payments in excess of 11 cents/kWh, which will rise to almost 16 cents/kWh by the end of the fixed price period. [12] A typical biomass qualifying facility receiving 100 percent fixed energy prices will likely see a price drop from 13 to 4 cents/kWh. According to PUC estimates, 54 biomass, biogas, and municipal solid waste fueled qualifying facilities will be affected by the end of the fixed price period, along with 10 biomass cogenerators in California with a combined capacity of 992 MW. These 64 plants represent 89 percent of the installed capacity of biomass qualifying facilities.

Regulatory/Legislative Restrictions: The CPUC's proposed electricity reforms could create additional financial risks for direct-combustion biomass facilities in California. In the past, California energy policy was perceived to be focused on the diversification of electricity generation technologies. Now, with the restructuring of California's electricity market, the focus seems to be somewhat shifting to a least-cost approach to generate electricity. Deregulation-related barriers to the biomass industry could take forms such as short-term market prices, long-term capital investment risks, and inadequacies in alternative energy subsidies. The December 20, 1995, decision by the CPUC, however, does conceptually make provisions for retaining renewables in the resource mix.

Location Constraints: (Significant Impact)
Lack of Suitable Sites: Direct-combustion power plants are generally limited to remote locations with adequate fuel supply near the site so that fuel can be economically transported.

Socioeconomic Constraints: (Significant Impact)
Poor Public Opinion: Another barrier to the biomass industry is that the financial community may be reluctant to invest in what they perceive as a risky business. The uncertainty of the power purchase agreement renegotiations and the inability of some biomass facilities to meet their debt obligations are key issues for investors. [12] Additionally, the impact of environmental regulations on the fuel supply is also a key concern.

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Electrical Generation Technologies Economic Input Worksheet

(All Cost Data in Real Terms and 1993 dollars)

Technology Number and Name: 8.1 Biomass Direct Combustion

Assumed Year of Operation: 2000

Note: Where a range of costs is listed, the low cost value precedes the high cost value.

Engineering Factors

Installed Net Capacity:	1 - 50 MW		
Heat Rate (Btu/kWh-HHV):	14100	to	20000
Plant Life (years):	30		
Duty Cycle (Capacity Factor):	Baseload		75% - 60%

Economic Factors

Instant Capital Cost for assumed year of operation (1993 $/kW): 1500 to 3300

Years Prior to Operation:	-5	-4	-3	-2	-1	Year of Operation
Capital Outlay (%):	0%	0%	0%	25%	50%	25%

O&M (including consumables): Fixed ($/kW-yr): 62 to 75

Variable (cents/kWh): 0.4 to 0.5 Escalation Rate (%/yr): 0.73%

Escalation of Capital Prior to Operating Date (%): 0.00%

Insurance Rate (% of capital cost/yr): Included

Fuel: Type: Biomass

Cost ($/mmBtu): 1.69 - 2.14 Esc. Rate (%/yr): ???

	Method	Duration (years)
Federal Depreciation Rate:	MACRS-DB	5
State Depreciation Rate:	SYD	12

Capital Depreciation Base (% of Capital Cost): 98%

% of Capital Cost Subject to Sales Tax: 50%

Data for Solar Technologies:

Solar Fraction (hours/year): N/A

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:34 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.1 Biomass Direct Combustion
HIGH/LOW CASE: Low
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 1 - 50 MW
END USER: IOU

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	1.9	126.0	2.6	171.4	3.3	213.7
O&M:	1.5	101.3	2.2	141.7	2.7	176.7
Fuel:	2.4	156.6	3.3	219.0	4.2	273.1
TOTAL:	5.8	383.9	8.1	532.2	10.1	663.5

PLANT CAPITAL COST:

	-5	-4	-3	-2	-1	0
Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	25.0%	50%	25%
Interest During Construction:			8.88%	5.50% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:
Year Commercial Operation: 2000
Plant Capacity Factor (CF): 75% 6570 Hrs
Plant Life (Years): 30

OPERATING PARAMETERS (Base Year $):
Operating & Maintenance Costs (O&M):
Fixed ($/kW-Yr): 62.00 (Base Year)
Variable (Cents/kWh): 0.400 (Base Year)

Fuel Type: Biomass
Fuel Costs (F) ($/MBtu): 1.69 (Base Year)
Heat Rate (HR) (Btu/kWh): 14100
Solar Fraction: 0.00% 0 Hrs

ECONOMIC PARAMETERS:
Base Year (Dollars): 1993
Inflation Rate: 3.20%
Investment Period (Years): 30

FLAGS: FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter: 1 Cost of Capital
Normalized (1) vs. Flow Through (0): 1 Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	10.42%	7.00% (rea
Cost of Preferred Stock (kp):	0.00%	0.00% (rea
Cost of Debt Financing (kd):	7.33%	4.00% (rea
Percent Common Equity (C/V):	50.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	50.00%	
Weighted Cost of Capital:	8.88%	5.50% (rea

DEBT COVERAGE:
Coverage Ratio: CR = 3.41

FIXED CHARGE RATE:
FCR: 0.104 0.070 (rea

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	5	Yrs
	SL		Yrs
	Base	100.00%	
State:	SYD	12	Yrs
	SL		Yrs
	Base	100.00%	
Capital Depreciation Base:		98.00%	
In-service month (1..12):		6	

PLANT CAPITAL COST ($/kW): 1993 Base Year 2000 Nominal
Overnight Construction Cost: 1500
Total Plant Cost: 1641 2046

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 06-Aug-96
RUN TIME: 08:43 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.1 Biomass Direct Combustion
HIGH/LOW CASE: High
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 1 - 50 MW
END USER: IOU

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	5.3	277.3	7.2	377.1	8.9	470.1
O&M:	2.2	116.2	3.1	162.6	3.9	202.7
Fuel:	4.3	225.0	6.0	314.7	7.5	392.4
TOTAL:	11.8	618.5	16.3	854.4	20.3	1,065.2

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	25.0%	50%	25%
Interest During Construction:			8.88%	5.50% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	60%	5256 Hrs
Plant Life (Years):	30	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	75.00 (Base Year)	
Variable (Cents/kWh):	0.500 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	2.14 (Base Year)	
Heat Rate (HR) (Btu/kWh):	20000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	30

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	1	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	10.42%	7.00% (rea
Cost of Preferred Stock (kp):	0.00%	0.00% (rea
Cost of Debt Financing (kd):	7.33%	4.00% (rea
Percent Common Equity (C/V):	50.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	50.00%	
Weighted Cost of Capital:	8.88%	5.50% (rea

DEBT COVERAGE:
Coverage Ratio: CR = 3.41

FIXED CHARGE RATE:
FCR: 0.104 0.070 (rea

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	5	Yrs
	SL		Yrs
	Base	100.00%	
State:	SYD	12	Yrs
	SL		Yrs
	Base	100.00%	
Capital Depreciation Base:		98.00%	
In-service month (1..12):		6	

PLANT CAPITAL COST ($/kW):

	1993 Base Year	2000 Nominal
Overnight Construction Cost:	3300	
Total Plant Cost:	3610	4501

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY:	8.1 Biomass Direct Combustion
HIGH/LOW CASE:	Low
PEAKING/BASELOAD:	Baseload
PLANT CAPACITY:	1 - 50 MW
END USER:	Municipal

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	1.2	81.9	2.0	130.2	2.5	162.3
O&M:	1.6	102.2	2.3	148.0	2.8	184.5
Fuel:	2.4	156.6	3.5	226.8	4.3	282.7
TOTAL:	5.2	340.6	7.7	504.9	9.6	629.5

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	25.0%	50%	25%
Interest During Construction:			7.02%	3.70% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	75%	6570 Hrs
Plant Life (Years):	30	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	62.00 (Base Year)	
Variable (Cents/kWh):	0.400 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	1.69 (Base Year)	
Heat Rate (HR) (Btu/kWh):	14100	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	30

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	1	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):		0.00%	0.00% (real
Cost of Preferred Stock (kp):		0.00%	0.00% (real
Cost of Debt Financing (kd):		7.02%	3.70% (real
Percent Common Equity (C/V):		0.00%	
Percent Preferred Stock (P/V):		0.00%	
Percent Debt Financing (D/V):		100.00%	
Weighted Cost of Capital:		7.02%	3.70% (real

DEBT COVERAGE:

Coverage Ratio:	CR =	1.70	

FIXED CHARGE RATE:

FCR:		0.081	0.047 (real

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			0.00%
Marginal State Income Tax Rate (t):			0.00%
Effective Marginal Income Tax Rate (T'):			0.00%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			0.00%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	0	Yrs
	SL		Yrs
	Base	100.00%	
State:	SYD	0	Yrs
	SL		Yrs
	Base	100.00%	
Capital Depreciation Base:		0.00%	
In-service month (1..12):		6	

PLANT CAPITAL COST ($/kW):

	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1500	
Total Plant Cost:	1612	2010

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.1 Biomass Direct Combustion
HIGH/LOW CASE: High
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 1 - 50 MW
END USER: Municipal

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	3.4	180.1	5.4	286.4	6.8	357.0
O&M:	2.2	117.2	3.2	169.8	4.0	211.7
Fuel:	4.3	225.0	6.2	325.8	7.7	406.2
TOTAL:	9.9	522.2	14.9	782.0	18.5	974.9

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	25.0%	50%	25%
Interest During Construction:			7.02%	3.70% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:
Year Commercial Operation: 2000
Plant Capacity Factor (CF): 60% 5256 Hrs
Plant Life (Years): 30

OPERATING PARAMETERS (Base Year $):
Operating & Maintenance Costs (O&M):
Fixed ($/kW-Yr): 75.00 (Base Year)
Variable (Cents/kWh): 0.500 (Base Year)

Fuel Type: Biomass
Fuel Costs (F) ($/MBtu): 2.14 (Base Year)
Heat Rate (HR) (Btu/kWh): 20000
Solar Fraction: 0.00% 0 Hrs

ECONOMIC PARAMETERS:
Base Year (Dollars): 1993
Inflation Rate: 3.20%
Investment Period (Years): 30

FLAGS: — **FOR:**
Exclude (1) vs. Include (0) Interest Tax Shelter: 1 Cost of Capital
Normalized (1) vs. Flow Through (0): 1 Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):		0.00%	0.00% (real
Cost of Preferred Stock (kp):		0.00%	0.00% (real
Cost of Debt Financing (kd):		7.02%	3.70% (real
Percent Common Equity (C/V):		0.00%	
Percent Preferred Stock (P/V):		0.00%	
Percent Debt Financing (D/V):		100.00%	
Weighted Cost of Capital:		7.02%	3.70% (real
DEBT COVERAGE:			
Coverage Ratio:	CR =	1.70	
FIXED CHARGE RATE:			
FCR:		0.081	0.047 (real

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			0.00%
Marginal State Income Tax Rate (t):			0.00%
Effective Marginal Income Tax Rate (T'):			0.00%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			0.00%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	0 Yrs
	SL	Yrs
	Base	100.00%
State:	SYD	0 Yrs
	SL	Yrs
	Base	100.00%
Capital Depreciation Base:		0.00%
In-service month (1..12):		6

PLANT CAPITAL COST ($/kW):	1993 Base Year	2000 Nominal
Overnight Construction Cost:	3300	
Total Plant Cost:	3547	4422

ESCALATION RATES:	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY:	8.1 Biomass Direct Combustion
HIGH/LOW CASE:	Low
PEAKING/BASELOAD:	Baseload
PLANT CAPACITY:	1 - 50 MW
END USER:	NUG

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	3.0	199.6	3.6	234.0	4.4	291.7
O&M:	1.5	99.1	1.9	127.6	2.4	159.1
Fuel:	2.4	156.6	3.1	201.6	3.8	251.3
TOTAL:	6.9	455.3	8.6	563.3	10.7	702.2

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	25.0%	50%	25%
Interest During Construction:			14.50%	10.95% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	75%	6570 Hrs
Plant Life (Years):	30	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):

Fixed ($/kW-Yr):	62.00	(Base Year)
Variable (Cents/kWh):	0.400	(Base Year)
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	1.69	(Base Year)
Heat Rate (HR) (Btu/kWh):	14100	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	30

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	0	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	24.98%	21.10% (rea
Cost of Preferred Stock (kp):	0.00%	0.00% (rea
Cost of Debt Financing (kd):	10.01%	6.60% (rea
Percent Common Equity (C/V):	30.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	70.00%	
Weighted Cost of Capital:	14.50%	10.95% (rea

DEBT COVERAGE:

Coverage Ratio: CR = 1.67

FIXED CHARGE RATE:

FCR: 0.135 0.100 (rea

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	5 Yrs
	SL	Yrs
	Base	100.00%
State:	SYD	12 Yrs
	SL	Yrs
	Base	100.00%
Capital Depreciation Base:		98.00%
In-service month (1..12):		6

PLANT CAPITAL COST ($/kW):

	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1500	
Total Plant Cost:	1729	2156

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY:	8.1 Biomass Direct Combustion
HIGH/LOW CASE:	High
PEAKING/BASELOAD:	Baseload
PLANT CAPACITY:	1 - 50 MW
END USER:	NUG

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	14.0	735.3	14.5	761.1	18.1	948.8
O&M:	2.1	112.5	2.6	139.0	3.3	173.3
Fuel:	4.3	225.0	5.3	278.0	6.6	346.6
TOTAL:	20.4	1,072.7	22.4	1,178.1	27.9	1,468.8

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	25.0%	50%	25%
Interest During Construction:			18.47%	14.80% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	60%	5256 Hrs
Plant Life (Years):	30	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	75.00 (Base Year)	
Variable (Cents/kWh):	0.500 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	2.14 (Base Year)	
Heat Rate (HR) (Btu/kWh):	20000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	30

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	0	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	24.98%	21.10% (real
Cost of Preferred Stock (kp):	0.00%	0.00% (real
Cost of Debt Financing (kd):	11.97%	8.50% (real
Percent Common Equity (C/V):	50.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	50.00%	
Weighted Cost of Capital:	18.47%	14.80% (real

DEBT COVERAGE:

Coverage Ratio: CR = 2.73

FIXED CHARGE RATE:

FCR: 0.193 0.156 (real

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	5	Yrs
	SL		Yrs
	Base	100.00%	
State:	SYD	12	Yrs
	SL		Yrs
	Base	100.00%	
Capital Depreciation Base:		98.00%	
In-service month (1..12):		6	

PLANT CAPITAL COST ($/kW):	1993 Base Year	2000 Nominal
Overnight Construction Cost:	3300	
Total Plant Cost:	3944	4918

ESCALATION RATES:	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

8.2 BIOMASS GASIFICATION

BACKGROUND

Biomass is any material that is directly or indirectly derived from plant life. Renewable biomass feedstocks, both silvicultural (woody) and agricultural varieties, are usually dispersed, have low mass density, and contain 50 to 60 percent moisture. Therefore, there are substantial costs involved in collection, transportation, and processing (sizing and drying) biomass feedstocks.

Biomass is easier to gasify than coal because it has a much higher volatile matter content: 70 to 80 percent for wood versus 34 to 45 percent for coal. It also has high char reactivity, or higher carbon conversion capability. In the presence of steam, biomass char gasifies rapidly at relatively low temperatures, evident from the data on ultimate and proximate analyses of Pittsburgh bituminous coal and Douglas fir wood:

Ultimate Analysis (Dry Basis; % Weight)

Feedstock	*Carbon*	*Hydrogen*	*Nitrogen*	*Sulphur*	*Oxygen*	*Ash*
Coal	75.5	5.0	1.2	3.1	4.9	10.3
Douglas Fir	52.3	6.3	0.1	0	40.5	0.8

Proximate Analysis (Dry Basis; % Weight)

Feedstock	*Volatile Matter*	*Fix Carbon*	*Ash*
Coal	33.9	55.8	10.3
Douglas Fir	86.2	13.7	0.7

One notes that biomass contains a high percentage of oxygen. The fuel’s own oxygen and water are the two main elements that form gaseous molecules in lignocellulosic (biomass) feedstocks.

Pyrolysis is the precursor to gasification. Both pyrolysis and gasification are endothermic processes and require external heat energy input to initiate and complete the energy conversion processes. In some gasification processes, a portion of the feedstock is burned inside the reactor to supply the needed endothermic heat. A true pyrolysis/gasification process will require thermal decomposition of the feedstock in the complete absence of air environment. Major design considerations in a biomass gasification process include the following: [25]

- Chemical charge medium -- air, oxygen, hydrogen, and steam
- Method of heat and mass transfer -- directly or indirectly fired
- Feed type and form -- chip, block, cubes, pellets and fines
- Residue type -- dry or slagging
- Products -- fuel gas, gas and oil, gas, oil and char, gas/synthesis liquids and chemical
- Pressure -- suction, atmospheric, and high pressure

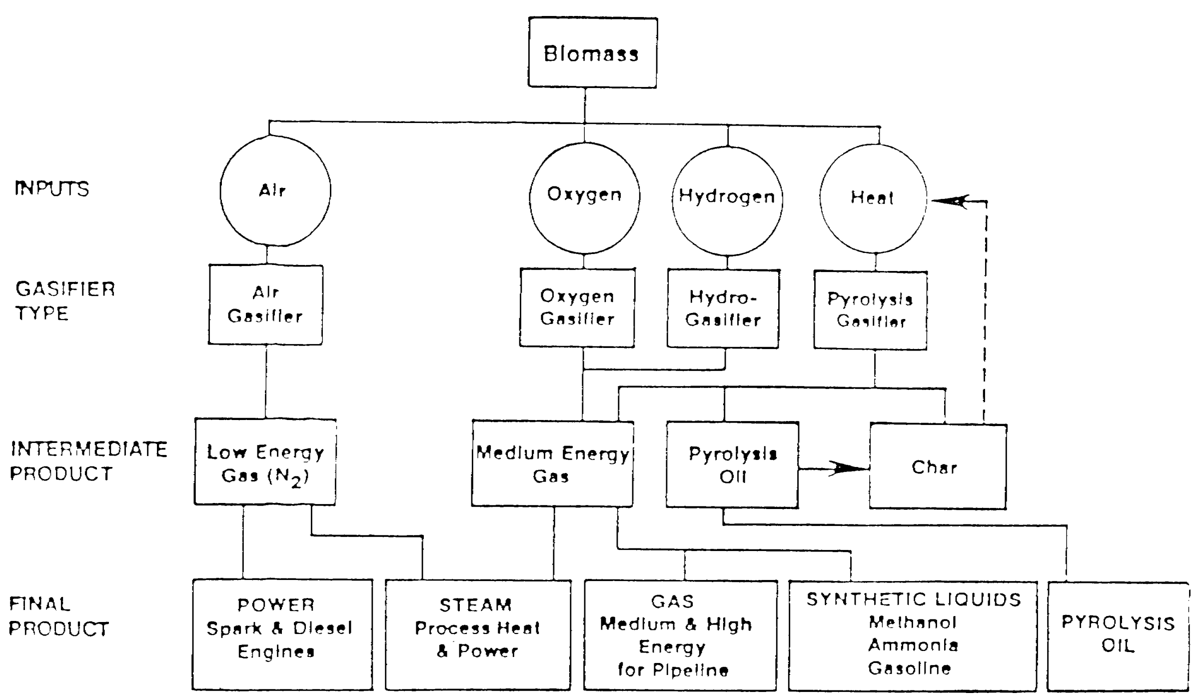
The gasification processes and their products are illustrated in Figure 8.2-1. Air blown gasifiers produce Low Btu Gas (LBG) ranging in heating value of 80 to 150 British thermal units per standard cubic foot (Btu/scf). Since air contains 79 percent nitrogen by volume, the air gasification process dilution of the fuel gas will occur by the presence of nitrogen. Most of the LBG producing gasifier designs came from the design of low Btu coal gasifier technologies. The fuel gas composition will vary with reactor design, fuel moisture, and operating condition. The flame temperature of LBG is 3200°F. It can be easily ignited, and stable flame can be maintained in the furnace environment. The versatility of LBG, however, is limited in the following ways:

- LBG cannot be transmitted over pipeline or conveniently stored and has to be used on-site or across the fence (close coupled) as it is generated.

- Use of LBG as substitute fuel in natural gas firing boiler will require extensive boiler retrofit work and gas cleaning steps to remove tar and ash, and severe derating of the boiler could be experienced.

FIGURE 8.2-1

GASIFICATION PROCESSES AND THEIR PRODUCTS



Source: [33]

- Use of LBG in diesel engines will require thorough cleaning and cooling of the gas and derating of the engine can be expected. Modern high compression internal combustion engines normally require fuel gas having at least 160 Btu/scf. A schematic sketch of gasifier system for an internal combustion engine is shown in Figure 8.2-2.

- Direct use of LBG in combustion turbine will require a hot gas cleaning system. Hot gas cleaning is still a developing technology. Demonstration of such system has currently been planned for the Pacific International Center for High Technology Research (PICHTR) project in Hawaii.

Typically, LBG is best suited as fuel for process heat production, process steam production, and small scale electrical power generation in close coupled conditions.

Medium Btu Gas (MBG) can be produced through the substoichiometric thermal decomposition process by using pure oxygen and steam and by indirectly heating the feedstock. The heating value of the MBG produced from biomass ranges from 200 to 550 Btu/scf. The thermochemical conversion of biomass is shown in Figure 8.2-3.

FIGURE 8.2-2

SCHEMATIC SKETCH OF A BASIC GASIFIER SYSTEM
FOR AN INTERNAL COMBUSTION ENGINE

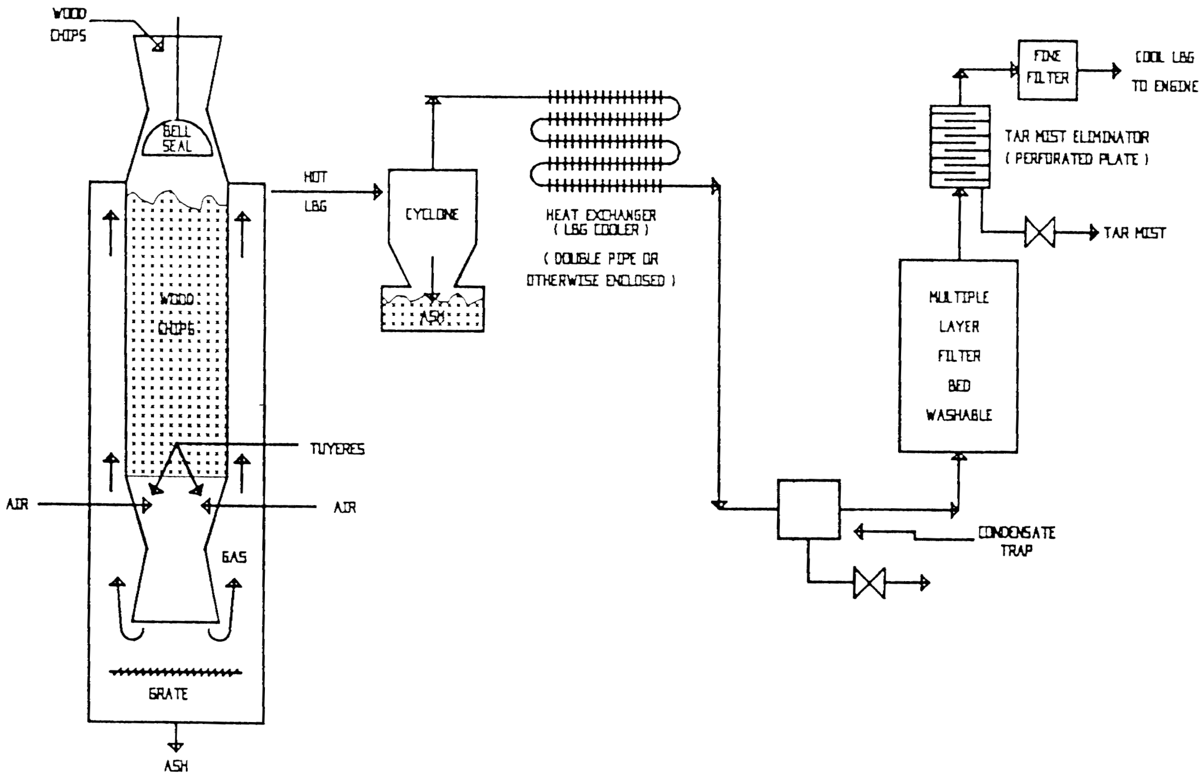
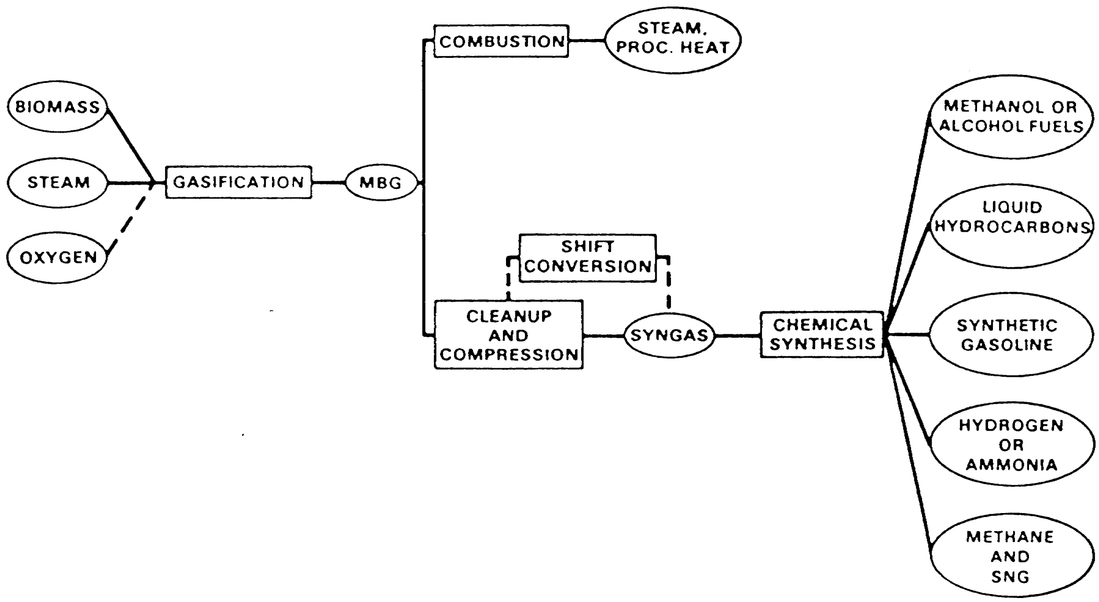


FIGURE 8.2-3

THERMOCHEMICAL CONVERSION OF BIOMASS MEDIUM BTU GASIFICATION



Source: [33]

MBG has the following attractive characteristics:

- Due to its higher heating value, minimal retrofitting of natural firing boiler will be needed.

- Derating of the boiler will be minimal.

- Due to higher flame temperature than LBG, MBG can be used in retrofitted lime recovery kilns that require high flame temperature in the paper and pulp industry.

- Due to the higher energy density, which is two to five times higher than LBG, MBG can be transported moderate distances by pipeline at reasonable costs.

- MBG's hydrogen to carbon (H/C) ratio could be catalytically adjusted to produce Substitute Natural Gas (SNG).

MBG gasification project development work has been initiated by IGT (pressurized steam oxygen process), the University of Missouri-Rolla (fluidized bed), Battelle Memorial Institute, and Columbus Laboratory (multi-solid fluidized bed). SNG gasification process development has been initiated by Pacific Northwest Laboratory (catalytic gasification), Texas Tech University (fluidized bed), and Wright Malta (pressurized Auger design).

DESCRIPTION

Gasifier technologies available for biomass feedstocks (wood and certain agricultural residues) are broadly grouped into the following:

1. Fixed Bed (Moving Packed Bed)
   (a) Updraft (counterflow)
   (b) Downdraft (co-flow)
   (c) Crossdraft

2. Fluidized Bed (single solid, multi-solid, directly heated, indirectly heated)
   (a) Atmospheric
   (b) Pressurized
   (c) Bubbling
   (d) Circulating

3. Entrained Bed

4. Tumbling Bed

5. Stirred Bed

The simplest gasifier is the updraft (counterflow) design shown in Figure 8.2-4. There are several variations of this type of gasifier design. The fuel gas exits from the gasifier at a relatively low temperature carrying uncracked tar, oil, other chemicals, and high loads of particulates and unpyrolyzed char. Use of this fuel gas will require appropriate gas cleaning through scrubbing or filter media. Gas scrubbing robs the sensible heat of the hot gas and also produces a water pollution control problem associated with the tar and oil content of the waste water. A close coupled gasifier-boiler set up could use the sensible heat of the gas without requiring gas scrubbing.

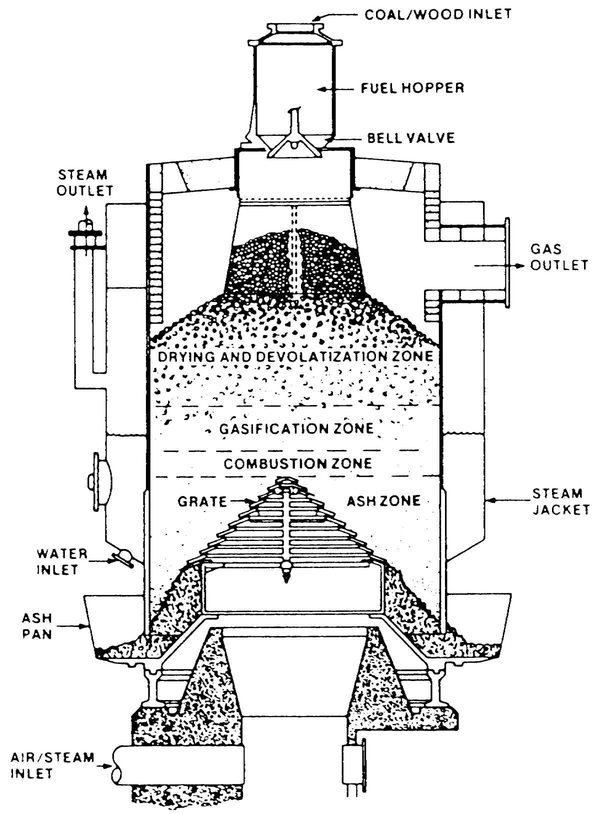
The downdraft (co-flow) gasifier shown in Figure 8.2-5 is primarily designed to reduce the uncracked tar, oil, and other carry-over materials. The gas passes through the intense hot zone where tars, oils, and chars are gasified. The low exit velocity of the gases from the gasifier results in lower carry over of particulates. Appropriate gas cleaning and cooling of the gasifier offgas, however, is needed in order to use it as fuel gas for internal combustion engine units. Downdraft gasifiers are more responsive than updraft units to surges in gas demands which are experienced when fueling engines.

The gasification process in a crossdraft fixed bed gasifier is similar to a downdraft unit, as shown in Figure 8.2-6. In this case, air is introduced through a nozzle. A narrow hearth zone of high temperature is created where the fuel’s tar content and char are wholly gasified. The narrow hearth core enables the crossdraft unit to rapidly respond to the load fluctuations.

A fluidized bed gasifier is a refractory lined vertical shaft reactor, and the fluidizing medium is sand, ash, or other inert solids. The inert bed is supported on a perforated distributor plate. The

FIGURE 8.2-4

SINGLE STAGE FIXED BED UPDRAFT WOOD GASIFIER



Source: [28]

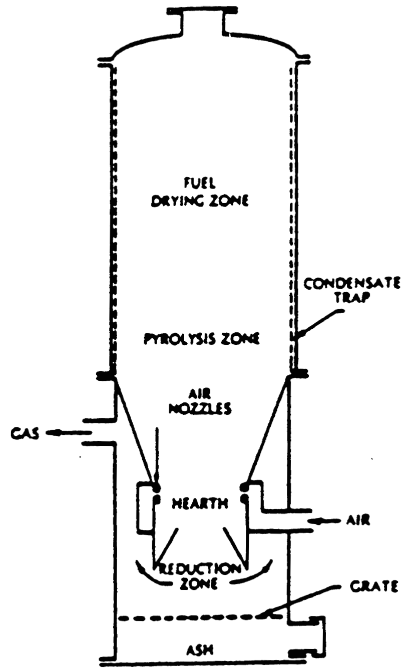
grid design of the distribution plate provides uniform distribution of the fluidizing air. The bed is fluidized by supplying a controlled flow of fluidizing air. A conceptual view of such a reactor is shown in Figure 8.2-7.

There are two types of fluidized bed units in use today: the bubbling bed and the circulating bed. The bubbling bed unit is a packed dense inert bed that has expanded uniformly in the reactor vessel to allow the gas to flow at in-bed velocities of 1.5 to 2 feet per second (ft/sec) with the pressure drop through the bed balanced against the solid mass. At this state, the solid particles move around locally in a semistable arrangement resembling a bubbling, boiling liquid. Any temperature change to the bed due to the insertion of feed will be transmitted throughout the bed, similar to the fluid medium.

The circulating unit has in-bed velocities in the range of eight to 10 ft/sec. In this situation, the solids must be continuously replenished as fast as they are entrained to maintain the solid in the reactor. The operation of the fluidized bed in this mode of continuous entrainment and

FIGURE 8.2-5

SCHEMATIC VIEW OF A FIXED BED DOWNDRAFT GASIFIER



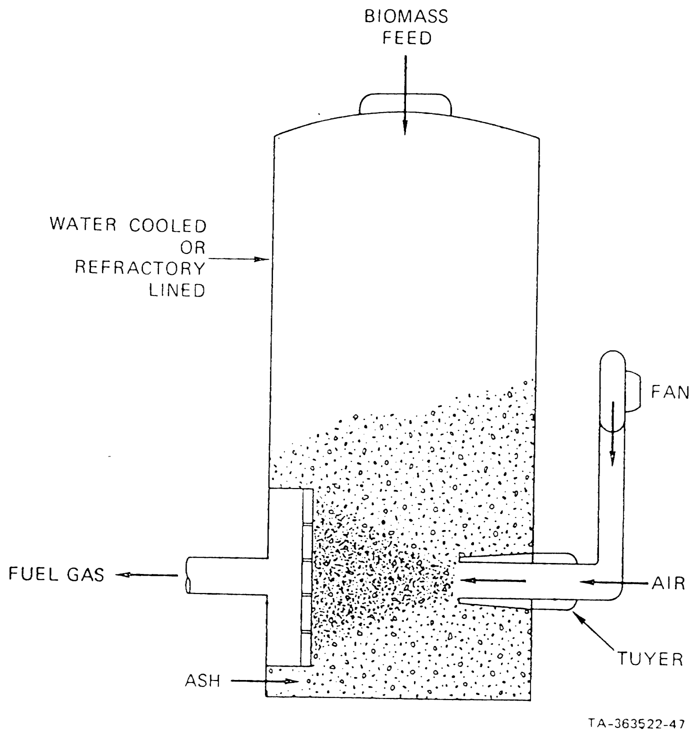
Source: [34]

replenishment of solids is referred to as circulating fluidized bed unit. The circulating fluid bed unit is more efficient and, therefore, more widely used. The feedstocks are finely shredded and sometimes injected directly into the bed, and coarser materials are commonly dropped onto the bed from the top. The fluidizing bed units are designed to operate at an atmospheric or pressurized state. Both directly and indirectly heated fluid bed gasifiers have been used in the biomass gasification processes. They have been very effective in handling high moisture, high ash, and mixed particle sized feedstocks. Fluidized bed gasifiers will experience high carbon losses and, as such, will use cyclone separators to recover valuable char from the gas stream. The recovered chars are sometime fired in an externally located char burner, and the heat of char combustion is utilized to heat the fluidizing solid required in the gasification process.

After many in-house pilot plant studies, the Occidental Research Corporation, sharing costs with the U.S. Environmental Protection Agency (EPA), built a $15 million, 200-tons-per-day, solid waste flash pyrolysis demonstration facility in the city of El Cajon, California. The flash pyrolysis process is based on the concept of entrained bed pyrolysis process, shown in Figure 8.2-8. The inert transport medium is heated in an externally located char burner and is maintained at 900 to 1100°F. Like FBG, entrained bed units have high heat transfer characterization and, because of turbulent mixing occurring in the transport phase of the gasification, wide varieties of biomass can be gasified in these units. This technology, however, failed to become a commercial success.

FIGURE 8.2-6

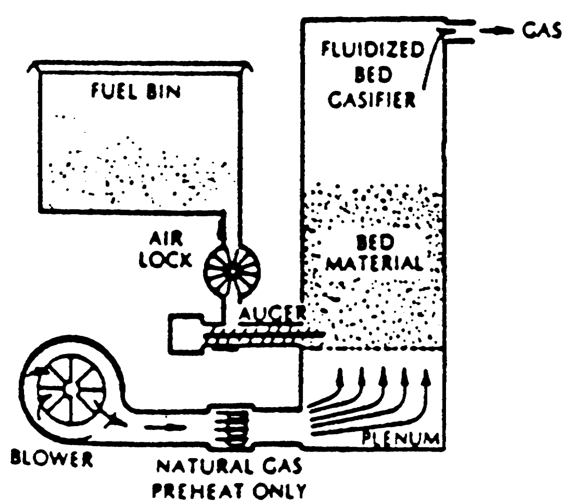
SCHEMATIC VIEW OF A CROSS DRAFT GASIFIER



Source: [25, Chapter 13]

FIGURE 8.2-7

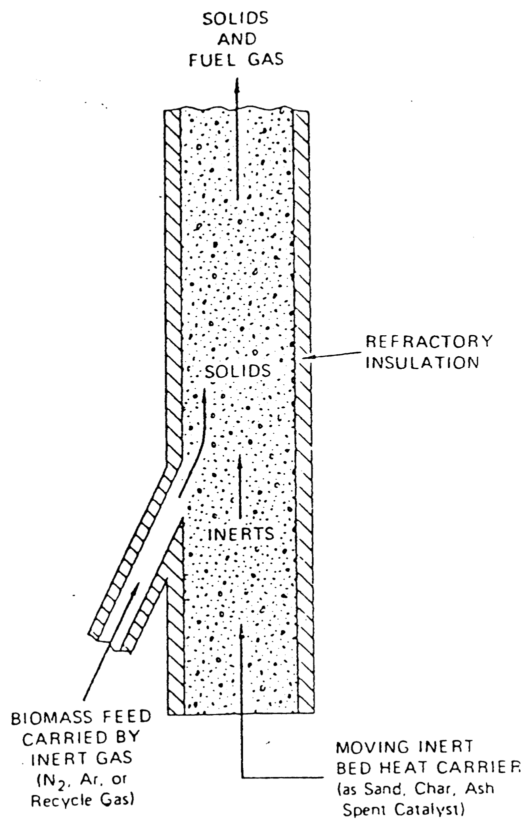
SCHEMATIC VIEW OF FLUIDIZED BED REACTOR



Source: [34]

FIGURE 8.2-8

SCHEMATIC VIEW OF AN ENTRAINED BED GASIFIER



Source: [25, Chapter 13]

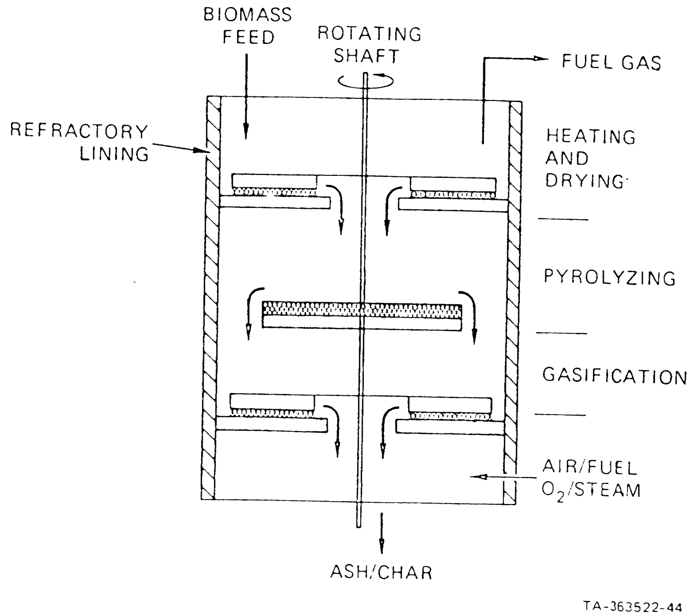
The tumbling bed gasifier was first demonstrated by Monsanto in a solid waste project. Indirectly fired tumbling bed gasifiers have also been working in waste tire gasification processes. The tumbling action created by the rotating drum produces stirring and active volatilization. Many such reactors have since been built to produce both LBG and MBG.

The stirred bed gasifier is also called a multiple hearth gasifier. [27] A schematic view of the reactor is shown in Figure 8.2-9. In this case, the feedstocks are introduced into the top section of the gasifier. The reactor is segmented into discrete process stages where sequential thermal decomposition or the gasification process is conducted. The constant stirring of feedstocks on each stage contrasts the stagnant bed of a fixed bed gasifier. No commercial or utility scale stirred bed biomass gasifier units have been operated in the United States.

Catalytic gasification of biomass (preferably silvicultural) has been extensively studied in various experimentation laboratories extensively to maximize production of SNG by enhancing char

FIGURE 8.2-9

SCHEMATIC VIEW OF A STIRRED BED GASIFIER



Source: [25, Chapter 13]

gasification. Alkaline carbonates (sodium and potassium) have been used to increase the graphite gasification rates, increase gas yields, and alter the gas products distributions. No public or private demonstration projects have evolved from these studies. [31]

Gasification Development:

Small-scale, private level biomass gasification facilities have been working in many developing countries, such as the Philippines, Africa, Brazil, and India. They supply the energy for motor vehicles, boats, pump stations, and even small electric generating stations. [29] Most of these countries have limited petroleum fuel resources and plentiful biomass resources. Moreover, the standard of living and work environment, labor intensive versus leisure style, are different from that of the United States.

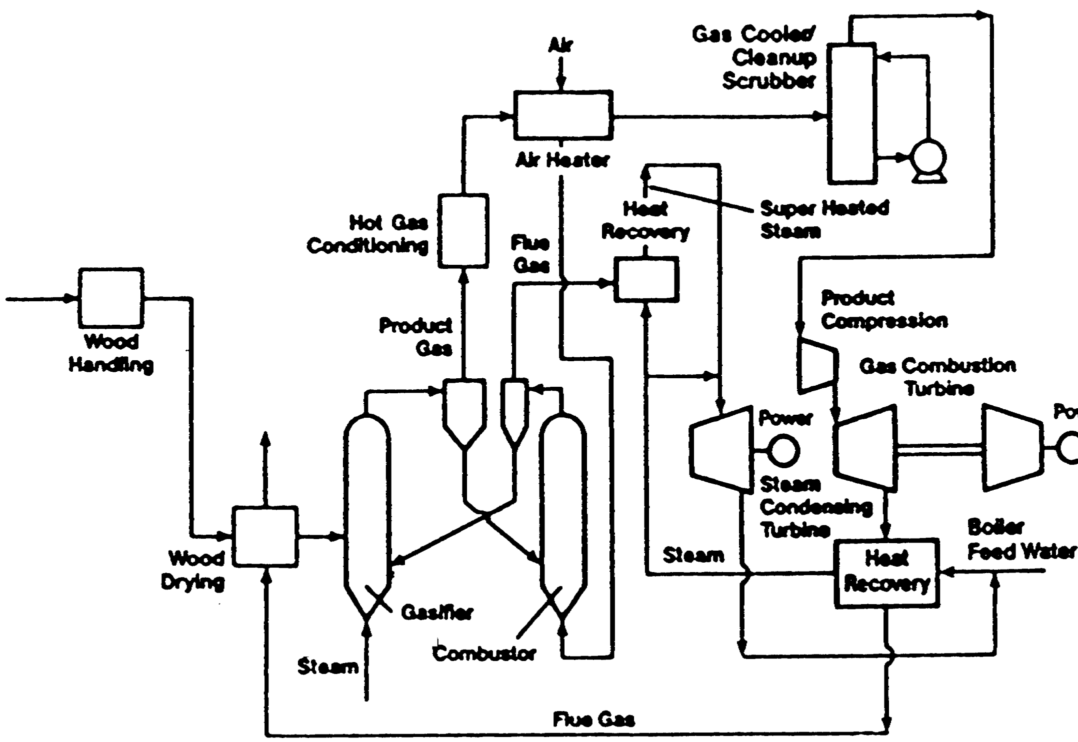
Since the U.S. energy market is different from those of developing countries, commercial biomass gasification system development efforts are focused on producing electricity through reliable and continuously running electric generating facilities. [23,24] Even though some investigators believe there are merits in following the development of small gasification systems involving internal combustion engines or even simple cycle systems, widespread use of such devices in the U.S. may have only a limited market, if any. On the other hand, utility-sized processes, such as Integrated Gasification Combined Cycle (IGCC) systems (Figure 8.2-10) with reliable, high efficiency gas cleaning systems, have shown merit. Two systems (high versus low pressure) offered by Scandinavian Commercial Developers for CHESF project in northeast Brazil are currently being evaluated by the Global Environmental Facility. [24]

The high pressure system has to be designed to deliver clean hot gas directly to the combustion turbine combustor. This design requires the exit gas to be generated at a high enough pressure to allow the necessary pressure drops in the gas cleaning and associated piping, control, and injection system components. At the same time, the system must also be able to meet the high pressure demand of the turbine process.

The cooling and quenching of LBG will mean significant loss of overall conversion efficiency and its use in a combustion turbine will require major modifications of the combustor component. Such action for MBG gas will result in a minimal loss of efficiency and few modifications to the turbine combustor chamber. [24] The concept that LBG in general can be labelled as "producer gas" and that flame temperatures of the biomass derived fuel gases are drastically lower than natural gas may be misleading. Table 8.2-1 shows combustion properties of natural gas, LBG, MBG, and producer gas.

FIGURE 8.2-10

BIOMASS GASIFICATION/COMBINED CYCLE SYSTEM SCHEMATIC



Source: [10]

Revised December 1996

TABLE 8.2-1

COMBUSTION PROPERTIES OF NATURAL GAS, LBG, MBG, AND PRODUCER GAS

Typical Combustion Data	Typical Natural Gas	Typical Low Btu Gas	Typical Medium Gas	Typical Producer Gas
Composition				
CO	—	18.9	19.55	27.1
CO_2	1.8	9.8	28.90	5.0
CH_4	97.7	4.5	12.10	0.5
H_2	—	12.8	38.81	16.6
N_2	0.5	50.5	0.30	50.8
H_2O	—	3.5	—	—
Misc.	—	—	0.34	—
Heating Value (Btu/scf)	1030	153	300	146
Air to Fuel Ratio	9.708	1.218	2.31	1.09
Threshold Flame Temperature-°F	3560	3200	3550	3010

The RENUGAS process was specifically developed by the Institute of Gas Technology (IGT) for pressurized fluidized bed gasification of biomass to produce either an industrial fuel gas or a chemical synthesis gas depending on air or oxygen blown operation. It is a single stage fluid bed reactor with a deep bed of inert solids that provides stable fluidization action for turbulent transfer of heat energy to the feedstock (endothermic) to activate the gasification reaction. The 100-tons-per-day RENUGAS process development unit, built for a U.S. Department of Energy (DOE) program, is shown in Figure 8.2-10. This unit has had test runs with a variety of feedstocks from refuse-derived fuel (RDF) to woody and herbaceous biomass. It has been selected for a 100-tons-per-day demonstration unit at the PICHTR project in Hawaii. [21]

PICHTR Process

The project is financed by the DOE and the state of Hawaii in a cost shared program. It employs the IGT's RENUGAS pressurized air/oxygen gasifier, which is a 45 to 100 tons per day (tpd) Engineering Development Unit operating at one to two millipascal (mPa) seconds at 850 to

900°C, using bagasse and wood as feedstocks. The product gas is designed to be LBG with 150 Btu/scf heating value. The site is the HC&G sugar mill at Paia, Maui, Hawaii. System analysis and project oversight are being provided by the National Renewable Energy Laboratory (NREL). In Phase I, the gasifier will be operated at a feed rate of 45 tpd, at a maximum pressure of one megapascal (MPa), for about four months. Phase I started at the beginning of June 1995. In late 1995, Phase II activities will include a hot gas cleanup unit and gas turbine hookup to generate three to five MW of electricity. [24] The project cost is $12 million for the gasifier system only. NREL has estimated that such a commercial system could be built for 1300 $/kW for 25 to 50 MW projects.

Vermont Project

Future Energy Resource Company (FERCO) of Atlanta, Georgia, is the licensee of the Battelle indirect gasification system. They are building a scaled up unit at the Burlington Electric Department's McNeil Station in Burlington, Vermont. The project, which is in two phases, will first take feedstock from the 50 MW station and the product gas will be burned in the boiler. The scale of operation is about 200 tpd. The second phase activities include installation of a hot gas cleaning system for the electricity generation of 15 MW in a gas turbine. The project is jointly funded by the DOE and FERCO. The construction is expected to start in fall 1995. [24] A schematic view of the Battelle biomass gasification process is shown in Figure 8.2-11.

Feeding System

Pneumatic conveying and subsequent injection of finely shredded feedstock are commonly adopted for low pressure (up to 5 psi) systems. For 15 psi units, double chamber gatelocks, rotary valves, or air locks have been used. Traditional designs of lockhoppers, double bell, and bell in conjunction with sliding gate have worked well in the past for atmospheric pressure units. The critical design considerations for higher pressure feeding system is to have a system that will withstand the total differential pressure across the air lock. There are several proprietary high pressure feeding designs that can be adopted for the biomass feedstocks, and there are many custom designed metered fuel injection systems for high pressure reactors in the market now. [2]

Mr. T.R. Miles, of T.R. Miles Consulting Engineers, designed more than 15 custom feeders for high pressure gasification systems. These systems can handle wood chips up to two inches in size. [7] An efficient lockhopper design should isolate the feeding system from the direct contact with hot reactor unit and should provided an appropriate injection valve. One of Mr. Miles' designs is shown in Figure 8.2-12.

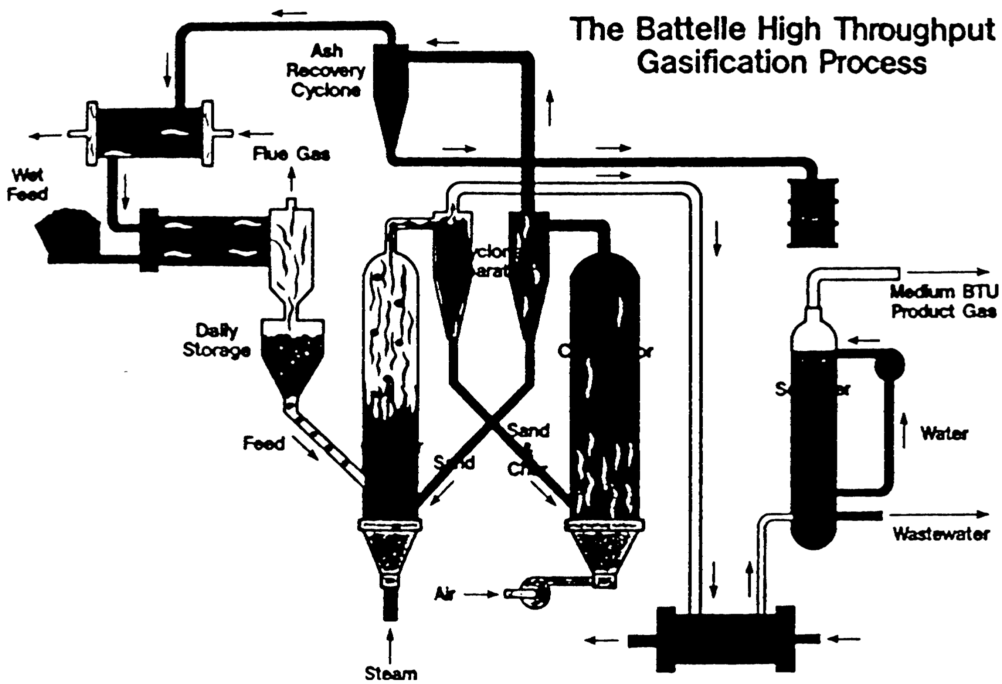
Drying

The heating value of the fuel gas decreases with moisture content of the feedstock. Green biomass contains 45 to 50 percent moisture. The heating value of a bone dry feedstock is 110 Btu/scf. If the moisture content of the same feedstock is at a level of 30 percent, its heating value will drop to 80 Btu/scf.

Use of live product gas or steam, saturated or superheated, to dry the feedstock is to be decided primarily from an economical view point. Use of waste energy is preferable in all cases. It is difficult to justify the use of superheated steam to dry feedstock. The cost of superheated steam

FIGURE 8.2-11

BATTELLE BIOMASS GASIFICATION PROCESS SCHEMATIC



Source: [19]

derived from the use of biomass feedstock has to be weighed against the benefit of increased heating value of the fuel gas that could be produced from the drier feedstock.

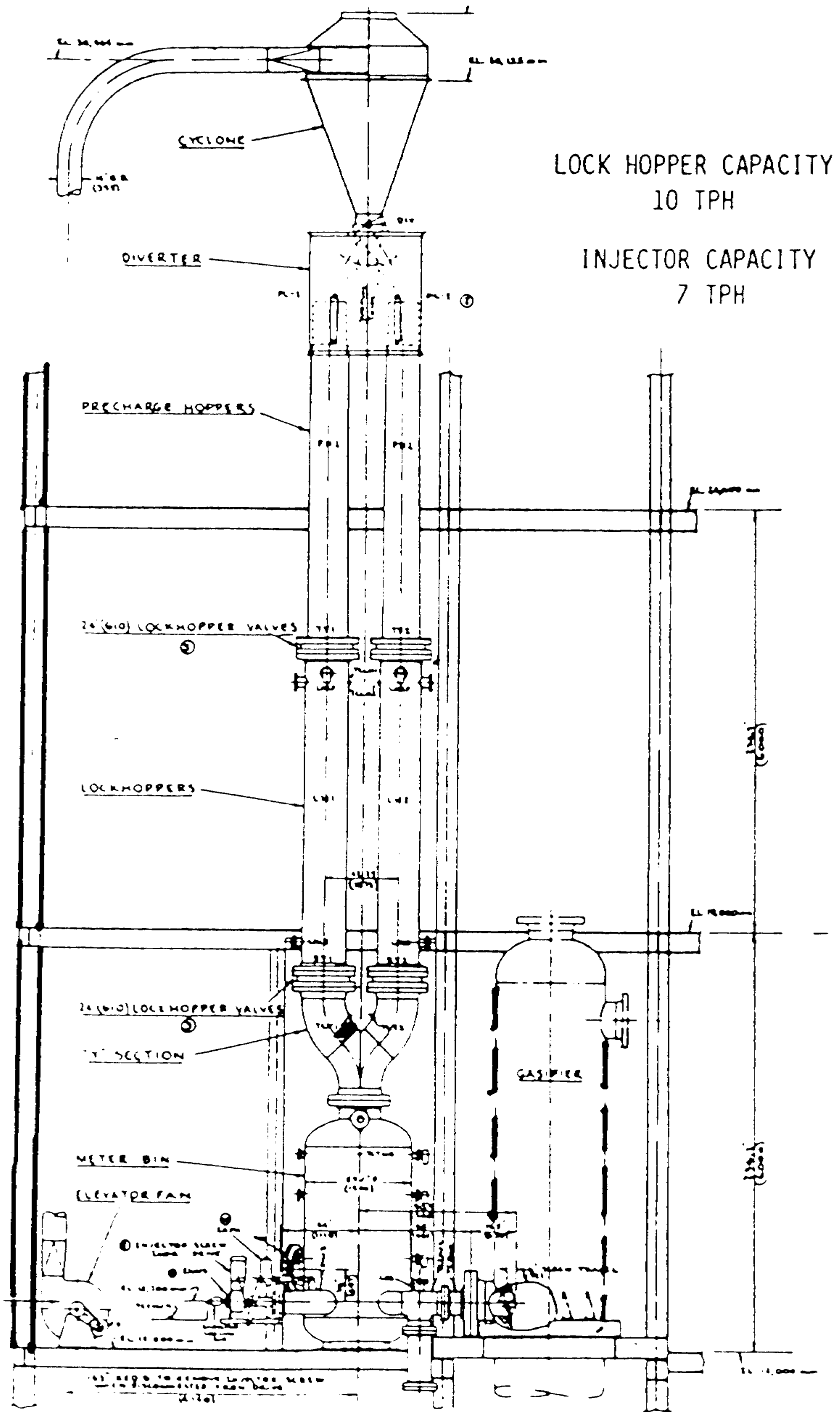
Ash Fouling

Ash fouling of heat transfer surfaces -- such as convective tube walls of the boiler, fluid bed sand and refractory surfaces of the reactor -- becomes more of a problem when the feedstock is agricultural residues and wastes rather than wood. [3] Agricultural residues such as straws, shells, pits and hulls contain alkaline chlorides (sodium and potassium). [1] Slagging deposits containing tar, oil, unpyrolyzed char, and other solid particulates will severely limit the potentials of energy recovery from the agricultural residues and wastes. [4, 5] In a fluidized bed, alkali presence forms “sand babies,” which agglomerate on the bed and collect on walls, ledges, protuberances, and other locations. [6]

Tree trunks and large limbs contain the least amount of alkali. Small branches, twigs, and foliage contain high percentages of potassium and sodium salts. Bagasse contains low levels of alkali, whereas rice straw presents the most serious deposits and agglomeration problems. Almond shells can have a high percentage of potassium salts. [8]

FIGURE 8.2-12

BIOMASS FEEDER DESIGN SKETCH- 7 TPD, 450 PSIG SYSTEM



Source: T. R. Miles, ***Miles Biomass Feeders***, Personal Communication, November 1991.

Hot Gas Cleanup (HGCU)

Cleaning a gas without cooling it first enables the gas stream to retain its sensible heat and, at the same time, simplifies its process flow, reliability, and enhancement of overall conversion efficiency. Much of the fouling elements present in the hot offgas of the gasifiers at temperatures of 300°F to 1850°F can be cleaned up by allowing the gas stream to flow through ceramic filters. These filters have much resistance to aggressive chemicals and the capability of removing particles down to below 0.01 pounds per mega-British thermal units (lb/MBtu). [9,10]

As the filter media become burdened with deposits, backflow blasts from pulse jets are used to dislodge most of the fouling elements, which will ultimately be caught in the ash hopper of the filter housing. Sorbent materials can be added to the flue gas stream to absorb sulphur dioxide (SO_2), alkali, and other gas phase contents and thereby clean off the valuable hot fuel gas. [11]

Biomass derived fuel gas contains tars and oils at levels corresponding to two grams per standard cubic foot (g/scf) for a total load of 160 grams per minute (g/min). [11] To avoid condensation of these elements and to best use their fuel value in a gas turbine combustion chamber, the gas temperature should be above 1000°F. The desirable range of temperature is 1200°F to 1800°F with 0.2 to 1.0 sec gas residence time. The Westinghouse HGCU system tested for the IGT's 10 tpd RENUGAS-Process Development Unit (PDU) demonstration is shown in Figure 8.2-13. [10,11]

In the field of commercial scale biomass fuel gas based electric power generation, IGCC and Pressurized Fluidized Bed Combustor (PFBC) systems are being developed as the most promising. The HGCU system is crucial to the success of this development program. In IGCC systems, the HGCU unit must operate in reduced gas atmospheres (i.e., in the presence of H_2, CO and CH_4), in high stream pressure (150 to 350 psi) and at an in-bed temperature of 1650°F.

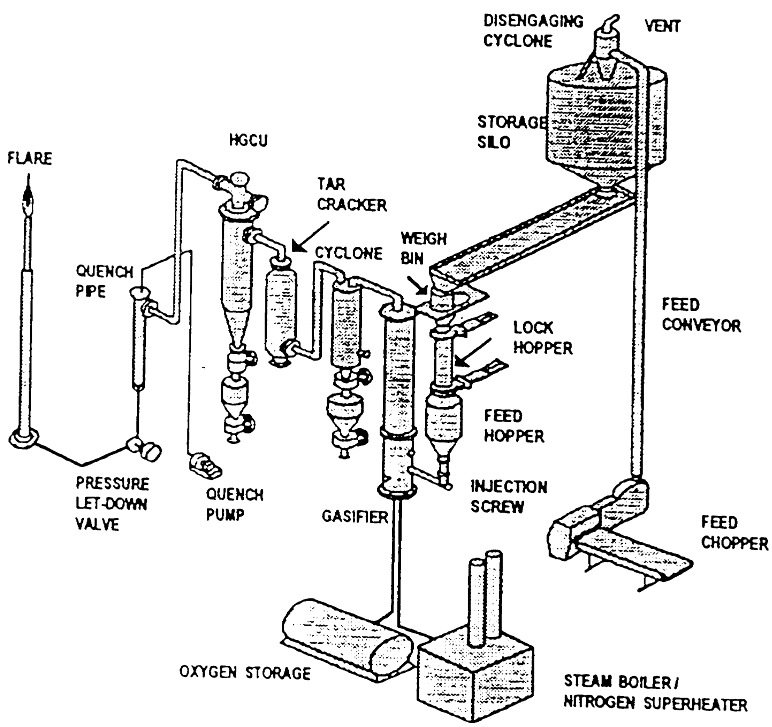
In the field of HGCU development work, cyclone with induced agglomeration, ceramic filter bed, moving granular bed, ceramic bag filter, and ceramic barrier filter designs are being followed. The major attention has now been focused on the ceramic barrier filter system. The leading manufacturer of this system is Westinghouse Electric Corporation. [14,15]

The Westinghouse design consists of stacked arrays of filter elements supported from a common tube sheet structure. By arranging the ceramic candle elements to a common plenum, individual arrays are built. Each array of filter elements is cleaned by a single pulse jet system. The individual plenum arrays are stacked vertically from a common support structure, thereby forming the filter cluster. Each cluster is free to grow. [10,15] A schematic view of the Westinghouse ceramic candle HGCU system is shown in Figure 8.2-14. The Westinghouse units have been used in Texaco's entrained bed coal gasifiers, Foster-Wheeler crossflow carbonizers, and Kellog-Foster-Wheeler Wilsonville SCS facility gasifiers. [13] Filtration efficiency in excess of 99 percent has been reported for coal burning fluidizing bed units. Field test data with biomass fuel gasifiers are still not yet available.

Conventional bag filtration with a special NEXTRE (3M) bag and MELTAC's rigid sintered steel filters systems has been tested to trap the ashes with only limited success. When a cyclone

FIGURE 8.2-13

RENUGAS 10 TPD PROCESS DEVELOPMENT UNIT CURRENT CONFIGURATION



Source: B. C. Wiant *et al*., "Biomass Gasification Hot Gas Cleanup Demonstration Program Status," ***Proceedings of the Sixth National Bioenergy Conference***, Reno/Sparks, Nevada, October 2-6. 1994.

system was included with the bag filtration system, the filtration efficiency improved. [16] Particulate matter, methane, hydrocarbons, and tar have to be removed from the raw biosyngas before it can be used directly for fuel synthesis. Typical H_2/CO ratio for raw biosyngas is 0.7, but for methanol synthesis, the same ratio must be 2.0. [17,19] This ratio can be achieved by catalytic conditioning of the SNG produced from biomass gasification. Two catalysts (DN-34 and ICI-46) were tested, and it was found that the conditioning alone is not complete. When these two catalysts are in the stream, however, the hydrogen to carbon monoxide ratio (H/C) could be reached. [18,20]

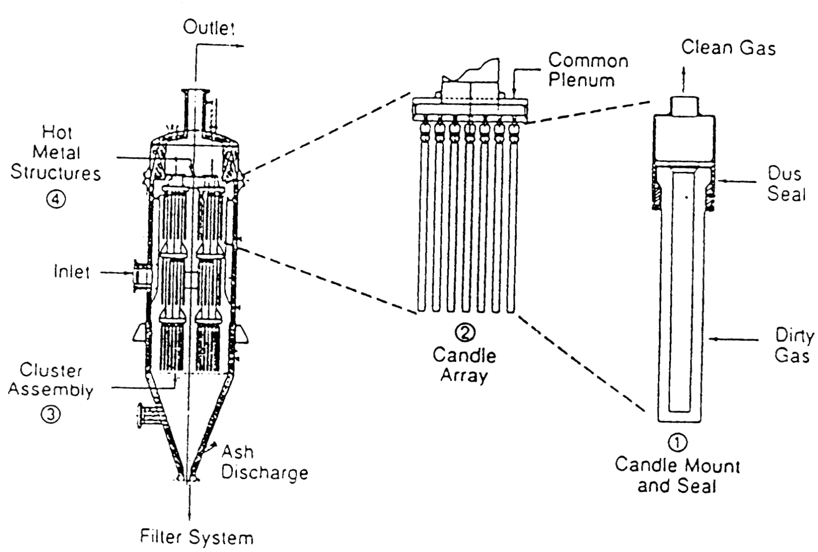
COMMERCIAL AVAILABILITY

Technology Maturity:

Biomass gasification technology is commercially available for the generation of fuel gas and the subsequent burning of the gas in a boiler. The fuel gas generated can also be used in engine-generator sets to produce electricity. The one limiting factor, however, is the necessity to

FIGURE 8.2-14

HOT GAS CLEANUP SYSTEMS-WESTINGHOUSE CANDLE FILTER SYSTEM



Source: T. E. Lippert *et al.*, Westinghouse Advanced Particles Filter Systems, ***Proceedings of the Coal-Fired Power Systems 94-Advances in IGCC and PFBC Contractors Review Meeting***, Morgantown, W. Virginia, June 21-23, 1994.

clean the gas of particulates, tars, and oils prior to burning in the engine. If the product of biomass gasification is process heat or process steam, then the combustion route is preferable over gasification. Although small-scale motive power generation schemes may have merits in some developing countries, it has very little appeal in the United States. With deregulation of California's electricity markets, however, distributed power generation may have some merits. Ultimately, the availability of low cost woody biomass, development of commercially available and advanced hot gas cleaning technology, and long term supply of conventional fuels will decide the destiny of any such endeavors. Commercial, industrial, and utility scale biomass derived fuel gas utilization may be more promising through IGCC and PFBC systems. Both of these systems are developing technologies, and it will take considerable development work before the commercial use of biomass derived fuel gas in electrical generation takes place.

Existence of Supplier(s):

Currently, there are few, if any, large commercial markets for biofuel gasifiers, and there are no commercial or utility scale biogas powered electric generating systems currently operating in the U.S. The shock of the 1973 oil embargo brought into focus the need for the development of indigenous alternate fuels, which began a big push for gasifier designs. Currently, however, the energy economics of the U.S. are such that there are few incentives to use biomass derived fuel gas in utility systems. Further, the biofuel gasification with electric power generation technology has not reached the same reliability and predictability status as natural gas fired boiler-steam turbines or natural gas fired combustion turbine power generation systems.

Some of the current prospective commercial scale medium Btu gasifier developers include the following:

1. Tampella Power Company
   2600 Reach Road
   P.O. Box 3308
   Williamsport, PA 17701
   (717) 327-3247, Fax:(717) 327-3141
   Licensee of IGT's U-Gas Technology for coal and wood and Air Blown pressurized FBG.

2. IGT Energy Development Center
   4201 W. 36th Street
   Chicago, IL 60632
   Dr. Mike Quischak,(312) 567-3650
   RENUGAS and U-GAS FBG for biomass and RDF.

3. Battelle Columbus Laboratory
   Mark Paisley, (614) 424-4958
   Zurn Nepco, an Architectural and Engineering firm, is building a demonstration gasifier unit at the 50 MW wood fired stoker boiler plant in Burlington, Vermont. Under contract from FERCO, the licensee of the Battelle gasification process (steam gasification at one atmosphere or at elevated pressure). The product is MBG. The gasifier is designed for 200 tons per day feed. In phase one, MBG will be burned in the boiler. If phase 2 activity is funded, the MBG will be cleaned by a hot gas clean up system and used in a 15 MW gas turbine generator unit.

4. Pyropower Corporation
   P.O. Box 85480
   San Diego, CA 92186-5480
   Bob Gamble, Director of Engineering, (619) 458-3000
   Pressurized circulating fluid bed (air blown) in Finland

5. John Brown E&C
   7909 Parkwood Circle Drive
   Houston, Texas 77036
   Mike Butler, Vice President of Engineering, (713) 988-3684
   Most of the engineers in this company are from the Davy-McKee, Lakeland, Florida, operation and most likely now own a pressurized Winkler gasifier that Davy-McKee developed earlier in Germany.

6. Northern States Power (NSP) of Minneapolis, Minnesota, has been operating one Tampella air-blown pressurized fluid bed gasification plant using alfalfa stems as feedstock. The 75-MW power generation facility has a Westinghouse 251 gas turbine unit. Contact Max Delovey of NSP for more information.

7. Weyerhauser Corporation, headquartered in Tacoma, Washington, has several IGCC installations at the Company's North Carolina facility. They employ a Tampella pressurized air blown fluid bed unit (LBG), Battelle atmospheric pressure dual fluid bed design unit (MBG), Battelle pressurized dual fluid bed unit (MBG), and a Tampella atmospheric pressure air blown fluidized bed (LBG) unit. Contact Dr. Del Raymond for more information.

In the late 1970s and early 1980s, there were a large number of gasifier designers, and many of them had demonstrated their technical viabilities. A complete listing of earlier design gasifiers, their ratings, and the manufacturers names and addresses can be found in reference 22. There were also many design efforts to produce MBG and SNG by using oxygen, steam, and hydrogen. Among the pioneers were Arizona State University, Battelle Columbus Laboratory, Battelle Pacific Northwest Laboratory, Garrett Research, Tech Air, and Wright Malta.

Competitive Cost:
There are few, if any, actual operational data on commercial or utility scale biomass derived fuel gas-powered electricity generation facilities that can be used to calculate reliable life-cycle cash-flow analyses. It is believed that in order for this technology to be competitive, especially for stand alone power plants, advances in the electric generation plants are needed in terms of power to heat ratio with low cost fossil fuels (oil and gas), . A comparison of a present day steam generating facility with IGCC is being presented below: [24]

Cost Factors	***Steam Generation***	***IGCC***
Capital Cost	$1800/kW	1300 - 1500 $/kW
Efficiency	20%	45%
Capacity	50 MWe	50 MWe
O&M Costs (cents/kWh)	0.5	0.5
Fuel Only Cost (cents/kWh)	3.6 (@ 40/ton dry)	1.6
Capital Recovery(cents/kWh)	4.2	3.0 - 3.5
Load (Capacity) Factor	85%	85%
Return on Investment	8%	8%

Another cost factor data prepared by Mr. Paisley of Battelle Columbus Laboratory is presented below. [19] The divergence in these two estimates shows little validity of such computational estimates.

Plant Size:	56 MW	
Type of Plant:	Gasification/cogeneration system	
Gasifier Plant:	$15 x 10^6	$/kW = 267
Turbines:	$43.1 x 106	$/kW = 770
TOTAL	**$58.1 x 10^6**	**$/kW = 1037**

Operating Cost Components:

Return on Investment	10%	
Capital Charge Rate	20%	
Capital	$/yr = 11.6 x 10^6	cents/kWh = 2.63
Fuel	$/yr = 7.17 x 10^6	cents/kWh = 1.62
O&M Personnel	$/yr = 0.56 x 10^6	cents/kWh = 0.13
Purchased Supplies	$/yr = 1.18 x 10^6	cents/kWh = 0.27
TOTAL	**$/yr = 20.51 x 10^6**	**cents/kWh = 4.65**

There are not enough reliable operating data to build consensus on this subject.

Purchase Order and Construction Lead Time:
Once the technology for the commercial size biomass power electric generating systems is developed, construction lead time is expected to be the same as for conventional power plants. The permitting process will be simpler than conventional oil and coal fired power plants. Even though significant reliable environmental emission data from utility scale biomass derived fuel gas fired power generation is not currently available, and many state permitting authorities hesitate to issue operating permits under such circumstances, it can be defended based on the technology base data. The base data show that compared to conventional oil and coal fired power plants, environmental pollution factors for biomass powered electric power generating plants would be less severe. Although the longest lead time items are the gasifier and the hot gas cleaning systems, standard turbine generating systems can be used. The equipment systems for fuel preparation and processing operations are fully developed and most of them are off-the-shelf items. The total schedule is assumed to be two to three years, depending on the size and complexity of the facility.

Conclusion:
Small biomass fueled gasifiers are currently available under limited conditions from a number of manufacturers. These units are mainly used for close-coupled applications such as firing the gas in kilns, boilers, or engines. Firing raw, uncleaned biomass-derived LBG fuel gas to a boiler originally designed for fossil fuel firing is not practical. Severe derating and fouling of boiler tube banks and high retrofit costs will result, and the operating problems will be high. Dedicated boilers firing clean LBG are a possibility, but may not be cost effective.

Currently, low fossil fuel prices --$17 per barrel of crude oil, $2.80 per MMBtu of natural gas -- and the minimum operating supervision needed for fossil-fueled system are attractive featuers in electricity generation projects. In comparison, biomass-derived LBG electricity generation requires labor-intensive fuel processing and handling technologies and supervised operations, with uncertain and continuously shrinking local fuel resources and rising fuel costs. What is appropriate for developing countries with limited natural conventional fuel resources may not be economically justifiable for the developed countries of the world.

The future commercial biomass gasification system will probably be the circulating fluidized bed design. It has the ability to accept a variety of biomass fuel, offer quick load-responsive operation, and provide high carbon conversion efficiency. The preferred fuel gas will be MBG produced either by an oxygen and steam system or by an indirect heating system, in total absence of an air system. Commercial biomass gasification ventures may find success in IGCC applications (Figure 8.2-10).

Both LBG and MBG will require reliable hot gas cleaning systems before they can be used in combustion turbines. Scrubbing of hot LBG gas will also create a water pollution problem. It will be hard to justify employment of catalytic tar cracking and the use of costly HGCU systems for small internal combustion engine driven power plant projects fueled by LBG. They may, however, be justified for large commercial/utility MBG generating plants.

RESEARCH AND DEVELOPMENT GOALS (Significant Impact)

Research and development efforts in the commercialization of biomass gasification and power generation systems hinge on (1) long-term uniform quality fuel availability, (2) designing gasifiers to accept various types of biomass fuels, (3) a clear understanding of the thermochemical process technology as related to gasification reaction kinetics with multi-grade biomass fuels, (4) cost-effective technology to clean the ash, tar, oil, and alkali content of the raw gas, (5) ensuring reliability to produce a uniform grade of fuel gas for new stand-alone, single-purpose systems as well as retrofitted power generation units, and (6) increasing turbine blade efficiency.

Reduced Capital Costs: (Significant Impact)
Advanced gasification technologies (MBG/SNG) are still in the developing stage. Capital cost reductions for plant equipment systems will hinge on cost-effective material selection, manufacturing methods, and improved system design work. Capital costs associated with HGCU systems are related to types of fuel, the extent of fuel mix used in the process and the application of the product gas in the industrial process. Development of alternatives to ceramic candle type filters should be sought to bring about cost-effective HGCU systems. Use of cyclone and bag filter systems should be reviewed to bring to the market a competitive yet effective HGCU system.

Capital costs associated with front-end processing equipment system could be lowered by planning a regional biomass processing station rather than individual plant-site processing. This scheme can be defended by the fact that each fuel processing plant requires elaborate fugitive dust, rodent, noise pollution, and other environmental control systems. Each plant would also face competetion in fuel procurement, and the actual processing of the fuel is costly in capital and O&M. A central facility would produce more a uniform quality of fuel, ensure steady flow of fuel to the plant, and meet regulatory codes more easily.

Improved Performance: (Significant Impact)
Availability/Reliability/Durability: The reliable, continuous operation of gasifiers utilizing wide varieties of biomass feedstocks and generation of clean fuel gas as motive power fuel remain to be demonstrated.

Lower Operation and Maintenance Costs: (Significant Impact)
One important element of lowering the operating costs is to reduce the overall costs of feedstock. Woody biomass is becoming costly at more than 40 $/ton every month. Agricultural biomass is cheap, but it is also seasonal and has high ash, calcium, and potassium contents. Blending of the two biomass varieties (silvicultural and agricultural) as feedstock may be one way to reduce the feedstock costs.

Biomass fuel has to be sized and otherwise processed to enable the introduction of uniform metered quantity feed to a gasifier. If the biomass fuel is of only one variety, such as wood, the process system can be engineered to a least cost feed preparation scheme. For a mixed type biomass feeding system, the cost-effective fuel modification scheme and overall process system integration have to be adopted to reduce O&M costs. Regional fuel collection, hauling, and processing should be weighed against a central fuel preparation facility. The objective of the design will be to lower the O&M costs associated with the processing, handling, and feeding work.

Reduced Environmental Impacts: (Significant Impact)
Environmental Impacts: Pollution from biomass gasification process is less severe compared to conventional coal gasification/combustion systems. As more projects are developed within an Air Pollution Control District (APCD), there will be increasing pressure to control emissions, even on projects that were previously considered too small. The use of HGCU and catalytic tar cracking systems will improve the emission quality, and the current market place pollution control equipment systems can be used to achieve acceptable clean air system.

DEPLOYMENT ISSUES (Potential “Show Stopper”)

Biomass gasification can only be justified when the product gas will be used to generate electricity at a cost competitivewith conventional fuel generated power. The developing technologies have demonstrated that an MBG fired IGCC project can compete with conventional power generation. Equipment design optimization, system integration, and modular unit design engineering are on the horizon. The problem of cleaning hot gasifier product gas has been recognized, and valuable efforts are being made to reduce if not eliminate the fouling factors.

Environmental Constraints: (Significant Impact)
Air Pollution: Environmental issues for a biomass gasification process depend on the specific gasification process technology, equipment system designs, and operating conditions of the subsystems. For example, feedstock storage, handling, and processing will have fugitive dust emissions, odor, vermin, and leachate run-off. The emissions occur during accidental and routine maintenance defective seals, feed valves, ash removal systems, and other various gas outflow

systems. Particulate emissions may contain benzo(a)pyrene or other chemicals. Particulate, SOx and NOx emissions are much smaller in comparison to fossil fuel-fired power generating plants.

The waste water of LBG plant may contain acetic acid, ethyl benzene, pyrene, anthracene, biphenyl, and metals such as lead, cadmium, iron, zinc, and manganese. The solid waste primarily consists of ash, unpyrolyzed char, and carbon dust. The ashes contain trace metals such as silica, alumina, and calcium oxide. The disposal of the ashes must meet the current EPA regulation. Other than the fuel preparation system, the gasifier and the electric generation systems can be designed to meet noise pollution ordinances. The whole tree chip making or shredding of bark and trimmings may create occasional noise above the acceptable levels. Performing this task in remote locations may solve this problem.

There are seldom objectionable thermal discharges in the IGCC design concept. The destruction or disturbance of habitat through the use of woody biomass depends upon the forestry management and planned approved harvesting method. Use of agricultural wastes and residues creates an improved environment and better agricultural life. Scenic resource impacts should not be an issue unless the clear-cutting forestry method is used to harvest woody biomass. The gasification plant can be designed to please any aesthetic taste of a community.

Financial Constraints: (Potential "Show Stopper")
Availability of Financing: Gasification technologies will probably be hit hardest by the loss of tax incentives because the acceptable commercial technology is still in its developing stage. Capital cost for commercial size units has been estimated to be competitive with conventional fossil fuel fired systems. See Section 3.7, IGCC, for more information.

High Capital Costs: Front-end fuel collecting, handling, transporting, and processing equipment have high capital and O&M costs. HGCU units and feeding, ash handling, and emission control systems will initially be high capital-cost items, until demand in the marketplace brings a large numbers of designers and manufacturers into the competitive biomass gasification trade world.

Fuel and Resource Constraints: (Potential "Show Stopper")
High Cost of Fuel: Biomass gasification is faced with uncertain and continuously shrinking local fuel resources and rising fuel costs.

Governmental Constraints: (Significant Impact)
See the discussion under Section 8.1.

Utility Integration Constraints: (Significant Impact)
See the discussion under Section 8.3.

Location Constraints: (Significant Impact)
A well-planned commercial gasification electricity generating facility should not face any location constraints if the gasifier is capable of multifuel firing and accepts silvicultural and agricultural biomass as feedstock. In many cases, agricultural biomass could be procured on a no fuel cost basis from farmers. To support a commercial size biomass gasification system, however, a

fuel crop plantation facility should be planned. Merits of Brazil’s short rotation fuel crop plantation scheme have been documented.

Socioeconomic Constraints: (Potential “Show Stopper”)
Poor Public Opinion: Biomass is considered a dirty fuel by some, and “not in my backyard” concerns can stop projects near urban or rural residential areas. Confusion of biomass-to-energy with residential wood combustion also poses problems. Public education on the merits of gasification over combustion should be pursued.

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Electrical Generation Technologies Economic Input Worksheet

(All Cost Data in Real Terms and 1993 dollars)

Technology Number and Name: 8.2 Biomass Gasifier w/Engine Generator

Assumed Year of Operation: 2000

Note: Where a range of costs is listed, the low cost value precedes the high cost value.

Engineering Factors

Installed Net Capacity:	15 - 75 MW		
Heat Rate (Btu/kWh-HHV):	14382	to	17000
Plant Life (years):	15		
Duty Cycle (Capacity Factor):	Baseload		75% - 60%

Economic Factors

Instant Capital Cost for assumed year of operation (1993 $/kW): 1840

Years Prior to Operation:	-5	-4	-3	-2	-1	Year of Operation
Capital Outlay (%):	0%	0%	20%	30%	40%	10%

O&M (including consumables): Fixed ($/kW-yr): 49.05 to 56.21

Variable (cents/kWh): 0.46 to 0.8 — **Escalation Rate (%/yr):** 0.73%

Escalation of Capital Prior to Operating Date (%): 0.00%

Insurance Rate (% of capital cost/yr): Included

Fuel: Type: Biomass

Cost ($/mmBtu): 1.69 - 2.14 — Esc. Rate (%/yr): ???

	Method	Duration (years)
Federal Depreciation Rate:	MACRS-DB	5
State Depreciation Rate:	SYD	12

Capital Depreciation Base (% of Capital Cost): 98%

% of Capital Cost Subject to Sales Tax: 50%

Data for Solar Technologies:

Solar Fraction (hours/year): N/A

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.2 Biomass Gasifier w/Engine Generator
HIGH/LOW CASE: Low
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 15 - 75 MW
END USER: IOU

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	3.1	206.5	3.9	255.1	4.8	318.1
O&M:	1.3	87.8	1.7	108.6	2.1	135.3
Fuel:	2.4	159.7	3.0	197.4	3.7	246.1
TOTAL:	6.9	454.0	8.5	561.1	10.6	699.5

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	20.0%	30.0%	40%	10%
Interest During Construction:			8.88%	5.50% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	75%	6570 Hrs
Plant Life (Years):	15	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):

Fixed ($/kW-Yr):	49.05 (Base Year)	
Variable (Cents/kWh):	0.460 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	1.69 (Base Year)	
Heat Rate (HR) (Btu/kWh):	14382	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	15

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	1	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	10.42%	7.00% (real)
Cost of Preferred Stock (kp):	0.00%	0.00% (real)
Cost of Debt Financing (kd):	7.33%	4.00% (real)
Percent Common Equity (C/V):	50.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	50.00%	
Weighted Cost of Capital:	8.88%	5.50% (real)

DEBT COVERAGE:

Coverage Ratio: CR = 4.58

FIXED CHARGE RATE:

FCR: 0.123 0.088 (real)

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	5 Yrs
	SL	Yrs
	Base	100.00%
State:	SYD	12 Yrs
	SL	Yrs
	Base	100.00%
Capital Depreciation Base:		98.00%
In-service month (1..12):		6

PLANT CAPITAL COST ($/kW):

	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1840	
Total Plant Cost:	2080	2593

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.2 Biomass Gasifier w/Engine Generator
HIGH/LOW CASE: High
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 15 - 75 MW
END USER: IOU

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	3.9	206.5	4.9	255.1	6.1	318.1
O&M:	2.1	108.9	2.6	134.6	3.2	167.8
Fuel:	3.6	191.2	4.5	236.4	5.6	294.7
TOTAL:	9.6	506.6	11.9	626.0	14.8	780.5

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	20.0%	30.0%	40%	10%
Interest During Construction:			8.88%	5.50% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	60%	5256 Hrs
Plant Life (Years):	15	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	56.21	(Base Year)
Variable (Cents/kWh):	0.800	(Base Year)
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	2.14	(Base Year)
Heat Rate (HR) (Btu/kWh):	17000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	15

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	1	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	10.42%	7.00% (real)
Cost of Preferred Stock (kp):	0.00%	0.00% (real)
Cost of Debt Financing (kd):	7.33%	4.00% (real)
Percent Common Equity (C/V):	50.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	50.00%	
Weighted Cost of Capital:	8.88%	5.50% (real)

DEBT COVERAGE:

Coverage Ratio: CR = 4.58

FIXED CHARGE RATE:

FCR: 0.123 0.088 (real)

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	5	Yrs
	SL		Yrs
	Base	100.00%	
State:	SYD	12	Yrs
	SL		Yrs
	Base	100.00%	
Capital Depreciation Base:		98.00%	
In-service month (1..12):		6	

PLANT CAPITAL COST ($/kW):

	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1840	
Total Plant Cost:	2080	2593

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.2 Biomass Gasifier w/Engine Generator
HIGH/LOW CASE: Low
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 15 - 75 MW
END USER: Municipal

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	2.6	167.8	3.4	222.3	4.2	277.1
O&M:	1.3	88.0	1.7	109.9	2.1	137.0
Fuel:	2.4	159.7	3.0	199.3	3.8	248.5
TOTAL:	6.3	415.5	8.1	531.4	10.1	662.5

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	20.0%	30.0%	40%	10%
Interest During Construction:			7.02%	3.70% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	75%	6570 Hrs
Plant Life (Years):	15	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	49.05 (Base Year)	
Variable (Cents/kWh):	0.460 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	1.69 (Base Year)	
Heat Rate (HR) (Btu/kWh):	14382	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	15

FLAGS: / **FOR:**

Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	1	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	0.00%	0.00% (real
Cost of Preferred Stock (kp):	0.00%	0.00% (real
Cost of Debt Financing (kd):	7.02%	3.70% (real
Percent Common Equity (C/V):	0.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	100.00%	
Weighted Cost of Capital:	7.02%	3.70% (real

DEBT COVERAGE:
Coverage Ratio: CR = 2.54

FIXED CHARGE RATE:
FCR: 0.110 0.076 (real

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			0.00%
Marginal State Income Tax Rate (t):			0.00%
Effective Marginal Income Tax Rate (T'):			0.00%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			0.00%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	0 Yrs
	SL	Yrs
	Base	100.00%
State:	SYD	0 Yrs
	SL	Yrs
	Base	100.00%
Capital Depreciation Base:		0.00%
In-service month (1..12):		6

PLANT CAPITAL COST ($/kW):	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1840	
Total Plant Cost:	2022	2521

ESCALATION RATES:	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.2 Biomass Gasifier w/Engine Generator
HIGH/LOW CASE: High
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 15 - 75 MW
END USER: Municipal

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	3.2	167.8	4.2	222.3	5.3	277.1
O&M:	2.1	109.1	2.6	136.2	3.2	169.8
Fuel:	3.6	191.2	4.5	238.7	5.7	297.6
TOTAL:	8.9	468.1	11.4	597.1	14.2	744.4

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	20.0%	30.0%	40%	10%
Interest During Construction:			7.02%	3.70% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	60%	5256 Hrs
Plant Life (Years):	15	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	56.21	(Base Year)
Variable (Cents/kWh):	0.800	(Base Year)
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	2.14	(Base Year)
Heat Rate (HR) (Btu/kWh):	17000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	15

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	1	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	0.00%	0.00% (real)
Cost of Preferred Stock (kp):	0.00%	0.00% (real)
Cost of Debt Financing (kd):	7.02%	3.70% (real)
Percent Common Equity (C/V):	0.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	100.00%	
Weighted Cost of Capital:	7.02%	3.70% (real)

DEBT COVERAGE:

Coverage Ratio: CR = 2.54

FIXED CHARGE RATE:

FCR: 0.110 0.076 (real)

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			0.00%
Marginal State Income Tax Rate (t):			0.00%
Effective Marginal Income Tax Rate (T'):			0.00%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			0.00%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	0 Yrs
	SL	Yrs
	Base	100.00%
State:	SYD	0 Yrs
	SL	Yrs
	Base	100.00%
Capital Depreciation Base:		0.00%
In-service month (1..12):		6

PLANT CAPITAL COST ($/kW):

	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1840	
Total Plant Cost:	2022	2521

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.2 Biomass Gasifier w/Engine Generator
HIGH/LOW CASE: Low
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 15 - 75 MW
END USER: NUG

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	5.2	339.6	5.4	357.5	6.8	445.7
O&M:	1.3	87.3	1.6	105.0	2.0	130.9
Fuel:	2.4	159.7	2.9	192.2	3.6	239.6
TOTAL:	8.9	586.5	10.0	654.7	12.4	816.2

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	20.0%	30.0%	40%	10%
Interest During Construction:			14.50%	10.95% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:
- Year Commercial Operation: 2000
- Plant Capacity Factor (CF): 75% — 6570 Hrs
- Plant Life (Years): 15

OPERATING PARAMETERS (Base Year $):
- Operating & Maintenance Costs (O&M):
  - Fixed ($/kW-Yr): 49.05 (Base Year)
  - Variable (Cents/kWh): 0.460 (Base Year)

- Fuel Type: Biomass
- Fuel Costs (F) ($/MBtu): 1.69 (Base Year)
- Heat Rate (HR) (Btu/kWh): 14382
- Solar Fraction: 0.00% — 0 Hrs

ECONOMIC PARAMETERS:
- Base Year (Dollars): 1993
- Inflation Rate: 3.20%
- Investment Period (Years): 15

FLAGS: — **FOR:**
- Exclude (1) vs. Include (0) Interest Tax Shelter: 1 Cost of Capital
- Normalized (1) vs. Flow Through (0): 0 Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	24.98%	21.10% (real)
Cost of Preferred Stock (kp):	0.00%	0.00% (real)
Cost of Debt Financing (kd):	10.01%	6.60% (real)
Percent Common Equity (C/V):	30.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	70.00%	
Weighted Cost of Capital:	14.50%	10.95% (real)

DEBT COVERAGE:
- Coverage Ratio: CR = 1.95

FIXED CHARGE RATE:
- FCR: 0.158 — 0.122 (real)

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	5	Yrs
	SL		Yrs
	Base	100.00%	
State:	SYD	12	Yrs
	SL		Yrs
	Base	100.00%	
Capital Depreciation Base:		98.00%	
In-service month (1..12):		6	

PLANT CAPITAL COST ($/kW):	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1840	
Total Plant Cost:	2262	2820

ESCALATION RATES:	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:35 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.2 Biomass Gasifier w/Engine Generator
HIGH/LOW CASE: High
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 15 - 75 MW
END USER: NUG

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	10.3	540.3	9.6	504.7	12.0	629.2
O&M:	2.0	107.7	2.4	127.5	3.0	159.0
Fuel:	3.6	191.2	4.3	226.4	5.4	282.2
TOTAL:	16.0	839.2	16.3	858.6	20.4	1,070.4

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	20.0%	30.0%	40%	10%
Interest During Construction:			18.47%	14.80% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	60%	5256 Hrs
Plant Life (Years):	15	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	56.21 (Base Year)	
Variable (Cents/kWh):	0.800 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	2.14 (Base Year)	
Heat Rate (HR) (Btu/kWh):	17000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	15

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	0	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	24.98%	21.10% (real)
Cost of Preferred Stock (kp):	0.00%	0.00% (real)
Cost of Debt Financing (kd):	11.97%	8.50% (real)
Percent Common Equity (C/V):	50.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	50.00%	
Weighted Cost of Capital:	18.47%	14.80% (real)

DEBT COVERAGE:

Coverage Ratio: CR = 2.98

FIXED CHARGE RATE:

FCR: 0.211 0.173 (real)

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	5 Yrs
	SL	Yrs
	Base	100.00%
State:	SYD	12 Yrs
	SL	Yrs
	Base	100.00%
Capital Depreciation Base:		98.00%
In-service month (1..12):		6

PLANT CAPITAL COST ($/kW):

	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1840	
Total Plant Cost:	2397	2988

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

8.3 ANAEROBIC DIGESTION OF LIVESTOCK MANURE

DESCRIPTION

Anaerobic digestion is a biological process which produces a gas principally composed of methane and carbon dioxide (biogas) from an organic waste and a stabilized residue or digestate. In general, three groups of microorganisms are involved in the process. The first is hydrolyzing bacteria that convert complex organic material into soluble compounds. The second group is acid forming (actogenic) bacteria that convert soluble compounds into organic acids of low molecular weight. These acids are then converted into methane and carbon dioxide by the third group, methane-forming (methanogenic) bacteria. For the digestion of soluble or easily biodegradable materials, such as livestock manure, the methane forming step is slower and is the rate-determining step. For other biomass materials, such as cellulosic materials, however, the first fermentation steps -- hydrolysis and acidification -- can be the limiting steps. Temperature affects the rate of digestion and should be maintained in the mesophillic range (95 to 105°F) with an optimum of 100°F. It is possible to operate in the thermophillic range (135 to 145°F), but the digestion process is subject to upset if not closely monitored.

An anaerobic digester is an engineered containment vessel designed to promote the growth of anaerobic bacteria. There are eight types of reactors used for anaerobic digestion: covered lagoon, plug flow, complete mix, packed bed, upflow anaerobic sludge blanket (UASB), anaerobic contact, anaerobic sequencing batch (ASBR), and high solids. Types of digesters and their characteristics are summarized in Table 8.3-1. [1]

Ambient temperature covered lagoons are typically suited to digestion of dilute wastes such as flushed dairy and hog manure. The lagoons are unheated, and the biogas production varies with ambient temperature. Coarse ruminant manure solids need to be separated from the influent into the lagoon. Coarse solids decompose very slowly and could fill the lagoon or form a floating seal on the surface stopping the biogas production process. [1]

Plug flow reactors are used for the digestion of thicker dairy cow wastes, and they move the feed through the reactor by hydraulic displacement in a distinct plug. A plug flow reactor is not suitable for wastes with less than 10 percent solids. If the collected waste is too dry, water or a liquid organic waste can be added. Plug flow reactors are typically large rectangular tanks with no moving parts. Heat pipes are suspended in the digester and circulate hot water that maintains the digester at constant temperature. [1]

Complete mix reactors are the most flexible of all the anaerobic digesters as far as the variety of wastes they can accommodate. This flexibility stems from the intimate contact between the microbial populations and the undigested organic waste brought about by the mixing action. Mixing is accomplished by gas recirculation, mechanical propellers, or liquid recirculation. These reactors are usually above ground, insulated, round tanks with conical bottoms for easy removal of settled solids. Gas is usually collected in a cover above the tank. [1]

TABLE 8.3-1

TYPES OF DIGESTERS AND THEIR CHARACTERISTICS

Type of Digester	***Technology Status***	***Level of Technology***	***Influent Total Solids Conc. (wet wt. basis)***	***Type of Solids Allowable***	***Supplemental Heat Needed?***	***Hydraulic Retention Time (days)***
Ambient Temp. Covered Lagoon	commercial	low	0.1 - 2%	fine	no	40+
Plug Flow	commercial	low	11 - 13%	coarse	yes	15+
Complete Mix	commercial	medium	2 - 10 %	coarse	yes	15+
Packed Bed	commercial	medium	0.5 - 2%	soluble	yes	2+
Upflow Anaerobic Sludge Blanket (UASB)	commercial	high	0.5 - 2%	soluble	yes	2+
Anaerobic Sequencing Batch (ASBR)	experimental	medium	0.5 - 8%	coarse	yes	2+
High Solids	demonstration	medium	20 - 35%	coarse	yes	15+
Anaerobic Contact	commercial	medium	0.1 - 10%	coarse	yes	2+

Packed bed reactors contain spheres, plastic baffles, or wood bats as media. Anaerobic bacteria grow on the media and feed on soluble organics as waste slowly flows through the media. ***Attached growth reactors***, a kind of packed bed system, are typically used for dilute soluble wastes not typical of manures; however, they could be considered for treatment of screened flushed manure and milking parlor process water. Anaerobic bacteria are retained in the digester either on the surface of packing materials or in a sludge blanket and digest material from solution as it passes by.

UASB digesters are fed waste water from the bottom and a continuous flow of waste moves through an expanded layer of sludge. The design promotes the formation of sludge particles that are heavier than water and stay in suspension in the digester. Both digester types concentrate large microbial masses and rapidly decompose soluble waste. The advantage of high throughput due to short retention times is offset by the fact that tank volume is substantially reduced compared to other digester designs and the amount of equipment necessary for operation is also substantially increased, resulting in high capital costs. [1]

Anaerobic sequencing batch reactors are currently experimental. An ASBR treats waste in small batches. Waste and settled sludge are pumped into the partially filled reactor, and the batch is mixed for several hours before the particulates are allowed to settle. Soluble organics decompose readily while solids settle and decompose over a longer period. Treated effluent is removed from the top of the reactor while excess sludge is taken from the bottom. This process is then repeated. This technology requires significant process control and is equipment intensive. High microbial populations, however, allow for rapid decomposition of solubles, and the reactor design allows the retention of solids for later decomposition. [1]

High solids digesters have been used with sorted municipal solid waste (MSW) with 20 to 35 percent total solids. Flow through and batch systems have been built and demonstrated in the U.S. and Europe. This technology is in the demonstration stage in the U.S. [2] The majority of systems tested have been small, pilot-scale batch systems that have modified conventional anaerobic digestion technology (typically plug flow or complete mix) to accommodate the higher influent solids loading rates. In Europe, full-scale commercial systems are available in France and Belgium for the processing of MSW and are known as anaerobic composting systems. These are called the VALORGA and DRANCO systems, respectively. [2] These systems have not been demonstrated in the digestion of animal manures. There may be rheological limitations in the high solids digestion of cow manures, since at concentrations greater than 14 percent total solids, cow manure may not be easily pumped with conventional pumps. At concentrations greater than 18 percent total solids, cow manure does not contain free water and liquid recycle is not possible. It may be possible to develop a continuous feed high solids digester for animal manure. There are, however, no known pilot studies, and batch operation is beyond the ability of a typical farm. [1]

Anaerobic contact reactors are very similar to complete mix reactors. One difference is the presence of a settling tank in the anaerobic contact reactor, which helps maintain high microbial populations. This difference results in the reduction of the hydraulic retention time from a minimum of 15 days for a complete mix reactor to a minimum of 2 days for an anaerobic contact reactor.

Specific technology description and project lead time parameters are provided on the Electric Generation Characterization Worksheet for biomass anaerobic fermentation at the end of this section.

COMMERCIAL AVAILABILITY

Technology Maturity:
Lagoon, plug flow, and complete mix digester technologies are commercially available and have been demonstrated for use with agricultural wastes. The packed bed reactor, UASB, and anaerobic contact reactor are commercially available for treating municipal and industrial wastewater but have not been fully demonstrated with livestock manures. ASBR and high solids technologies are in the demonstration phase of their development. High solids anaerobic digestion process is commercially available for treatment of the organic fraction of municipal solid waste. Examples of biogas energy projects in California and abroad follow.

Under the California Energy Commission's State Agricultural and Forestry Residue Utilization Act Program, several anaerobic digestion projects were evaluated. The Knudsen and Sons project in Chico, California, treated wastewater that contained organic matter from fruit-crushing and wash-down in a covered and lined lagoon. The biogas produced was burned in a boiler.

At the Langerwerf Dairy in Durham, California, cow manure is scraped and fed into a plug flow digester. The biogas produced is used to fire a 85 kilowatt (kW) gas engine. The engine operates at a 35 kW capacity level and drives a generator to produce electricity. Electricity and heat generated offset all dairy energy demand. The system has been in operation since 1982.

At a similar project started in 1972 at Royal Farms No. 1 in Tulare, California, swine manure is slurried and sent to a hypalon-covered lagoon for biogas generation. The collected biogas fuels a 70 kW engine-generator and a 100-kW engine-generator. The electricity generated on-farm is able to meet monthly electric and heat energy demand except in the month of March. Given the success of this project, three other swine farms (Sharp Ranch, Fresno and Prison Farm) have also installed floating covers on lagoons. [3]

BioRecycling Technologies, Inc. (BTI) of Fontana, California, has designed and built several on-farm anaerobic fermentation plants in Israel, Italy, and Yugoslavia. BTI is currently in the planning and design stages for a facility near Chino, California to process manure from about 40,000 cows. [4]

Other methane generation facilities that have come on-line since 1982 include a 500 kW unit for the City of Turlock; a 1,050 kW unit at J.R. Wood Inc.; and a 1,500 kW unit for the City of Oxnard. [5] A 40 kW unit at CalPoly is scheduled to go on-line in Fall 1996.

Biogas has also been tested in dual fuel engines in Chile. The results indicate a five percent increase in fuel consumption, 50 percent less NOx than diesel, increased amounts of hydrocarbons and carbon monoxide, and no knocking. [6] The study concluded that biogas is a suitable fuel for internal combustion engines in the absence of corrosive agents.

Existence of Supplier(s):
Anaerobic digestion uses readily available technology which, in many cases, is constructed on-site. Equipment includes holding tanks or lagoons, mixing tanks, piping, covers, and other vessels for reactions. High operating pressures are not encountered and equipment requirements are minimal. Frequent overhauls resulting from the corrosive action of hydrogen sulfide in the biogas are a concern with the engine-generator set, but can be prevented with proper gas filtering and engine maintenance.

Competitive Cost:
Anaerobic digestion systems on livestock farms usually have zero fuel cost. Animal waste must be collected and held in certain storage areas such as liquid waste holding lagoons, regardless of whether anaerobic digesters are used. After installation, a digester becomes part of the waste treatment system, taking the place of the waste storage facility.

Certain anaerobic digestion systems coupled with an engine generator set are cost competitive when used to offset electricity purchases in agricultural settings such as dairies and hog farms. Given the current avoided cost of electricity, sale of electricity generated by these systems back to the utilities is not a profitable venture. Economic analyses performed on 12 existing farm-scale anaerobic digesters indicate that plug flow digesters and covered lagoon digesters have economic merit. The complete mix digesters, however, are not cost competitive for on-farm applications. The economic statistics were calculated using surveyed operational data on those 12 farms. Tables 8.3-2 and 8.3-3 list operational and economic indicators for the three types of reactors.

Purchase Order and Construction Lead Time:
Each application is unique to a particular site, and most systems can be easily constructed on-site due to their small size. It is expected that off-the-shelf packages could be put together using existing equipment. Based upon a designer’s estimate, a lead time of 12 months was used in the economic analyses for an on-farm digestion system. [3]

Conclusion:
Most anaerobic digestion technologies are commercially available. Where unprocessed wastes cause odor and water pollution such as in large dairies, anaerobic digestion reduces the odor and liquid waste disposal problems and produces a biogas fuel which can be used for process heating and/or electricity generation.

Methane digestion is a mature technology in municipal wastewater treatment, and many wastewater treatment plants use the methane as fuel for producing electricity. This technology is also commercially available using manure as a feedstock, and several successful applications of this technology on livestock farms have proven that properly designed systems that are regularly

TABLE 8.3-2

INSTALLATION AND OPERATIONAL DATA FOR TWELVE ON-FARM DIGESTER SYSTEMS

Farm Name	Dairy Herd Size	System Type	Gas Production (cubic feet/day) (60% CH4)[a]	Capital Cost[b] ($)	Annual O&M Cost[b] ($)	Electricity Production[a] (10^3 kWh/yr)	Thermal Prod. (gallon propane/yr)[a]	Electricity Offset[b] ($/yr)	Thermal Offset[b] ($/yr)	Year in Operation Since	Other Benefits ($/yr)[c]
Mason Dixon	2,285	Plug flow 1	120,000	260,000	15,000	1500-1700	NA	92,000	0	1979, 81, 85	5,000
Agway	500	Slurry tank	12,000	175,000	3,650	145-150	8000-8400	17,500	5,700	1981	10,000
Fairgrove	700	Plug flow 2	35,000-50,000	200,000	10,407	435-620	NA	40,000	0	1981	18,000
Foster	600	Plug flow 3	28,000	300,000	10,000	NA	NA	40,000	0	1982	40,000
Langerwerf	400	Plug flow 4	30,000	200,000	10,000	300	NA	36,000	15,000	1982	17,000
Arizona	3,000	Plug flow 5	115-120 K	300,000	21,500	1300-1700	NA	140,000	0	1983	0
Oregon	300	Loop	15,000	120,000	3,750	200-250	NA	13,500	1,200	1983	0
Grant	750	Mixed tank 1	29,000	185,000	12,000	375-400	NA	26,000	0	1984	12,000
Cooperstown	490	Mixed tank 2	23,625	500,000	8,000	NA	17000-18000	0	10,600	1985	25,000
Royal	Swine	Covered lagoon 1	70,000 (75% CH4)	100,000	1,000	700-750	NA	43,500	5,000	1982	0
Lou	Swine	Covered lagoon 2	35,200	16,000	500	NA (Gas flared)	4400-4700	0	2,500	1992	0
Martin	Swine	Covered lagoon 3	389,000	85,128	2,500	150-175	NA	10,625	0	1994	0

Source: [7]

TABLE 8.3-3

ECONOMIC INDICATORS OF THREE TYPES OF ON-FARM DIGESTERS

	REACTOR TYPES		
Profitability Index	***Plug Flow***	***Complete Mix***	***Covered Lagoon***
Cost Effectiveness Index (CEI)[a]	0.72	1.13	0.62
Net Present Value[b] ($)	158,045	-20,948	77,563
Internal Rate of Return (%)	15.1	7.0	16.9
Pay-back Period[b] (years)	9.1	24.5	8.0

[a] CEI is the annualized cost of a system divided by its annual revenue and energy savings. A CEI of less than 1.00 indicates a profitable venture

[b] Real discount rate = 8.0%.

Source: [4]

maintained by the farmer can be profitable. Each hog farm, dairy or feedlot requires a specially designed system which takes into account animal type, size of operation, manure-handling system, and climate.

RESEARCH AND DEVELOPMENT GOALS (Significant Impact)

Several issues are hampering the deployment of anaerobic digestion technologies. Technical issues include cold winter conditions reducing biogas yield from unheated digesters, requiring heating of the digester; difficulty in integrating existing waste collection systems into the digester systems; mechanical handling of feedstock feeding, and the discharging of effluent from a high-solids anaerobic digestion process.

Reduced Capital Costs: (Significant Impact)
Installation: Anaerobic digestion plant equipment is expensive, especially for small- to medium-sized installations. Improvements in plant design and materials are required. The covered lagoon digester has become popular for on-farm use because lagoons are already used for waste water treatment and storage on livestock farms, and because they cost less than the conventional anaerobic reactors used for waste water treatment.

Resource Development: There is a considerable biomass resource in livestock manure that can be used in anaerobic digestion processes. Depending on the manure collection techniques used, each farm will have its own optimum conversion requirements, so each process must be developed independently.

Improved Performance: (Significant Impact)
Availability/Reliability/Durability: Additional work is needed to characterize the performance of high solids, attached growth (packed) and anaerobic sequencing batch reactors using agricultural wastes.

Lower Operational and Maintenance Costs: (Significant Impact)
Fuel Modification: Incorporation of anaerobic digestion systems into the design of livestock operations such as dairies would reduce the capital costs associated with the modification of manure management systems when anaerobic digesters are added as an afterthought. Front-end design would also reduce the operation and maintenance costs of anaerobic digestion systems.

Development of high efficiency, low cost gas clean-up systems to remove the hydrogen sulfide from the biogas would help reduce the frequency of engine overhauls and thereby lower O&M costs. Low cost gas clean-up systems are important since high capital costs are a barrier to the deployment of this technology.

Reduced Environmental Impacts: (Significant Impact)
Post-Event Clean-Up: Markets for waste byproducts need to be developed. For example, additional revenue streams from the sale of digested solids to gardeners for use as compost would go a long way in reducing the economic barriers to this technology.

DEPLOYMENT ISSUES (Potential "Show Stopper")
The barriers preventing the deployment of energy generating facilities utilizing biomass through anaerobic digestion are institutional and economic. These include high capital costs for a given throughput, the ability of the farmer to obtain financing for such systems, unfavorable electric utility rate structures, and a history of poor performance.

Environmental Constraints: (Significant Impact)
Water Pollution: Where unlined covered lagoon digesters are used, this technology may impact groundwater quality by leaching waste water into the local aquifer, depending upon many site-related factors such as soil porosity and the height of the water table (especially during the rainy season).

Financial Constraints: (Potential "Show Stopper")
Availability of Financing: The barrier to the financing of anaerobic digester systems is that few, if any, credit sources will recognize the revenue stream from the system. Nontraditional financing such as lease financing is limited to portions of the system that can be removed and resold. Venture capital is available, but the interest rates charged by these firms is typically prohibitively high. [1]

High Capital Cost: Front-end engineering costs to assure plant permitting, fuel collection and handling, digester construction, engine/generator set, and emission control equipment are high. Most profitable systems will cost in excess of $200,000, a sizable investment that farmers are hesitant to make because of the uncertain reputation of these systems.

Utility Integration Constraints: (Potential "Show Stopper")
Undependable Avoided Cost Contracts: Small power generators are paid at very low avoided costs, made to undergo exhaustive and time consuming review processes, required to purchase expensive intertie equipment, and are bound by complex contracting procedures that are not accommodating to independent power producers. [3]

The major barrier is the demand charge within composite electric rates billed to farms. Demand is the highest rate of electricity consumption measured over any 15-minute period during a month. A good farm biogas system is operational 85 percent of the time, while an excellent one is operational 92 percent of the time. Demand charges, however, are recorded in any month the farm engine/generator is not operational 99.97 percent of the time. This level of operation is virtually impossible over any extended period because regular maintenance requirements such as oil changes often exceed 15 minutes. As an example, a farm may pay an average of 0.09 $/kWh for electricity. The farm, however, is billed 0.045 $/kWh for energy use, 0.04 $/kW for demand and $0.005 as a basic service charge. It is easy to see how demand charges can become a substantial portion of the bill when the biogas system is not in operation. [1]

Socioeconomic Constraints: (Potential "Show Stopper")
Poor Public Opinion: Bad reputation due to poor experience with digesters in the past and consolidation within the farming communities has prevented the investment in and proliferation of biogas energy systems.

REFERENCES

1. Mark Moser, RCM Digesters, "Biogas Combustion Technologies," document in preparation for the California Energy Commission, Sacramento, Calif.

2. M. Kayhanian *et al*., ***Energy Recovery from MSW Using a High Solids Anaerobic Digestion/Aerobic Composting Process***, Vol. 1, California Energy Commission Publication # P500-90-027CN, Sacramento, Calif., 1995.

3. Interview with Mark Moser, President, RCM Digesters, July 1995.

4. P. Lusk, Resource Development Associates, ***Methane Recovery from Animal Manures: A Current Opportunities Casebook***, National Renewable Energy Laboratory, Golden, Colo., December 1994, pp. 53-68.

5. H. Isaacson, T. Hayes, and D. Chynoweth, "Pipeline Quality Methane from Biomass and Wastes," ***Proceedings from the Eleventh Energy Technology Conference***, Government Institutes, Inc., Wash. D.C., August 1984, pp. 1294-1305.

6. R. Hodam and R. Williams, "Gasification: Industrial State of the Art," ***Proceedings of the Ninth Energy Technology Conference***, Government Institutes, Inc., Wash. D.C., June 1982.

7. James Young, ***An Economic Analysis of Biogas Recovery Systems on California Farms***, Research and Development Office, California Energy Commission, Sacramento, Calif., August 1995.

Electrical Generation Technologies Economic Input Worksheet

(All Cost Data in Real Terms and 1993 dollars)

Technology Number and Name:	8.3 Anaerobic Digester w/Engine Generator
Assumed Year of Operation:	2000

Note: Where a range of costs is listed, the low cost value precedes the high cost value.

Engineering Factors

Installed Net Capacity:	80 - 350 kW	
Heat Rate (Btu/kWh-HHV):	15000	
Plant Life (years):	20	
Duty Cycle (Capacity Factor):	Baseload	75% - 60%

Economic Factors

Instant Capital Cost for assumed year of operation (1993 $/kW): 1542 to 2500

Years Prior to Operation:	-5	-4	-3	-2	-1	Year of Operation
Capital Outlay (%):	0%	0%	0%	0%	0%	100%

O&M (including consumables): Fixed ($/kW-yr): 110 to 120

Variable (cents/kWh): 1 Escalation Rate (%/yr): 0.73%

Escalation of Capital Prior to Operating Date (%): 0.00%

Insurance Rate (% of capital cost/yr): Included

Fuel: Type: Biomass

Cost ($/mmBtu): 1.69 - 2.14 Esc. Rate (%/yr): ???

	Method	Duration (years)
Federal Depreciation Rate:	MACRS-DB	20
State Depreciation Rate:	SYD	28

Capital Depreciation Base (% of Capital Cost): 85%

% of Capital Cost Subject to Sales Tax: 50%

Data for Solar Technologies:

Solar Fraction (hours/year): N/A

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:36 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY:	8.3 Anaerobic Digester w/Engine Generator
HIGH/LOW CASE:	Low
PEAKING/BASELOAD:	Baseload
PLANT CAPACITY:	80 - 350 kW
END USER:	IOU

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	2.6	173.6	3.4	224.0	4.3	279.2
O&M:	3.0	197.2	3.9	255.9	4.9	319.0
Fuel:	2.5	166.5	3.3	216.1	4.1	269.4
TOTAL:	8.2	537.3	10.6	696.0	13.2	867.7

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	0.0%	0%	100%
Interest During Construction:			8.88%	5.50% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	75%	6570 Hrs
Plant Life (Years):	20	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	110.00 (Base Year)	
Variable (Cents/kWh):	1.000 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	1.69 (Base Year)	
Heat Rate (HR) (Btu/kWh):	15000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	20

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	1	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	10.42%	7.00% (rea
Cost of Preferred Stock (kp):	0.00%	0.00% (rea
Cost of Debt Financing (kd):	7.33%	4.00% (rea
Percent Common Equity (C/V):	50.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	50.00%	
Weighted Cost of Capital:	8.88%	5.50% (rea

DEBT COVERAGE:

Coverage Ratio: CR = 4.15

FIXED CHARGE RATE:

FCR: 0.140 0.105 (real

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	20 Yrs
	SL	Yrs
	Base	100.00%
State:	SYD	28 Yrs
	SL	Yrs
	Base	100.00%
Capital Depreciation Base:		85.00%
In-service month (1..12):		6

PLANT CAPITAL COST ($/kW):	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1542	
Total Plant Cost:	1598	1992

ESCALATION RATES:	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 06-Aug-96
RUN TIME: 08:44 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.3 Anaerobic Digester w/Engine Generator
HIGH/LOW CASE: High
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 80 - 350 kW
END USER: IOU

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	5.4	281.4	6.9	363.2	8.6	452.7
O&M:	3.7	193.7	4.8	251.3	6.0	313.3
Fuel:	3.2	168.7	4.2	218.9	5.2	272.9
TOTAL:	12.2	643.8	15.9	833.4	19.8	1,039.0

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	0.0%	0%	100%
Interest During Construction:			8.88%	5.50% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	60%	5256 Hrs
Plant Life (Years):	20	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	120.00	(Base Year)
Variable (Cents/kWh):	1.000	(Base Year)
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	2.14	(Base Year)
Heat Rate (HR) (Btu/kWh):	15000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	20

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	1	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	10.42%	7.00% (real)
Cost of Preferred Stock (kp):	0.00%	0.00% (real)
Cost of Debt Financing (kd):	7.33%	4.00% (real)
Percent Common Equity (C/V):	50.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	50.00%	
Weighted Cost of Capital:	8.88%	5.50% (real)

DEBT COVERAGE:

Coverage Ratio: CR = 4.15

FIXED CHARGE RATE:

FCR: 0.140 0.105 (real)

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	20	Yrs
	SL		Yrs
	Base	100.00%	
State:	SYD	28	Yrs
	SL		Yrs
	Base	100.00%	
Capital Depreciation Base:		85.00%	
In-service month (1..12):		6	

PLANT CAPITAL COST ($/kW):

	1993 Base Year	2000 Nominal
Overnight Construction Cost:	2500	
Total Plant Cost:	2591	3230

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:36 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.3 Anaerobic Digester w/Engine Generator
HIGH/LOW CASE: Low
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 80 - 350 kW
END USER: Municipal

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	1.5	100.3	2.3	151.0	2.9	188.3
O&M:	3.0	198.0	4.0	261.2	5.0	325.7
Fuel:	2.5	166.5	3.3	219.8	4.2	274.0
TOTAL:	7.1	464.9	9.6	632.0	12.0	788.0

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	0.0%	0%	100%
Interest During Construction:			7.02%	3.70% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	75%	6570 Hrs
Plant Life (Years):	20	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	110.00 (Base Year)	
Variable (Cents/kWh):	1.000 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	1.69 (Base Year)	
Heat Rate (HR) (Btu/kWh):	15000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	20

FLAGS:

	FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1 Cost of Capital
Normalized (1) vs. Flow Through (0):	1 Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):		0.00%	0.00% (real)
Cost of Preferred Stock (kp):		0.00%	0.00% (real)
Cost of Debt Financing (kd):		7.02%	3.70% (real)
Percent Common Equity (C/V):		0.00%	
Percent Preferred Stock (P/V):		0.00%	
Percent Debt Financing (D/V):		100.00%	
Weighted Cost of Capital:		7.02%	3.70% (real)

DEBT COVERAGE:

Coverage Ratio:	CR =	2.12	

FIXED CHARGE RATE:

FCR:		0.095	0.061 (real)

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			0.00%
Marginal State Income Tax Rate (t):			0.00%
Effective Marginal Income Tax Rate (T'):			0.00%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			0.00%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	0 Yrs
	SL	Yrs
	Base	100.00%
State:	SYD	0 Yrs
	SL	Yrs
	Base	100.00%
Capital Depreciation Base:		0.00%
In-service month (1..12):		6

PLANT CAPITAL COST ($/kW):	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1542	
Total Plant Cost:	1598	1992

ESCALATION RATES:	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:54 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY:	8.3 Anaerobic Digester w/Engine Generator
HIGH/LOW CASE:	High
PEAKING/BASELOAD:	Baseload
PLANT CAPACITY:	80 - 350 kW
END USER:	Municipal

	CONSTANT (REAL) DOLLARS		NOMINAL REFERENCE YEAR DOLLARS			
	1993 (Base Yr)		1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	3.1	162.7	4.7	244.9	5.8	305.3
O&M:	3.7	194.5	4.9	256.6	6.1	319.9
Fuel:	3.2	168.7	4.2	222.6	5.3	277.5
TOTAL:	10.0	525.8	13.8	724.1	17.2	902.7

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	0.0%	0%	100%
Interest During Construction:			7.02%	3.70% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	60%	5256 Hrs
Plant Life (Years):	20	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	120.00 (Base Year)	
Variable (Cents/kWh):	1.000 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	2.14 (Base Year)	
Heat Rate (HR) (Btu/kWh):	15000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	20

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	1	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	0.00%	0.00% (real)
Cost of Preferred Stock (kp):	0.00%	0.00% (real)
Cost of Debt Financing (kd):	7.02%	3.70% (real)
Percent Common Equity (C/V):	0.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	100.00%	
Weighted Cost of Capital:	7.02%	3.70% (real)

DEBT COVERAGE:

Coverage Ratio: CR = 2.12

FIXED CHARGE RATE:

FCR: 0.095 0.061 (real)

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			0.00%
Marginal State Income Tax Rate (t):			0.00%
Effective Marginal Income Tax Rate (T'):			0.00%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			0.00%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	0 Yrs
	SL	Yrs
	Base	100.00%
State:	SYD	0 Yrs
	SL	Yrs
	Base	100.00%
Capital Depreciation Base:		0.00%
In-service month (1..12):		6

PLANT CAPITAL COST ($/kW):	1993 Base Year	2000 Nominal
Overnight Construction Cost:	2500	
Total Plant Cost:	2591	3230

ESCALATION RATES:	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:36 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.3 Anaerobic Digester w/Engine Generator
HIGH/LOW CASE: Low
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 80 - 350 kW
END USER: NUG

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	3.9	253.9	4.6	304.0	5.8	379.0
O&M:	3.0	195.1	3.7	242.1	4.6	301.8
Fuel:	2.5	166.5	3.1	206.7	3.9	257.7
TOTAL:	9.4	615.5	11.5	752.8	14.3	938.5

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	0.0%	0%	100%
Interest During Construction:			14.50%	10.95% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:

Year Commercial Operation:	2000	
Plant Capacity Factor (CF):	75%	6570 Hrs
Plant Life (Years):	20	

OPERATING PARAMETERS (Base Year $):

Operating & Maintenance Costs (O&M):		
Fixed ($/kW-Yr):	110.00 (Base Year)	
Variable (Cents/kWh):	1.000 (Base Year)	
Fuel Type:	Biomass	
Fuel Costs (F) ($/MBtu):	1.69 (Base Year)	
Heat Rate (HR) (Btu/kWh):	15000	
Solar Fraction:	0.00%	0 Hrs

ECONOMIC PARAMETERS:

Base Year (Dollars):	1993
Inflation Rate:	3.20%
Investment Period (Years):	20

FLAGS:

		FOR:
Exclude (1) vs. Include (0) Interest Tax Shelter:	1	Cost of Capital
Normalized (1) vs. Flow Through (0):	0	Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	24.98%	21.10% (real)
Cost of Preferred Stock (kp):	0.00%	0.00% (real)
Cost of Debt Financing (kd):	10.01%	6.60% (real)
Percent Common Equity (C/V):	30.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	70.00%	
Weighted Cost of Capital:	14.50%	10.95% (real)

DEBT COVERAGE:

Coverage Ratio: CR = 2.35

FIXED CHARGE RATE:

FCR: 0.190 0.153 (real)

TAX PARAMETERS:

Marginal Federal Income Tax Rate (T):			35.00%
Marginal State Income Tax Rate (t):			9.30%
Effective Marginal Income Tax Rate (T'):			41.05%
State Sales Tax Rate (ts):	7.25%	50%	3.63%
Other Taxes (Property) (to):			1.09%
Federal Investment Tax Credit (ITC):			0.00%
Federal Energy Tax Credit (FETC):			0.00%
State Energy Tax Credit (SETC):			0.00%

DEPRECIATION:

Federal:	MACRS-DB	20	Yrs
	SL		Yrs
	Base	100.00%	
State:	SYD	28	Yrs
	SL		Yrs
	Base	100.00%	
Capital Depreciation Base:		85.00%	
In-service month (1..12):		6	

PLANT CAPITAL COST ($/kW):

	1993 Base Year	2000 Nominal
Overnight Construction Cost:	1542	
Total Plant Cost:	1598	1992

ESCALATION RATES:

	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.

ELECTRIC GENERATION TECHNOLOGY

RUN DATE: 31-Jul-96
RUN TIME: 10:54 AM

LEVELIZED COST OF ELECTRICITY OVER PROJECT LIFE (FROM OPERATING YEAR TO END OF LIFE)

TECHNOLOGY: 8.3 Anaerobic Digester w/Engine Generator
HIGH/LOW CASE: High
PEAKING/BASELOAD: Baseload
PLANT CAPACITY: 80 - 350 kW
END USER: NUG

	CONSTANT (REAL) DOLLARS 1993 (Base Yr)		NOMINAL REFERENCE YEAR DOLLARS 1993 (Base Yr)		2000 (Oper. Yr)	
	Cents/kWh	$kW-Yr	Cents/kWh	$/kW-Yr	Cents/kWh	$/kW-Yr
Capital:	11.1	584.1	12.6	664.6	15.8	828.5
O&M:	3.6	190.4	4.4	230.3	5.5	287.2
Fuel:	3.2	168.7	3.9	204.2	4.8	254.5
TOTAL:	17.9	943.1	20.9	1,099.1	26.1	1,370.2

PLANT CAPITAL COST:

Year Prior to Year of Construction:	-5	-4	-3	-2	-1	0
Cash Flows (%):	0%	0%	0.0%	0.0%	0%	100%
Interest During Construction:			18.47%	14.80% (Real)		
Escalation of Capital Cost Prior to Operation:			3.20%	0.00% (Real)		

PLANT OPERATION PARAMETERS:
- Year Commercial Operation: 2000
- Plant Capacity Factor (CF): 60% 5256 Hrs
- Plant Life (Years): 20

OPERATING PARAMETERS (Base Year $):
- Operating & Maintenance Costs (O&M):
  - Fixed ($/kW-Yr): 120.00 (Base Year)
  - Variable (Cents/kWh): 1.000 (Base Year)
- Fuel Type: Biomass
- Fuel Costs (F) ($/MBtu): 2.14 (Base Year)
- Heat Rate (HR) (Btu/kWh): 15000
- Solar Fraction: 0.00% 0 Hrs

ECONOMIC PARAMETERS:
- Base Year (Dollars): 1993
- Inflation Rate: 3.20%
- Investment Period (Years): 20

FLAGS: | **FOR:**
- Exclude (1) vs. Include (0) Interest Tax Shelter: 1 Cost of Capital
- Normalized (1) vs. Flow Through (0): 0 Accounting

FINANCIAL PARAMETERS (After Income Tax):

DISCOUNT RATE (Cost of Capital):

Cost of Common Equity (ke):	24.98%	21.10% (real)
Cost of Preferred Stock (kp):	0.00%	0.00% (real)
Cost of Debt Financing (kd):	11.97%	8.50% (real)
Percent Common Equity (C/V):	50.00%	
Percent Preferred Stock (P/V):	0.00%	
Percent Debt Financing (D/V):	50.00%	
Weighted Cost of Capital:	18.47%	14.80% (real)

DEBT COVERAGE:
- Coverage Ratio: CR = 3.63

FIXED CHARGE RATE:
- FCR: 0.257 0.218 (real)

TAX PARAMETERS:
- Marginal Federal Income Tax Rate (T): 35.00%
- Marginal State Income Tax Rate (t): 9.30%
- Effective Marginal Income Tax Rate (T'): 41.05%
- State Sales Tax Rate (ts): 7.25% 50% 3.63%
- Other Taxes (Property) (to): 1.09%
- Federal Investment Tax Credit (ITC): 0.00%
- Federal Energy Tax Credit (FETC): 0.00%
- State Energy Tax Credit (SETC): 0.00%

DEPRECIATION:

Federal:	MACRS-DB	20	Yrs
	SL		Yrs
	Base	100.00%	
State:	SYD	28	Yrs
	SL		Yrs
	Base	100.00%	
Capital Depreciation Base:		85.00%	
In-service month (1..12):		6	

PLANT CAPITAL COST ($/kW):	1993 Base Year	2000 Nominal
Overnight Construction Cost:	2500	
Total Plant Cost:	2591	3230

ESCALATION RATES:	Actual:	Real:
Operating & Maintenance (Eo):	3.95%	0.73%
Fuel (Ef):	3.20%	0.00%
Capital Construction (Ec):	3.20%	0.00%

Please note: Some of the columns of numbers in the levelized cost box above may not precisely add up because of rounding inconsistencies in the computer model.